

REPORT OF THE ELECTRICITY COMMITTEE

This report covers significant electric regulatory orders issued by the Federal Energy Regulatory Commission (Commission or FERC) as well as several court issuances of national import in 2018.*

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I. RULEMAKINGS AND POLICY STATEMENTS

A. *Grid Resilience in Regional Transmission Organizations and Independent System Operators*

On January 8, 2018, FERC issued an *Order Terminating Rulemaking Proceeding, Initiating New Proceeding, and Establishing Additional Procedures* in response to a rule proposed by the Secretary of the Department of Energy (DOE) to establish a tariff mechanism for the purchase of energy from eligible resilient resources and the “recovery of costs and a return on equity” (ROE) for such resources through a “resilience rate.”¹ The Commission terminated the DOE’s proposed rule on the basis it did not meet the requirements of section 206 of the Federal Power Act (FPA).² First, the proposed rule and associated record evidence did not demonstrate that the existing tariffs of the regional transmission organizations (RTOs) and independent system operators (ISOs) are unjust, unreasonable, and unduly discriminatory or preferential.³ The Commission emphasized that

1. Grid Resilience in Regional Transmission Organizations and Independent System Operators, 162 F.E.R.C. ¶ 61,012 at PP 1-2 (2018).

2. *Id.* at P 14.

3. *Id.* at P 15.

comments submitted by the RTOs/ISOs did not reveal any past or planned generator retirements that threatened grid resilience.⁴ Second, the record did not support a finding that the proposed rule allowing certain eligible resources to receive cost-of-service rates would be just, reasonable, and not unduly discriminatory or preferential.⁵

However, given the importance of resilience challenges, the Commission initiated a new proceeding to: 1) develop a common understanding of what bulk power system resilience means and requires; 2) understand how each RTO/ISO assesses resilience; and 3) to determine whether additional Commission action on resilience is required.⁶ The Commission sought comments from RTOs/ISOs and stakeholders regarding those primary objectives and sub-issues.⁷ The Commission emphasized that bulk power system resilience will remain a priority.⁸

B. Revised Critical Infrastructure Protection Reliability Standard CIP-003-07

On April 19, 2018, FERC issued a Final Rule, Order No. 843, approving revised Reliability Standard CIP-003-07.⁹ The standard responded to directives issued by the Commission in Order No. 822,¹⁰ which had approved the previous version of the standard, CIP 003-06. In the Order, FERC approved modifications that the North American Electric Reliability Corporation (NERC) had submitted in response to the directives in Order No. 822, finding that the modifications contained in Reliability Standard CIP-003-07 improved the existing standard by (1) clarifying the obligations pertaining to electronic access control for low impact [Bulk Electric System] Cyber Systems; (2) adopting mandatory security controls for transient electronic devices; . . . and (3) requiring responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances related to low impact BES Cyber Systems.¹¹ Order No. 843 also approved NERC's proposed revised definitions¹² and directed NERC "to develop and submit modifications to Reliability Standard CIP-003-7 to include an explicit requirement that responsible entities implement controls to mitigate the risk of malicious code that could result from third-party transient electronic devices."¹³ Finally, Order No. 843 rejected FERC's own proposal in the Notice of Proposed Rulemaking to require clear, objective criteria for electronic access controls for low impact BES Cyber Systems.¹⁴

4. *Id.*

5. *Id.* at P 16.

6. 162 F.E.R.C. ¶ 61,012 at PP 17-18.

7. *Id.* at PP 19-28.

8. *Id.* at P 28.

9. Final Rulemaking, *Revised Critical Infrastructure Protection Reliability Standard CIP-003-07*, 83 Fed. Reg. 17,913 (2018) (to be codified at 18 C.F.R. pt. 40).

10. Final Rulemaking, *Revised Critical Infrastructure Protection Reliability Standards*, 81 Fed. Reg. 4,177 (2016).

11. 83 Fed. Reg. 17,913, at 17,914.

12. *Id.*

13. *Id.* at 17,918.

14. *Id.* at 17,917.

C. Essential Reliability Services and the Evolving Bulk-Power System -- Primary Frequency Response

On February 15, 2018, FERC adopted, by Order No. 842, a final rule which modifies the *pro forma* Large Generator Interconnection Agreement (LGIA) and the *pro forma* Small Generator Interconnection Agreement (SGIA) to “require new large and small generating facilities, including both synchronous and non-synchronous, interconnecting through a LGIA or SGIA to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection.”¹⁵ The rule also establishes certain uniform minimum operating requirements, “including maximum droop and deadband parameters and provisions for timely and sustained response.”¹⁶ The Commission adopted the final rule because of “the effect upon primary frequency response from the ongoing changes to the nation’s generation resource mix” and because technical advances have enabled variable energy resources to provide primary frequency response.¹⁷

The rule applies “to newly interconnecting generation facilities that execute, or request the unexecuted filing of, an LGIA or SGIA,” and “to existing large and small generating facilities that take any action that requires the submission of a new interconnection request that results in the filing of an executed or unexecuted interconnection agreement on or after the effective date” of the Final Rule.¹⁸ The rule does not apply to “existing generating facilities that do not submit new interconnection requests that result in an executed or unexecuted interconnection agreement at this time,” “a subset of combined heat and power (CHP) facilities, or generating facilities regulated by the Nuclear Regulatory Commission (NRC).”¹⁹ The rule identifies electric storage resources as a special case subject to “specific accommodations.”²⁰

D. Order No. 841, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators

On February 15, 2018, FERC adopted a Final Rule in Order No. 841, amending its regulations “to remove barriers to the participation by electric storage resources” in the capacity, energy, and ancillary service markets operated by RTOs and ISOs.²¹ FERC found existing RTO/ISO tariffs to be unjust and unreasonable

15. Order No. 842, *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response*, 162 F.E.R.C. ¶ 61,128 (2018) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 842].

16. *Id.* at P 1; *see also id.* at PP 56-58 (regarding maximum droop and deadband parameters), and 94 (regarding provisions for timely and sustained response).

17. *Id.* at P 19.

18. *Id.* at PP 2, 132.

19. *Id.* at P 2 and n.2; *see also id.* at PP 143 (regarding existing generating facilities not submitting new interconnection requests), 155 (regarding Combined Heat and Power facilities), and 202 (regarding NRC regulated facilities).

20. Order No. 842, *supra* note 15, at PP 176-77.

21. Order No. 841, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, III F.E.R.C. STATS. & REGS. ¶ 31,398, 83 Fed. Reg. 9,580 (2018) (to be codified at 18 C.F.R. pt. 35.28) [hereinafter Order No. 841].

because they failed to provide for participation by these resources in their markets,²² and required each RTO/ISO to revise its tariff to establish a participation model that recognizes the physical and operational characteristics of electric storage resources and facilitates their participation in RTO/ISO markets by (1) ensuring that a resource using the participation model is “eligible to provide all capacity, energy and ancillary services” that the resource is technically capable of providing; (2) ensuring that a resource using the participation model can be dispatched and “can set the wholesale market clearing price as both a wholesale seller and a wholesale buyer consistent with existing market rules that govern” when a resource can set price; (3) accounting “for the physical and operational characteristics of electric storage resources through bidding parameters or other means;” and (4) establishing a “minimum size requirement for participation in the RTO/ISO markets that does not exceed 100 kW.”²³ The Final Rule also requires RTOs/ISO tariffs to specify that the sale of electric energy from the RTO/ISO markets to an electric storage resource and the sale back of that stored energy to the markets must be at the wholesale locational marginal price (LMP).²⁴ FERC required each RTO/ISO to submit a compliance filing by December 3, 2018, and to implement the tariff revisions by December 3, 2019.²⁵ In the Final Rule, FERC declined to move forward at this time with rules regarding the participation by distributed energy resources in RTO/ISO markets, and initiated a Technical Conference in Docket No. RM18-9-000 to gather more information.²⁶

E. Reform of Generator Interconnection Procedures and Agreements

On April 19, 2018, the Commission issued Order No. 845, which sets forth its Final Rule amending the *pro forma* Large Generator Interconnection Procedures (LGIP) and *pro forma* LGIA for generators of more than 20 megawatts (MW).²⁷ The Final Rule implements ten specific reforms designed to improve certainty for interconnection customers, promote informed interconnection decisions and enhance the efficiency of the interconnection process.

To improve certainty for interconnection customers, the Final Rule:

- “removes the limitation that interconnection customers may only exercise the option to build a transmission provider’s interconnection facilities and stand-alone network upgrades when the transmission provider cannot meet the dates proposed by the interconnection customer;”²⁸ and

22. *Id.* at P 1.

23. *Id.* at PP 3-4.

24. *Id.* at P 4.

25. *Id.* at PP 6, 348.

26. Order No. 841, *supra* note 21, at P 5.

27. Order No. 845, *Reform of Generator Interconnection Procedures and Agreements*, 163 F.E.R.C. ¶ 61,043 (2018) (to be codified at 18 C.F.R. pt. 37) [hereinafter Order No. 845].

28. *Id.* at PP 3, 85.

- requires “transmission providers to establish interconnection dispute resolution procedures that allow a disputing party to unilaterally seek non-binding dispute resolution.”²⁹

To promote more informed interconnection decisions, the Final Rule:

- “requires transmission providers to outline and make public a method for determining contingent facilities;”³⁰
- “requires transmission providers to list the specific study processes and assumptions for forming the network models used for interconnection studies;”³¹
- “revises the definition of ‘Generating Facility’ to expressly include electric storage resources;”³² and,
- requires transmission providers to post certain interconnection study metrics to increase the transparency of interconnection study completion timeframes.³³

Finally, to improve the efficiency of the interconnection process, the Final Rule:

- allows interconnection customers “to request a level of interconnection service that is lower than their generating facility capacity;”³⁴
- “requires transmission providers to allow for provisional interconnection agreements that provide for limited operation of a generating facility prior to completion of the full interconnection process;”³⁵
- “requires transmission providers to create a process for interconnection customers to use surplus interconnection service at existing points of interconnection;”³⁶ and
- “requires transmission providers to set forth a procedure to allow transmission providers to assess and, if necessary, study an interconnection customer’s technology changes without affecting the interconnection customer’s queued position.”³⁷

F. Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators

In Order 844, the Commission determined that current RTO/ISO practices “with respect to reporting uplift payments and operator-initiated commitments,”

29. *Id.* at PP 3, 133.

30. *Id.* at PP 4, 199.

31. *Id.* at PP 4, 236-242.

32. Order No. 845, *supra* note 27, at PP 4, 275.

33. *Id.* at PP 4, 305.

34. *Id.* at PP 5, 367.

35. *Id.* at PP 5, 438-42.

36. *Id.* at PP 5, 467-84.

37. Order No. 845, *supra* note 27, at PP 5, 518-25.

and transmission constraint penalty factors are insufficiently transparent.³⁸ As such, per the Final Rule and revised regulations, each RTO/ISO must establish in its tariff monthly reporting obligations with respect to: (1) “uplift payments for each transmission zone, broken out by day and uplift category;” (2) “total uplift payments for each resource;” (3) “for each operator-initiated commitment, the size of the commitment, transmission zone, commitment reason, and commitment start time;” and (4) the “transmission constraint penalty factors used in its market software,” including the circumstances under which those factors can set [LMPs] and any process by which they can be changed.”³⁹ In the Final Rule, the Commission made certain modifications to the Notice of Proposed Rulemaking (NOPR) proposals to address disclosure of potentially commercially sensitive information, including the timing of the release of certain reports.⁴⁰

G. Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets

On December 20, 2018, the Commission issued a NOPR seeking comment on a proposal to modify the horizontal market power analysis required by market-based sellers participating in certain RTO and ISO markets.⁴¹ The NOPR is an outgrowth of the Commission’s Order No. 816 NOPR, which was issued July 19, 2014, and was intended to streamline and improve the market-based rate program’s processes and procedures.⁴²

Specifically, in any RTO/ISO administered energy, ancillary services or capacity markets subject to Commission-approved RTO/ISO monitoring and mitigation, the Commission proposes not to require market-based rate sellers to submit indicative screens for certain RTO/ISO markets and submarkets. In addition, for RTOs and ISOs that lack an RTO/ISO-administered capacity market, market-based rate sellers would be relieved of the requirement to submit indicative screens if their market-based rate authority is limited to sales of energy and/or ancillary services. To implement this proposal, the Commission would require market-based rate sellers in any initial application for market-based rate authority, a change in status filing, or an updated market power analyses to represent that, “[i]n lieu of submitting the indicative market power screens,” that the seller is relying on Commission-approved market monitoring and mitigation to address potential horizontal market power sellers may have in those markets.⁴³ A similar representation would be made by sellers in RTOs and ISOs that lack an RTO/ISO administered capacity market if their market-based rate authority is limited to wholesale sales of energy and ancillary services.⁴⁴

38. Order No. 844, *Uplift Cost Allocation and Transparency in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 163 F.E.R.C. ¶ 61,041 at P 1 (2018).

39. *Id.*

40. *Id.* at P 5.

41. Notice of Proposed Rulemaking, *Refinements to Horizontal Market Power Analysis for Sellers in Certain Regional Transmission Organization and Independent System Operator Markets*, 165 F.E.R.C. ¶ 61,268 (2018).

42. *Id.* at P 22.

43. *Id.* at P 43.

44. *Id.* at P 44.

H. Revisions to Parts 45 and 46 of the Commission's Regulations

On July 19, 2018, the Commission issued a NOPR proposing revisions to its regulations related to interlocking officers and directors. The revisions were prompted by the Commission Staff's 2016 Biennial Staff Memo Concerning Retrospective Analysis of Existing Rules.⁴⁵ The proposed changes are narrow in scope, reflecting statutory changes and industry comments.

I. Cyber Security Incident Reporting Reliability Standards

The Commission issued Order No. 848⁴⁶ on July 19, 2018, directing NERC to develop and submit modifications to NERC Reliability Standards to augment the mandatory reporting of Cyber Security Incidents. Currently, NERC Reliability Standard CIP-008-5⁴⁷ requires responsible entities to report to the Electricity Information Sharing and Analysis Center (E-ISAC) a Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity, also known as a Reportable Cyber Security Incident.

FERC directed NERC to broaden required reporting in the following ways:

- Require responsible entities to report compromises and attempts to compromise an Electronic Security Perimeter.⁴⁸
- Require responsible entities to report compromises and attempts to compromise Electronic Access Control or Monitoring Systems that perform the following functions: (1) authentication; (2) monitoring and logging; (3) access control; (4) interactive remote access; and (5) alerting.⁴⁹
- Require the following minimum information be included in reports: (1) the functional impact, where possible, that the Cyber Security Incident achieved or attempted to achieve; (2) the attack vector that was used; and (3) the level of intrusion that was achieved or attempted or as a result of the Cyber Security Incident.⁵⁰
- Establish reporting timelines based on a risk impact assessment and incident prioritization.⁵¹
- Require the reports continue to go to the E-ISAC but also the Department of Homeland Security Industrial Control Systems Cyber Emergency Response Team (ICS-CERT) or its successor.⁵²

45. *Revisions to Parts 45 and 46 of the Commission's Regulations*, 164 F.E.R.C. ¶ 61,032 at P 4 (2018).

46. Order No. 848, *Cyber Security Incident Reporting Reliability Standards*, 83 Fed. Reg. 36,727 (2018) [hereinafter Order No. 848].

47. NERC, RELIABILITY STANDARD CIP-008-5 – CYBER SECURITY – INCIDENT REPORTING AND RESPONSE PLANNING (2012), [https://www.nerc.com/pa/Stand/Project20086CyberSecurityOrder706Version5CIPStanda/CIP-008-5_clean_\(2012-0326\).pdf](https://www.nerc.com/pa/Stand/Project20086CyberSecurityOrder706Version5CIPStanda/CIP-008-5_clean_(2012-0326).pdf).

48. Order No. 848, *supra* note 46, at P 52.

49. *Id.* at P 54.

50. *Id.* at P 88.

51. *Id.* at P 89.

52. *Id.* at P 90. After issuance of Order No. 848, the National Cybersecurity and Communications Integration Center (NCCIC) realigned its organizational structure and integrated like functions previously performed independently by the ICS-CERT and the United States Computer Emergency Readiness Team. As such, NCCIC is the successor organization of the ICS-CERT. *See generally* U.S. DEP'T HOMELAND SEC., NATIONAL

- File with FERC an annual, anonymized summary of reports.⁵³

J. Implementation of Amended Section 203(a)(1)(B) of the FPA

On June 29, 2018, FERC issued a NOPR to amend its merger regulations to reflect statutory changes in section 203 of the FPA. Section 203(a)(1)(B) of the FPA was changed to add a \$10 million threshold on mergers subject to FERC's review and authorization.⁵⁴ Section 203(a)(7) was added to require that FERC promulgate a rule that requires FERC to be notified of any mergers that are in excess of \$1 million and do not require FERC review and authorization under section 203(a)(1)(B).⁵⁵ FERC's NOPR makes the necessary changes to 18 C.F.R. § 33.1(a)(1)(ii) and 18 C.F.R. § 33.12 to address the statutory changes in FPA sections 203(a)(1)(B) and additions in 203(a)(7), respectively.⁵⁶

K. Accounting and Ratemaking Treatment of Accumulated Deferred Income Taxes and Treatment Following the Sale or Retirement of an Asset

On November 15, 2018, FERC issued a Policy Statement⁵⁷ and NOPR⁵⁸ addressing the accounting and ratemaking treatment of Accumulated Deferred Income Taxes (ADIT) and federal tax expense allowance resulting from the reduction in corporate income tax rates from 35% to 21% for jurisdictional public utilities, natural gas pipelines, and oil pipelines following the Tax Cuts and Jobs Act of 2017 (Tax Cuts and Jobs Act).⁵⁹ As FERC explained, "ADIT arises from timing differences between the method of computing taxable income for reporting to the [Internal Revenue Service (IRS)] and the method of computing income for regulatory accounting purposes,"⁶⁰ such as through the use of accelerated depreciation. This timing difference results in lower tax expense paid to the IRS as compared to that paid by customers in rates to the utility early in the life of a depreciable rate base asset, a result which reverses in the latter years of asset's service life. As a result, the tax rate change will result in a reduction in a public utility's future tax liabilities and is thus considered excess ADIT. This excess ADIT is required to be returned to customers through a public utility's transmission rates.⁶¹

CYBERSECURITY AND COMMUNICATIONS INTEGRATION CENTER (NCCIC), <https://ics-cert.us-cert.gov/> (last visited Feb. 27, 2019).

53. Order No. 848, *supra* note 46, at P 90.

54. Notice of Proposed Rulemaking, *Implementation of Amended Section 203 of the FPA*, 83 Fed. Reg. 61,338, 61,339 (2018) (to be codified at 18 C.F.R. pt. 33).

55. *Id.*

56. *Id.* at 61,340-41.

57. Policy Statement, *Accounting and Ratemaking Treatment of Accumulated Deferred Income Taxes and Treatment Following the Sale or Retirement of an Asset*, 165 F.E.R.C. ¶ 61,115 (2015) [hereinafter Policy Statement]. As stated in the Policy Statement's title, it also establishes accounting and ratemaking treatment of ADIT following the sale or retirement of an asset.

58. Notice of Proposed Rulemaking, *Public Utility Transmission Rate Changes to Address Accumulated Deferred Income Taxes*, 165 F.E.R.C. ¶ 61,117 (2018).

