REPORT OF THE ELECTRICITY REGULATION COMMITTEE

This report covers significant calendar 2012 electric regulatory orders of the Federal Energy Regulatory Commission (FERC) and the Electric Reliability Council of Texas (ERCOT).*

I. INTRODUCTION

The Electricity Regulation Committee has a broad focus with a jurisdiction that overlaps that of several more tightly focused Energy Bar Association committees. Thus, this report generally does not address transmission reliability and planning (System Reliability, Planning, and Compliance Committee), wholesale market-based rates (Power Generation and Marketing Committee), enforcement (Compliance and Enforcement Committee), renewable energy and demand-side management (Renewable Energy Committee and Demand-Side Resources and Smart Grid Committee), or court appeals (Judicial Review Committee).

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II. RULEMAKINGS AND POLICY STATEMENTS

A. Order Nos. 1000-A and B

On May 17, 2012, Order No. 1000-A[1] denied all Order No. 1000 rehearing requests but provided clarifications, including: (1) Local transmission projects do not require approval at regional or inter-regional level unless the provider seeks to have their costs allocated in those plans;[2] (2) Regional plans must specify that enrolled parties are subject to project cost allocations if they receive benefits from the project;[3] (3) Public utility provider tariffs must describe how stakeholders may provide input on inter-regional facilities and cost allocation;[4] (4) Rights of first refusal (ROFRs) are not obviated where project costs are allocated solely to a retail distribution service;[5] (5) Non-incumbent qualification cannot require state approval to operate in the state or registration with the North American Electric Reliability Corporation (NERC);[6] (6) The same evaluation process must be used for non-incumbent and incumbent developer projects;[7] and (7) Non-public utility providers may choose whether to obtain FERC-jurisdictional transmission service.[8] Order No. 1000 cost-of-service principles were retained with clarifications, including the finding that postage stamp rate design can sometimes meet the requirement that costs be allocated commensurate with benefits received.[9]

Order 1000-B, issued October 18, 2012, granted clarifications.[10] The Order No. 681 allowance of preferences to load-serving entities in allocations of firm transmission rights remains.[11] A Federal Power Act (FPA) section 205 filing is not required for project specific application of a regional cost allocation policy.[12] The FERC has authority to eliminate incumbent transmission provider ROFRs for projects selected for cost allocation in a regional plan,[13] and incumbent ROFRs are eliminated for any new project selected for regional cost allocation.[14] Whether ROFRs could be maintained for smaller provider projects where all costs are allocated to a single zone with more than one transmission owner is left for the compliance stage.[15] To permit regional flexibility, clarification of how a

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1. Order No. 1000-A, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 139 F.E.R.C. ¶ 61,132 (2012).
2. *Id.* at P 190.
3. *Id.* at P 275.
4. *Id.* at PP 522-23.
5. *Id.* at PP 428-30.
6. *Id.* at PP 441, 443-44.
7. *Id.* at PP 441, 444.
8. *Id.* at PP 276-78.
9. *Id.* at P 735.
10. Order No. 1000-B, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 141 F.E.R.C. ¶ 61,044 (2012).
11. *Id.* at P 11.
12. *Id.* at PP 18-27.
13. *Id.* at P 37.
14. *Id.* at P 52.
15. *Id.* at P 54.

benefit-cost evaluation should apply to regional or inter-regional projects was not provided.[16]

B. Policy Statement on Promoting Transmission Investment Through Pricing Reform

The November 15, 2012 Policy Statement "provide[s] guidance regarding [the FERC's] evaluation of applications for electric transmission incentives under section 219 of the [FPA]."[17] First, under the nexus test, "applicants [must] demonstrate a connection between the incentive(s) requested under Order No. 679 and the proposed investment, and that the incentive(s) requested address the risks and challenges that a project faces."[18] The FERC "will no longer rely on the routine/non-routine analysis . . . as a proxy for the nexus test."[19] Instead, it is "necessary to analyze the need for each individual incentive, and the total package of incentives . . . ."[20] Second, the Policy Statement reaffirmed that certain rate incentives, including recovery of construction work in progress, "pre-commercial costs as an expense or as a regulatory asset," and costs of projects "that are abandoned for reasons beyond the applicant's control, . . . may mitigate risk not accounted for in the base [return on equity (ROE)]."[21] Applicants are to "examine the use of risk-reducing incentives before seeking an incentive ROE based on a project's risks and challenges."[22] The FERC declined to "specifically identify project characteristics or risks and challenges that would merit an incentive ROE,"[23] but offered general guidance.[24] Such projects may include those that "relieve chronic or severe grid congestion that has had demonstrated cost impacts to consumers, . . . unlock location constrained generation resources, . . . [or] apply new technologies to facilitate more efficient and reliable usage and operation of existing or new facilities."[25] The FERC "will no longer consider . . . a stand-alone incentive ROE based on . . . utilization of an advanced technology."[26] It will consider advanced technologies "as part of the overall nexus analysis."[27] Applicants must "demonstrate that alternatives to the project have been, or will be, considered in either a relevant transmission planning process or another appropriate forum."[28] The FERC "expects applicants . . . to limit[] the application of the incentive ROE . . . to a cost estimate."[29]

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16. *Id.* at P 64.

17. *Promoting Transmission Investment Through Pricing Reform*, 141 F.E.R.C. ¶ 61,129 at P 1 (2012).

18. *Id.* at P 6.

19. *Id.* at P 10.

20. *Id.*

21. *Id.* at P 11.

22. *Id.* The FERC clarifies that such an approach would not require applicants to file separate applications, but rather to demonstrate first "how risk-reducing incentives are utilized" and then demonstrate that "remaining risks and challenges merit an incentive ROE." *Id.* at P 11 n.12.

23. *Id.* at P 17.

24. *Id.*

25. *Id.* at P 21.

26. *Id.* at P 23.

27. *Id.*

28. *Id.* at P 25.

29. *Id.* at P 28.

C. Frequency Regulation Compensation

Order No. 755-A denied rehearing of two regulation service compensation issues.[30] As to dispatch signal responses requiring movement against the overall Area Control Error (ACE) correction, individual Regional Transmission Organizations (RTO) and Independent System Operators (ISO) have discretion in managing the energy limitations of regulation resources.[31] As to whether Order No. 755's "uniform payment to all cleared resources" required uniform payment within the system operator's footprint or a smaller region,[32] the FERC did not narrow the scope of regulation markets to subregions, but said RTOs/ISOs may propose such divisions.[33]

D. Changes to Electric Quarterly Reports

On September 21, 2012, Order No. 768[34] revised Electric Quarterly Report (EQR) content and extended EQR requirements to "non-public utility" market participants (as defined in FPA section 201(f)[35]) with "more than a *de minimis* market presence."[36] "*De minimis*" means "non-public utilities that make 4,000,000 MWh or less of annual wholesale sales."[37]

Order No. 770 replaced software-based EQR reporting with a web-based interface.[38]

III. RTO/ISO REGIONAL DEVELOPMENTS

A. ISO New England

Wholesale market efforts in New England in 2012 continued to focus largely on changes to, and implementation of, ISO New England Inc.'s (ISO-NE) Forward Capacity Market (FCM). On January 19, 2012, the FERC issued an order on the region's FCM redesign efforts,[39] granting partial rehearing,[40]

30. Order No. 755-A, *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, 138 F.E.R.C. ¶ 61,123 at P 1 (2012).

31. *Id.* at P 13.

32. *Id.* at P 11 (quoting Order No. 755, *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, F.E.R.C. STATS. & REGS. ¶ 31,324, 31,489, 76 Fed. Reg. 67,260, 67,283 (2011) (to be codified at 18 C.F.R. pt. 35)).

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

34. Order No. 768, *Electricity Market Transparency Provisions of Section 220 of the Federal Power Act*, 140 F.E.R.C. ¶ 61,232 (2012) [hereinafter Order No. 768].

35. 16 U.S.C. § 824(f) (2012) (non-public utilities are: "the United States, a State or any political subdivision of a State, an electric cooperative that receives financing under the Rural Electrification Act of 1993 or that sells less than 4,000,000 megawatt hours of electricity per year," or agents and instrumentalities of the foregoing).

36. Order No. 768, *supra* note 34, at P 1 & n.3.

37. *Id.* at P 54.

38. Order No. 770, *Revisions to Electric Quarterly Report Filing Process*, 141 F.E.R.C. ¶ 61,120 at P 1 (2012).

39. *ISO New England Inc.*, 138 F.E.R.C. ¶ 61,027 at P 1 (2012) [hereinafter January 19 Order].

40. *Id.* The FERC granted partial rehearing regarding the mitigation of out-of-market (OOM) resources clearing in prior Forward Capacity Auctions (FCA) that occurred before the implementation of new market rules required by the FERC's April 13, 2011 order in *ISO New England Inc.*, 135 F.E.R.C. ¶ 61,029 (2011) [hereinafter April 13 Order]. *Id.* at P 1 nn.1-2. The January 19 Order, *supra* note 39, along with the April 13 Order, *supra*, are referred to collectively as the FCM Redesign Orders.

granting clarification,[41] and otherwise denying rehearing of its April 13 Order, which was summarized in this Committee's 2012 Report.[42] The January 19 Order reaffirmed that the FCM redesign must include an offer floor mitigation regime and more comprehensive zonal modeling, "with mitigation rules that address seller-side market power."[43]

On January 31, ISO-NE and the New England Power Pool Participants Committee (NEPOOL) filed a broadly supported agreement to extend the current FCM rules with two changes[44] through the FCM auction for the 2016-2017 capacity commitment period to be held in February 2013 (FCA 7) and, for FCM auctions and periods beyond that, to explore and develop additional improvements to the FCM design.[45] The FERC accepted that agreement on March 30, 2012, but directed ISO-NE to "file rules fulfilling its compliance obligations under the [FCM Redesign Orders] in time for implementation by FCA 8, that is, by December 3, 2012."[46] Following an extensive stakeholder process, ISO-NE filed on December 3, 2012, a contested package of revisions to the FCM and FCM-related rules in response to the FCM Redesign Orders.[47]

Regarding FCM auction activity in 2012, the FERC accepted the informational filing preceding,[48] and the results of,[49] the sixth FCM auction for the June 2015 through May 2016 capacity commitment period.