59. Tax Cuts and Jobs Act, Pub. L. No. 115-97, 131 Stat. 2054 (2017) [hereinafter Tax Cut and Jobs Act].

60. Policy Statement, *supra* note 57, at P 3.

61. Order No. 144, *Tax Normalization for Certain Items Reflecting Timing Differences in the Recognition of Expenses or Revenues for Ratemaking and Income Tax Purposes*, F.E.R.C. STATS. & REGS. ¶ 30,254 (1981), *order on reh'g*, Order No. 144-A, F.E.R.C. STATS. & REGS. ¶ 30,340 (1982) [hereinafter Order No. 144].

FERC's Policy Statement addresses the treatment of excess ADIT for both accounting and ratemaking purposes, including the accounting of excess ADIT following the sale or retirement of an asset after the change in the federal income tax rate (*i.e.*, December 31, 2017). While the Policy Statement is applicable to public utilities, natural gas pipelines, and oil pipelines, with respect to public utilities, the Policy Statement: (1) confirms that for both accounting and ratemaking purposes, the amortization of any excess and/or deficient ADIT in Account 254 and 182.3 should be recorded as offsetting entries or Accounts 410.1 or 411.1, respectively; and (2) clarifies that following the sale or retirement of an asset after December 31, 2017, in cases for which excess or deficient ADIT did not transfer to the purchaser of the asset, any excess or deficient ADIT associated with an asset must continue to be amortized in seller's rates. Finally, the Policy Statement requires that public utilities must make certain disclosures with respect to excess ADIT in their FERC Form No.1 or 1-A filings.

In its Proposed Rule, FERC proposes to require all public utility transmission providers under an Open Access Transmission Tariff, a transmission owner tariff, or other rate schedule filed with FERC to revise those schedules to account for the tax rate reduction legislated by the Tax Cuts and Jobs Act.⁶² This requirement applies to both transmission formula rates and to stated rates established in periodic rate proceedings. Specifically, for public utilities with formula transmission rates, FERC proposes to require each public utility to (1) include an adjustment mechanism in the formula appropriately reflect excess or deficient ADIT in rate base;⁶³ (2) include a new permanent worksheet in the formula rate template to annually track information related to excess or deficient ADIT;⁶⁴ and (3) provide for the flow back of plant-based ADIT no more rapidly than over the life of the underlying asset. For stated rates, the Proposed Rule would require each public utility to separately adjust rate base and expense allowances to return any excess ADIT caused by the tax rate reduction to ratepayers.⁶⁵ FERC stated that these reforms are necessary to permit ratepayers to receive the benefits of the federal corporate income tax reduction, which constitutes a reduction in the utility's expense of providing service.⁶⁶

II. RTO/ISO DEVELOPMENTS

A. *ISO New England, Inc.*

1. *New England Power Generators Association, Inc. v. FERC*

On January 19, 2018, the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit) found that it lacked jurisdiction to consider a petition for review brought

62. *See generally* 165 F.E.R.C. ¶ 61,117.

63. *Id.* at PP 1-5, 15-19, 26-28.

64. *Id.* at PP 46-50.

65. *Id.* at PP 1-5, 15-19, 29, 40-42.

66. *Id.* at P 1.

by the New England Power Generators Association (Association) because the Association had failed to seek rehearing of an underlying FERC order.⁶⁷ The Association sought review of a series of FERC orders⁶⁸ related to a scarcity pricing mechanism in the New England Power market. The Tariff Order at issue in the petition concerned tariff revisions proposed by ISO New England, Inc. (ISO-NE), to improve generator performance and reliability. The Complaint Order at issue in the petition concerned FERC's rejection of the proposed tariff revisions and the institution of an FPA section 206 proceeding to determine new tariff rates.

With respect to the Tariff Order, the court explained that the Association's filing of a Motion for Clarification on an unrelated issue did not satisfy the explicit requirements of FPA section 313(a).⁶⁹ It was not sufficient that a group of Indicated Generators filed a rehearing request of the Tariff Order, since section 313(a) requires that the petitioner and the party requesting rehearing be one and the same. The court held that this requirement was not satisfied, even though some Association members were also part of the Indicated Generators group that requested rehearing of the Tariff Order.⁷⁰

The court also rejected the Association's argument that it had reasonable grounds for failing to seek rehearing of the Tariff Order given its view that the Complaint Order and the Tariff Order were inextricably linked. The court explained that "The 'reasonable ground' exception is 'reserved for an extraordinary situation,' such as when a Commission practice is admitted or adjudged to be unlawful."⁷¹ The court acknowledged that the two orders concerned related content, but noted that "[a]pplying the exception to the Association's petition would render section 313(b)'s strict jurisdictional bar toothless for Commission initiated section 206 proceedings, as any complaint would be 'inextricably linked' to the earlier agency proceedings."⁷²

With respect to the Complaint Order, of which the Association did request rehearing, the court found that FERC's decision was not arbitrary and capricious.⁷³

2. New England Power Generators Association, Inc. v. FERC

The U.S. Court of Appeals for the District of Columbia Circuit ruled that FERC failed to explain adequately why FERC found ISO-NE capacity market rules to be just and reasonable but nearly found identical rules for PJM Interconnection, L.L.C. (PJM), to be unjust.⁷⁴ Petitioners filed complaints with FERC under section 206 of the FPA⁷⁵ against ISO-NE's Tariff provisions establishing lock-

67. *New England Power Generators Ass'n, Inc. v. FERC*, 879 F.3d 1192 (D.C. Cir. 2018).

68. *ISO New England, Inc.*, 147 F.E.R.C. ¶ 61,172 (2014) (the Tariff Order), *reh'g denied*, 153 F.E.R.C. ¶ 61,223 (2015) (the Tariff Rehearing Order); *see also New England Power Generators Ass'n v. ISO New England, Inc.*, 150 F.E.R.C. ¶ 61,053 (the Complaint Order), *reh'g denied*, 153 F.E.R.C. ¶ 61,222 (2015) (the Complaint Rehearing Order).

69. 16 U.S.C. § 825l(a) (2005).

70. *New England Power Generators Ass'n*, 879 F.3d at 1192.

71. *Id.* at 1199 (citing *Save Our Seabasticon v. FERC*, 431 F.3d 379, 382 (D.C. Cir. 2005) (quoting *Wisconsin Power & Light Co. v. FERC*, 363 F.3d 453, 460 (D.C. Cir. 2004)).

72. *Id.* at 1199.

73. *Id.* at 1201.

74. *New England Power Generators Ass'n, Inc. v. FERC*, 881 F.3d 202 (D.C. Cir. 2018).

75. 16 U.S.C. § 825e.

in and capacity-carry-forward rules for new entrants in the ISO-NE's forward capacity market (FCM). Petitioners, citing FERC's prior rejection of similar rules in PJM,⁷⁶ argued ISO-NE's proposed changes discriminated against existing suppliers at the expense of new entrants. The court, while recognizing that the rational put forth by FERC may be just and reasonable, concluded that FERC's failure to reconcile its decision in the ISO-NE matter with its own precedent reflected the absence of reasoned decision-making.⁷⁷

3. *ISO New England, Inc.*

FERC accepted ISO-NE's proposed revisions to its Transmission, Markets and Services Tariff (Tariff) to modify its FCM through the addition of a secondary market, referred to as Competitive Auctions with Sponsored Policy Resources (CASPR).⁷⁸ CASPR is to provide a process which facilitates the transfer of capacity supply obligations from existing capacity resources to new state-sponsored resources and, thus, allow the regional wholesale market "to better accommodate actions taken by New England states to procure certain resources outside of ISO-NE's wholesale markets."⁷⁹

According to ISO-NE, New England states have sought to meet climate change goals using of out-of-market contracts to procure a "potentially significant increase in the quantities" of non-greenhouse gas emitting generating resources, or Sponsored Policy Resources (SPR).⁸⁰ It identified two principal concerns with the states' approach. First, it argued that these out-of-market actions could result in price suppression and thus negatively impact the market's ability to retain existing resources and attract new, competitively-compensated resources.⁸¹ Second, it argued that they may cause consumers to "pay twice" for the same capacity, *i.e.*, once through the existing FCM, which utilizes a minimum offer price rule (MOPR) that requires new resources to offer capacity above some price floor and prohibits the reflection of any out-of-market support in an offer into the FCM, and again through the out-of-market payments.⁸² To overcome these problems, ISO-NE proposed a secondary auction, *i.e.*, CASPR, in which existing resources that were awarded capacity supply obligations in an FCM could transfer those obligations to state-sponsored resources.⁸³

FERC reviewed ISO-NE's proposal under section 205 of the FPA.⁸⁴ In accepting ISO NE's proposed revisions, it noted that states' use of out-of-market payments "raises a potential conflict with the Commission's interest in maintaining efficient and competitive wholesale electricity markets."⁸⁵ Its decision rested

76. *PJM Interconnection, L.L.C.*, 128 F.E.R.C. ¶ 61,157 (2009).

77. *New England Power Generators Ass'n*, 881 F.3d at 213.

78. *ISO New England, Inc.*, 162 F.E.R.C. ¶ 61,205 (2018).

79. *Id.* at P 1.

80. *Id.* at P 4.

81. *Id.* at P 5.

82. The price floor is set for each type of resource; out-of-market revenue is precluded unless the support is widely available to other market participants. *Id.* at P 5.

83. 162 F.E.R.C. ¶ 61,205 at P 2.

84. 16 U.S.C. § 824d (2018).

85. 162 F.E.R.C. ¶ 61,205 at P 10.

on its finding that ISO-NE's FCM, under CASPR, will continue to maintain resource adequacy at just and reasonable rates and that the FCM can continue to attract and maintain resource investment at a reasonable cost.⁸⁶ While ISO-NE acknowledged that, where necessary, it elected to prioritize the preservation of competitive prices in the FCM at the expense of accommodating the entry of SPR, FERC found that that ISO-NE "appropriately focuse[d] on ensuring that [CASPR] does not undermine FCM's ability to attract resource investment . . . when the system requires it."⁸⁷

4. *ISO New England Inc.*

On July 2, 2018, FERC issued an order denying ISO-NE's request to waive certain market rules to retain Constellation's Mystic Generating Station units 8 and 9 (Mystic) for New England's regional fuel security.⁸⁸ FERC also initiated a section 206 proceeding to allow for ISO-NE to file interim tariff measures to retain fuel security resources (Docket No. EL18-182).

FERC found that ISO-NE's waiver request was an inappropriate vehicle to retain a resource for fuel security.⁸⁹ The Commission determined that a new tariff process that permits the retention of resources for fuel security must be submitted for Commission approval under section 205(d) of the FPA.⁹⁰ A request for waiver of ISO-NE's market rules is legally insufficient to accomplish that measure.⁹¹ FERC also ruled that the waiver request was not sufficiently limited in scope.⁹²

FERC acted *sua sponte* to provide Constellation with a limited extension of ISO-NE's FCM's deadline to announce unconditional retirement from July 6, 2018 to January 4, 2019, approximately one month prior to the February 4, 2019, start date of ISO-NE's Forward Capacity Auction (FCA) 13.⁹³

FERC found ISO-NE's methodology and assumptions in its Operational Fuel Security Analysis (OFSA) and Mystic Retirement Studies reasonable and accepted ISO-NE's conclusions that the retirement of Mystic would cause the violation of NERC standards in the New England control area as soon as 2022.⁹⁴ The Commission rejected arguments that ISO-NE should have used a probabilistic analysis in both the OFSA and Mystic Retirement Studies, finding it reasonable rather, for ISO-NE to use a deterministic analysis because such analysis allowed for the assessment of the reliability impact of the loss of Mystic and for identification of potential NERC violations.⁹⁵ FERC found that due largely to fuel security concerns that the premature retirement of Mystic may cause ISO-NE to violate NERC standards.⁹⁶

86. *Id.* at PP 10, 32.

87. *Id.* at P 32.

88. *ISO New England, Inc.*, 164 F.E.R.C. ¶ 61,003 (2018).

89. *Id.* at P 47.

90. *Id.*

91. *Id.* at 36.

92. *Id.* at 48.

93. 164 F.E.R.C. ¶ 61,003, at P 59.

94. *Id.* at P 2.

95. *Id.* at P 50.

96. *Id.* at P 52.

FERC ordered ISO-NE on or before August 31, 2018, to submit interim tariff revisions that provide for the filing of a short-term cost-of-service agreement to address demonstrated fuel security concerns; or submit a filing explaining why its current tariff is not unjust and unreasonable.⁹⁷ FERC noted that there are differences between cost-of-service agreements for resources retained for local transmission security needs versus cost-of-service agreements for resources retained for regional fuel security concerns.⁹⁸ The Commission suggested that it may be reasonable for resources retained for fuel security to be offered into the FCM at an offer price that is above zero, but still be subject to mitigation by the Internal Market Monitor (IMM).⁹⁹ If the resource does not clear the Forward Capacity Auction (FCA), the resource would be compensated under a cost-of-service agreement and would also be subject to the performance and penalty violations pursuant to the terms of that agreement.¹⁰⁰

The Commission suggested that ISO-NE also include an *ex ante* cost allocation proposal for resources retained for fuel security.¹⁰¹ FERC ordered that its cost allocation precedent to be followed and that the beneficiaries of the service rendered be identified.

5. *Constellation Mystic Power, LLC*

On July 13, 2018, FERC accepted for filing an Agreement between Mystic, Exelon Generation Company, LLC (Exelon), and ISO-NE, “provid[ing for] cost-of-service compensation to Mystic for the continued operation of the Mystic 8 and 9 natural gas-fired generation units (Mystic 8 and 9),” effective June 1, 2022.¹⁰²

On March 23, 2018, Exelon notified ISO-NE that it would retire its Mystic 8 and 9 units located in Boston Massachusetts unless Exelon obtained cost-of-service compensation for the units, including fuel supply charges associate with a liquefied natural gas (LNG) import terminal.¹⁰³ Thereafter, ISO-NE, Mystic and Exelon entered into the Agreement, filed with FERC on May 16, 2018, that enabled ISO-NE “to retain [the] Mystic 8 and 9 [units] to ensure fuel security in New England for the period of June 1, 2022 to May 31, 2024.”¹⁰⁴

Separately, on May 1, 2018, ISO-NE filed with FERC, in Docket No. ER18-1509-000, to request a waiver of several tariff provisions to enable it to enter into this cost-of-service Agreement.¹⁰⁵ On July 2, 2018, as discussed above, the Commission denied ISO-NE’s waiver request and instituted a FPA section 206 proceeding in Docket No. EL18-182-000.¹⁰⁶

The Commission stated, based on a preliminary analysis, “that the Agreement has not been shown to be just and reasonable and may be unjust, unreasonable,

97. *Id.* at P 12.

98. 164 F.E.R.C. ¶ 61,003 at P 57.

99. *Id.*

100. *Id.*

101. *Id.* at P 58.

102. *Constellation Mystic Power, LLC*, 164 F.E.R.C. ¶ 61,022 (2018).

103. *Id.* at P 3.

104. *Id.* at P 1.

105. *Id.* at P 4.

106. *Id.*

unduly discriminatory or preferential, or otherwise unlawful”; however, there are “issues of material fact that cannot be resolved based on the record before us and includes issues that are more appropriately addressed in hearing procedures.”¹⁰⁷ The Commission directed the “presiding judge to conduct hearing procedures and certify the record to the Commission without issuing an initial decision.”¹⁰⁸ The hearing is to address how capital expenditures under the Agreement will be adjusted once their costs are known; how fuel supply charges should account for the costs of the LNG facility,¹⁰⁹ while cost allocation issues applicable to the Agreement will be addressed in Docket No. EL18-182-000.¹¹⁰

Commissioners Powelson and Glick, writing separately, dissented from the Order, explaining that they view the decision as favoring Exelon over ISO-NE ratepayers because it approves a short-term and very likely expensive solution to a reliability problem and short-circuits the Commission’s order in Docket No. EL18-182-000.¹¹¹

6. *ISO New England Inc.*

In a 2-1 decision, which followed an evidentiary proceeding and two rounds of briefing, FERC conditionally accepted the Cost-of-Service Agreement (COS Agreement) among Mystic, Exelon and ISO-NE.¹¹² The COS Agreement will provide compensation for the continued operation of the Mystic 8 & 9 units and the Everett liquefied natural gas terminal (Everett), from June 1, 2022 through May 31, 2024.¹¹³ In conditionally accepting the COS Agreement, FERC directed Mystic to submit a compliance filing on or before February 18, 2019, and established a paper hearing to ascertain whether and how the ROE methodology that FERC recently proposed in *Coakley*¹¹⁴ should apply in the case. Initial briefs on the ROE issue are due on or before April 19, 2019, and reply briefs are due on or before July 18, 2019.¹¹⁵

FERC set Mystic’s and Everett’s capital structures at 52.4% debt and 47.6% equity, based on June 2018 data, which is the capital structure of Exelon, because if an entity does not have its own capital structure the Commission requires the use of the capital structure of the company’s ultimate corporate parent.¹¹⁶ Mystic’s proposed rate base reflected gross plant in service as of December 31, 2017, or \$1,021,103,968.¹¹⁷ FERC did not accept Mystic’s total rate base, finding that Mystic failed to satisfy FERC’s original cost test, which limits a utility’s “return on (and recovery of) the lesser of the net original cost of plant or, when plant assets

107. 164 F.E.R.C. ¶ 61,022 at P 11.

108. *Id.* at P 12 (citation omitted).

109. *Id.* at PP 19-20 (regarding capital expenditures) and PP 34-38 (regarding fuel supply charges).

110. *Id.* at P 41.

111. *Id.* at app. A5, B1-3.

112. *ISO New England Inc.*, 165 F.E.R.C. ¶ 61,267 (2018).

113. *Id.* at PP 8, 11.

114. Opinion No. 531, *Martha Coakley v. Bangor-Hydro Elec. Co.*, 147 F.E.R.C. ¶ 61,234 (2014), *vacated and remanded*, *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017).

115. 147 F.E.R.C. ¶ 61,234 at P 169.

116. 165 F.E.R.C. ¶ 61,267 at P 52.

117. *Id.* at P 53.

change hands in arms-length transactions, the purchase price of the plant.”¹¹⁸ Therefore, FERC directed Mystic to make a compliance filing, which would disclose the results of a recalculation of Mystic’s cost-of-service study using the gross plant-in-service and accumulated depreciation values that reflect the results of the net original cost study.¹¹⁹ Mystic proposed a starting gross and net plant-in-service of \$60 million for Everett. The issue before FERC was whether it is just and reasonable for Mystic to pay Exelon’s original investment in Everett through the Fuel Supply Charge, and FERC ruled that it is not, and that Mystic should only recover 90 percent of Everett’s fixed costs.¹²⁰ Mystic proposed a formula rate that would allow Mystic to make cost adjustments which are computed in accordance with the formula without making a new section 205 filing for each adjustment. But Mystic only proposed to true-up a subset of these formula inputs: (1) capital expenditures; (2) O&M; (3) A&G; (4) cash working capital; (5) return; and (6) taxes.¹²¹ FERC disagreed with this approach and directed that COS Agreement true-up mechanism apply to the entire COS Agreement, with the exception of the ROE.¹²² A clawback provision in the COS Agreement would require Mystic to refund specified monies that it received under the COS Agreement to ratepayers should it choose to participate in ISO-NE’s markets after the COS Agreement terminates – Mystic’s proposal failed to include a clawback mechanism, and the Commission found that unjust and unreasonable. Mystic is directed to correct these measures in its compliance filing.

B. *New York Independent System Operator, Inc.*

1. *Coalition for Competitive Electricity, et al. v. Zibelman*

An increasing number of states have adopted programs to provide non-market revenues to nuclear power plants demonstrated to be in danger of closing due to their failure to recover the full cost of operation from FERC-authorized wholesale capacity and energy markets.¹²³ These programs typically create “Zero-Emission Credits” (ZECs), a saleable interest constituting the zero-emissions attributes of one megawatt-hour of electricity production by an eligible nuclear facility. Such credits must be purchased by retail electric distributors in an amount determined by their level of electric sales within the State.¹²⁴

In *Coalition for Competitive Electricity, et al. v. Zibelman*, the Second Circuit was presented with a challenge, by non-nuclear merchant generators, to New York’s ZEC Program as preempted by the FPA or the Dormant Commerce Clause

118. *Id.* at P 63.

119. *Id.* at P 64.

120. *Id.* at P 134.

121. 165 F.E.R.C. ¶ 61,267 at P 165.

122. *Id.* at P 197.

123. See, e.g., *An Act concerning Nuclear Energy, S2313/A3724*, Assembly No. 3724, 218th Leg. (N.J. 2018), available at <https://www.njleg.state.nj.us/2018/Bills/PL18/16-HTML> (directing the creation of a ZEC program); see also Press Release, Connecticut Dep’t of Energy & Env’tl. Prot., DEEP and PURA Release Final Resource Assessment, Appraisal, and Determination of Millstone Report (Feb. 1, 2018), <https://www.ct.gov/deep/cwp/view.asp?Q=600578&A=4965>.

124. *Coalition for Competitive Elec. v. Zibelman*, 272 F. Supp. 3d 554 (S.D.N.Y. 2017); *Electric Power Supply Ass’n, et al. v. Star*, No. 17 CV 1164 (N.D. Ill. 2017).

in federal district court.¹²⁵ The three-judge panel rejected the preemption challenge and determined that plaintiffs lacked standing to pursue a Dormant Commerce Clause claim.¹²⁶ The court determined that “field preemption” was not present as Plaintiffs had “failed to identify an impermissible ‘tether’” between New York’s ZEC Program and FERC jurisdictional market auctions as required by *Hughes v. Talen Energy Marketing, LLC*.¹²⁷ It found that, by employing auction market pricing in the ZEC Program, the Program’s effect upon wholesale pricing and generator economic retirements were insufficient to serve as such a tether, as compared to the *Hughes* decision’s requirement for an express program mandate that generators successfully participate in the auction.¹²⁸ The court stressed the FPA’s division of regulatory responsibility over the electric generation and delivery system between the States and FERC as a factor negating any preemptive significance to the above “affects” asserted by Plaintiffs.¹²⁹ Finally, the court cited to FERC’s decisions finding no conflict between State authorized ZEC programs and its regulated merchant auctions, and further noted what it found to be an inconsistency in Plaintiffs’ acceptance of Renewable Energy Credit (REC) programs as not subject to preemption whereas what it found to be very similar ZEC programs were so subject.¹³⁰

Citing many of the same considerations that led it to reject “field preemption,” the court, finding the ZEC Program to be a legitimate state concern and within state jurisdiction, and further finding that its operation caused no clear damage to federal goals, rejected Plaintiffs argument of “conflict preemption”.¹³¹ Finally, the court rejected Plaintiffs Dormant Commerce Clause claim, finding that Plaintiffs lacked standing to pursue it because Plaintiffs asserted injuries did not arise from any discrimination in treatment of intra versus interstate commerce as the result of the New York Program, but rather due to their “production of energy from fuels that New York disfavors.”¹³²

2. *New York Independent System Operator, Inc.*

On February 15, 2018, FERC issued an order accepting, subject to further compliance filing, certain revisions to the New York Independent System Operator, Inc.’s (NYISO) tariff that were submitted by the NYISO to comply with Order No. 1000 and FERC’s Fourth Compliance Order¹³³ in the proceeding.¹³⁴ Specifically, the NYISO proposed: (1) “a *pro forma* development agreement for its public policy transmission planning process . . . to establish requirements for entering into a Public Policy Development Agreement and the consequences of terminating that Agreement”;¹³⁵ (2) “revisions to Attachment Y of the tariff to require that any

125. Coalition for Competitive Elec., et al. v. Zibelman, 906 F. 3d. 41 (2d Cir. 2018).

126. *Id.* at 55.

127. *Id.* at 46 (citing *Hughes v. Talen Energy Mktg., LLC*, 136 S.Ct. 1288, 1293 (2016)).

128. *Id.* at 56-57.

129. *Id.* at 57.

130. *Zibelman*, 906 F. 3d at 55.

131. *Id.* at 57.

132. *Id.* at 58.

133. *N.Y. Indep. Sys. Operator, Inc.*, 153 F.E.R.C. ¶ 61,341 (2015).

134. *N.Y. Indep. Sys. Operator, Inc.*, 162 F.E.R.C. ¶ 61,107 (2018).

135. *Id.* at P 11.

developer execute a Reliability Development Agreement if it is selected” pursuant to NYISO’s public policy transmission planning process as a solution to a Reliability Need;¹³⁶ (3) “a new interconnection process for transmission projects” (the Transmission Interconnection Procedures);¹³⁷ (4) a pro forma operating agreement (Operating Agreement) for Nonincumbent Transmission Owners;¹³⁸ and (5) certain other conforming tariff revisions.¹³⁹ FERC accepted the NYISO’s proposed tariff revisions, effective April 1, 2016, but required additional revisions to be filed within 30 days of the issuance of the Order.¹⁴⁰

C. *PJM Interconnection, L.L.C.*

1. *Electric Power Supply Association, et al. v. Star*

*Electric Power Supply Association, et al. v. Star*¹⁴¹ involves a challenge to the Illinois ZEC program. Plaintiffs (non-nuclear merchant generators and municipalities purchasing wholesale electricity) focused their preemption claims upon the Illinois program’s “price-adjustment” feature. They contended that this feature, which reduces the permitted ZEC credit where the annual average energy price in PJM and Midcontinent Independent System Operator, Inc. (MISO) auctions rises above a specified level, improperly restricts the authority of FERC to establish just and reasonable wholesale electricity prices under the FPA.¹⁴²

Circuit Judge Easterbrook, writing for a unanimous Panel, rejected this claim, finding that the FPA divides authority over electricity production and sale, with FERC regulating sales in interstate commerce (including market auctions) and states regulating retail pricing plus facilities used in distributing and generating electricity. He further noted that:

This allocation leads to conflict, because what states do in the exercise of their powers affects interstate sales, just as what FERC does in the exercise of its powers affects the need for and economic feasibility of plants over which the states possess authority. For decades the Supreme Court has attempted to confine both the Commission and the states to their proper roles, while acknowledging that each use of authorized power necessarily affects tasks that have been assigned elsewhere.¹⁴³

Judge Easterbrook noted that in its most recent decision on this matter, *Hughes v. Talen Energy Marketing, LLC*,¹⁴⁴ the Supreme Court “dr[e]w a line between state laws whose effect depends on a utility’s participation in an interstate

136. *Id.* at P 12.

137. *Id.* at P 23.

138. *Id.* at P 47.

139. 162 F.E.R.C. ¶ 61,107 at P 171.

140. *Id.* at P 1.

141. *Electric Power Supply Ass’n v. Star*, 904 F.3d 518 (7th Cir. 2018) [hereinafter *EPSA*].

142. *Id.* at 522. The district court, and the parties before the Second Circuit, argued a number of procedural issues respecting whether and how the district court had jurisdiction to adjudicate the preemption claim, but the appellate court dismissed these as of no importance since federal court jurisdiction of these federal question claims was clear under 28 U.S.C. § 1331 (2018). *Id.* The court further noted that, at its request, the United States, joined by FERC, filed an *amicus* brief stating its position that Illinois’ ZEC program did not interfere with interstate pricing auctions and was not otherwise preempted. *Id.* at 521-23.

143. *Id.* at 523.

144. *Hughes*, 136 S.Ct. 1288.

auction (forbidden) and state laws that do not so depend but that may affect auctions (allowed).¹⁴⁵ Thus, the mere fact that most nuclear plants choose as a business decision to participate in FERC-regulated wholesale pricing auction, that that participation affects the pricing established by the auction and that that pricing is then used to determine the level of ZEC pricing, constituted but an “incidental” and permissible affect upon FERC’s authority.¹⁴⁶ Illinois’ ZEC program did not require, as did the Maryland program in *Talen*, that nuclear generators sell their energy or capacity in FERC-regulated auctions but also permitted such sales through bilateral contracts separate from the auctions. Plaintiffs’ claims of impermissible effects were simply “an inevitable consequence of a system in which power is shared between state and national governments,” and not a basis for preempting state authority.¹⁴⁷

The court rejected Plaintiffs’ Dormant Commerce Clause claim by noting that Congress has not been silent on the division of Federal and State authority respecting electric generation and sales but has rather legislated on the matter in the FPA, preserving State authority to adopt programs such as the ZEC program.¹⁴⁸ Moreover, the court held that Illinois, through the ZEC Program, had engaged in no overt discrimination against interstate commerce, but rather had merely limited its program to its boundaries as required under the Constitution.¹⁴⁹

2. *PJM Interconnection, L.L.C.*

In *PJM Interconnection, L.L.C.*,¹⁵⁰ PJM proposed to revise its allocation of day-ahead Operating Reserves and real-time balancing Operating Reserves (*i.e.*, “uplift costs”) to cover Up-to-Congestion transactions (UTC) as well as other Virtual Transactions,¹⁵¹ and to discontinue the netting of bilateral transactions for the purpose of uplift allocation and to change the calculation of uplift payments. FERC rejected the filing as unjust and unreasonable, concluding that UTC transactions differ from other virtual transactions and thus that uplift allocations are not properly imposed upon them.¹⁵² FERC concluded that UTCs necessitate that each of two node transactions must clear the market unlike INCs/DECs where only a

145. *EPSA*, 904 F.3d at 523. The court noted that the *Talen* “subsidy” was received only where a generator was selected to sell electricity through the market auction and not otherwise, whereas the ZEC program imposed no such requirement. *Id.*

146. *Id.* at 523-24.

147. *Id.* at 524. As further support for its above conclusion, the court noted that, in *Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 F.E.R.C. ¶ 61,236 (2018), FERC accepted the authority and permissibility of state programs to support preferred types of generation though such programs affected market auction pricing.

148. *EPSA*, 904 F.3d at 524-25.

149. *Id.* at 525.

150. *PJM Interconnection, L.L.C.*, 162 F.E.R.C. ¶ 61,019 (2018). “Uplift is paid to different classes of market participants, under specified conditions to ensure that resources do not operate at PJM’s direction at a financial loss.” *Id.* at n.3.

151. *Id.* at P 1. Such transactions include “incremental offers of supply (INC) and decrement demand bids (DEC)”. *Id.* Virtual transactions are financial transactions in RTO auction markets which do not involve the actual sale or transmission of electricity. Financial marketers submit bids to buy or to sell specific paper amounts of electricity at specific nodes of the PJM grid (*i.e.*, INCs & DEC), or to transmit as well as buy and sell paper electricity between two specified nodes on the grid. *Id.* at P 1, n.4.

152. *Id.* at PP 43-44.

single node transaction needs to do so. UTCs also involve transmission which INCs/DECs do not.¹⁵³

PJM deemed it appropriate to assign uplift costs to all virtual transactions (*i.e.*, both UTCs and INC/DECs) because any of these transactions can impact the commitment and dispatch of generation resources in the day-ahead market as well as transmission flows and, thus, can influence the amount of uplift cost incurred.¹⁵⁴ Assignment of these cost to all types of virtual transactions, including UTCs, would thus be appropriate under applicable precedent on allocating costs based on cost causation.¹⁵⁵ FERC rejected this position, asserting that UTCs do not cause uplift cost incurrence.¹⁵⁶

FERC granted rehearing, however, and reversed its prior determination not to permit the exclusion of internal bilateral transactions from uplift allocation calculations, finding that such transactions do not cause the incurrence of uplift costs.¹⁵⁷ It reaffirmed its rejection of PJM's proposed modification of the calculation of uplift payments finding PJM had failed to demonstrate how that modification would function and achieve its purpose of financially protecting resources that respond to PJM dispatch instructions.¹⁵⁸

2. *PJM Power Providers Group v. FERC*

On January 26, 2018, the D.C. Circuit denied a challenge brought by a coalition of energy providers, a public utility holding company and its subsidiaries of orders by FERC approving PJM's tariff regarding the estimated cost of new entry.¹⁵⁹ Petitioners' argued that the estimated cost, which approximated the revenue that a newly constructed power generator would need to recoup its costs submitted by PJM and approved by FERC was too low.¹⁶⁰ Consequently, petitioners argued that the PJM tariff that FERC approved was not just and reasonable.¹⁶¹ The court acknowledged its longstanding deferential standard of review when examining FERC orders and reiterated that orders issued by FERC must be supported by substantial evidence and will be affirmed unless they are arbitrary, capricious or an abuse of discretion.¹⁶²

3. *Monongahela Power Co., et al.*

On August 26, 2016, FERC issued a Show Cause Order¹⁶³ to PJM establishing a proceeding under section 206 of the FPA to determine whether PJM and its Transmission Owners (TOs) are complying with their obligations under its Order 890.¹⁶⁴ PJM TOs responded to the Show Cause Order by stating that no revisions

153. *Id.* at P 44.

154. 162 F.E.R.C. ¶ 61,019 at P 13.

155. *Id.* at P 12.

156. *Id.* at P 44. FERC reaffirmed its conclusion in an Order issued on rehearing. *PJM Interconnection, L.L.C., order on reh'g*, 164 F.E.R.C. ¶ 61,168 at PP 6-12 (2018).

157. 162 F.E.R.C. ¶ 61,019 at PP 15-16.

158. *Id.* at PP 19-20.

159. *PJM Power Providers Grp. v. FERC*, 880 F.3d 559 (D.C. Cir. 2018).

160. *Id.* at 561-62.

161. *Id.* at 562.

162. *Id.*

163. *Monongahela Power Co.*, 156 F.E.R.C. ¶ 61,134 (2016).

164. *Id.* at P 1.

to the PJM Operating Agreement (OA) are required as it already complies with Order 890, but also filed Attachment M-3 as an Amendment to the PJM OA and Tariff modifying each to provide additional detail regarding the process its TOs employed for planning certain locally planned transmission facilities.¹⁶⁵

In its February 15, 2018, Order, FERC found PJM TOs were not in full compliance with Order 890 as respects local transmission planning as follows: (i) TOs often conducted significant transmission planning activities before alerting PJM and transmission users that such local transmission projects (which result in a “Supplemental Project” to be evaluated in the PJM Regional Transmission Planning process) were required; (ii) transmission users were not receiving an opportunity to review and comment on the criteria, assumptions and models that TOs used to identify the need for such local transmission projects (*i.e.*, Supplemental Projects); (iii) criteria, assumptions and models provided were vague and insufficiently detailed to support transmission user review and comment upon proposed projects; and thus (iv) TOs’ transmission planning was not being conducted with the transparency and involvement of transmission users as required by Order 890.¹⁶⁶ Turning to PJM’s Attachment M-3 filing, FERC accepted as appropriate its principal effect of transferring the statement of Supplemental Project transmission planning requirements from the PJM OA to the PJM Tariff.¹⁶⁷ This transfer eliminates a requirement for stakeholder approval of changes in these requirements, but FERC held that its required approval of all such changes before they become effective provides sufficient protection against arbitrary and unlawful PJM or TO conduct.¹⁶⁸ FERC continued to require changes to Attachment M-3’s terms to implement its above stated conclusion that PJM and TOs’ existing implementation of Order 890, respecting local transmission planning, violated the terms of that Order.¹⁶⁹

An Order on Rehearing and Compliance was also issued on the preceding Order. In that Order, FERC denied rehearing.¹⁷⁰ FERC also accepted PJM’s timing, meeting, posting, and choice of dispute resolution procedures over intervenor objections.¹⁷¹

4. *Old Dominion Electric Cooperative, et al. v. PJM Inter connection, L.L.C.*

On February 23, 2018, FERC issued an order directing FERC staff to convene a technical conference to address issues raised in two FPA section 206 and

165. *Monongahela Power Co.*, 162 F.E.R.C. ¶ 61,129 at PP 2-4 (2018).

166. *Id.* at PP 10-12, 38-39, 74, 77. PJM’s responsive argument, that transmission project solutions must often be developed and presented with the statement of project need to permit productive Stakeholder review, was rejected. The above failings, FERC found, violated Order No. 890’s transparency and coordination requirements.

167. *Id.* at PP 92-97.

168. *Id.* at P 92.

169. *Id.* at PP 100-15. FERC specified in these modifications, specific requirements for the number of meetings, time periods between steps in the planning process (*i.e.*, review/comment on assumptions, review/comment on proposed transmission project solutions, etc.). FERC also required PJM to clarify what dispute resolution procedures would apply to this transmission planning activity, but left it to PJM to define the specific procedures to be implemented. Additional modifications, such as a PJM assumption from TOs of all local transmission planning, were rejected by FERC. *Id.* at P 117.

170. *Monongahela Power Co., et al.*, 164 F.E.R.C. ¶ 61,217 at PP 11-28 (2018).

171. *Id.* at PP 38-59.

306 complaints related to the transition and procurement of capacity under PJM's Reliability Pricing Model (RPM) as well as the methodology PJM uses in determining capacity procurement targets.¹⁷² In doing so, FERC rejected PJM's request that FERC summarily dismiss the complaints as collateral attacks on previous FERC orders on PJM's capacity market.¹⁷³ FERC noted that FPA section 206 "recognizes that a rate previously found just and reasonable may be found unjust and unreasonable in a later proceeding"¹⁷⁴ and that the complainants had raised a number of issues that warranted further examination.¹⁷⁵

5. *Energy Storage Association, et al. v. PJM Interconnection, L.L.C.*

On March 30, 2018, the Commission issued an Order granting, in part, a complaint against PJM pertaining to changes it had made in its frequency regulation (Regulation) market and instituting a staff-led technical conference.¹⁷⁶ The complaints at issue were filed by the Energy Storage Association (ESA) and jointly by Renewable Energy Systems Americas (RESA) and Invenergy Storage Development, LLC (Invenergy). The Regulation market changes at issue concerned: (1) a revision to PJM's benefits factor curve resulting in a cap on Regulation D (RegD) resource procurement at 40% of the overall resources procured to meet PJM Regulation needs and (2) changes to the calculation of RegD signals.¹⁷⁷

The ESA complaint challenged PJM's changes on the grounds that the underlying mechanisms for determining both were absent from the PJM's filed tariff. Such an omission would go against the FPA and Commission precedent. The Invenergy complaint focused solely on the RegD signal redesign. PJM responded to these complaints by characterizing the Regulation market changes as operational matters that did not have to be included in its Tariff.¹⁷⁸

In its Order, the Commission noted that decisions regarding what information should be included in a tariff are guided by its "rule of reason" policy, which states that any provisions substantively affecting rates, terms, and conditions of service are to be included in the tariff.¹⁷⁹ The Commission concluded that the benefits factor curve and Regulation signal both meet all three of these criteria and therefore should be included in PJM's Tariff. The Commission further directed Staff to institute a technical conference to examine issues beyond the question of the proper inclusions in the PJM tariff.¹⁸⁰ Specifically, the Commission noted that "the purposes for which PJM procures Regulation service from Regulation resources warrants further investigation"¹⁸¹

172. *Old Dominion Elec. Coop. v. PJM Interconnection, L.L.C.*, 162 F.E.R.C. ¶ 61,160 at PP 1, 57 (2018).

173. *Id.* at P 28.

174. *Id.* at P 56 (citing *Oxy USA v. FERC*, 64 F.3d 679, 690 (D.C. Cir. 1995) ("the fact that a rate was once found reasonable does not preclude a finding of unreasonableness in a subsequent proceeding."); see also *Black Oak Energy v. PJM Interconnection, LLC*, 122 F.E.R.C. ¶ 61,208 at PP 26-27 (2008) (determining not to dismiss complaint as collateral attack).