On July 31, 2012, the FERC conditionally accepted changes to New England's regional system planning process (RSP) that clarify how to treat resources that seek unsuccessfully to leave the FCM through De-List Bids or Non-Price Retirement Requests ISO-NE rejects for reliability reasons.[50] The FERC noted "in accordance with its commitment to make pertinent information widely available, ISO-NE will make a reasonable effort to provide its stakeholders, in as timely a manner as reasonably possible, information on, *inter alia*, the criteria used and basis for determining whether or not to conduct studies for de-list bids"[51] and conditioned acceptance on revised tariff sheets reflecting this understanding.[52] The first compliance filing was rejected.[53] A second, submitted November 26, 2012, is pending.[54]

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41. January 19 Order, *supra* note 39, at P 1. The FERC granted clarification on the issues of (i) "whether categorical exemptions from offer floor mitigation can be introduced and developed through the . . . stakeholder process," and (ii) "whether the . . . stakeholder process may consider the costs to be included in the demand response benchmark." *Id.* at P 1 n.3.

42. *Report of the Electricity Regulation Committee*, 33 ENERGY L.J. 227, 234-35 (2012) [hereinafter *2012 Report*].

43. January 19 Order, *supra* note 39, at P 1.

44. FCM-Related ISO-NE Tariff Revisions Filing, ISO New England Inc. and New England Power Pool Participants Comm., FERC Docket No. ER12-953 (Jan. 31, 2012). The changes (1) extend and set the floor price for the seventh FCM auction at $3.15/kW-month, and (2) result in the modeling of four load zones for each FCM auction. *Id.* at 3.

45. *Id.* at 2-3.

46. *ISO New England Inc.*, 138 F.E.R.C. ¶ 61,238 at Ordering P (B) (2012).

47. *See generally* Forward Capacity Market Redesign Compliance Filing, FERC Docket No. ER12-953-001 (Dec. 3, 2012).

48. *ISO New England Inc.*, 138 F.E.R.C. ¶ 61,196 (2012).

49. *ISO New England Inc.*, 140 F.E.R.C. ¶ 61,143 (2012).

50. *ISO New England Inc.*, 140 F.E.R.C. ¶ 61,088 (2012).

51. *Id.* at P 30.

52. *Id.* at P 32.

On December 7, 2012, the FERC accepted and suspended revisions to the ISO-NE Information Policy to allow it to disclose, under a nondisclosure agreement (NDA) between it and a natural gas pipeline company, confidential forecast and real-time output information on New England natural gas-fueled generation to operating personnel of pipelines serving those resources.[55] ISO-NE submitted this as a "step in a series of operational and market" changes to ensure reliability and market efficiency by "facilitating communication and coordination between control room operators of the electric and gas networks."[56] The filing was challenged by generators concerned that the NDA did not sufficiently protect their business interests. The FERC set the changes for accelerated settlement procedures.[57] The parties could not reach settlement and those procedures were terminated.[58] An ISO-NE request for expedited rehearing and clarification of the December 7 Order was then submitted and is pending.[59]

On April 19, 2012, the FERC accepted ISO-NE and New York Independent System Operator, Inc. (NYISO) tariff changes to add real-time external transaction bidding and scheduling rules, together known as Coordinated Transaction Scheduling (CTS), to enhance the market efficiency of transactions over certain ISO-NE/NYISO AC interfaces.[60] The changes are effective August 1, 2013, subject to two weeks' notice of the actual effective date.[61] In accepting the changes, the FERC noted substantial consumer and production cost savings in both the ISO-NE and NYISO.[62]

B. New York Independent System Operator

On March 15, 2012, the FERC rejected the NYISO proposal to minimize Lake Erie region loop flows.[63] NYISO proposed a new interface pricing policy for transactions to export power from NYISO into the PJM Interconnection, L.L.C. (PJM) system around Lake Erie and through both the Ontario Independent Electricity System Operator (ISEO) and the Midwest Independent Transmission System Operator, Inc. (MISO).[64] The FERC found that the use of two distinct modes of pricing and scheduling did not comply with earlier

53. *ISO New England Inc.*, 141 F.E.R.C. ¶ 61,072 at P 1 (2012).

54. Filing of ISO New England Inc. in Compliance with Order in FERC Docket No. ER12-1914, FERC Docket No. ER12-1914-001 (Nov. 26, 2012).

55. *ISO New England Inc.*, 141 F.E.R.C. ¶ 61,196 (2012), *reh'g requested*, FERC Docket No. ER13-356-001 (Dec. 19, 2012).

56. *Id.* at P 5.

57. *Id.* at PP 31-34.

58. Order of Chief Judge Terminating Settlement Judge Procedures, FERC Docket No. ER13-356-000 (Dec. 14, 2012).

59. Request for Expedited Rehearing and Clarification of ISO New England Inc., FERC Docket No. ER13-356-000 (Dec. 19, 2012).

60. *ISO New England Inc.*, 139 F.E.R.C. ¶ 61,047 at P 1 (2012) [hereinafter *ISO-NE CTS Order*]; *New York Indep. Sys. Operator, Inc.*, 139 F.E.R.C. ¶ 61,048 at P 1 (2012) [hereinafter *NYISO CTS Order*].

61. *ISO-NE CTS Order*, *supra* note 60, at PP 19, 23; *NYISO CTS Order*, *supra* note 60, at P 27. In its compliance filing, NYISO is also required to identify its CTS-enabled proxy generator buses. *NYISO CTS Order*, *supra* note 60, at P 27.

62. *ISO-NE CTS Order*, *supra* note 60, at P 24; *NYISO CTS Order*, *supra* note 60, at P 29.

63. *New York Ind. Sys. Operator, Inc.*, 138 F.E.R.C. ¶ 61,195 at P 1 (2012).

64. *Id.* at P 3.

orders.[65] NYISO was "required to submit a further compliance filing that includes . . . an interface pricing methodology that uses NERC tag information to determine actual source and sink for a transaction and calculates prices based on the actual energy flows at all times."[66]

On rehearing, the FERC ruled NYISO must "submit a detailed proposal along with complete explanations of how its proposal will better align scheduled and real-time energy flows."[67]

On September 20, 2012, the FERC accepted a NYISO and PJM compliance proposal to jointly manage specific flowgates and relieve congestion,[68] including revisions to the NYISO-PJM Joint Operating Agreement (JOA), for monetary settlements resulting from redispatch requests, and rules on "when the redispatch process must be initiated, and . . . terminated."[69] A further compliance filing must consider the impact of certain phase angle regulators when they operate.[70]

On June 22, 2012, the FERC granted in part and denied in part a complaint against NYISO alleging flawed implementation of buyer-side market power mitigation in the New York City installed capacity (ICAP) market, with the potential to "artificially suppress prices [there] and permit uneconomic market entry."[71] The FERC found NYISO's implementation generally "sufficiently transparent and objective,"[72] but directed certain adjustments to NYISO's calculation of mitigation and offer floor exemptions.[73] It rejected assertions that NYISO's determination that a project's unit net cost of new entry was deficient.[74]

C. PJM Interconnection

In February 2012, PJM filed modifications to its interconnection queue.[75] On April 30, 2012, the FERC accepted moving to a six-month queue cycle, a sliding queue component, a separate small generation project queue process, modifications to the use of deactivating units Capacity Interconnection Rights, and revisions to the suspension process for projects and deposits.[76] It required PJM (1) to make deadlines for studies and assurances binding, (2) to clarify what constitutes a "material adverse effect," and (3) to explain modified deposits for small generation interconnections.[77]

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65. *Id.* at P 18 (noting a failure to comply with *New York Ind. Sys. Operator, Inc.*, 133 F.E.R.C. ¶ 61,276 (2010), and *New York Ind. Sys. Operator, Inc.*, 136 F.E.R.C. ¶ 61,011 (2011)).

66. *Id.* at P 21.

67. *New York Indep. Sys. Operator, Inc.*, 140 F.E.R.C. ¶ 61,140 at P 21 (2012).

68. *New York Indep. Sys. Operator, Inc.*, 140 F.E.R.C. ¶ 61,205 at PP 4, 19 (2012).

69. *Id.* at PP 7-8.

70. *Id.* at P 21.

71. *Astoria Generating Co. v. New York Ind. Sys. Operator, Inc.*, 139 F.E.R.C. ¶ 61,244 at PP 1, 10 (2012).

72. *Id.* at P 3.

73. *Id.* at PP 60-63, 72-76, 85-87.

74. *Id.* at PP 93, 105-113.

75. PJM Interconnection, L.L.C. OATT Modifications, FERC Docket No. ER12-1177-000 (Feb. 29, 2012).

76. *PJM Interconnection, L.L.C.*, 139 F.E.R.C. ¶ 61,079 (2012).

77. *Id.* at PP 35, 66, 71.