175. 162 F.E.R.C. ¶ 61,160 at P 54.

176. *Energy Storage Ass'n v. PJM Interconnection, L.L.C.*, 162 F.E.R.C. ¶ 61,296 (2018).

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

178. *Id.* at PP 31-33.

179. *Id.* at P 103.

180. *Id.* at P 110.

181. 162 F.E.R.C. ¶ 61,296 at P 111.

6. *Calpine Corporation, et al. v. PJM Interconnection, L.L.C.*

On June 29, 2018, FERC issued an order granting a complaint brought by Calpine Corp (Calpine), *et alia*, alleging that PJM's MOPR is unjust and unreasonable because it does not capture the impact of state-provided or required "out-of-market" payments, which act as a subsidy for resources that are otherwise "out-of-the-market" in the PJM capacity market, which, in turn, artificially suppresses prices.¹⁸² FERC's order also rejected a PJM filing¹⁸³ that included two proposals designed to address the "out-of-market" payments, which were (1) a two-state annual action, referred to as "Capacity Repricing," or (2) in the event FERC rejected Capacity Repricing, a revised MOPR to mitigate capacity offers from new and existing resources, referred to as "MOPR-Ex."¹⁸⁴

FERC rejected PJM's Capacity Repricing proposal on the grounds that it would result in the separation of price and quantity in the PJM market for the sole purpose of facilitating market participation by resources that receive out-of-market support, resulting in incorrect price signals.¹⁸⁵ FERC rejected PJM's MOPR-Ex proposal on the grounds that PJM did not provide a valid reason for the disparity among resources that receive subsidies and resources that do not.¹⁸⁶ FERC granted the Calpine, *et al.*, complaint, finding that PJM's current tariff is unjust, unreasonable, and unduly discriminatory, and FERC subsequently instituted a section 206 proceeding¹⁸⁷ to address out-of-market subsidies in PJM's capacity market and their effect on competition, price distortions, and cost shifts.¹⁸⁸

Dissents were issued by Commissioners LaFleur and Glick.¹⁸⁹ A concurring opinion was issued by Commissioner Powelson.¹⁹⁰

7. *PJM Interconnection, L.L.C.*

FERC accepted in part and rejected in part an annually repeated PJM tariff Filing to incorporate cost responsibility assignments for, in this year, forty-five new transmission projects into PJM's transmission rate, including the first Targeted Market Efficiency Projects (TMEPs) between PJM and MISO under the MISO-PJM Joint Operating Agreement (JOA).¹⁹¹ The annual filing incorporates those transmission projects approved by the PJM Board as part of PJM's Regional Transmission Expansion Plan.¹⁹²

8. *Delaware Public Service Comm'n, et al. v. PJM Interconnection, L.L.C., et al.*

182. *Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 F.E.R.C. ¶ 61,236 at PP 1-3, 15 (2018).

183. *See generally* FERC Docket Nos. ER18-1314-000, *et al.* (June 29, 2018).

184. 163 F.E.R.C. ¶ 61,236 at P 4.

185. *Id.* at PP 63-64.

186. *Id.* at P 100.

187. *See generally id.*

188. *Id.* at P 150.

189. *See generally* 163 F.E.R.C. ¶ 61,236 (LaFleur, C., dissenting) (Glick, R., dissenting).

190. *See generally id.* (Powelson, R., concurring).

191. *PJM Interconnection, L.L.C., et al.*, 164 F.E.R.C. ¶ 61,002 (2018).

192. *Id.* at P 3.

In the above-referenced development,¹⁹³ FERC granted rehearing of an Order from April 22, 2016 in which it had affirmed a PJM decision to apply its solution-based distribution factor (DFAX) method to assign cost responsibility to certain transmission project costs to correct generation stability related, reliability issues respecting the Salem and Hope Creek Nuclear Generating Stations located at Artificial Island, New Jersey.¹⁹⁴ DFAX is an approved transmission cost allocation method for allocating a portion of the costs of transmission projects constructed to enhance grid reliability.¹⁹⁵ It allocates cost on the basis of increased transmission flow to areas whose transmission capacity is increased by the project.¹⁹⁶ However, FERC concluded that projects constructed to enhance generation stability are not intended to, and do not primarily, benefit the grid through enhanced transmission flow to their destination areas, but rather avoid generation outages or production reduction caused by transmission system instability and thus benefit all regions served by the generation affected.¹⁹⁷

FERC reached its decision on the basis of a PJM White Paper that suggested two alternative allocation methods – the Stability Interface DFAX Method and the Stability Deviation Method.¹⁹⁸ After concluding that the DFAX Method does not allocate transmission improvement costs that enhance generation stability “in a manner that is at least roughly commensurate with their benefits,” FERC directed a hearing to determine what alternative allocation method would comply with transmission cost allocation standards.¹⁹⁹

9. *PJM Interconnection, L.L.C.*

In *PJM Interconnection, L.L.C.*,²⁰⁰ FERC accepted revisions proposed by PJM to its OATT and OA to (1) avoid assessing duplicative or otherwise improper congestion charges on “pseudo-tie transactions” between generators in MISO selling electricity into PJM and (2) provide a new means to hedge financial exposure for “pseudo-tied resources” exporting power from PJM to MISO.²⁰¹ American Municipal Power, Inc., and Illinois Municipal Electric Agency (IMEA) contested PJM’s filing, contending that it failed to remove the duplicative congestion charges, would result in inefficient dispatch and discriminated against their electric transmission activities, while Financial Marketers requested that the number of bidding points available for UTC transactions be increased.²⁰² FERC rejected AMP’s, IMEA’s and Financial Marketers’ arguments.²⁰³

10. *PJM Interconnection, L.L.C.*

193. *Delaware Pub. Serv. Comm'n & Maryland Pub. Serv. Comm'n v. PJM Interconnection, L.L.C.*, 164 F.E.R.C. ¶ 61,035 (2018) [hereinafter DFAX Order].

194. *PJM Interconnection, L.L.C.*, 155 F.E.R.C. ¶ 61,090 at P 2 (2016).

195. *Id.* at P 5 n.7.

196. *Id.* at PP 4-5.

197. DFAX Order, *supra* note 193, at PP 9-11.

198. *Id.* at P 23.

199. *Id.* at PP 38, 42-43.

200. *PJM Interconnection, L.L.C.*, 164 F.E.R.C. ¶ 61,073 (2018).

201. *Id.* at PP 1, 7-11.

202. *Id.* at PP 20-21.

203. *Id.* at PP 19, 25-28 and 37.

FERC affirmed, on rehearing, its February 2018 Order permitting PJM to reduce the number of nodes at which Financial Marketers could submit virtual transactions (*i.e.*, both INCs/DECs and UTCs) to assure that such transactions achieve their intended benefits to market operations, which include improvement of day-ahead and real-time market price convergence, price discovery, and market liquidity.²⁰⁴

11. *PJM Interconnection, L.L.C., et al.*

On September 14, 2018, FERC accepted revisions to PJM's Consolidated Transmission Owners Agreement (CTOA) and the PJM tariff filed by PJM, NextEra Energy Transmission MidAtlantic, LLC (NEET MidAtlantic) and Rochelle Municipal Utilities (RMU) (collectively, Applicants) to accommodate the acquisition by NEET MidAtlantic of transmission facilities from RMU.²⁰⁵ Applicants proposed to replace RMU's Formula Rate with NEET MidAtlantic's previously accepted Formula Rate template as well as certain transmission rate incentives into the PJM tariff.²⁰⁶ FERC also granted, subject to conditions and the outcome of Docket No. ER16-2716-002, NEET MidAtlantic's request for authorization for its affiliates or subsidiaries to use its Formula Rate and incentives previously approved for NEET MidAtlantic.²⁰⁷

In Docket No. ER16-2716-000, NEET MidAtlantic filed its Formula Rate along with a request for certain transmission rate incentives under Order No. 679²⁰⁸ for recovery of future investments in transmission facilities in PJM.²⁰⁹ FERC accepted revisions to the CTOA and tariff effective as of closing of the transaction subject to a compliance filing.²¹⁰ FERC directed a number of other revisions to the tariff on compliance.²¹¹ Of note, FERC indicated that, in the NEET MidAtlantic Incentives Order, use of the hypothetical capital structure was granted only until NEET MidAtlantic's first transmission project entered service and, after, use of actual capital structure was required.²¹² Finally, FERC granted NEET MidAtlantic's request to create a regulatory asset for transaction costs associated with the transfer of the transmission assets and to amortize that asset over five years beginning the first year that costs are assessed to customers under the Formula Rate, subject approval of rate recovery in a future section 205 filing.²¹³

12. *PJM Interconnection, L.L.C.*

204. *Id.* at P 40.

205. *PJM Interconnection, L.L.C.*, 164 F.E.R.C. ¶ 61,185 (2018) [hereinafter NEET MidAtlantic Formula Rate Order].

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

207. *Id.* at P 2.

208. Order No. 679, *Promoting Transmission Investment through Pricing Reform*, F.E.R.C. STATS. & REGS. ¶ 31,222 (2006) (codified at 18 C.F.R. pt. 35), *order on reh'g*, Order No. 679-A, F.E.R.C. STATS & REGS. ¶ 31,236 (2006), *order on reh'g*, 119 F.E.R.C. ¶ 61,062 (2007); *see also* Policy Statement, *Promoting Transmission Investment through Pricing Reform*, 141 F.E.R.C. ¶ 61,129 (2012).

209. *NextEra Energy Transmission MidAtlantic, LLC*, 161 F.E.R.C. ¶ 61,141 at PP 6-14 (2017).

210. 164 F.E.R.C. ¶ 61,185, at P 13.

211. *Id.* at PP 3-4.

212. *Id.* at P 3.

213. *Id.* at P 30.

On July 27, 2018, PJM submitted revisions to its credit policy for Financial Transmission Rights (FTRs) to incorporate a minimum credit requirement for FTRs equal to \$0.10/MWh (Volumetric Credit Requirement) to limit potential exposure to FTR portfolios with little to no credit requirement relative to the MWh volume of the positions in the FTR portfolios.²¹⁴ FERC accepted the Volumetric Credit Requirement for filing, effective September 3, 2018.²¹⁵

“PJM explain[ed] that its market participants can acquire FTR positions in monthly, annual and long-term FTR auctions, but they must satisfy credit and collateral rules under the PJM Tariff.”²¹⁶ “PJM explain[ed] that, despite the recent improvements in its credit rules, there remained potentially significant risk exposure in its FTR credit policy, due to FTR holder with large FTR portfolios that have minimal or no collateral requirements.”²¹⁷ The Volumetric Credit Requirement had been a “new, additional calculation that will occur after the current path-specific FTR credit requirement calculation based on FTR Historical Values.”²¹⁸ Further, “PJM stat[ed] that when considering the price threshold for the Volumetric Credit Requirement, it found the Volumetric Credit Requirement provid[ed] a reasonable balance between decreasing credit shortfalls for large FTR portfolios and limiting additional credit requirements.”²¹⁹ “PJM propos[ed] a one-time transition period to assist FTR holders with the initial implementation impact, which permits a market participant’s credit shortfall to not result in a default unless such a default was not remedied upon the expiration date of the transition period.”²²⁰ Lastly, “PJM request[ed] a waiver of the Commission’s regulations requiring the submission of this filing not less than 60 days. . . after the Volumetric Credit Requirement was submitted.”²²¹

FERC accepted “PJM’s proposed Volumetric Credit Requirement, effective September 3, 2018, as requested.”²²² “Specifically, [FERC] agreed that the \$0.10/MWh minimum credit requirement for FTRs helps address the specific risks to market participants due to large FTR portfolios that may be under-collateralized.”²²³ “As PJM [would] apply the higher of the credit requirements based on the FTR Historic Value or the Volumetric Credit Requirement, the proposal help[ed] address risks associated with large FTR portfolios that may continue to be under-collateralized as a result of prior FTR credit policies in PJM.”²²⁴ FERC “agree[d] that the price threshold established in the Volumetric Credit Requirement reasonably balances the need to remedy credit shortfalls for large FTR portfolios while limiting the impact to market participants in its FTR market.”²²⁵

214. *PJM Interconnection, L.L.C.*, 164 F.E.R.C. ¶ 61,215 at P 1 (2018).

215. *Id.*

216. *Id.* at P 2.

217. *Id.* at P 4.

218. *Id.* at P 5.

219. 164 F.E.R.C. ¶ 61,215, at P 6.

220. *Id.* at P 7.

221. *Id.* at P 8.

222. *Id.* at P 13.

223. *Id.*

224. 164 F.E.R.C. ¶ 61,215, at P 13.

225. *Id.*

13. *DC Energy, LLC v. PJM Interconnection, L.L.C.*

DC Energy, LLC (DC Energy) filed a complaint under sections 206 and 306 of the FPA against PJM, alleging “PJM’s collateral and minimum capitalization requirements for FTR auction participants are unjust and unreasonable” because they do not require FTR market participants to be adequately capitalized.²²⁶ DC Energy cited the example of an entity that defaulted after “amass[ing] an FTR portfolio of 890 million MWh while posting” minimal collateral.²²⁷ PJM’s collateralization requirement does not require any collateral for an FTR purchased at less than the Adjusted FTR Historical Value.²²⁸ DC Energy proposed to revise PJM’s requirements for open FTR portfolios by requiring a volumetric minimum collateral of \$0.05/MWh, a minimum collateral based on mark-to-auction valuation, and updated collateralization requirements based on each FTR market participant’s risk and scope of activities.²²⁹

PJM subsequently submitted a filing under section 205 of the FPA proposing to modify its FTR collateral requirements.²³⁰ In light of PJM’s filing, FERC instituted a paper hearing on DC Energy’s complaint and asked for additional briefing on a number of issues to allow it to determine whether the PJM tariff would be unjust and unreasonable even after PJM’s proposed modifications are in place.²³¹

D. *Midcontinent Independent System Operator, Inc.*

1. *Ameren Services Co. v. FERC*

On January 26, 2018, the D.C. Circuit vacated and remanded five FERC orders that rejected MISO Transmission Operators’ (TOs’) request to self-fund indirect interconnection upgrades of 345 kilovolts (kV) or greater (Network Upgrades), required for interconnection of an electric generating facility, seeking to interconnect directly elsewhere on the system.²³² The immediate impact of the D.C. Circuit’s opinion is that FERC’s elimination of MISO TOs’ unilateral right to self-fund Network Upgrades that are directly interconnected to a member transmission owner’s system is vacated and therefore currently has no legal effect.²³³ Judge Silberman, writing for the majority in a 2-1 opinion, ordered FERC to supplement its record on remand, and provide “reasoned consideration” as to whether risks in constructing indirect (or affected systems) and direct Network Upgrades – risks like insurance coverage deductibles and the potential for environmental and reliability litigation are “baked in” to the MISO *pro forma* GIA revisions it ordered.²³⁴ Although the court did not rule on the merits, it charged FERC to consider the effect of its orders on the ability of MISO TOs to attract future capital

226. *DC Energy, LLC v. PJM Interconnection, L.L.C.*, 164 F.E.R.C. ¶ 61,216 at P 1 (2018).

227. *Id.* at P 6.

228. *Id.* at P 4.

229. *Id.* at P 5.

230. *Id.* at P 27.

231. 164 F.E.R.C. ¶ 61,216, at PP 28-29.

232. *Ameren Servs. Co. v. FERC*, 880 F.3d 571, 585 (D.C. Cir. 2018).

233. *Id.*

234. *Id.* at 582.

and satisfy the capital attraction standard as articulated by the United States Supreme Court in *Hope*.²³⁵

2. *Midcontinent Independent System Operator, Inc., et al.*

On December 15, 2017, Ameren Services Company (Ameren) filed an incentive request with FERC on behalf of its affiliate Ameren Transmission Company of Illinois (Ameren Transmission) that sought an ROE adder of 100 basis points on their build of the Components and associated “under-build.”²³⁶ As part of its request, Ameren requested authorization to assign the incentive adder to any entity that could potentially undertake the development of the Components – including Ameren affiliates.²³⁷ FERC previously granted a set of incentives under Order 679 for the Components including: 100% construction work in progress (CWIP) recovery, abandoned plant recovery, a hypothetical capital structure, and the authority to assign those incentives to others.²³⁸

On February 13, 2018, FERC issued its order.²³⁹ FERC denied Ameren’s request for incentive rate treatment and any assignment of that incentive and denied Ameren’s request to pursue the rate incentive through an FPA section 205 action.²⁴⁰ FERC found that the Components did meet the rebuttable presumption for eligibility for incentives because they were the result of their designation by MISO as MVPs under Criterion 1 and were placed on Appendix A of the MISO Transmission Expansion Process, which FERC had previously found to meet the presumption.²⁴¹ However, it found that despite meeting section 219 requirements, the Components failed to demonstrate a nexus between the requested incentives and investments as required by Order 679.²⁴² FERC explained that it found a lack of nexus primarily because of the late stage of Ameren’s development of the projects (according to the Missouri Commission 77% of both Components costs had already been spent and 89% of the larger Illinois Rivers component had been spent, at the time of the filing).²⁴³ FERC reasoned that a project that is further along in its development cycle “typically faces fewer remaining risks and challenges, and we find that is true here.”²⁴⁴ FERC further agreed with certain parties that the previously awarded incentives for the Components have already mitigated many of the risks.²⁴⁵ With regard to Ameren’s request for authorization of incentives in an FPA section 205 action, FERC denied that request on similar grounds,

235. *Id.*; see also *FPC v. Hope Nat. Gas Co.*, 320 U.S. 591, 603 (1944).

236. *Midcontinent Indep. Sys. Operator, Inc., et al.*, 165 F.E.R.C. ¶ 61,083 at PP 1, 4 (2018) [hereinafter *November Rehearing Order*].

237. *Id.* at P 1.

238. *Midwest Ind. Transmission Sys. Operator, Inc.*, 141 F.E.R.C. ¶ 61,121 at P 1 (2012) (granting transmission rate incentives for Mark Twain); see also *Ameren Servs. Co.* 135 F.E.R.C. ¶ 61,142 (2011) (conditionally granting transmission rate incentives for Illinois Rivers).

239. *Midcontinent Indep. Sys. Operator, Inc.*, 162 F.E.R.C. ¶ 61,099 (2018).

240. *Id.* at P 1.

241. *Id.* at P 16.

242. *Id.* at P 58.

243. *Id.* at PP 59-60.

244. 162 F.E.R.C. ¶ 61,099, at P 59.

245. *Id.* at P 60.

finding that additional incentive action for the Components was not needed.²⁴⁶ The requested transmission tariff changes were also denied.²⁴⁷

3. *Indianapolis Power & Light Co. v. Midcontinent Independent System Operator, Inc.*

Indianapolis Power & Light Company (Indianapolis Power) and MISO each filed a request for rehearing from the February 1, 2017, FERC order denying in part and granting in part relief requested by Indianapolis Power under FPA sections 206 and 306 wherein FERC directed MISO to submit proposed tariff revisions to accommodate the participation of all electric storage resources within 60 days of the issuance of the Complaint Order.²⁴⁸ Indianapolis Power “argue[d] that requiring tariff changes, without requiring accompanying operational changes and changes to MISO’s dispatch, is insufficient to ensure that MISO’s treatment of its grid-scale lithium battery energy storage system is just and reasonable and not unduly discriminatory or preferential.”²⁴⁹ Indianapolis Power also argued that the Commission erred in refusing to require MISO to unbundle primary frequency response from the existing Schedule 3 of the *pro forma* Open Access Transmission, Energy and Operating Reserve Markets Tariff to compensate primary frequency response separately and to establish a stand-alone market for primary frequency response.²⁵⁰ Indianapolis Power also challenged the Commission’s reliance on MISO’s assurances regarding “state of charge” management and the impact that participation in MISO’s regulation market would have on the useful life of a Battery Facility.”

On March 23, 2018, FERC issued its Order on Rehearing and Compliance.²⁵¹ It denied Indianapolis Powers’ request for rehearing.²⁵² While the Commission noted that the structure of tariff changes under MISO’s compliance filing in the proceeding had a number of deficiencies,²⁵³ the Commission granted in part MISO’s request for rehearing regarding the timing of MISO’s compliance obligations and accepted MISO’s Compliance Filing in the proceeding subject to the Commission’s acceptance of MISO’s future Order No. 841²⁵⁴ compliance filing,²⁵⁵ which Order requires RTO/ISO markets to submit tariff provisions to establish a participation model for electric storage resources.

246. *Id.* at P 63.

247. *Id.* at P 66.

248. *Indianapolis Power & Light Co. v. Midcontinent Indep. Sys. Operator, Inc.*, 162 F.E.R.C. ¶ 61,266 at P 1 (2018). On April 3, 2017, in Docket No. ER17-1376-000, MISO submitted proposed tariff revisions to comply with the Complaint Order in part by creating a new resource category known as Stored Energy Resource – Type II (SER-Type II). On June 29, 2017, in Docket No. ER17-1376-001, MISO submitted an amendment requesting a revised effective date of December 1, 2017 for its proposed tariff revisions, due to software-related reasons (Compliance Filing).

249. *Id.* at P 14.

250. *Id.*

251. *Id.* at P 1.

252. *Id.* at P 3.

253. 162 F.E.R.C. ¶ 61,266, at P 60.

254. Order No. 841, *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, F.E.R.C. STATS. & REGS. ¶ 31,398, 83 Fed. Reg. 9,580 (2018).

255. 162 F.E.R.C. ¶ 61,266, at PP 31, 35, 41.

4. *Midcontinent Independent System Operator, Inc.*

On April 17, 2018, FERC issued an order accepting revisions to MISO's tariff to provide for the recovery of the costs of Target Market Efficiency Projects (TMEPs).²⁵⁶ MISO's proposal to revise its tariff was driven by two prior orders of FERC that: (1) revised the MISO-PJM (Joint Operating Agreement) JOA to create a new category of interregional transmission projects (TMEPs) to address historical congestion along the MISO-PJM seam and to adopt a method for allocating the costs of such projects between MISO and PJM;²⁵⁷ and (2) approved revisions to MISO's tariff to adopt the method proposed by MISO and the MISO Transmission Operators (TOs) for assigning MISO's share of TMEP costs within the MISO region.²⁵⁸ The Commission determined that the MISO/MISO TOs' proposal "is just and reasonable as it reflects the Commission's practice of providing for the recovery of the cost of a transmission facility over its useful life."²⁵⁹ Accordingly, the Commission approved the proposed tariff revisions and dismissed arguments raised in protest.

5. *Midcontinent Independent System Operator, Inc.*

On June 21, 2018, FERC issued its order finding that certain provisions in the MISO's Open Access Transmission Tariff (OATT) regarding the termination of Generator Interconnection Agreements (GIAs) were unjust and unreasonable.²⁶⁰ The finding was based on a potential conflict between MISO's *pro forma* GIA and MISO's GIP that came to light in a prior proceeding.²⁶¹ In particular, FERC raised concern that an Interconnection Customer's ability to extend its commercial operating date (COD) under Article 2.3.1 of the *pro forma* GIA appeared to conflict with section 4.4.4 of MISO's Generator Interconnection Procedures (GIP) under which any extension of the COD – apart from certain narrow circumstances – was a material modification that would result in the Interconnection Customer being withdrawn from the interconnection queue. In the paper hearing proceeding, MISO proposed certain revisions to Article 2.3.1 of its *pro forma* GIA and section 4.4.4 of its GIP to resolve the potential conflict. FERC determined that, with some modifications, MISO's proposed revisions to the GIA and GIP were just and reasonable.

256. *Midcontinent Indep. Sys. Operator, Inc.*, 163 F.E.R.C. ¶ 61,028 at P 6 (2018).

257. *Midcontinent Indep. Sys. Operator, Inc.*, 161 F.E.R.C. ¶ 61,005 at P 1 (2017). The compliance filings implementing the terms of this order were subsequently accepted by FERC. *PJM Interconnection, L.L.C.*, FERC Docket No. ER17-718-001 (Dec. 12, 2017) (delegated letter order) and *Midcontinent Indep. Sys. Operator, Inc.*, FERC Docket No. ER17-721-001 (Dec. 12, 2017) (delegated letter order).

258. *Midcontinent Indep. Sys. Operator, Inc.*, 161 F.E.R.C. ¶ 61,004 at P 1 (2017) (Regional Cost Allocation Order), *order denying reh'g*, 162 F.E.R.C. ¶ 61,253 (2018). The compliance filing was subsequently accepted. *Midcontinent Indep. Sys. Operator, Inc.*, FERC Docket No. ER17-2246-001 (Dec. 12, 2017) (delegated letter order). Pursuant to the Regional Cost Allocation Order, MISO's share of TMEP costs are to be assigned to all transmission pricing zones that receive positive congestion contribution benefits from a TMEP in excess of \$5,000 or 1% of MISO's share of the total TMEP cost. *Id.* The regional allocation method approved by FERC would be in effect for the balance of the five-year period, ending December 31, 2018, for transitioning Entergy Corporation and its operating companies into MISO and, during the transition period, no project costs would be allocated to MISO South (the Second Planning Area). *Id.*

259. *Midcontinent Indep. Sys. Operator, Inc.*, 163 F.E.R.C. ¶ 61,028 at P 39 (2018).

260. *Midcontinent Indep. Sys. Operator, Inc.*, 163 F.E.R.C. ¶ 61,210 at P 1 (2018).

261. *Midcontinent Indep. Sys. Operator, Inc.*, 161 F.E.R.C. ¶ 61,076 at P 2 (2017).

6. *Verso Corp. v. Federal Energy Regulatory Commission*

This decision presented a twist on the court's recent application of the filed rate doctrine and prohibition against retroactive ratemaking.²⁶² Sections 205 and 206 of the FPA authorize FERC to order refunds after a rate has been suspended or placed in effect subject to refund²⁶³ or after a refund effective date has been established on the Commission's own motion or in response to a complaint.²⁶⁴ Here, the court upheld a series of FERC orders implementing reallocation of costs among load serving entities in the American Transmission Company (ATC) service territory within the MISO footprint resulting in surcharges for certain customers. The court upheld FERC's position that its remedial authority under section 309 of the FPA²⁶⁵ can be read in harmony with the requirements of section 206 and the filed rate doctrine. The court explained that section 309 allows FERC to equitably assess retroactive surcharges, at least in the context of the facts of this case as summarized below, where FERC found that a flaw in prior rate design had caused costs to be disproportionately allocated among customers without regard to benefits and exercised its remedial authority to reallocate costs in response to a series of complaints.²⁶⁶

7. *Midcontinent Independent System Operator, Inc.*

On August 31, 2018, the Commission issued an Order on Remand from the D.C. Circuit. The D.C. Circuit vacated several orders of the Commission which determined that interconnecting generators should have the option to fund network upgrades identified in the MISO generator interconnection process.²⁶⁷ The D.C. Circuit found that the Commission failed to support its prior determination that allowing transmission owners to choose the method in which interconnecting generators will fund network upgrades results in undue discrimination or unjust and unreasonable rates.²⁶⁸ The D.C. Circuit further found that the Commission failed to adequately address arguments that allowing interconnecting generators to elect to fund network upgrades denies transmission owners the opportunity to earn a return on network upgrades.²⁶⁹

In its August 31 Order on Remand, the Commission reversed its "determination that transmission owners and affected system operators should not be allowed the unilateral right to elect to provide initial funding for network upgrades"²⁷⁰ and directed MISO "to file Tariff sheets within 30 days from the date of this order that restore the right of the transmission owner to unilaterally elect the Transmission

262. *Compare* *Verso Corp. v. FERC*, 898 F.3d 1 (D.C. Cir. 2018) *with* *Louisiana Public Service Comm'n v. FERC*, 883 F.3d 929 (D.C. Cir. 2018).

263. *See* 16 U.S.C. § 824d.

264. 16 U.S.C. § 824e (2005).

265. 16 U.S.C. § 825h.

266. *Verso Corp.*, 898 F.3d at 11.

267. *Midcontinent Indep. Sys. Operator, Inc.* 164 F.E.R.C. ¶ 61,158 at P 1 (2018).

268. *Ameren Servs.*, 880 F.3d at 571.

269. *Id.* at 579-80.

270. 164 F.E.R.C. ¶ 61,158, at P 1.

Owner Initial Funding option for the capital cost of the network upgrades . . . effective prospectively from the date of this order.”²⁷¹ The Commission also requested further briefing on how to address interconnection agreements and facilities and construction agreements that were entered into during the time period between June 24, 2015 and the date of the Order on Remand, “where the interconnection customer provided Generator Up-Front Funding and the transmission owner or affected system operator that was party to the agreement would have elected the Transmission Owner Initial Funding option instead.”²⁷²

8. *Midcontinent Independent Transmission System Operator, Inc.*

On September 20, 2018, FERC issued an Order on rehearing and clarification addressing whether any limitation should be placed on export pricing to PJM for MVPs by MISO.²⁷³ FERC denied the Request for Rehearing but granted Requests for Clarification.²⁷⁴

When the Commission approved several utilities’ move to PJM from MISO, it found that an “elongated and highly irregular seam” would exist between portions of MISO and PJM.²⁷⁵ This irregular seam “would ‘island’ portions of MISO (e.g., Wisconsin and Michigan) from the remainder of MISO and would divide highly interconnected transmission systems across which substantial trade takes place” and these trades would be subject to rate pancaking, thereby impeding the goals of Order No. 2000.²⁷⁶ When the MVP filing was filed, FERC allowed the collection of an MVP charge for all exports and wheel-through transaction, except for those that would sink into PJM.²⁷⁷ The Commission stated it had not been shown that MVP charges to transactions that would sink in PJM would not result in rate pancaking along the MISO-PJM seam.²⁷⁸ FERC denied the rehearing request and the Order was appealed to the 7th Circuit.²⁷⁹ The 7th Circuit ruled against FERC and remanded the Order back to FERC.²⁸⁰

In its Order on remand, the Commission further developed the record and found that current conditions of the MISO-PJM seam had evolved that transactions from MISO to PJM no longer warranted the exemption for MVP charges.²⁸¹ The Commission based the elimination of the prohibition by finding that: (1) the changes in geography of the seam make it less irregular;²⁸² (2) the improvement in market-to-market coordination between MISO and PJM;²⁸³ and (3) that MVP

271. *Id.* at P 34.

272. *Id.* at P 36.

273. *Midwest Indep. Transmission Sys. Operator, Inc.*, 164 F.E.R.C. ¶ 61,191 at P 1 (2018).

274. *Id.* at P 2.

275. *Id.* at P 3.

276. *Id.*

277. *Id.* at P 6.

278. 164 F.E.R.C. ¶ 61,191 at P 6.

279. *Id.* at P 7.

280. *Id.* at P 11.

281. *Id.* at P 13.

282. *Id.* at P 14.

283. 164 F.E.R.C. ¶ 61,191 at P 15.

projects were built for regional benefits that included the ability the ability to export electricity and improved regional efficient dispatch.²⁸⁴ FERC also rejected the claims that by allowing MVP charges to be assessed to PJM export transactions would violate Order 1000.²⁸⁵ The Commission further noted that evidence was presented that these charges are “expected to be small relative to the average interface prices of MISO and PJM for both day-ahead and real-time transactions.”²⁸⁶ FERC also observed that “if an entity does not take transmission service under the MISO Tariff and, for example, takes transmission service only under the PJM Tariff, MISO will not assess that entity an MVP Usage Rate charge.”²⁸⁷

The Commission denied the requests for rehearing because it found: (1) MISO-PJM seam had matured to the point that its previous concerns had been mitigated;²⁸⁸ (2) MVPs support and benefit all users and, as such, there are no cost shifts;²⁸⁹ and (3) it was proper use of MISO’s FPA section 205 filing rights.²⁹⁰ FERC clarified “that transmission service subject to the MVP Usage Rate is taken voluntarily; the MVP Usage Rate is charged only to monthly net actual energy withdrawals, export schedules, and through schedules.”²⁹¹ The second clarification FERC made was “that only the portion of an MVP’s cost that is allocated to MISO may be recovered in the MISO MVP Usage Rate, and the portion of an MVP’s cost that is allocated under the JOA to PJM may not be included in the MISO MVP Usage Rate.”²⁹² The Commission denied the request for clarification that MVP projects had to be vetted through the MISO-PJM JOA.²⁹³

9. *Midcontinent Independent System Operator, Inc.*

On May 16, 2018, MISO submitted proposed revisions to its tariff related to resource suspension and retirement under MISO’s “Attachment Y” process. MISO’s proposed changes were intended to provide greater alignment between the Planning Resource Auction (PRA) and the “Attachment Y” process and provide greater flexibility for generation resource owners to make retirement decisions.²⁹⁴ Specifically, MISO proposed to treat all initially submitted Attachment Y notifications as notices to “suspend,” rather than retire, a generation resource.²⁹⁵ Resource owners would then have the right to rescind the notification while the owner considers market conditions during an “Attachment Y Conversion Period,” which MISO defined as “between the date of submission of the Attachment Y Notice and the June 1st start of the third full planning year following the submittal

284. *Id.* at PP 16, 18.

285. *Id.* at P 17.

286. *Id.* at P 18.

287. *Id.* at P 17.

288. 164 F.E.R.C. ¶ 61,191 at P 33.

289. *Id.* at P 34.

290. *Id.* at PP 38-39.

291. *Id.* at P 35.

292. *Id.* at P 42.

293. 164 F.E.R.C. ¶ 61,191 at P 41.

294. *Midcontinent Indep. Sys. Operator, Inc.* 164 F.E.R.C. ¶ 61,214 at PP 1, 7 (2018).

295. *Id.* at P 7.

of the Attachment Y Notice.”²⁹⁶ Finally, MISO proposed to remove the requirement that a generation owner specify a period for a suspension in the Attachment Y Notice on the basis that such a long-term outlook is often uncertain.²⁹⁷

On July 11, 2018, Commission staff issued a deficiency letter seeking additional information from MISO regarding its proposed tariff changes.²⁹⁸ On July 27, 2018, MISO filed its response.²⁹⁹ On September 25, 2018, the Commission issued an order accepting MISO’s proposed tariff changes effective July 16, 2018.³⁰⁰ In rejecting arguments from some intervenors that the proposed changes would impair the planning process by allowing resource owners additional time to make retirement decisions, the Commission concluded that “MISO’s proposal allows market participants to make more efficient retirement decisions by providing the flexibility to align such decisions with market outcomes (*i.e.*, whether they clear the Auction), which may result in increased participation and more efficient outcomes.”³⁰¹

10. *Midcontinent Independent System Operator, Inc.*

On October 31, 2018, FERC issued an order accepting a MISO tariff filing (Time Bar Filing) to establish time limits to initiate market and transmission settlement disputes and alternative dispute resolution (ADR), and to perform associated adjustments and corrections to settlement statements.³⁰²

The Time Bar Filing proposed: (1) a 120-calendar day time limit for initiating transmission or market settlements disputes; (2) a two year time limit for the resettlement of settlement statements to correct any MISO system or software error that MISO discovers during the course of dispute resolution or otherwise; (3) a 90-calendar day time limit for initiating informal ADR, unless the tariff sections applicable to a non-market or transmission settlement dispute specify a different time period; (4) a 90-calendar day time limit for initiating formal ADR; and (5) a requirement that disputes involving market or transmission settlements be timely submitted under the appropriate tariff provisions before the dispute is eligible for ADR.³⁰³

FERC accepted the Time Bar Filing to be effective November 1, 2018, subject to a clean-up type compliance filing. FERC agreed with MISO that “it is reasonable for MISO to limit the two-year resettlement period to continuing errors (which include system or software errors) because these may not be readily discoverable” and “that limiting corrections to continuing errors reflects an appropriate balance between requiring market participants to promptly initiate claims involving readily discoverable one-time MISO errors and the correction of more long-lasting MISO errors that may not be readily discoverable.”³⁰⁴ MISO made

296. *Id.* at P 16.

297. *Id.* at P 17.

298. *Id.* at P 11.

299. 164 F.E.R.C. ¶ 61,214 at P 11.

300. *Id.* at P 1.

301. *Id.* at P 44.

302. *Midcontinent Indep. Sys. Operator, Inc.*, 165 F.E.R.C. ¶ 61,065 at P 1 (2018).

303. *Id.* at PP 4-5.

304. *Id.* at P 24.

the required compliance filing on November 6, 2018. FERC accepted MISO's compliance filing by letter order dated December 7, 2018.³⁰⁵

11. *Midcontinent Independent System Operator, Inc., et al.*

On November 5, 2018, FERC issued an *Order on Rehearing* (November Rehearing Order) granting in part and denying in part the Request for Rehearing of Ameren of FERC's February 18, 2018 order (February Order).³⁰⁶ Ameren had requested to implement a transmission rate incentive pursuant to Order No. 679³⁰⁷ for the Illinois Rivers and Mark Twain components of the Grand Rivers Project (Project) in Illinois and Missouri in the MISO region.³⁰⁸ In the February Order, FERC denied Ameren's request to grant a 100-basis point incentive adder to its ROE for the Illinois River and Mark Twain components of the Project because Ameren had failed to demonstrate that remaining risks and challenges associated with those components warranted the requested ROE incentive.³⁰⁹

On rehearing, Ameren argued that FERC erred in denying the ROE incentive to the Illinois Rivers component on the basis of its construction progress.³¹⁰ FERC affirmed that it considers construction progress in awarding ROE incentives for all incomplete projects based on project risks and challenges.³¹¹ However, FERC denied the rehearing request because Ameren failed to demonstrate that any remaining risks in the Illinois Rivers component, which was approximately 90% complete, were sufficient to warrant the ROE incentive.³¹²

Ameren also argued that FERC erred in denying the ROE incentive to the Mark Twain component by failing to address that component separately from the Illinois Rivers component.³¹³ FERC agreed and found that the Mark Twain component is not substantially complete and continues to face risks and challenges that warrant the ROE incentive.³¹⁴ FERC granted rehearing and explained that the Mark Twain component qualifies for the ROE incentive because it will relieve chronic and severe congestion that has demonstrated cost impacts to consumers and will unlock location-constrained generation resources.³¹⁵ Furthermore, Ameren demonstrated that it would use best practices in management and procurement and is taking the necessary steps to minimize risk.³¹⁶ FERC found that a 50-

305. FERC Docket No. ER18-1648-002 (Dec. 7, 2018).

306. *November Rehearing Order*, *supra* note 236, at P 1.

307. Order No. 679, *Promoting Transmission Investment through Pricing Reform*, F.E.R.C. STATS. & REGS. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, F.E.R.C. STATS. & REGS. ¶ 31,236, *order on reh'g*, 119 F.E.R.C. ¶ 61,062 (2007).

308. *November Rehearing Order*, *supra* note 236, at P 1.

309. *Id.* at P 5.

310. *Id.* at P 7.

311. *Id.* at P 10.

312. *Id.* at P 11.

313. *November Rehearing Order*, *supra* note 236, at PP 7, 16.

314. *Id.* at P 17.

315. *Id.* at P 19.