On July 11, 2012, the FERC granted a FirstEnergy Solutions Corp. and Allegheny Energy Supply Company, LLC (collectively, FirstEnergy) complaint against PJM contending that when existing transmission capability not reflected in PJM's annual model for allocating auction revenue rights (ARRs) later "becomes available during the planning period, it is unjust and unreasonable for [load-serving entities] who . . . had their ARR requests pro-rated in the annual allocation to be denied the [newly-available financial transmission rights (FTRs)] (or the corresponding ARRs)."[78] The FERC found PJM's tariff

> unjust, and unreasonable, and unduly discriminatory, because it fails to allocate the ARRs or the revenue associated with the FTRs resulting from the return to service of existing transmission capability to parties with historic rights over these paths, and because it varies the allocation of ARRs or the revenue associated with the FTRs depending on whether they become available from the return to service of existing transmission capability or result from newly-constructed or upgraded transmission capability.[79]

PJM is to apply the same procedures for the return to service of upgraded or newly-constructed capability, which allocate additional ARRs associated with such capability to customers whose ARRs were pro-rated in the annual allocation.[80]

In September 2012, the FERC denied rehearing[81] of the American Transmission Systems, Inc. (ATSI) Realignment Order,[82] reaffirming its finding that "ATSI's voluntary choice to move from [MISO to PJM] does not render the transmission expansion cost allocation methodologies of either RTO unjust or unreasonable or unduly discriminatory simply because [they] may differ."[83]

D. Midwest Independent System Operator

In 2009, the MISO brought suit in a United States district court for breach of contract and promissory estoppel relating to Duquesne Light Company's (Duquesne) efforts to remain a transmission-owning member of PJM and to avoid integrating into the MISO region.[84] As required by the court, MISO requested that the FERC establish procedures to consider three issues: first, that the FERC assess whether Duquesne's execution of the Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc. (TOA) created a binding commitment to MISO; second, if so, determine whether Duquesne had to pay the withdrawal fee specified in TOA; and third, if so, determine what a just and reasonable exit fee would be.[85] The FERC determined the TOA was a binding commitment,[86] and

78. *FirstEnergy Solutions Corp. v. PJM Interconnection, L.L.C.*, 140 F.E.R.C. ¶ 61,019 at PP 1, 7 (2012).

79. *Id.* at P 23.

80. *Id.* at PP 23, 26-27.

81. *American Transmission Sys., Inc. v. PJM Interconnection, L.L.C.*, 140 F.E.R.C. ¶ 61,226 (2012).

82. *American Transmission Sys., Inc. v. PJM Interconnection, L.L.C.*, 129 F.E.R.C. ¶ 61,249 (2009).

83. 140 F.E.R.C. ¶ 61,226, at P 22.

84. Midwest Indep. Transmission Sys. Operator, Inc. v. Duquesne Light Co., No. 1:09-cv-1289-TWP-DML, 2010 WL 2771873, at *4-5 (S.D. Ind. July 12, 2010) (granting motion to stay pending agency adjudication).

85. *Id.* at P 7.

Duquesne had to pay an exit fee,[87] but it set the fee amount for hearing and settlement.[88]

On April 20, 2012, Southwest Power Pool, Inc. (SPP) filed a JOA (WAPA-SPP Agreement) between SPP and Western Area Power Administration, Upper Great Plains Region (WAPA).[89] Four days later, SPP and WAPA, among others, petitioned for FERC findings as to a JOA between SPP and MISO (MISO-SPP Agreement) that: (1) MISO had to "respect the reciprocal coordinated flowgates of a third party that has executed a reciprocal coordination agreement with SPP"; (2) the proposed WAPA-SPP Agreement is such an agreement; and (3) MISO must respect WAPA's flowgates as reciprocal coordinated flowgates.[90]

The FERC conditionally accepted, observing "it [would] enhance coordination between the parties."[91] It required clarification that the WAPA-SPP Agreement did not apply to transmission owners in other regions.[92] It ruled the Congestion Management Process, implemented as a service under Part II of Module F of MISO's tariff, "requires reciprocity with third parties [with] reciprocal coordination agreements with one or more of the parties to a reciprocal agreement."[93] Because of the WAPA and MISO reciprocal coordination agreements with SPP, MISO had to "treat its flowgates with [WAPA] as reciprocal coordinated flowgates."[94]

On April 19, 2012, the FERC approved MISO's transmission project cost allocations for a five-year transition period after Entergy joins MISO.[95] Costs of new transmission projects are to be allocated separately to Entergy and the current MISO footprint, each called a "Planning Area," to ensure "comparability."[96] The FERC found a transition was needed. First, Entergy must be brought into the MISO planning process, which differs from Entergy's.[97] Once all reliability, economic, and Multi-Value (MVP) Projects that meet MISO-defined benefits criteria are identified, the MISO and Entergy areas will have achieved comparability for those types of projects.[98] Second, upgrade benefits should be commensurate with costs incurred.[99] MVP portfolio costs are spread across all loads, but the 2011 MVP portfolio was planned

86. *Id.* at PP 24-32.
87. *Id.* at PP 37-39.
88. *Id.* at PP 43-47.
89. *Southwest Power Pool, Inc.*, 140 F.E.R.C. ¶ 61,199 at P 1 (2012).
90. *Id.* at PP 1, 11.
91. *Id.* at P 101.
92. *Id.* at PP 91, 106.
93. *Id.* at PP 7, 45.
94. *Id.* at P 45.
95. *Midwest Independent Transmission System Operator, Inc.*, 139 F.E.R.C. ¶ 61,056 at PP 1, 12 (2012).
96. *Id.* at PP 9-10, 28.
97. *Id.* at P 93.
98. *Id.* at PP 99, 115.
99. *Id.* at P 115.

without Entergy.[100] Only after a portfolio including Entergy is developed, may costs be spread across both planning areas.[101]

In response to concerns raised by certain MISO stakeholders in prior proceedings, on May 17, 2012, the FERC commenced an investigation of whether MISO's formula rate protocols ensure just and reasonable rates, and whether their scope of participation, transparency, and ability for interested parties to challenge transmission owners' implementation of formula rates is adequate.[102] The protocols set out processes for receiving, validating, and sharing information and calculating transmission rates.[103]

On March 30, 2012, the FERC accepted a MISO interconnection queue reform proposal,[104] and on June 27, 2012, accepted MISO's compliance filing.[105] The FERC found they would provide additional certainty for developers in financing projects. Improvements include removal of most front-end timing deadlines, reductions in deposits for deliverability-only studies, and requirements that project developers put cash-at-risk to move forward in the back-end of the process.[106]

On June 11, 2012,[107] the FERC accepted MISO's resource adequacy enhancements including: annual resource adequacy requirements and a voluntary planning resource auction;[108] seven new local resource zones with local clearing to address limitations on capacity;[109] an opt-out provision, allowing participants to submit a fixed resource adequacy plan;[110] a deficiency charge based on the cost of new entry for entities short on capacity;[111] use of energy efficiency resources to supply capacity;[112] a two-year transition to honor agreements for zone-to-zone transfer (grandmother agreements);[113] and tracking of retail load to assign capacity obligations to retail suppliers with a new default methodology in retail choice areas.[114] MISO will continue to rely on state processes for resource planning, load forecasting, demand response, and energy efficiency investment decisions. The FERC found MISO's new voluntary one-year capacity mechanism, which includes self-schedule and opt-out provisions, respects state regulatory processes.[115]

On August 31, 2012, the FERC conditionally accepted MISO's revisions to cost allocation and mitigation measures relating to Revenue Sufficiency

100. *Id.* at PP 69-70.
101. *Id.* at P 70.
102. *Midwest Indep. Transmission Sys. Operator, Inc.*, 139 F.E.R.C. ¶ 61,127 at PP 1, 8 (2012).
103. *Id.* at PP 6-7.
104. *Midwest Indep. Transmission Sys. Operator, Inc.*, 138 F.E.R.C. ¶ 61,233 at PP 1-2 (2012).
105. *Midwest Indep. Transmission Sys. Operator, Inc.*, 139 F.E.R.C. ¶ 61,253 at P 1 (2012).
106. 138 F.E.R.C. ¶ 61,233, at PP 12-13, 15.
107. *Midwest Indep. Transmission Sys. Operator, Inc.*, 139 F.E.R.C. ¶ 61,199 (2012).
108. *Id.* at P 6.
109. *Id.*
110. *Id.* at P 18.
111. *Id.* at P 40.
112. *Id.* at P 233.
113. *Id.* at P 74.
114. *Id.* at P 223.
115. *Id.* at P 42.

Guarantee (RSG) costs incurred in connection with Voltage and Local Reliability (VLR) unit commitments.[116]

E. Southwest Power Pool

In September 2012, the FERC conditionally accepted SPP's proposed revisions to use market software tools to systematically send automated curtailment instructions to reduce the output of Non-Dispatchable Resources in the Energy Imbalance Service (EIS) market during periods of transmission congestion, instead of the current manual process of issuing curtailment instructions.[117] It determined that SPP's proposal to automate curtailment should apply only prospectively to "*new* Non-Dispatchable Resources . . . commercially operable on or after October 15, 2012" (i.e., the requested effective date).[118] It found SPP had not justified application of its proposal for *existing* Non-Dispatchable Resources (i.e., commercially operable before October 15, 2012).[119] It directed SPP to employ a stakeholder process to examine retrofitting existing Non-Dispatchable Resources to monitor and act on SPP's proposed automated curtailment instructions.[120] SPP's proposed curtailment priority level for Non-Dispatchable Resources was accepted subject to modification. For point-to-point service, the FERC stated a Non-Dispatchable Resource should receive a NERC TLR level 5 curtailment priority up to the firm transmission service reserved for that resource, whether the output is scheduled or unscheduled.[121] Also, a Non-Dispatchable Resource designated as a network resource should get the same NERC "TLR level 5 curtailment priority [as] other firm designated network resources, up to the level of output designated for [it]."[122] The FERC directed SPP to modify its proposal or explain "why it cannot operationally satisfy [these] provisions."[123] SPP is to address Non-Dispatchable Resources in SPP's proposed Integrated Marketplace in a compliance filing.[124]

On October 18, 2012, the FERC conditionally accepted SPP's filing to transition from its EIS market to an Integrated Marketplace.[125] SPP's proposal included a Day-Ahead Energy and Operating Reserve market with locational marginal pricing and virtual bidding, a Day-Ahead and Intra-Day Reliability Unit Commitment (RUC) process, a Real-Time Balancing Market, a market-based congestion management process including a market for Transmission Congestion Rights (TCR) and allocation of Auction Revenue Rights (ARR), formation of a new SPP Balancing Authority assuming the responsibilities of the current sixteen separate Balancing Authority Areas, and a market power

116. *Midwest Indep. Transmission Sys. Operator, Inc.*, 140 F.E.R.C. ¶ 61,171 at P 1 (2012).