316. *Id.* at P 20.

basis point adder for the ROE incentive, not Ameren's requested 100-basis point adder, is appropriate.³¹⁷

12. *Midcontinent Independent System Operator, Inc., et al.*

In this order, FERC approved a new cost allocation methodology for Targeted Market Efficiency Projects (TMEPs) in the MISO.³¹⁸ MISO allocates its share of TMEP costs to transmission pricing zones based on how much congestion benefit the project would provide to specific zones.³¹⁹ The congestion benefit is calculated by identifying the nodal congestion contribution for each load node which includes the following: (1) shadow price, (2) measure of load's contribution to congestion in the day-ahead and real-time markets, and (3) amount of load served.³²⁰ FERC approved the following three changes to the calculation methodology:

- (1) incorporate generator nodes in the determination of the congestion contribution, rather than considering only load nodes;
- (2) add "net" to reflect that aggregating the load node and generator node congestion contributions gives the net benefits of the upgrade to each Transmission Pricing Zone; and
- (3) discontinue applying the formula to all five-minute dispatches in the real-time market, so that the formula would apply only to the hours in the day-ahead market in which the Reciprocal Coordinated Flowgate experienced congestion.³²¹

E. *Southwest Power Pool, Inc.*

1. *Indicated SPP Transmission Owners v. Southwest Power Pool, Inc.*

In this proceeding, FERC denied a complaint filed against Southwest Power Pool (SPP), alleging that the SPP tariff was unjust and unreasonable.³²² Specifically, the Complainants objected that, when a new SPP transmission owner is integrated into an existing transmission pricing zone, the SPP tariff allowed the costs of the new TO's existing transmission facilities to be allocated across the entire pricing zone, resulting in shifting of costs between new and existing transmission customers in the zone.³²³

FERC denied the Complaint, finding that the Complainants had not met their burden of proof under section 206 because the SPP tariff did not prohibit costs shifts that result from the addition of a new transmission owner to an existing zone.³²⁴ FERC rejected Complainants' assertion that cost shifts in the form of increased network service rates result when a new transmission owner's transmission system is integrated into an existing zone.³²⁵ FERC found that the SPP tariff

317. *Id.* at P 21. In support of that determination, the Commission cited its 50-basis point ROE incentive awarded to the Edic-Pleasant Valley 345 kv line in the NYISO region. *Id.* at P 21 (citing *New York Indep. Sys. Operator, Inc.*, 151 F.E.R.C. ¶ 61,004 (2015)).

318. *Midcontinent Indep. Sys. Operator, Inc.*, 165 F.E.R.C. ¶ 61,163 at P 18 (2018).

319. *Id.* at P 2.

320. *Id.* at P 3.

321. *Id.* at P 5.

322. *Indicated SPP Transmission Owners v. Southwest Power Pool, Inc.*, 162 F.E.R.C. ¶ 61,213 at P 1 (2018).

323. *Id.*

324. *Id.* at P 60.

325. *Id.* at P 61.

permitted some degree of shifting of cost responsibility for existing transmission costs in the context of integrating a new transmission owner into SPP.³²⁶ It further noted that granting the Complaint would require FERC to find that “any potential cost shift that results from the reallocation of existing transmission costs when a new transmission owner joins an ISO or RTO like SPP is *per se* unjust and unreasonable and must be prohibited, absent agreement of the existing transmission owner in whose zone the new transmission owner has been placed.”³²⁷ FERC further explained that such an approach would prevent FERC from considering the issues that must be evaluated in order to properly determine if a particular cost allocation is just and reasonable, which include the scope, configuration, and operational characteristics of the new owner’s transmission facilities, as well as the effects on transmission planning and system reliability. FERC also noted precedent indicating “that the magnitude of a cost shift, not the mere existence of a cost shift, is what is relevant for determining whether a rate is just and reasonable.”³²⁸

The Complainants submitted a request for rehearing, in which they abandoned their original arguments and instead argued that the proponents of new transmission must bear the burden of proving that no cost shifts will be caused by integrating the transmission into the pricing zone.³²⁹ FERC rejected this request on October 3, 2018.³³⁰

2. *South Central MCN LLC*

In this proceeding, the Commission approved an FPA section 203 application filed by South Central MCN LLC (South Central) requesting authorization to permit it to acquire certain transmission lines and related assets from the City of Nixa, Missouri (Nixa Assets), located in SPP and interconnected to transmission facilities in SPP Zone 10 and Zone 3.³³¹ South Central confirmed that its annual transmission revenue requirement (ATRR) for the assets would be “based on the net book value of the assets, as adjusted for further depreciation at the time of closing,” despite the purchase price resulting in an acquisition premium, and South Central would not seek authorization to recover through rates any amount in excess of the estimated net book value.³³² The Commission concluded that the proposed transaction would not have an adverse effect on rates.³³³

3. *Southwest Power Pool, Inc.*

On March 15, 2018, FERC accepted tariff revisions proposed by SPP to add an ATRR formula rate template and implementation protocols for transmission service using the facilities of South Central MCN LLC (South Central) after South Central transfers functional control of the Nixa Assets to SPP.³³⁴ SPP used its

326. *Id.* at P 62.

327. 162 F.E.R.C. ¶ 61,213 at P 62.

328. *Id.* at P 66.

329. *Indicated SPP Transmission Owners v. Southwest Power Pool, Inc.*, 165 F.E.R.C. ¶ 61,005 at P 1 (2018).

330. *Id.*

331. *South Central MCN LLC*, 162 F.E.R.C. ¶ 61,214 at PP 1-2 (2018).

332. *Id.* at P 7.

333. *Id.* at P 43.

334. *Southwest Power Pool, Inc.*, 162 F.E.R.C. ¶ 61,215 at P 1 (2018).

“newly-revised Transmission Owner Zonal Placement Process to review the zonal placement of the Nixa Assets and the rate impacts of such zonal placement.”³³⁵ According to SPP, these internal criteria, used in conjunction with the special tariff requirements applicable to load that converts from service under the Southwestern Tariff to service under the SPP tariff, required placement of the Nixa Assets in Zone 10.³³⁶ SPP argued that inclusion of the Nixa Assets in Zone 10 was just and reasonable based on the benefits the facilities would provide to the SPP region and FERC policy to promote participation in RTOs.³³⁷ Placing the Nixa Assets under SPP’s functional control would further FERC’s goals of promoting transmission-only company ownership of transmission facilities and increasing the participation of public power in SPP transmission planning. SPP further contended that adding the Nixa Assets would fill in a gap in the SPP footprint, and therefore allow for more efficient and cost-effective transmission planning, including the identification of zonal transmission solutions to increase system reliability and reduce congestion.³³⁸

The Commission found that SPP’s proposed Tariff revisions raised issues of material fact, and accepted the proposed revisions subject to the outcome of hearing and settlement procedures and the outcome of the ongoing proceedings in Docket Nos. ER15-2594, ER17-953, and EL18-16.³³⁹ On August 20, 2018, the Commission rejected separate motions filed by SPP and South Central requesting clarification and rehearing.³⁴⁰

4. *Southwest Power Pool, Inc.*

This decision addressed exceptions to an Initial Decision issued by the presiding Administrative Law Judge concerning a proposal by SPP to incorporate into SPP’s existing transmission pricing Zone 17, certain transmission facilities of Tri-State Generation and Transmission Association, Inc. (Tri-State), along with the ATRR for those facilities,³⁴¹ Nebraska Public Power District (NPPD), the dominant transmission owner in Zone 17, filed the underlying protest.³⁴²

At hearing, the parties had litigated whether the proposed placement of Tri-State in Zone 17 and the resulting rate, were just and reasonable and, specifically, whether the proposal would shift some of the costs of Tri-State’s existing transmission facilities to TOs and customers in Zone 17.³⁴³ The parties also litigated what refunds, if any, would be owed by Tri-State if the Commission determined that SPP’s proposed zonal placement of Tri-State and the resulting rate were unjust and unreasonable.³⁴⁴ The Presiding Judge determined that SPP’s proposal to place

335. *Id.* at P 6.

336. *Id.* at P 10.

337. *Id.* at P 11.

338. *Id.* at P 15.

339. 162 F.E.R.C. ¶ 61,215 at P 32.

340. *Southwest Power Pool, Inc.*, 164 F.E.R.C. ¶ 61,120 at P 7 (2018).

341. *Southwest Power Pool, Inc.*, 163 F.E.R.C. ¶ 61,109 at P 4 (2018).

342. *Id.* at P 1.

343. *Id.*

344. *Id.*

the Tri-State transmission facilities in Zone 17 was just and reasonable and that, as a result, no refunds were owed.³⁴⁵

The Commission affirmed the Initial Decision, concluding that SPP's application of its zonal placement criteria rendered a just and reasonable result.³⁴⁶ First, the Commission determined that zonal selection criteria do not need to explicitly include consideration of costs shifts.³⁴⁷ Second, any adjustment to the alleged cost shift to Zone 17 customers that was known and measurable within a five-to-seven year period in the future was properly considered in calculating the cost shift.³⁴⁸ Third, shifting cost responsibility for some degree of legacy costs is not *per se* unjust and unreasonable, but cost shifts that result in significant rate increases to customers, unaccompanied by commensurate benefits, are unjust and unreasonable.³⁴⁹ In reaching its conclusion, the Commission relied on: (i) the size of its ATRR; (ii) the geographic scope of its transmission system; and (iii) the extent to which its facilities were integrated with and embedded within the transmission facilities of existing SPP transmission owners.³⁵⁰ Finally, the Commission held that no determination is required as to whether proposed alternative zonal placements were also just and reasonable or whether SPP's proposal is more or less reasonable than such alternatives.³⁵¹

5. *Southwest Power Pool, Inc.*

In this order, FERC addressed revisions to the SPP tariff to implement a Resource Adequacy Requirement (RAR) for the SPP footprint and to clarify the types of authorities that may impose rules that are considered force majeure events.³⁵² The Commission had rejected SPP's previously submitted revisions regarding resource adequacy policies, providing guidance on how to more fully develop its proposal.³⁵³

In its filing, SPP proposed to revise its tariff to include a new Attachment AA (Resource Adequacy), which contained all the terms and conditions relevant to the establishment, compliance, and enforcement of the requirement that each load responsibility entity (LRE) in the SPP Balancing Authority Area maintain sufficient capacity and planning reserves to serve its forecasted load.³⁵⁴ These terms and conditions included:

- the roles and responsibilities for the LRE, market participant, generator owner, and SPP (as the transmission provider) under the RAR process;³⁵⁵

345. *Id.* at P 2.

346. 163 F.E.R.C. ¶ 61,109 at P 2.

347. *Id.* at P 38.

348. *Id.* at P 157.

349. *Id.* at P 183.

350. 163 F.E.R.C. ¶ 61,109 at P 107.

351. *Id.* at P 145.

352. *Southwest Power Pool, Inc.*, 164 F.E.R.C. ¶ 61,092 at P 1 (2018).

353. *Id.* at P 3.

354. *Id.* at P 5.

355. *Id.*

- the requirement that LREs maintain a planning reserve margin of at least 12% (unless an LRE has a resource mix that is at least 75% hydro-based, then the planning reserve margin is 9.89%);³⁵⁶
- the load requirements of an LRE that will be subject to Attachment AA, relying on a calculation of net peak demand, including its winter season obligation;³⁵⁷
- the qualification of various resources as capacity to satisfy all or portions of the LRE's RAR or winter season obligation;³⁵⁸
- the requirement that all power purchase agreements be backed by verifiable capacity;³⁵⁹
- an annual deliverability study to evaluate the resources of generator owners to determine the amount of capacity that the resource may deliver to the SPP Balancing Authority Area without affecting reliability or requiring additional transmission upgrades;³⁶⁰
- the requirement that generator owners submit a workbook that reflects their amount of capacity available through the deliverability study, along with capacity sales to other entities if the generator owner intends to be deemed to have deliverable capacity; and³⁶¹
- a system for assessing deficiency payments, which will be collected from market participants representing LREs that fail to comply with the RAR.³⁶²

Separately, SPP proposed to revise its tariff to clarify the types of authorities that may impose rules that are considered force majeure events, encompassing “any curtailment order, regulation, or restriction imposed by governmental, military, or lawfully established civilian authorities.”³⁶³

The Commission accepted SPP's proposed Tariff revisions, effective July 1, 2018, as requested.

6. *Southwest Power Pool, Inc.*

On August 30, 2018, SPP submitted, pursuant to section 205 of the FPA,³⁶⁴ proposed revisions to its tariff to add an ATRR for certain facilities of GridLiance High Plains LLC (GridLiance) located in the Oklahoma panhandle (Oklahoma Assets) once GridLiance transfers functional control of those facilities to SPP.³⁶⁵ After considering comments and protests, the Commission accepted and suspended SPP's proposed revisions to its tariff, to become effective November 1, 2018, subject to refund, and established hearing and settlement procedures.³⁶⁶

356. *Id.* at P 9.

357. 164 F.E.R.C. ¶ 61,092 at P 11.

358. *Id.* at P 12.

359. *Id.* at P 3.

360. *Id.* at P 20.

361. *Id.* at P 22.

362. 164 F.E.R.C. ¶ 61,092 at P 6.

363. *Id.* at P 26.

364. 16 U.S.C. § 824d.

365. *Southwest Power Pool, Inc.*, 165 F.E.R.C. ¶ 61,066 at P 1 (2018) (footnotes omitted).

366. *Id.*

The Commission also granted SPP's request for waiver of section 35.13 of the Commission's regulations regarding the provision of cost-of-service statements, consistent with the Commission's prior approval of formula rates.³⁶⁷ However, to the extent that parties at the hearing can show the relevance of additional information needed to evaluate the proposal, the Commission indicated that the Administrative Law Judge can provide for appropriate discovery of such information.³⁶⁸

F. California Independent System Operator Corporation

1. California Public Utilities Comm'n v. FERC

The U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit) granted a petition for review challenging FERC's determination that Pacific Gas & Electric Company (PG&E) was entitled to an ROE incentive adder for its continued participation in the California Independent System Operator (CAISO).³⁶⁹ The court agreed that FERC's summary approval of the ROE incentive had not adequately addressed objections that the adder was unjustified in light of state law restrictions on PG&E's ability to withdraw from the CAISO.³⁷⁰ Under FERC's Order No. 679, a transmission-owning utility participating in an RTO or ISO such as the CAISO is presumed to be eligible for an ROE incentive adder,³⁷¹ but the court found that FERC had improperly applied this presumption such that "ongoing membership itself is the sole criterion of receipt of an incentive adder."³⁷² Under the case-by-case review of incentives required by Order No. 679, the court reasoned, "the voluntariness of a utility's membership in a transmission organization is logically relevant to whether it is eligible for an adder."³⁷³ The court concluded that FERC's summary ruling granting PG&E an adder was not consistent with the requirements of Order No. 679 and, thus, represented an unexplained departure from its longstanding policy that utilities should not be awarded incentives "for past conduct or for conduct which they are otherwise obligated to undertake."³⁷⁴ The court also found that FERC erred by effectively creating a generic ROE adder in contravention of Order No. 679.³⁷⁵ Finally, the court rejected FERC's contention that the appeal was an impermissible collateral attack on Order No. 679.³⁷⁶

2. California Independent System Operator Corp.

On January 18, 2018, FERC issued an order accepting a set of six tariff revisions submitted by CAISO to enhance its rules governing the resource adequacy

367. *Id.* at P 40.

368. *Id.*

369. California Pub. Utils. Comm'n v. FERC, 879 F.3d 966, 970 (9th Cir. 2018).

370. *Id.* at 973.

371. *Id.* at 970-71 (discussing Order No. 679, *Promoting Transmission Investment Through Pricing Reform*, 116 F.E.R.C. ¶ 61,057 (2006), *order on reh'g*, Order No. 679-A, 117 F.E.R.C. ¶ 61,345 (2006), *order on reh'g*, Order No. 679-B, 119 F.E.R.C. ¶ 61,062 (2007)).

372. *California Pub. Utils. Comm'n*, 879 F.3d at 974.

373. *Id.* at 975.

374. *Id.* at 977-78.

375. *Id.* at 978.

376. *Id.* at 979.

program in California.³⁷⁷ Specifically, FERC accepted revisions to the CAISO tariff to:

- (1) Allow capacity located in a local capacity area that is procured as system capacity to provide substitute capacity based on how the capacity is shown on the resource adequacy plan;³⁷⁸
- (2) Cap a load serving entity's monthly local resource adequacy requirement at its monthly system level requirement;³⁷⁹
- (3) Streamline the outage evaluation process for resource adequacy capacity;³⁸⁰
- (4) Adjust the timeline for the monthly resource adequacy process;³⁸¹
- (5) Clarify the tariff provisions regarding use of the default method for allocating flexible capacity procurement costs,³⁸² and
- (6) Streamline the resource adequacy reporting obligations for small load serving entities.³⁸³

FERC accepted the CAISO tariff revisions effective February 15, 2018, as requested.³⁸⁴

3. *California Independent System Operator Corp.*

On June 21, 2018, FERC issued an order accepting in part, subject to condition, and rejecting in part, proposed tariff revisions submitted by CAISO to implement its Commitment Cost Enhancements Phase 3 initiative.³⁸⁵ Specifically, FERC: (1) conditionally accepted tariff revisions to implement a methodology to allow eligible resources to include opportunity cost adders to their commitment costs and energy bid costs;³⁸⁶ (2) accepted tariff revisions to clarify the definition of a use-limited resource;³⁸⁷ (3) accepted tariff revisions to allow renegotiation of outdated or erroneous negotiated values used for commitment cost and generated energy bids;³⁸⁸ (4) accepted certain minor corrective and clarifying tariff revisions;³⁸⁹ (5) rejected tariff revisions to give scheduling coordinators the ability to register alternative market values for certain resource characteristics in the

377. *California Indep. Sys. Operator Corp.*, 162 F.E.R.C. ¶ 61,042 at P 1 (2018).

378. *Id.* at P 28.

379. *Id.* at P 39.

380. *Id.* at P 45.

381. *Id.* at P 50.

382. 162 F.E.R.C. ¶ 61,042 at P 50.

383. *Id.*

384. *Id.* at P 1.

385. *California Indep. Sys. Operator Corp.*, 163 F.E.R.C. ¶ 61,211 at Ordering Paragraphs (A)-(B) and Appendix (2018).

386. *Id.* at PP 32-34.

387. *Id.* at P 35.

388. *Id.* at P 53.

389. *Id.*

CAISO's Master File, in addition to physical design capability values;³⁹⁰ (6) rejected tariff revisions to remove ramp rates as components of daily bids;³⁹¹ and (7) rejected certain minor clarifying tariff revisions.³⁹²

FERC accepted the CAISO tariff revisions to the extent described above effective November 1, 2018, as requested.³⁹³ Pursuant to a later filing by CAISO, FERC modified the effective date of the tariff revisions to April 1, 2019.³⁹⁴

4. *Southern California Edison Company*

On August 23, 2018, FERC issued an order rejecting Southern California Edison Company's (SoCal Edison) proposed revisions to its Wholesale Distribution Access Tariff (WDAT).³⁹⁵ SoCal Edison had proposed revisions to: (1) facilitate the interconnection of energy storage devices to its distribution system, including extending the WDAT to apply to the transportation of capacity and energy used for Charging Demand (wholesale electric energy withdrawn from the grid to charge an energy storage device) and modifying the WDAT to permit SoCal Edison to curtail Charging Demand before curtailing retail or wholesale distribution load when the distribution system was strained; and, (2) align the WDAT more closely with CAISO's tariff.³⁹⁶

FERC ultimately rejected the proposed revisions to the WDAT regarding energy storage devices, finding that SoCal Edison had not adequately supported why it would be just and reasonable to curtail an energy storage device's Charging Demand before curtailing load.³⁹⁷ FERC noted that SoCal Edison's primary argument for this provision—that Charging Demand had not paid for system upgrades—fell short because SoCal Edison had no procedure that allowed Charging Demand the option to pay for needed system upgrades.³⁹⁸ FERC suggested that SoCal Edison continue working towards developing procedures for studying and accounting for energy storage devices' Charging Demand so that those loads would be treated in a similar manner as other loads, and not in an unduly discriminatory or preferential manner.³⁹⁹

5. *Southern California Edison*

In *Southern California Edison Company*,⁴⁰⁰ FERC clarified what activities are considered transmission planning activities subject to the requirements of Order Nos. 890 and 1000. FERC agreed with CAISO and certain of its TOs that Order Nos. 890 and 1000 were focused on planning for the expansion of transmission systems: “[T]he Commission adopted the transmission planning requirements in Order No. 890 to remedy opportunities for undue discrimination in expansion

390. 163 F.E.R.C. ¶ 61,211 at PP 44-47.

391. *Id.* at P 53.

392. *Id.*

393. *Id.* at P 1, Ordering Paragraph (A).

394. *California Indep. Sys. Operator Corp.*, 165 F.E.R.C. ¶ 61,038 at P 5 (2018).

395. *Southern Cal. Edison Co.*, 164 F.E.R.C. ¶ 61,130 at P 1, Ordering Paragraph (B) (2018).

396. *Id.* at PP 3, 7-9, 16.

397. *Id.* at P 39.

398. *Id.*

399. *Id.*

400. *Southern Cal. Edison Co.*, 164 F.E.R.C. ¶ 61,160 at P 37 (2018).

of the transmission grid.”⁴⁰¹ FERC thus ruled that transmission-related maintenance and compliance activities—characterized at a Technical Conference as asset management projects and activities—were not subject to Order No. 890’s transmission planning requirements.⁴⁰² FERC explained that the concept of expansion does not include activities such “as maintenance, compliance, work on infrastructure at the end-of-useful life, and infrastructure security undertaken to maintain a transmission owner’s existing electric transmission system and meet its regulatory compliance requirements.”⁴⁰³ The order also notes that the CAISO’s transmission planning process, as filed at FERC, was limited to: “reliability needs; economic needs; public policy requirements and directives; location-constrained resource interconnection facilities (which are radial generation tie facilities ultimately paid for by generators as they come on-line); [and] maintaining the feasibility of long-term [congestion revenue rights].”⁴⁰⁴

6. *Nevada Hydro Company, Inc.*

On September 20, 2018, FERC dismissed as premature the petition of Nevada Hydro Company (Nevada Hydro) for a declaratory ruling that its 500 MW pumped storage facility and 30-mile interconnecting transmission line, the Lake Elsinore Advanced Pumped Storage (LEAPS) facility, is a transmission project and thus eligible for cost-recovery.⁴⁰⁵ Nevada Hydro argued that it satisfies FERC’s criteria for storage to operate as a transmission facility because it will operate LEAPS as a wholesale transmission facility that will transport stored energy to serve retail load (similar to a transmission line), will provide voltage support that is necessary for the operation of the transmission system (like the storage project at issue in *Western Grid*),⁴⁰⁶ and, through its storage capability, will be able to transmit electricity to both SoCal Edison and San Diego Gas & Electric Company (SDG&E) to alleviate existing transmission constraints and reliability issues.⁴⁰⁷

CAISO and a number of other protestors argued that it is CAISO’s regional transmission planning process, and not a market participant’s petition to FERC, that should determine whether a facility is a transmission facility and is needed to address a transmission constraint.⁴⁰⁸ FERC agreed, finding that it could not even determine whether LEAPS is a transmission project and thus eligible for cost-recovery until LEAPS has been studied in the CAISO transmission planning process (which CAISO has committed to doing).⁴⁰⁹ FERC further noted that its *Storage Policy Statement*⁴¹⁰ provides guidance only if an electric storage resource seeks

401. *Id.* at P 31.

402. *Id.* at P 30.

403. *Id.* at P 32.

404. *Id.* at n.61.

405. *Nevada Hydro Co.*, 164 F.E.R.C. ¶ 61,197 at P 22 (2018).

406. *Id.* at P 4; *see also Western Grid Dev., LLC*, 130 F.E.R.C. ¶ 61,056 (2010), *reh’g denied*, 133 F.E.R.C. ¶ 61,029 (2010).

407. 164 F.E.R.C. ¶ 61,197 at PP 3-4.

408. *Id.* at PP 10-11.

409. *Id.* at P 23.

410. *Utilization of Electric Storage Resources for Multiple Services When Receiving Cost-Based Rate Recovery*, 158 F.E.R.C. ¶ 61,051 at PP 9, 13 (2017).

cost recovery, and not on whether a particular electric storage resource is a transmission facility eligible for cost recovery.⁴¹¹

7. *California Independent System Operator Corp.*

On October 29, 2018, FERC issued an order accepting proposed tariff revisions submitted by CAISO, effective November 1, 2018.⁴¹² Specifically, FERC accepted the CAISO's proposal to refine its market rules associated with Energy Imbalance Market (EIM) bid adders, which reflect an EIM participating resource's costs to comply with California's greenhouse gas regulations, to limit the hourly megawatt quantity of an EIM bid adder that can be used in the market optimization to the EIM participating resource's dispatchable bid range between the resource's base schedule and its effective upper economic bid for the relevant operating hour.⁴¹³ FERC also directed CAISO to submit an informational report to FERC by January 1, 2020, that describes the extent to which certain specified types of situations materialize during the 12 months after the implementation of the tariff revisions.⁴¹⁴

8. *California Independent System Operator Corp.*

On November 14, 2018, FERC issued an order accepting the following proposed revisions to the CAISO tariff related to CAISO's provision of reliability coordinator (RC) service in the Western Interconnection: (1) a new tariff section containing the provisions specific to RC service;⁴¹⁵ (2) a *pro forma* RC service agreement to be entered into by RC customers receiving RC service from CAISO;⁴¹⁶ and (3) a rate schedule to implement the RC service charge.⁴¹⁷ As requested by CAISO, FERC accepted most of the tariff revisions effective November 15, 2018 and accepted the balance of the tariff revisions related to the RC rate schedule to become effective July 1, 2019.⁴¹⁸

9. *California Independent System Operator Corp.*

On November 26, 2018, FERC issued an order on tariff revisions filed by CAISO to temporarily keep in place previously accepted CAISO tariff provisions intended to address the effects of natural gas system limitations on CAISO's system and market operations related to the limited operability of the Aliso Canyon gas storage facility.⁴¹⁹ Specifically, FERC accepted CAISO's proposals to extend, until December 31, 2019, previously accepted tariff provisions to (1) improve the accuracy of the gas commodity price indices used in the CAISO's day-ahead market by reflecting the most recent gas commodity price information;⁴²⁰ (2) allow scheduling coordinators to seek after-the-fact cost recovery of incremental fuel costs associated with default energy bids and generated bids by submitting a filing

411. 164 F.E.R.C. ¶ 61,197 at P 24.

412. *California Indep. Sys. Operator Corp.*, 165 F.E.R.C. ¶ 61,050 at P 1 (2018).

413. *Id.* at PP 1, 7, 17.

414. *Id.* at P 18.

415. *California Indep. Sys. Operator Corp.*, 165 F.E.R.C. ¶ 61,116 at P 4 (2018).

416. *Id.* at P 1.

417. *Id.*

418. *Id.* at PP 45-51.

419. *California Indep. Sys. Operator Corp.*, 165 F.E.R.C. ¶ 61,161 at P 1 (2018).

420. *Id.* at P 16.

to FERC pursuant to section 205 of the FPA;⁴²¹ (3) implement a natural gas constraint that limits the maximum amount of gas that can be burned by gas-fired resources in the Southern California Gas Company and SDG&E gas regions;⁴²² (4) allow CAISO to deem certain internal transmission constraints to be uncompetitive as part of CAISO's local market power mitigation process when it enforces a gas constraint;⁴²³ (5) allow CAISO to suspend virtual bidding when virtual bids may detrimentally affect market efficiency due to the enforcement of a natural gas constraint;⁴²⁴ and (6) allow CAISO to provide scheduling coordinators with advisory day-ahead commitment schedules produced in CAISO's residual unit commitment process on a two-day-ahead basis.⁴²⁵ FERC rejected CAISO's proposal to extend, until December 31, 2019, previously accepted tariff provisions to allow CAISO to increase or decrease the gas commodity price it uses to calculate commitment cost caps and default energy bids in its real-time market by applying gas price scalars.⁴²⁶ FERC also directed CAISO to submit a compliance filing to remove the gas price scalar proposal.⁴²⁷

G. Southeast

1. *Piedmont Municipal Power Agency v. Duke Energy Carolinas, LLC*

In this case, FERC granted a complaint brought by Piedmont Municipal Power Agency (Piedmont) against Duke Energy Carolinas, LLC (DEC), under sections 206 and 306 of the FPA asserting that DEC has inappropriately assessed against Piedmont wholesale transmission charges related to amortized deferred costs recorded in FERC Account 406 without receiving approval from FERC in violation of the filed-rate doctrine and the Backstand Service Agreement on file at FERC.⁴²⁸ The Backstand Service Agreement concerns purchases by Piedmont from DEC for capacity and energy when entitlements from the Catawba Nuclear Station Units 1 and 2 and McGuire Nuclear Station Units 1 and 2 are unavailable due to planned or unplanned outages or temporary reductions.⁴²⁹

FERC granted the complaint, and set the matter for settlement and hearing procedures, finding that DEC had failed to satisfy its obligation to obtain prior approval under FPA section 205 to recover these wholesale transmission charges.⁴³⁰ FERC held that the fact that the charges were recorded in an account for developing rates that the utility is authorized to charge for utility services does not constitute approval for ratemaking purposes.⁴³¹ FERC further held that it has exclusive jurisdiction over wholesale rates and is not bound by state commission

421. *Id.* at P 34.

422. *Id.* at P 35.

423. *Id.* at P 45.

424. 165 F.E.R.C. ¶ 61,161 at P 45.

425. *Id.*

426. *Id.* at P 50.

427. *Id.* at PP 47-51.

428. *Piedmont Mun. Power Agency v. Duke Energy Carolinas, LLC*, 162 F.E.R.C. ¶ 61,109 at P 1 (2018).

429. *Id.* at P 2.

430. *Id.* at P 41.

431. *Id.* at PP 31-32.

decisions when examining retail rates.⁴³² Finally, FERC ruled that the fact that the Backstand Service Agreement had been accepted for filing in a delegated letter order, by its own terms, “does not authorize recovery of costs without pre-approval by means of a section 205 filing.”⁴³³ FERC directed DEC to refund to Piedmont all amounts improperly billed under the Backstand Service Agreement.⁴³⁴

III. TRANSMISSION RATES/FORMULA RATES

A. *Kansas Corp. Comm’n v. FERC*

In this case, the D.C. Circuit found that the Kansas Corporation Commission (KCC) lacked standing to challenge several orders in which FERC granted requests by public utilities to approve formula rates for use by the utilities’ future affiliates.⁴³⁵ The KCC argued that FERC’s preapproval of rates for use by public utilities “at some unknown time in the future” was inconsistent with FERC’s obligation under section 205 of the FPA to review rates to ensure they are just and reasonable.⁴³⁶ The court concluded, however, that “[b]y that same argument . . . KCC has not suffered an injury in fact sufficient to establish standing.”⁴³⁷ The KCC’s arguments that FERC had violated the FPA and fixed legal rights, the court reasoned, amounted to “no more than a generalized interest in the proper application of the law” insufficient to establish injury in fact.⁴³⁸ And any burden that the orders might impose on KCC to challenge the rates of future affiliates under section 206 of the FPA was “not imminent.”⁴³⁹ Finding that the harm alleged by KCC was “conjectural or hypothetical,”⁴⁴⁰ the court observed that “[t]he particularized effect of FERC’s orders will not be felt by KCC unless an ‘attenuated chain of possibilities’ occurs.”⁴⁴¹ Finally, the court found that KCC could not establish injury in fact based on a claim that it would be bound by the challenged orders in any proceeding involving use of the formula rates by future affiliates.⁴⁴²

B. *Alcoa Power Generating Inc.--Long Sault Division, et al.*

On December 22, 2017, the Tax Cuts and Jobs Act lowered the federal corporate income tax rate from a minimum 35% to a flat 21% rate, effective January 1, 2018. In response, on March 13, 2018 and March 15, 2018, FERC issued a series of unconsolidated show cause orders directing a number of public utilities

432. *Id.* at P 32, n.46 (citing *Virginia Elec. and Power Co.*, 128 F.E.R.C. ¶ 61,026 at PP 22, 31-34 (2009)).

433. 162 F.E.R.C. ¶ 61,109 at P 37.

434. *Id.* at Ordering Paragraph (F).

435. *Kansas Corp. Comm’n v. FERC*, 881 F.3d 924, 926 (D.C. Cir. 2018), *pet. for en banc review denied*, 2018 U.S. App. LEXIS 9045 (April 10, 2018).

436. *Id.* at 929.

437. *Id.* at 926.

438. *Id.* at 930.

439. *Id.*

440. *Kansas Corp. Comm’n*, 881 F.3d at 930 (quoting *Lujan v. Defenders of Wildlife*, 504 U.S. 555, 560 (1992)).

441. *Id.* (quoting *Clapper v. Amnesty Int’l USA*, 568 U.S. 398, 410 (2013)).

442. *Id.* at 931.

(collectively, Respondents) to propose revisions to their transmission rates to reflect the change in the federal corporate income tax rate or to show cause why they should not be required to do so.⁴⁴³ A number of show cause orders were directed at transmission owners with formula rates with a fixed federal income tax rate.⁴⁴⁴ Another series of show cause orders were directed at transmission owners with stated transmission rates.⁴⁴⁵ Pursuant to those orders, FERC indicated that it would consider proposals to review Respondents' proposed revisions on a single-issue ratemaking basis.⁴⁴⁶ In response, Respondents took various positions, with a few Respondents opting to show why they should not have to revise rates,⁴⁴⁷ others indicating they would make a complete rate case filing at a later date,⁴⁴⁸ and others using various methodologies to revise their rates.⁴⁴⁹

C. Ameren Illinois Company, et al.

On June 21, 2018, FERC instituted proceedings pursuant to section 206 of the FPA to examine the methodology used by various public utilities for calculating ADIT balances in their projected test year and/or annual true-up calculations for their transmission formula rates.⁴⁵⁰ FERC noted that, following the issuance of a Private Letter Ruling by the IRS in April 2017,⁴⁵¹ as well as a recent FERC order rejecting application of a two-step averaging methodology to certain transmission owners' annual formula rate true-up calculations,⁴⁵² it undertook a review of transmission formula rates and identified the Respondents as utilities that currently use the two-step averaging methodology to calculate the ADIT component of rate base in their projected test year calculations and/or annual true-up calculations.⁴⁵³ FERC stated that, if a public utility uses the proration methodology in the IRS's regulations to calculate ADIT balances in forward-looking formula rates, then the public utility need not apply an additional averaging step in order to comply with the IRS's Consistency Rule or Normalization Rules.⁴⁵⁴ FERC found that the Respondents' use of a two-step averaging methodology to determine ADIT balances may be unjust and unreasonable, or unduly discriminatory or preferential.⁴⁵⁵ The Commission stated that the Respondents could address the issue by revising their formula rate templates to eliminate the use of the two-step averaging methodology.⁴⁵⁶ The Commission directed the Respondents and other interested parties to file initial briefs no later than 30 days after publication in the Federal

443. *Alcoa Power Generating Inc.--Long Sault Division, et al.*, 162 F.E.R.C. ¶ 61,224 (2018).

444. *AEP Appalachian Transmission Co., et al.*, 162 F.E.R.C. ¶ 61,225 (2018).

445. 162 F.E.R.C. ¶ 61,224 at P 1.

446. *Id.* at PP 4-5.

447. *Citizens Sunrise Transmission, LLC*, 165 F.E.R.C. ¶ 61,101 (2018).

448. *Startrans IO, LLC*, 165 F.E.R.C. ¶ 61 at P 105 (2018).

449. *Alcoa Power Generating Inc. – Long Sault Div., et al.*, 165 F.E.R.C. ¶ 61,094 (2018).

450. *Ameren Illinois Co., et al.*, 163 F.E.R.C. ¶ 61,200 (2018).

451. *Id.* at P 7 (citing I.R.S. Priv. Ltr. Rul. 201717008 (Jan. 25, 2017) (released April 28, 2017)).

452. *Id.* at P 9 (citing *Midcontinent Indep. Sys. Operator, Inc.*, 163 F.E.R.C. ¶ 61,061 (2018)).

453. *Id.* at P 13.

454. *Id.*

455. 163 F.E.R.C. ¶ 61,200 at P 13.

456. *Id.* at P 14.

Register,⁴⁵⁷ and established a refund effective date as the date of the notice of the initiation of the proceedings in the Federal Register.⁴⁵⁸ The Commission noted that it expects to issue a final order within six months of receiving reply briefs.⁴⁵⁹

D. GridLiance West Transco LLC

On July 24, 2018, FERC granted a request by GridLiance West Transco LLC (GridLiance) for certain transmission incentives and established hearing procedures for the transmission project's overall ROE.⁴⁶⁰ The project, estimated at \$25 million, consists of upgrades to an existing 15-mile 230 kV facility located in southern Nevada.⁴⁶¹ FERC granted GridLiance's request for 100% recovery of prudently-incurred abandonment costs, inclusion of 100% CWIP in rate base, and a 50-basis point ROE adder for being an independent transmission company.⁴⁶² However, FERC stated that GridLiance's request for a 10.6% ROE was not just and reasonable, and set it for hearing procedures.⁴⁶³ Commissioner Glick concurred in the vote noting his view that FERC should conduct a comprehensive formal review of its transmission incentives policy.⁴⁶⁴

E. AEP Appalachian Transmission Company, Inc.

On March 15, 2018, FERC issued several orders to address the effects of the Tax Cuts and Jobs Act.⁴⁶⁵ This order followed the Show Cause Orders issued to certain public utilities that use transmission formula rates with a fixed line item of 35 percent for the federal corporate income tax rate under an open access transmission tariff or transmission owner tariff.⁴⁶⁶ A number of public utilities named as respondents in the Show Cause Orders proposed revisions to their transmission formula rates.⁴⁶⁷ In this Order, the Commission accepted the proposed revisions, explaining: "This change to Respondents' transmission formula rates will ensure that the customers receive the benefits of the reduced federal corporate income tax rate when Respondents make their formula rate true-up calculations for rate year 2018 in their 2019 true-ups."⁴⁶⁸ In addition, the Commission terminated the section 206 proceedings established by the Show Cause Orders. The Commission noted that this Order did not address all of the proceedings initiated by the Show Cause Order, and other proceedings will be addressed in other orders.⁴⁶⁹

457. *Id.* at P 16.

458. *Id.* at P 17.

459. *Id.*

460. *GridLiance West Transco LLC*, 164 F.E.R.C. ¶ 61,049 (2018).

461. *Id.* at P 3.

462. *Id.* at P 1.

463. *Id.* at P 17.

464. 164 F.E.R.C. ¶ 61,049 at P 2 (Glick, R., concurring).

465. *AEP Appalachian Transmission Co.*, 165 F.E.R.C. ¶ 61,092 at P 2 (2018); *see also* Tax Cut and Jobs Act, *supra* note 59.

466. *AEP Appalachian Transmission Co.*, 162 F.E.R.C. ¶ 61,225 at P 5 (2018).

467. 165 F.E.R.C. ¶ 61,092 at P 6.

468. *Id.* at P 18.

469. *Id.* at P 1 n.1.