117. *Southwest Power Pool, Inc.*, 140 F.E.R.C. ¶ 61,255 at PP 1, 2 & nn.2, 6 (2012).

118. *Id*. at PP 1, 47.

119. *Id.* at P 48.

120. *Id.* at P 49.

121. *Id.* at P 53.

122. *Id.*

123. *Id.*

124. *Id.* at P 59.

125. *Southwest Power Pool, Inc.*, 141 F.E.R.C. ¶ 61,048 (2012).

monitoring and mitigation plan.[126] The FERC directed SPP to submit modifications to "ensure that a well-designed market will be in place at the proposed effective date [of March 1, 2014]."[127] The FERC also found that SPP's market-based congestion management proposal provided "an adequate congestion cost hedge for the first year" of market operations, but required modifications to the financial tools used to help market participants manage congestion charges.[128] It required that SPP's TCR auctions be subject to review by the Market Monitor and mitigation.[129] It also directed SPP to modify the annual and monthly ARR allocation process to more accurately reflect system realities and account for monthly and seasonal differences,[130] to reflect the limitations for firm point-to-point customers with redispatch obligations,[131] and to account for parties with historical rights and incremental ARRs from network upgrades made to the transmission system.[132]

The FERC accepted SPP's market power study submitted for approval to charge market-based rates for regulation and contingency reserves in the ancillary services markets.[133] However, it required more comprehensive market power mitigation and monitoring provisions for SPP's day-ahead and real-time markets and SPP's RUC process. The FERC ordered several revisions to clarify the parameters for the mitigation of economic withholding for energy and operating reserves.[134] It also required more detail and justification on proposals for market participants to develop and submit mitigated energy, operating reserves, start-up, and no-load offers;[135] SPP's conduct and impact thresholds;[136] and the mitigation for "physical withholding and unavailability of facilities."[137] The FERC also ordered SPP to take certain actions for the move to the Integrated Marketplace.[138] It established various reporting, future filing, and post-market assessment requirements.[139] It granted SPP's request to extend the initial compliance filing deadline to February 15, 2013.[140]

The FERC dismissed comments that SPP's balancing process was flawed because the projected benefits did not properly capture the impact of dramatically declining gas prices.[141] It held concerns about the function of the process were outside the scope of the section 205 proceeding.[142] It found SPP correctly calculated and reallocated revenue requirements under the Balanced

126. *Id.* at P 17.
127. *Id.* at PP 1-2.
128. *Id.* at P 245.
129. *Id.* at P 239.
130. *Id.* at PP 264-65.
131. *Id.* at P 268.
132. *Id.* at P 281.
133. *Id.* at P 383.
134. *Id.* at PP 403-16.
135. *Id.* at PP 420-23.
136. *Id.* at PP 441-47.
137. *Id.* at PP 450-54.
138. *Id.* at P 309.
139. *Id.* at PP 463, 465, 499.
140. Notice of Extension of Time, FERC Docket Nos. ER12-1179-000, ER12-1179-001 (Nov. 28, 2012).
141. *Southwest Power Pool, Inc.*, 141 F.E.R.C. ¶ 61,149 at PP 15, 26 (2012).
142. *Id.* at P 26.

Portfolio Process.[143] Finally, it declined to defer action on the filing until SPP completed its unintended consequences review of the Balanced Portfolio projects.[144]

In Order Nos. 745 and 745-A, the FERC required RTOs and ISOs to file tariff revisions to implement a compensation approach for demand response resources participating in wholesale energy markets, including a net benefits test, a cost allocation mechanism, and protocols to measure and verify a demand response resource's performance.[145] SPP made its compliance filing in July 2011, and on January 19, 2012, the FERC rejected portions.[146] It found SPP's proposal to use the existing demand response compensation provisions in its EIS market, and pay the full locational imbalance price (equivalent to the locational marginal price (LMP)) when a demand response resource complies with SPP dispatch instructions, did not satisfy the requirements of Order No. 745.[147] It stated SPP must either propose a net benefits test or demonstrate its existing practice effectively determines that a demand response resource is a cost-effective alternative in all hours and supports the cost allocation requirements of Order No. 745.[148] It found that SPP's mechanism for billing the market participant based on the grossed-up load value at the settlement location where the demand response took place was noncompliant because SPP had not demonstrated it proportionately allocates the costs of the demand response purchase to those that benefit.[149] Therefore, SPP must submit a mechanism to allocate demand response costs for those times when demand response resources are cost-effective, as determined by a net benefits test.[150] It also required SPP to explain how its measurement and verification protocols (being evaluated in the Order No. 719 compliance proceedings) satisfy the requirements of Order No. 745.[151]

F. California Independent System Operator Corporation

On September 20, 2011, the California Independent System Operator Corporation (CAISO) filed to eliminate intertie convergence bidding, citing market inefficiencies related to the Real-Time Imbalance Energy Offset (RTIEO).[152] On November 25, 2011, the FERC accepted and suspended the revisions subject to the outcome of technical conference procedures.[153] In its

143. *Id.* at P 25.

144. *Id.* at P 26.

145. Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, 76 Fed. Reg. 16,658, 16,659 (2011) (to be codified at 18 C.F.R. pt. 35), *reh'g denied*, Order No. 745-A, 137 F.E.R.C. ¶ 61,215 (2011); *see also Sw. Power Pool, Inc.*, 138 F.E.R.C. ¶ 61,041 at P 3 (2012).

146. 138 F.E.R.C. ¶ 61,041, at P 1.

147. *Id.* at PP 17-19.

148. *Id.* at P 19.

149. *Id.* at P 30.

150. *Id.*

151. *Id.* at P 22; *see also* Order No. 719, *Demand Response Compensation in Organized Wholesale Energy Markets*, 125 F.E.R.C. ¶ 61,071 (2008), *modified on reh'g*, Order No. 719-A, 128 F.E.R.C. ¶ 61,059 (2009).

152. Tariff Amendment Eliminating Convergence Bidding at the Interties, FERC Docket No. ER11-4580-000 (Sept. 20, 2011).

153. *California Indep. Sys. Operator Corp.*, 137 F.E.R.C. ¶ 61,157 at P 1 (2011).

technical conference reply comments, CAISO requested a deferral so it could move forward with an intertie pricing and settlement (IPS) stakeholder process on the restoration of intertie convergence bidding[154] and, on July 27, 2012, stated it was abandoning the IPS process and would address "intertie pricing and settlement[s] . . . through a new stakeholder initiative . . . addressing compliance with the . . . [FERC's] variable energy resources rulemaking,"[155] Order No. 764.[156] The Western Power Trading Forum (WPTF) requested the FERC rule on "CAISO's proposal to eliminate intertie convergence bidding based on the record" or, in the alternative, direct CAISO to file the culmination of the IPS stakeholder work by November 1, 2012.[157]

On November 19, 2012, the FERC conditionally accepted CAISO's implementation of a Replacement Requirement for Resource Adequacy Maintenance Outages.[158] This is a "resource adequacy and outage management replacement procedure"[159] intended to become effective when the California Public Utilities Commission (CPUC) replacement rule expired in January 2013.[160] The FERC held that the backstop procurement product in CAISO's proposal had not been shown to be a separate mechanism than the Capacity Procurement Mechanism (CPM).[161] The CPM had a minimum designation of thirty days, while CAISO's proposal would "cover maintenance outages and provide designations" from a term as short as one day to as long as thirty-one days.[162] The FERC also found that the proposed compensation formula had not been shown to be just and reasonable because the CPM had a minimum thirty-day term, whereas CAISO's backstop procurement could have been used for a term as brief as one day.[163]

On June 8, 2012, the FERC approved a proposal by the CAISO to revise its Transmission Control Agreement (TCA) to provide that no party

> shall be liable to any other Party for any losses, damages, claims, liability, costs, or expenses (including legal expenses) arising from the performance or non-performance of its obligations under this Agreement except to the extent that its grossly negligent performance of this Agreement (including intentional breach) results directly in physical damage to property owned, operated by, or under the operational control of any of the other Parties or in the death or injury of any person . . .

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154. Reply Comments of the California Independent System Operator and the Department of Market Monitoring, FERC Docket No. ER11-4580-000 (Mar. 30, 2012).

155. Market Notice, Cal. Indep. Sys. Operator Corp., Intertie Pricing and Settlement Initiative – Stakeholder Call 8/7/12 (July 27, 2012), *available at* http://www.caiso.com/Documents/IntertiePricing_SettlementInitiative-StakeholderCall8712.htm.

156. Order No. 764, *Integration of Variable Energy Resources*, 139 F.E.R.C. ¶ 61,246 (2012).

157. Motion for Expedited Consideration and Other Relief of the Western Power Trading Forum, FERC Docket No. ER11-4580-000 (Aug. 29, 2012).

158. *California Indep. Sys. Operator Corp.*, 141 F.E.R.C. ¶ 61,135 (2012).

159. *Id.* at P 1.

160. *Id.* at P 10.

161. *Id.* at PP 70-71.

162. *Id.*

163. *Id.* at P 73.

(called the gross negligence liability standard).[164] This replaced a simple negligence liability standard. The FERC also approved related TCA language that requires each participating transmission owner (PTO) to

> indemnify the CAISO and hold it harmless against all losses, damages, claims, liability, costs, or expenses (including legal expenses) arising from third party claims due to any act or omission of that [PTO] except to the extent that they result from intentional wrongdoing or gross negligence on the part of the CAISO or of its officers, directors, or employees

(called the gross negligence indemnification standard).[165] The FERC stated "we find CAISO's proposal to match the TCA's indemnity and liability standards to those in the Tariff appropriate and consistent with our precedent in both this and other markets."[166]

On May 25, 2012, CAISO filed revisions to its open access transmission tariff (OATT) "to integrate its transmission planning [process (TPP)] and generation interconnection procedures" (GIP).[167] CAISO's revisions were intended to facilitate planning for the transmission additions and upgrades needed to meet California's renewable portfolio standards. On July 24, 2012, the FERC conditionally accepted CAISO's revisions, subject to modification, to become effective July 25, 2012.[168] It conditionally accepted revisions pertaining to four provisions of the GIP including: (1) interconnection studies, (2) allocation of transmission plan deliverability, (3) interconnection financial security, and (4) construction and payment of network upgrades.[169] The FERC found the revisions met the objectives of Order No. 2003 by increasing the efficiency of CAISO's interconnection procedures and aligning those procedures with its TPP.[170] It noted CAISO's revisions satisfy the Order No. 2003 independent entity variation standard, which permit ISOs and RTOs to vary from *pro forma* interconnection procedures to meet regional needs.[171]

On August 28, 2012, CAISO proposed to expand its mitigation of exceptionally dispatched resources and to "revise its settlement of residual imbalance energy to prevent non-competitive prices . . . caused by [the exercise of] temporal market power."[172] "When CAISO identifies a need for ramping capability to meet a reliability issue not modeled by its market software, [CAISO] may issue an exceptional dispatch [order] to ensure that [the unit operates] at its minimum dispatchable level."[173] Operational differences make

164. *California Independent System Operator Corp*., 139 F.E.R.C. ¶ 61,198 at PP 1, 2 n.4 (2012).

165. *Id.* at P 2 n.4.

166. *Id.* at P 17.

167. Tariff Amendment to Integrate Transmission Planning and Generator Interconnection Procedures filed in FERC Docket No. ER12-1855-000 (Mar. 25, 2012).

168. *California Indep. Sys. Operator Corp.*, 140 F.E.R.C. ¶ 61,070 at P 1 (2012).

169. *Id.* at PP 45, 61, 67, 72, 83. The FERC imposed the condition that CAISO make a compliance filing within thirty days of the Order to clarify in its tariff that it will not require projects in interconnection Queue Clusters 1-4 to demonstrate they have in place a power purchase agreement to receive their requested deliverability status. *Id.* at P 68.

170. *Id.* at P 44.

171. *Id.*

172. *California Indep. Sys. Operator Corp.*, 141 F.E.R.C. ¶ 61,069 at PP 1, 5 (2012).

173. *Id.* at P 7.

certain resources more likely to be exceptionally dispatched.[174] CAISO presented evidence that, as a result, some resources could exercise "temporal market power" and obtain non-competitive prices.[175] CAISO proposed "to allow mitigation for exceptional dispatches" and "cap the payment for incremental residual imbalance energy at the greater of the locational marginal price . . . or [the] bid price."[176] The FERC accepted CAISO's proposed revisions finding that under certain market conditions, generators could predict that CAISO would exceptionally dispatch the resource up from minimum load to its minimum dispatchable level.[177] It found resources could be paid inflated prices for the residual imbalance energy and therefore approved CAISO's proposal.[178] It directed CAISO to submit a report in one year detailing reductions in reliance on exceptional dispatch.[179]

G. ERCOT

The Public Utility Commission of Texas (PUCT) initiated incentives for investment in generating capacity to address ERCOT resource adequacy. On June 28, 2012, it voted to increase the high system-wide offer cap from $3,000 per megawatt-hour (MWh) to $4,500 per MWh beginning on August 1, 2012.[180] Subsequently, to address long-term resource adequacy, the PUCT approved increases in this cap. Beginning on June 1, 2013, the high system-wide offer cap will be $5,000 per MWh and will eventually reach $9,000 per MWh on June 1, 2015.[181] The PUCT also set the peaker net margin at "less than or equal to a threshold of $300,000 per MW in 2012 and 2013, or the threshold set by ERCOT for a subsequent year."[182]

The PUCT adopted a new rule for Emergency Response Service (ERS) replacing Emergency Interruptible Load Service.[183] Under the ERS program, qualified loads, including aggregations of smaller loads, provide themselves for deployment to decrease firm load shedding. ERCOT can alter the duration of contract periods and renew contracts of ERS resources where the resources' obligation is exhausted before the end of a contract period.[184]

174. *Id.* at P 8.

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

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

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

178. *Id.* at P 42.

179. *Id.* at PP 44-45.

180. Order Adopting New § 25.508 As Approved at the June 28, 2012 Open Meeting, Tex. P.U.C. Project No. 37897 (June 29, 2012), *available at* http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/37897_162_730178.PDF.

181. 37 Tex. Reg. 8959 (Nov. 9, 2012) (codified at 16 TEX. ADMIN. CODE § 25.505(g)(6)(B) (2012)).

182. *Id.*; 16 TEX. ADMIN. CODE § 25.505(g)(6)(C).

183. Order Adopting Amendments to §25.505 as Approved at the October 25, 2012 Open Meeting, Tex. P.U.C. Project No. 40268 (Oct. 26, 2012), *available at* http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/40268_85_740332.PDF.

184. *Id.* at 36.

IV. TRANSMISSION RATES

A. Cost-Based Rates

On June 28, 2012, the FERC granted in part and denied in part Seminole Electric Cooperative's complaint against Florida Power and Light Company (FPL)[185] alleging FPL violated the FERC's *pro forma* OATT by misapplying the two alternative thresholds under which charges were applied for imbalance penalties.[186] Order Nos. 888 and 890 established a three-tiered structure for imbalance penalties, standardized in Schedule 4 of the *pro forma* OATT.[187] Seminole alleged FPL calculated the imbalance threshold at the lesser of the percentage in deviation bands or the megawatts out of balance from the scheduled delivery, when the threshold should be the greater of the two.[188] The FERC agreed.[189] Seminole also alleged FPL violated Schedule 4 by imposing the highest charge applicable under the greatest tier of penalties in an hour to all imbalances, rather than the tier applicable to each deviation.[190] The FERC disagreed, finding Schedule 4 did not require a single form of apportionment under every OATT.[191]

On September 20, 2012, the FERC granted in part municipal customers' formal challenge to the 2010 and 2011 annual updates[192] to the PPL Electric Utilities Corp. (PPL) transmission formula rates.[193] A 2009 settlement provided "protocols" for how PPL would annually update its transmission rates and any challenges to those updates.[194] The municipalities alleged the FERC should not have accepted certain costs PPL included in rates.[195]

The FERC summarily rejected the municipalities' contention that prior years' adjustments, including to state taxes, could be included in subsequent years' rates.[196] It also rejected contentions that PPL booked payments from ratepayers into incorrect accounts—including property insurance, payments from associated companies, and pension and benefit accounts—because the accounts at issue did not affect the rates paid.[197] It also rejected challenges to including property held for future use, finding PPL properly accounted for its allocation between retail and transmission uses.[198] It rejected other challenges, including challenges to an adder for joining PJM and to the ROE calculation methodology, as untimely, because the settlement was approved in 2009.[199] However, the FERC set for hearing allegations that data as to costs associated with PPL tax

185. *Seminole Elec. Coop., Inc. v. Florida Power & Light Co.*, 139 F.E.R.C. ¶ 61,254 (2012).
186. *Id.* at P 16.
187. *Id.* at PP 3, 7.
188. *Id.* at P 16.
189. *Id.* at PP 32-33.
190. *Id.* at P 16.
191. *Id.* at P 34.
192. *PPL Elec. Utils. Corp.*, 149 F.E.R.C. ¶ 61,231 at PP 1-2 (2012).
193. *Id.* at P 1. (The formula rate is contained in Attachment H-8 of PJM's OATT.)
194. *Id.* at P 3.
195. *Id.* at P 7.
196. *Id.* at PP 18, 34.
197. *Id.* at P 24.
198. *Id.* at P 29.
199. *Id.* at P 46.

filings used in a state rate case was inconsistent with that used in the 2010 annual update.[200] It also set for hearing whether PPL increases in administrative and general (A&G) benefits costs were prudent, but rejected other A&G salaries and benefits contentions.[201] The allocation of insurance cost increases between transmission and retail customers was set for hearing,[202] as was whether PPL's actual tax liabilities were appropriately adjusted in rates given allegations that PPL paid estimated taxes in excess of its final actual tax liability.[203] Also set for a hearing were issues of whether certain PPL accounts were settlement "black-boxes," the prudence of new transmission project cost overruns, outside litigation expenses, accumulated deferred income taxes, and the alleged allocation of distribution costs to transmission customers.[204]