F. Association of Businesses Advocating Tariff Equity v. Midcontinent Independent System Operator, Inc.

On November 15, 2018, the Commission issued an order calling for briefs in two complaint proceedings addressing the appropriate ROE to be included in transmission rates of the transmission-owning members of MISO⁴⁷⁰ following a remand of previous Commission orders by the D.C. Circuit.⁴⁷¹

On October 18, 2018, FERC responded to the *Emera Maine* remand by proposing a new methodology for determining whether an existing ROE remains just and reasonable and, if not, for determining the new just and reasonable ROE.⁴⁷² With regard to determining whether an existing ROE remains just and reasonable, the Commission proposes that, rather than relying solely on the DCF method as it has done in the past, it will now utilize three financial models that produce zones of reasonableness – the DCF, the Capital Asset Pricing Model (CAPM), and the expected earnings model.⁴⁷³ The zone of reasonableness produced by each model would be given equal weight and averaged to determine the composite zone of reasonableness.⁴⁷⁴ The Commission would then determine whether the utility or utilities at issue were of below-average, average, or above-average risk as compared to the proxy group.⁴⁷⁵ For a utility of average risk, the existing ROE would presumptively be just and reasonable⁴⁷⁶ if it were within the quarter of the zone of reasonableness centered on the midpoint.⁴⁷⁷ For a utility of below average risk, the existing ROE would presumptively be just and reasonable⁴⁷⁸ if it were within the quarter of the zone of reasonableness centered on the lower midpoint.⁴⁷⁹ For a utility of above average risk, the existing ROE would presumptively be just and reasonable if it were within the quarter of the zone of reasonableness centered on the upper midpoint.⁴⁸⁰

If the Commission determines that the existing ROE has become unjust and unreasonable, it must then proceed to set the new just and reasonable ROE. Rather than continuing to rely solely on the DCF method, FERC now proposes to use the three financial models mentioned above plus the Risk Premium method.⁴⁸¹ To do so, the Commission will average the central tendency of each of the first three methods plus the estimated cost of equity produced by the Risk Premium

470. *Association of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 165 F.E.R.C. ¶ 61,118 (2018) (Briefing Order); see also Opinion No. 551, *Association of Businesses Advocating Tariff Equity v. Midcontinent Indep. Sys. Operator, Inc.*, 156 F.E.R.C. ¶ 61,234 (2016) (*ABATE*), *reh'g pending*; see also *Arkansas Elec. Coop. Corp. v. ALLETE, Inc.*, 155 F.E.R.C. ¶ 63,030 (2016) (exceptions pending).

471. *Emera Maine v. FERC*, 854 F.3d 9 (D.C. Cir. 2017).

472. *Coakley v. Bangor Hydro-Elec. Co.*, 165 F.E.R.C. ¶ 61,030 at P 1 (2018).

473. *Id.* at P 4.

474. *Id.* at P 15.

475. *Id.*

476. *Id.* at P 26.

477. 165 F.E.R.C. ¶ 61,030 at P 57.

478. *Id.* at P 17.

479. *Id.* at P 30 n.63.

480. *Id.*

481. *Id.* at P 4.

method.⁴⁸² In the Briefing Order, FERC has directed briefs regarding whether and how the proposed methodology should apply to pending MISO complaints.

G. Arkansas Public Service Comm'n v. System Energy Resources, Inc.

On October 16, 2018, the Commission issued an Order Directing Briefs in which it proposed a new methodology for analyzing the base ROE component of rates under section 206 of FPA,⁴⁸³ and directed the participants to the applicable proceedings to submit briefs regarding the proposed new methodology.⁴⁸⁴ In the order, the Commission provided guidance regarding the effect of the Briefing Order on pending proceedings involving base ROE issues that have been set for hearing and settlement judge procedures.⁴⁸⁵ Given that the Commission “expect[s] the participants to ongoing proceedings [involving base ROE issues that have been set for hearing and settlement judge procedures] to address the merits and application of the proposed methodology in their [respective] proceedings,”⁴⁸⁶ the Commission determined that it was not necessary to hold currently ongoing proceedings in abeyance until the Commission issued an order after briefs were submitted in the Briefing Order.⁴⁸⁷ Thus, in its Ordering Paragraph, the Commission directed participants to ongoing proceedings and applicable Administrative Law Judges to continue with their ongoing proceedings.

H. Oklahoma Municipal Power Authority v. Oklahoma Gas and Electric Company

Under sections 206 and 306 of the FPA, Oklahoma Municipal Power Authority (OMPA) filed a complaint under FPA sections 206 and 306 against Oklahoma Gas and Electric Company (OG&E), contending that OG&E’s base ROE, which is a fixed component of OG&E’s transmission formula rate, was unjust and unreasonable and should be reduced to OG&E’s current equity cost level.⁴⁸⁸ OMPA also argued that OG&E’s formula rate required modification to appropriately reflect all of the effects of the Tax Cuts and Jobs Act of 2017 on OG&E’s ATRR.⁴⁸⁹

The Commission issued the complaint and set all matters for investigation under FPA section 206, which includes a trial-type evidentiary hearing, and settlement judge procedures.⁴⁹⁰ The Commission also found that OMPA’s two-step DCF analysis was adequate to establish a prima facie case that OG&E’s cost of equity may have declined significantly below the level of its existing 10.6% base ROE.⁴⁹¹ Additionally, the Commission concluded that any tax-related changes to

482. 165 F.E.R.C. ¶ 61,030 at P 59.

483. 16 U.S.C. § 824e (2005).

484. 165 F.E.R.C. ¶ 61,030 at P 61.

485. *Arkansas Pub. Serv. Comm'n v. Sys. Energy Res., Inc.*, 165 F.E.R.C. ¶ 61,119 at P 1 (2018).

486. *Id.* at P 5.

487. *Id.* at P 6.

488. *Oklahoma Mun. Power Auth. v. Oklahoma Gas & Elec. Co.*, 163 F.E.R.C. ¶ 61,114 at PP 1-2 (2018).

489. *Id.* at P 2.

490. *Id.* at P 3.

491. *Id.* at P 34.

OG&E's formula rate should ensure that OG&E's rates properly reflect the effects of the Tax Cuts and Jobs Act of 2017.⁴⁹²

IV. COMPLAINTS

A. *Turlock Irrigation District, et al. v. FERC*

In its September 2018 opinion in *Turlock Irrigation District, et al. v. FERC*,⁴⁹³ the Ninth Circuit found FERC's interpretation of the term "Adverse Impact" in an interconnection agreement to be overly narrow, and thus arbitrary and capricious.⁴⁹⁴ FERC rejected a complaint filed by Turlock Irrigation District and Modesto Irrigation District (collectively the Districts) against PG&E requesting FERC to order the utility to conduct a study to determine whether PG&E's decision to terminate a Remedial Action Scheme would have an adverse impact on the Districts, as that term is used in their interconnection agreements.⁴⁹⁵ The Ninth Circuit reaffirmed that although it reviews FERC's interpretation of contracts *de novo*, it will only defer to FERC's interpretation when FERC has relied on its technical expertise in framing that interpretation.⁴⁹⁶ In this case, the court found that FERC's "specialized knowledge of interconnected electrical systems may very well have informed its understanding of what qualifies as an 'Adverse Impact,'" but the agency "forfeited any deference it might otherwise have been owed by failing to demonstrate how its interpretations reflect its expertise in this area, or are typical of how those terms are used in the industry – or, indeed, by failing to even explain clearly how it interprets the terms at all."⁴⁹⁷

The Ninth Circuit also found FERC's decision arbitrary and capricious because the agency applied the wrong standard for initiating a study of potential Adverse Impacts under the interconnection agreement.⁴⁹⁸ The court found that the Interconnection Agreement requires PG&E to provide notice whenever a Long-Term Change to Operations "may reasonably result in an Adverse Impact" to a District's system, and that if the utility fails to provide such notice, the District has the right to demand a study if it has a "reasonable belief that the Long-Term Change to Operations may result or may have resulted in an Adverse Impact on [the District's] system."⁴⁹⁹ In denying the Districts' request for a study, the court found that FERC unlawfully applied a higher standard when it found that "the record reflects no supporting evidence regarding the likely impact on [the Districts'] Systems' due to the remedial action scheme reprogramming."⁵⁰⁰ By applying a different standard of proof than the one provided in the Interconnection Agreement, the court found that FERC breached the requirement for reasoned decision-

492. *Id.* at P 35.

493. *Turlock Irrigation Dist., et al. v. FERC*, 903 F.3d 862 (9th Cir. 2018).

494. *Id.* at 862.

495. *Id.* at 868.

496. *Id.*

497. *Id.* at 870.

498. *Turlock*, 903 F.3d at 872.

499. *Id.*

500. *Id.* at 873.

making, and thus acted arbitrarily and capriciously in rejecting the Districts' request for a study.⁵⁰¹ The court remanded the case to FERC for application of a broader definition of Adverse Impact that includes reductions in import capability into the Districts' systems and the proper standard for requesting a study of the effects of the determination to terminate the Remedial Action Scheme.⁵⁰²

B. Tilton Energy LLC v. PJM Interconnection, L.L.C.

On May 11, 2018, Tilton Energy LLC (Tilton), the owner of a 176 MW gas-fired facility (Facility) that is physically located in the MISO but pseudo-tied into PJM, filed a complaint against PJM after PJM notified Tilton that its pseudo-tie does not pass the market-to-market flowgate test set forth in the PJM tariff and, as a result, that the Facility would no longer be eligible to participate in the PJM capacity auctions after the 2021/2022 Delivery Year.⁵⁰³

On September 20, 2018, the Commission issued an order establishing paper hearing procedures to examine issues raised in the Complaint, including PJM's interpretation and application of the flowgate test, and established a refund effective date of May 11, 2018.⁵⁰⁴ The Commission outlined four issues to be developed in the paper hearing record: (1) how PJM determines whether a flowgate is "impacted by a Pseudo-Tie under the terms of the MISO-PJM JOA" and how PJM identifies an "eligible coordinated flowgate" resulting from a pseudo-tie from the MISO into PJM; (2) whether PJM applies the 5% shift factor threshold in the MISO-PJM JOA to determine "eligible coordinated flowgates" or, if not, why it does not, and whether this threshold or some other screen would be a reasonable means of identifying flowgates for which coordination could be required; (3) how PJM applied the flowgate test to the Tilton Facility's pseudo-tie; and (4) whether PJM intends to request, or expects MISO to request, coordination for any of the "eligible coordinated flowgates" identified for the Tilton Facility.⁵⁰⁵ Briefs were filed in late 2018. The Commission expects to render a decision prior to April 1, 2019.⁵⁰⁶

V. PUBLIC UTILITIES REGULATORY POLICY ACT

A. Zeeland Farm Services, Inc.

On May 17, 2018, FERC issued an order granting in part and denying in part Zeeland Farm Services, Inc.'s (Zeeland) request for waivers of certain filing requirements for qualifying facilities (QFs).⁵⁰⁷ Zeeland operates two 1.6 MW land-

501. *Id.*

502. *Id.* at 874.

503. Notice of Complaint, *Tilton Energy LLC v. PJM Interconnection, L.L.C.*, 83 Fed. Reg. 23,273 (2018).

504. *Tilton Energy LLC v. PJM Interconnection, L.L.C.*, 164 F.E.R.C. ¶ 61,204 (2018).

505. *Id.* at P 43.

506. *Id.* at P 46.

507. *Zeeland Farm Svcs., Inc.*, 163 F.E.R.C. ¶ 61,115 (2018).

fill gas-fueled electric biomass small power production facilities (located at Zeeland's soybean processing facility) that qualify as QFs; however, the QFs did not timely file their Form 556 self-certifications with FERC.⁵⁰⁸

Zeeland characterized the violations of the certification requirement as the result of a "good-faith, inadvertent error by individuals and companies otherwise not engaged in the power business."⁵⁰⁹ However, FERC found that Zeeland's reason for its failure to timely certify its facilities did not warrant a waiver of the filing requirement for the period between when the facilities would have been considered QFs and when the Form 556 self-certifications were filed.⁵¹⁰ FERC noted that Zeeland's units were out of compliance for many years and that Zeeland's arguments seeking waivers improperly minimize the importance of the filing requirement.⁵¹¹ FERC also found that Zeeland failed to identify extraordinary circumstances that would justify a waiver of the FPA's 60-day prior notice requirement to implement jurisdictional rates.⁵¹² Therefore, FERC ordered refunds of the time-value of money collected for the period the rate was collected without FERC authorization—that is, from the commencement of the sales until the date the QFs filed self-certifications, with the refunds limited so as not to cause the QFs to suffer a loss.⁵¹³

B. *Cloverland Electric Cooperative*

On July 9, 2018, FERC issued an order⁵¹⁴ denying Cloverland Electric Cooperative's (Cloverland) request under section 210(m) of the Public Utility Regulatory Policies Act of 1978 (PURPA),⁵¹⁵ to terminate its obligation under PURPA to enter into new power purchase obligations or contracts to purchase electric energy and capacity from QFs with a net capacity over 20 MW. Under PURPA section 210(m), electric utilities may seek termination of the requirement if FERC finds that the QFs have nondiscriminatory access to a relevant market under, including a wholesale market administered by an RTO/ISO.⁵¹⁶

FERC denied Cloverland's application because Cloverland attempted to rely on its status as a MISO market participant, though it is not itself a member of MISO.⁵¹⁷ FERC found that, even though Cloverland was a MISO market participant, membership in the RTO (or ISO) is a requirement for claiming an exemption under section 210(m)(1)(A).⁵¹⁸ FERC pointed out that the obligation to purchase

508. *Id.* at P 2.

509. *Id.* at P 4 (citation omitted).

510. *Id.* at P 11. However, FERC granted partial waivers of other applicable requirements so that the facilities could otherwise be treated as QFs for the period that the facilities were out of compliance with the certificate requirement. *Id.* at P 14.

511. *Id.* at P 13.

512. 163 F.E.R.C. ¶ 61,115 at P 16.

513. *Id.* at P 17 (citation omitted).

514. *Cloverland Elec. Coop.*, 164 F.E.R.C. ¶ 61,016 (2018).

515. 16 U.S.C. § 824a-3(m).

516. 16 U.S.C. § 824a-3(m)(1)(A).

517. 164 F.E.R.C. ¶ 61,016 at PP 9-10.

518. *Id.* at P 10.

from QFs resides with the electric utility, and that for purposes of applying a rebuttable presumption that QFs have nondiscriminatory access to the relevant wholesale markets, it draws a line with members of the RTO/ISO markets.⁵¹⁹ Entities that are not members are permitted to seek relief from the purchase obligation by making alternative showings, such as under section 210(m)(1)(B) or (C), pursuant to FERC's procedures in 18 C.F.R. § 292.310.⁵²⁰

C. Omaha Public Power District

On September 28, 2018, FERC issued an order denying rehearing⁵²¹ of an earlier order (issued on March 15, 2018 by the Director of the Division of Electric Power Regulation—Central pursuant to delegated authority)⁵²² granting the application of Omaha Public Power District (OPPD) to terminate its mandatory purchase requirement with respect to new contracts or obligations from QFs larger than 20 MW under section 210(m) of the PURPA.⁵²³ FERC rejected three arguments raised by Consolidated Edison Development (CED). First, FERC rejected CED's argument that CED's submission of an intervention in the proceeding rendered OPPD's application "contested," and, therefore, the Director was not permitted to act on the application pursuant to delegated authority.⁵²⁴ FERC found the fact that an intervention was filed did not make the matter contested.⁵²⁵ Second, FERC rejected CED's argument that the initial order's failure to acknowledge the intervention precluded CED from exercising its procedural right to comment on the application because CED was not required to wait for FERC to first grant its intervention before filing a protest, particularly since interventions and protests were due on the same date.⁵²⁶ Finally, CED argued on rehearing that its Burt County QF should be grandfathered under state law so that OPPD would not be excused from purchasing the output from that QF.⁵²⁷ Although FERC did not address the merits of CED's argument, since it was raised for the first time on rehearing, FERC noted that the initial order only granted the application with respect to *new* contracts or obligations, effective as of the date of filing of OPPD's application—December 21, 2017.⁵²⁸ FERC stated that to the extent CED seeks a determination that the Burt County QF had established a legally enforceable obligation prior to December 21, 2017, it could file a petition for a declaratory order with FERC.⁵²⁹

519. *Id.* at P 11.

520. *Id.* at P 9 (citing Order No. 688, *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, F.E.R.C. STATS. & REGS. ¶ 31,233, 71 Fed. Reg. 64,342 at P 125 (2006), *order on reh'g*, Order No. 688-A, F.E.R.C. STATS. & REGS. ¶ 31,250, 72 Fed. Reg. 35,871 (2007), *aff'd sub nom. American Forest & Paper Ass'n v. FERC*, 550 F.3d 1179 (D.C. Cir. 2008)).

521. *Omaha Pub. Power Dist.*, 164 F.E.R.C. ¶ 61,238 (2018).

522. *Id.* at P 1.

523. *Id.* at P 9.

524. *Id.*

525. 164 F.E.R.C. ¶ 61,238 at P 9.

526. *Id.* at P 10.

527. *Id.* at P 11.

528. *Id.* at PP 11-12.

529. 164 F.E.R.C. ¶ 61,238 at P 12.

VI. MISCELLANEOUS

A. *Monongahela Power Company, et al.*

In January 2018, FERC rejected without prejudice Monongahela Power Company's (Monongahela Power) application for approval of its acquisition of the Point Pleasants power plant from its unregulated marketing affiliate, finding that the Applicants had not demonstrated that the asset transfer would be in the public interest.⁵³⁰ FERC ruled that Monongahela Power did not qualify for the "safe harbor."⁵³¹ FERC determined that the mere fact that a state commission regulates an applicant and must approve the transaction at issue is insufficient to satisfy this safe harbor standard; instead, the Applicants must demonstrate that the state commission had adopted, or has in place, ring-fencing measures to protect customers against inappropriate cross-subsidization or the encumbrance of utility assets for the benefit of the unregulated affiliates.⁵³² FERC found no evidence to demonstrate that any ratepayer protections regarding cross subsidies were even proposed in the state proceeding.⁵³³ In addition to rejecting the Applicants' safe harbor claim, FERC found that Monongahela Power's competitive solicitation for the Pleasants Plant did not satisfy the *Ameren* guidelines, and denied authorization for the transaction without prejudice to a future application resulting from a new competitive solicitation process.⁵³⁴

B. *Wheatridge Wind Energy, LLC*

On January 18, 2018, FERC issued a proposed and final order granting the request of Wheatridge Wind Energy, LLC (Wheatridge), for an order under sections 210, 211, and 212 of the FPA, directing Umatilla Electric Cooperative (Umatilla) to interconnect with Wheatridge's proposed wind generation project (Project) and to provide transmission service to the Bonneville Power Administration (Bonneville).⁵³⁵ FERC found that "section 212(g) [of the FPA], which prohibits [FERC] from issuing an order that is inconsistent with state law governing retail marketing areas, [was] not implicated in the case."⁵³⁶ In addition, FERC found that Wheatridge's requested order would not cause Columbia Basin Electric Cooperative (Columbia Basin), which has a franchised retail service territory that is the location of the collector substation for energy from the Project, to lose its exclusive retail service territory or compel retail service in Columbia Basin's service territory to be provided by any entity other than Columbia Basin.⁵³⁷

530. *Monongahela Power Co., et al.*, 162 F.E.R.C. ¶ 61,015 (2018).

531. *Id.* at P 29.

532. *Id.*

533. *Id.* at P 30.

534. *Id.* at P 72.

535. *Wheatridge Wind Energy, LLC*, 162 F.E.R.C. ¶ 61,045 at P 1 (2018).

536. *Id.* at P 19.

537. *Id.* at P 21.

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