On September 20, 2012, the FERC set for hearing two *pro se* ratepayer challenges to the 2010 and 2011 annual updates of the Potomac-Appalachian Transmission Highline (PATH) transmission revenue requirements.[205] Challengers asserted PATH should not recover lobbying expenses,[206] general advertising expenses,[207] the costs of certain public relations professionals,[208] certain membership dues,[209] and contributions to civic groups,[210] including to the National Wild Turkey Federation.[211] They asserted some costs were double-booked.[212] The FERC found challengers, private citizens with homes in West Virginia receiving electrical service from subsidiaries of Allegheny Energy, Inc., a joint owner of PATH,[213] had FPA section 206 standing and were interested parties.[214] It set most contentions for hearing,[215] but summarily ruled the costs of contributions to the National Wild Turkey Federation were prudently incurred.[216]

B. Incentive Rates

The MISO requested approval, on behalf of Central Minnesota Municipal Power Agency (CMMPA) and Midwest Municipal Transmission Group (MMTG) (collectively, Applicants), of revisions to the MISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff (Tariff).[217] It also requested authorization to establish a regulatory asset account incentive to

200. *Id.* at PP 49, 51.
201. *Id.* at PP 54-55, 77.
202. *Id.* at P 58.
203. *Id.* at P 63.
204. *Id.* at PP 64-82.
205. *Alison Haverty and Keryn Newman v. Potomac-Appalachian Transmission Highline, LLC*, 140 F.E.R.C. ¶ 61,229 (2012).
206. *Id.* at P 48.
207. *Id.* at PP 51-54.
208. *Id.* at PP 58-59.
209. *Id.* at P 67.
210. *Id.* at P 73.
211. *Id.* at P 75.
212. *Id.* at P 64.
213. *Id.* at PP 4-5.
214. *Id.* at PP 107-08.
215. *Id.* at P 79.
216. *Id.* at P 82.
217. *Midwest Indep. Transmission Sys. Operator, Inc.*, 138 F.E.R.C. ¶ 61,021 at P 1 (2012).

include pre-commercial expenses not included in construction work in progress (CWIP) and O&M and allocated A&G expenses related to CMMPA's investment in the Brookings Project, which is part of a comprehensive regional planning initiative by eleven utilities in the Midwest region known as the Transmission Capacity Expansion Initiative by the Year 2020 (CapX2020).[218] Applicants stated they could not recover those costs "under the Tariff because CMMPA does not yet have transmission plant in-service and [thus] ha[s] a transmission plant allocator of zero."[219] The FERC held it had previously determined "the Applicants met the section 219 requirement of the FPA for incentive rate treatment for the Brooking[s] Project and that the Brookings Project[] is not routine."[220] The FERC restricted its review to "the nexus requirement of Order No. 679 and whether the Applicants' request for a regulatory asset account is tailored to CMMPA's risks and challenges."[221] The FERC granted the request to create the regulatory asset account finding that "the incentive is tailored to CMMPA's risks and challenges because this incentive will provide CMMPA with added up-front regulatory certainty and can reduce interest expense, improve coverage ratios, and facilitate the financing of the Brookings Project on good terms."[222] The FERC also authorized "CMMPA to accrue a carrying charge on the regulatory asset account" and "amortize the regulatory asset over [five] years," but rejected CMMPA's proposal to compound the carrying charge interest monthly finding such compounding "excessive."[223]

Missouri River Energy Services (MRES) petitioned for a declaratory order granting transmission incentive rate treatment under FPA section 219 for its investment in two transmission capacity expansion projects: the Fargo Project and the Brookings Project, which are part of the CapX2020 comprehensive regional planning initiative described above.[224] MRES sought 100% of prudently-incurred CWIP in rate base, 100% recovery of the prudently-incurred costs of transmission facilities cancelled or abandoned for reasons beyond MRES' control, and a hypothetical capital structure of 45% equity and 55% debt.[225] MRES stated it satisfies the rebuttable presumption of eligibility for incentives established in Order No. 679 because, *inter alia*, both projects have received Certificates of Need from the Minnesota Public Utilities Commission (MPUC).[226] The FERC held both projects satisfy the rebuttable presumption because the FERC had previously found that the MPUC "'considers whether the project ensures reliability or reduces congestion costs in evaluating an application for a Certificate of Need.'"[227] The FERC also held that sufficient

218. *Id.* at PP 1, 8.

219. *Id.* at P 8.

220. *Id.* at P 20; *see also Central Minn. Mun. Power Agency & Midwest Mun. Transmission Grp.*, 134 F.E.R.C. ¶ 61,115 (2011) (granting Applicants transmission rate incentives pursuant to FPA section 219).

221. 138 F.E.R.C. ¶ 61,021, at P 20.

222. *Id.* at P 21.

223. *Id.* at PP 22-23.

224. *Missouri River Energy Servs.*, 138 F.E.R.C. ¶ 61,045 at P 1 (2012).

225. *Id.*

226. *Id.* at P 13.

227. *Id.* at P 14 & n.22 (alteration in original) (quoting *Xcel Energy Servs., Inc.*, 121 F.E.R.C. ¶ 62,284 at P 53 (2007)).

nexus exists between the incentive rates requested and the investment MRES will make in the projects as the FERC had previously determined each project was a non-routine investment for other CapX2020 participants.[228] Regarding the specific incentives requested, the FERC granted MRES: (i) 100% recovery of prudently-incurred CWIP, conditioned on MRES providing "additional information regarding its accounting methods and procedures"; (ii) authority to recover all prudently-incurred project costs if the projects are abandoned or cancelled for reasons beyond MRES' control; and (iii) its requested hypothetical capital structure, as the FERC expects such capital structure incentive "will assist MRES in attracting financing," encourage further investments by MRES and its members in transmission, "allow [MRES] to receive returns comparable to those of [investor-owned utilities] investing in the [projects,] and will enhance [MRES'] ability to meet its debt obligations."[229]

In an order conditionally accepting a tariff, a transmission revenue requirement, a tariff capability lease, and instituting proceedings under FPA section 206, the FERC granted Citizens Energy Corporation's (Citizens Energy) request for clarification regarding transfer of transmission rate incentives.[230] Citizens Energy sought clarification that its wholly-owned subsidiary would "be entitled to the rights and privileges granted to Citizens Energy" in the order initially granting Citizens Energy certain transmission rate incentives.[231] The FERC treated Citizens Energy's request as one to assign its project incentives authorizations to its subsidiary.[232]

On May 22, 2012, the FERC denied rehearing of grants of rate incentive treatment.[233] In the original orders issued in 2008, the FERC applied its "Order No. 679 nexus test consistent with its clear practice at that time, which allowed for application of the nexus test on an aggregated basis to individual and unconnected projects."[234] However, in December 2010, the FERC announced that, on a prospective basis, if an applicant cannot "demonstrate that several individual projects are appropriately considered as a single overall project based on their characteristics or combined purposes," then it "may still file a single application seeking incentives for numerous individual and unconnected projects, but the [FERC] will consider each individual project separately in applying the nexus test and determining whether each project is routine or non-routine."[235] Based on applying the nexus test in 2008 consistent with then-existing precedent and the potential inequity to the applicants that had relied on the previously-granted incentives, the FERC denied rehearing in both proceedings.[236]

DATC Midwest Holdings, LLC (DATC) applied pursuant to FPA sections 205 and 219 for the "acceptance of a proposed formula rate . . . and transmission

228. *Id.* at P 19.

229. *Id.* at PP 24, 38.

230. *Citizens Sunrise Transmission LLC*, 138 F.E.R.C. ¶ 61,129 at PP 1, 44 (2012).

231. *Id.* at P 44.

232. *Id.* at P 45.

233. *Virginia Electric and Power Co.*, 139 F.E.R.C. ¶ 61,143 (2012); *Pepco Holdings, Inc.*, 139 F.E.R.C. ¶ 61,144 (2012).

234. 139 F.E.R.C. ¶ 61,143, at P 12; 139 F.E.R.C. ¶ 61,144, at P 13.

235. 139 F.E.R.C. ¶ 61,143, at P 11; 139 F.E.R.C. ¶ 61,144, at P 12.

236. 139 F.E.R.C. ¶ 61,143, at P 12; 139 F.E.R.C. ¶ 61,144, at P 13.

rate incentives for a portfolio of seven projects" deemed the "Midwest Portfolio."[237] The Midwest Portfolio comprises "more than 1,800 circuit miles of transmission, including 1200 circuit miles of 345 kV lines, 550 miles of 500 kV high-voltage direct-current (HVDC) lines, seven new substations and three new HVDC terminals that will stretch across five states (Iowa, Indiana, Wisconsin, Illinois and Ohio)."[238] DATC sought: (1) 100% recovery of prudently-incurred CWIP in rate base during development and construction, conditioned on acceptance of the Midwest Portfolio in MISO's Regional Transmission Expansion Plan (RTEP); (2) 100% recovery of the prudently-incurred costs of projects that are abandoned for reasons beyond DATC's control; (3) authority to establish a regulatory asset amortized with interest over five years including pre-commercial costs not capitalized or included in CWIP; and (4) a hypothetical capital structure of 55% equity and 45% debt during the pre-commercial phase.[239] DATC also sought "approval to use the return on equity (ROE) of 12.38% approved for MISO [t]ransmission [o]wners."[240] DATC acknowledged it did not meet the rebuttable presumption under Order No. 679 that the facilities it was proposing would "either ensure reliability or reduce the cost of delivered power by reducing . . . congestion," but argued it had provided sufficient evidence to demonstrate it met the requirements of section 219.[241] The FERC held DATC had failed to provide sufficient evidence to demonstrate that the Midwest Portfolio would ensure reliability or reduce congestion, but granted each of the requested rate incentives contingent on the projects' inclusion in the MISO RTEP and DATC's subsequent filing demonstrating the RTEP process had included a finding that the projects would ensure reliability or reduce the cost of delivered power by reducing congestion.[242] The FERC also held that while DATC had not provided sufficient evidence that the projects were a single project for rate incentive treatment, DATC satisfied the nexus test for each of the proposed projects because "the scope and effect of the [p]rojects are significant, making each project non-routine."[243] The FERC also found that "if DATC becomes a transmission-owning member of MISO, it will also be entitled to receive the then-current ROE that the FERC has approved for MISO transmission owners, as long as it remains a member of MISO."[244] The FERC set DATC's formula rates for hearing and settlement judge procedures.[245]

PJM filed proposed tariff revisions "seek[ing] to recover in [Public Service Electric and Gas Company's (PSEG)] cost-of-service formula rate prudently-incurred costs associated with the abandonment of the Branchburg-Roseland-Hudson 500 kV project (BRH Project),"[246] which was no longer to be included in PJM's RTEP based on a "revised load forecast indicating that the reliability

237. *DATC Midwest Holdings, LLC*, 139 F.E.R.C. ¶ 61,224 at P 1 (2012).

238. *Id.* at P 3.

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

240. *Id.* at P 13.

241. *Id.* at PP 24-26.

242. *Id.* at PP 37, 55, 63, 70, 76.

243. *Id.* at PP 49-50.

244. *Id.* at P 83.

245. *Id.* at P 93.

246. *PJM Interconnection, L.L.C.*, 140 F.E.R.C. ¶ 61,197 at P 1 (2012).

criteria violations that led to the development of the BRH Project could be fewer and less severe than those in the 2008 RTEP."[247] The FERC held PSEG eligible to recover prudently-incurred costs, finding "circumstances arose that resulted in [PSEG's] abandonment of the project, and that those circumstances were beyond [PSEG's] control."[248] However, it found PSEG "failed to provide sufficient detailed information on its costs, which raise a reasonable question as to the prudence of certain expenditures" and ordered hearing and settlement procedures.[249]

Northern Indiana Public Service Company (NIPSCO) petitioned under FPA section 219 for approval of transmission rate incentives for the Reynolds to Burr Oak to Hiple Project NIPSCO plans to construct under the MISO RTEP.[250] The FERC granted 100% recovery of prudently-incurred CWIP in rate base and recovery of prudently-incurred costs if the project is abandoned for reasons outside of NIPSCO's control.[251] It held NIPSCO met the rebuttable presumption under Order No. 679 that the project will ensure reliability or reduced the cost of delivered power by reducing congestion, because the MISO Board approved it under "Criterion 1" through the RTEP process, which the FERC previously determined entitles projects to the rebuttable presumption.[252] It met the nexus test because of its significant scope and effect.[253]

WPPI Energy (WPPI) petitioned for a declaratory order approving transmission rate incentives under FPA section 219 for its investment in the La Crosse Project, which is part of CapX2020.[254] WPPI sought, and the FERC granted, recovery of pre-commercial and other transmission-related expenses through a regulatory asset, a hypothetical capital structure of 45% equity and 55% debt, and recovery of prudently-incurred costs if the project is abandoned for reasons outside of WPPI's control.[255] The FERC found it had "previously determined that the La Crosse Project is entitled to the rebuttable presumption based upon the issuance of a Certificate of Need by the [MPUC]."[256] The FERC also noted it had previously found the La Cross Project non-routine and "that WPPI's request for incentives [met] the nexus requirement."[257]

PPL Electric Utilities Corporation (PPL) petitioned for a declaratory order approving transmission rate incentives under FPA section 219 for its investment in the NPR Project.[258] PPL sought a 100 basis point adder to PPL's base ROE and 100% recovery of prudently-incurred CWIP in rate base.[259] The FERC found that the NPR Project satisfies the requirements of section 219 because PJM has made a determination through its regional transmission planning

247. *Id.* at P 4.
248. *Id.* at P 24.
249. *Id.* at PP 29-31.
250. *Northern Ind. Pub. Serv. Co.*, 140 F.E.R.C. ¶ 61,035 at P 1 (2012).
251. *Id.* at PP 1, 9-10.
252. *Id.* at P 20.
253. *Id.* at PP 26-29.
254. *WPPI Energy*, 141 F.E.R.C. ¶ 61,004 at PP 1, 3 (2012).
255. *Id.* at PP 20-22, 24, 31-32.
256. *Id.* at P 9.
257. *Id.* at P 14.
258. *PPL Electric Utilities Corp.*, 141 F.E.R.C. ¶ 61,021 at P 1 (2012).
259. *Id.* at P 6.

process, which the FERC has previously found constitutes a "'fair and open regional planning process,'" that the NPR Project either mitigates congestion or ensures reliability.[260] The FERC also found the "NPR Project is not routine" because the scope of investment required "will present financial risks and challenges to PPL."[261] The FERC approved PPL's request for 100% recovery of prudently-incurred CWIP,[262] but denied PPL's request for the ROE adder, finding that "we are not persuaded that the regulatory, siting, and construction risks and challenges faced by PPL in developing the NPR Project warrant an ROE adder."[263]

Transource Missouri, LLC (Transource) applied under FPA sections 205 and 219 for acceptance of formula and transmission rate incentives for two electric transmission projects.[264] It sought recovery of 100% of CWIP, recovery of non-CWIP expenses through a regulatory asset with carrying charges, a hypothetical capital structure of 40% debt and 60% equity, recovery of 100% of prudently-incurred costs in the event one or both of the projects is abandoned for reasons beyond Transource's control, authority to change its base ROE through future "limited, single-issue" section 205 proceedings, adding a 50 basis point adder to its ROE for participation in a RTO and, for one project, adding a 100 basis point adder to compensate for that project's specific risks.[265] The FERC found Transource entitled to the rebuttable presumption of eligibility for the incentives because both projects were identified through Southwest Power Pool's regional planning process.[266] The FERC found Transource demonstrated a nexus between the project risks and the incentives requested as the projects are not routine.[267] It granted Transource's incentives with adjustments, but rejected future ROE changes through single-issue proceedings.[268] Finally, it found Transource had not demonstrated its formula rate was just and reasonable, but accepted it for filing, subject to refund and hearing procedures.[269]

The FERC granted a MISO and Ameren Services Company (Ameren) request for transmission rate incentives for Ameren's investment in two projects.[270] It granted recovery of all CWIP, recovery of all prudently-incurred costs if a project is abandoned for reasons beyond Ameren's control, and a hypothetical capital structure of 56% equity and 44% debt.[271] It also approved tariff revisions to transition the formula rate to a forward-looking formula rate.[272]

260. *Id.* at P 17 (quoting Order No. 679, F.E.R.C. STATS. & REGS. ¶ 31,222 at P 58 (2006)).
261. *Id.* at P 37.
262. *Id.* at P 43.
263. *Id.* at P 55.
264. *Transource Missouri, LLC*, 141 F.E.R.C. ¶ 61,075 at P 1 (2012).
265. *Id.* at PP 6-8.
266. *Id.* at P 20.
267. *Id.* at PP 40-41.
268. *Id.* at PP 50, 56, 61, 66-67, 71, 75-76.
269. *Id.* at PP 98-99.
270. *Midwest Indep. Transmission Sys. Operator, Inc.*, 141 F.E.R.C. ¶ 61,121 (2012).
271. *Id.* at PP 35, 44, 51.
272. *Id.* at P 1.

V. MERGERS AND ACQUISITIONS

Duke Energy Corporation and Progress Energy, Inc. applied for FERC authority to make Progress Energy a Duke Energy wholly-owned subsidiary. On September 30, 2011, the FERC approved the request subject to later market power mitigation.[273] The applicants' October 17, 2011 compliance filing was rejected on December 14, 2011, because it did not "remedy . . . adverse effects on competition, including screen failures, identified in the Merger Order."[274] The applicants' March 26, 2012 revised compliance filing proposed permanent mitigation through proposed transmission upgrades to increase power able to be imported to the Carolinas, with interim mitigation measures based on power sales, pending completion of that transmission.[275] On June 8, 2012, the FERC accepted the permanent mitigation measures, but revised the interim measures.[276]

On May 20, 2011, as amended on October 11, 2011, Exelon Corporation and Constellation Energy Group, Inc. sought FERC authority to merge, which was conditionally granted on March 9, 2012.[277] The FERC relied on the applicants' commitments "to divest 2,648 MW of nameplate generation capacity, . . . not to sell [divested] units . . . to any of eight identified entities (or any affiliates thereof), [and] to sell 500 MW of energy in the 5004/5005 submarket within PJM."[278]

On December 13, 2012, the FERC approved the merger between NRG Energy, Inc. and GenOn Energy, Inc. as consistent with the public interest.[279]

VI. PURPA

In response to a qualifying facility (QF) wind generator's challenge of a PUCT curtailment policy, the FERC found the policy inconsistent with the Public Utilities Regulatory Policies Act of 1978 (PURPA) and its regulations, but declined to initiate an enforcement action under PURPA section 210(h).[280] The FERC later accepted the curtailment policies when they were clarified to conform with the PURPA,[281] but held a PUCT order authorizing a utility to purchase non-firm energy from QFs based on locational imbalance prices inconsistent with the requirement that QFs be paid at full avoided-cost.[282]

The FERC declared a utility's proposed QF purchase curtailment policy inconsistent with PURPA section 210 and its regulations.[283] The utility proposed to curtail QF generation during "operational circumstances" when QF purchases "would require [the utility] to dispatch higher cost, less efficient resources [for] system load or make base load resources unavailable [to] the next

273. *Duke Energy Corp. and Progress Energy, Inc.*, 136 F.E.R.C. ¶ 61,245 at P 1 (2011).

274. *Duke Energy Corp. and Progress Energy, Inc.*, 137 F.E.R.C. ¶ 61,210 at P 66 (2011).

275. Revised Compliance Filing of Duke Energy Corporation and Progress Energy, Inc., FERC Docket No. EC11-60-004 (Mar. 26, 2012).

276. *Duke Energy Corp. and Progress Energy, Inc*., 139. F.E.R.C. ¶ 61,194 (2012).

277. *Exelon Corp. and Constellation Energy Grp., Inc.*, 138 F.E.R.C. ¶ 61,167 at PP 1-2 (2012).

278. *Id.*

279. *NRG Energy, Inc. & GenOn Energy, Inc.*, 141 F.E.R.C. ¶ 61,207 at P 1 (2012).

280. *Exelon Wind 1, LLC*, 140 F.E.R.C. ¶ 61,152 at PP 2-3 (2012).

281. *Id.* at PP 49, 51.

282. *Id.* at PP 52-53.

283. *Idaho Wind Partners 1, LLC*, 140 F.E.R.C. ¶ 61,219 (2012).

anticipated load."[284] A wind QF requested a declaration that the PURPA would be violated if the curtailed QF purchases were under fixed avoided-cost rate contracts, regardless of any Idaho Public Utility Commission (IPUC) approval.[285] The utility argued its proposed policy was within section 292.304(f)(1) of the FERC regulations, which permits curtailment of QF purchases if, due to operational circumstances, such purchases would "'result in costs greater than those [if the utility] generated an equivalent amount of energy itself.'"[286] The FERC declined to initiate enforcement because state proceedings were ongoing, but, relying on *Entergy Services, Inc.*,[287] determined the utility's QF curtailment policy was improper.[288] It determined section 292.304(f)(1) was not intended to override obligations incurred by a utility to purchase from a QF, and that "[a]s a party to long-term PPAs employing avoided-cost rates determined at the time these obligations were incurred, [the utility] may not curtail pursuant to section 292.304(f)(1)."[289] Commissioner Clark dissented, stating that premature FERC action "could inhibit the parties' willingness, or the Idaho Commission's ability, to come to a flexible, tailored accommodation" of the concerns of parties, including Idaho consumers.[290]

The FERC determined an Iowa distribution cooperative's disconnection of a retail consumer with a wind QF for failure to pay its retail electric service bills contravened the QF output purchase and sale requirement.[291] Failure to pay a bill could justify disconnection in some circumstances, but disconnection should occur only following FERC procedures for terminating that requirement.[292] The FERC directed settlement negotiations.[293]

Following stakeholder proceedings, the CAISO proposed to retain "scheduling priority for small [QFs] (20 MW or less) with . . . PURPA power purchase agreement[s]," end blanket QF scheduling priority, and allow cogeneration resources "scheduling priority for . . . capacity dedicated to . . . industrial hosts" (whether or not resources are QFs).[294] The FERC approved, finding the proposal encouraged QF development, furthered environmental and related policies, and recognized operational constraints on cogeneration with dedicated onsite industrial host processes.[295] It did not extend scheduling priorities to wind QFs not meeting the criteria.[296]

The FERC determined the IPUC's rejection of QF firm energy sales agreements with a utility contravened the PURPA and initiated a PURPA section 210(h) enforcement action.[297] The QFs executed purchase agreements prior to

284. *Id.* at P 3 (internal quotation omitted).
285. *Id.* at P 6.
286. *Id.* at P 36 (quoting 18 C.F.R. § 292.304(f)(1) (2012)).
287. *Entergy Servs., Inc.*, 137 F.E.R.C. ¶ 61,199 (2011).
288. 140 F.E.R.C. ¶ 61,219, at PP 32, 41.
289. *Id.* at P 39.
290. 140 F.E.R.C. ¶ 61,219 (Clark, Comm'r, dissenting).
291. *Swecker v. Midland Power Coop.*, 137 F.E.R.C. ¶ 61,200 at P 1 (2012).
292. *Id.* at P 39.
293. *Id.* at P 41.
294. *California Indep. Sys. Operator Corp.*, 141 F.E.R.C. ¶ 61,176 at PP 8, 36 (2012).
295. *Id.* at P 37.
296. *Id.* at P 40.
297. *Murphy Flat Power, LLC*, 141 F.E.R.C. ¶ 61,145 at P 1 (2012).

the date that the IPUC's new rules limiting QF eligibility for avoided-cost pricing became effective, but the utility did not execute the agreements until after that date. The FERC held that when a QF commits to sell to a utility, a binding obligation is created and a contract executed by both sides may not be a condition precedent to an enforceable obligation.[298] Even though the FERC had not previously initiated enforcement actions against the IPUC,[299] the FERC did so here because the IPUC continued to implement policies previously found inconsistent with the PURPA.[300] Commissioner Clark dissented, stating an enforcement action was against "longstanding" FERC policy where the FERC "makes a legal determination but . . . allows the project developer to fight its own fight" rather than "expend federal resources."[301] He faulted the FERC for "invok[ing] the power of the federal government to proactively champion a private interest that may contradict the best interests of the consumers of a state."[302]

The FERC granted three petitions to terminate, under PURPA section 210(m) and FERC regulation section 292.310, on a service territory-wide basis, the obligation to purchase output of QFs with a net capacity above 20 MW.[303] Consistent with Order No. 688,[304] the FERC found QFs had nondiscriminatory access to competitive wholesale electricity markets.[305] In each case, the utility participates in an RTO market with "Day 2" markets for capacity and energy. In another instance, the FERC denied a blanket waiver of mandatory purchase obligation for QFs 1 MW or smaller. It acknowledged the difficulty of identifying small QFs, such as those participating in net metering programs, not self-certifying with the FERC, and did not require the utility to further attempt to identify such small QFs.[306]

The FERC twice rejected Public Service Company of New Mexico (PNM) requests for termination of QF purchase obligations. The first time, rejection was because PNM failed to identify all potentially affected QFs.[307] As to PNM's second request, the FERC first determined that PNM met its notice obligation of identifying potentially affected QFs in its service territory, and rejected an intervenor assertion that PNM should have notified all potentially affected QFs

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298. *Id.* at PP 20, 24. The FERC also determined that neither *res judicata* nor any statutory or regulatory deadline barred the petitioners' challenge, and that the filing fee generally required for petitions for declaratory order did not apply to a petition for enforcement of the PURPA. *Id.* at PP 27-29.

299. *See, e.g.*, *Cedar Creek Wind, LLC*, 137 F.E.R.C. ¶ 61,006 (2011); *Rainbow Wind Ranch, LLC*, 139 F.E.R.C. ¶ 61,077 (2012).

300. 141 F.E.R.C. ¶ 61,145, at P 25.

301. *Id.* at 1 (Clark, Comm'r, dissenting).

302. *Id.* at 2 (Clark, Comm'r, dissenting).

303. *ALLETE, Inc.*, 138 F.E.R.C. ¶ 61,108 (2012); *Consumers Energy Co.*, 139 F.E.R.C. ¶ 61,069 (2012); *Otter Tail Power Co.*, 140 F.E.R.C. ¶ 62,229 (2012).

304. Order No. 668, *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. 61,342 (2006), *order on reh'g*, Order No. 688-A, F.E.R.C. STATS. & REGS. ¶ 31,250, 72 Fed. Reg. 35,872 (2007), *aff'd sub nom.* American Forest & Paper Ass'n v. FERC, 550 F.3d 1179 (D.C. Cir. 2008).

305. Specifically, the FERC found that the QFs had access to "independently administered, auction-based day-ahead and real-time wholesale markets for the sale of electric energy and to wholesale markets for long-term sales of capacity and electric energy." 139 F.E.R.C. ¶ 61,069, at P 14.

306. *Id.* at PP 1, 2, 6, 19.

307. *Public Serv. Co. of N.M.*, 139 F.E.R.C. ¶ 61,128 at P 2 (2012).

in the region claimed to constitute the competitive wholesale markets to which QFs have access.[308] But the FERC concluded the Four Corners Hub was not comparable to competitive "Day 2" markets, thus PNM did not show potentially affected QFs have access to wholesale markets that are of comparable competitive quality to independently administered, auction-based day-ahead and real-time power markets.[309] PNM failed to show QFs had a "meaningful opportunity" to sell other than to the utilities to which they were connected.[310]

On February 16, 2012, the FERC affirmed that ten QF owners that failed to file QF self-certifications before making wholesale sales must make refunds.[311] The owners sought waivers for non-compliance periods, and were granted them except for rate purposes.[312] The FERC distinguished other cases where refunds were not required. In *Ashland Windfarm, LLC* the projects were "owned by individuals, trusts and charities inexperienced in [FERC] regulatory matters and the power industry,"[313] whereas petitioners were "wholly-owned subsidiaries of an international energy company and reasonably should have been aware of the FERC's regulations."[314] *WM Renewable Energy, L.L.C.* involved non-compliance for only months, whereas some QF owners were noncompliant for years.[315] The FERC reaffirmed reliance on *LG&E-Westmoreland Southampton*, which had imposed refunds.[316]

The FERC granted market-based rate authority to a wind QF, conditioned on review of a market power study in another proceeding,[317] and required refunds for the period prior to that authorization.[318] The QF had failed to seek market-based rate authorization prior to losing a small power production exemption.

VII. GENERATION INTERCONNECTION

A January 19, 2012 letter order conditionally accepted a settlement between MidAmerican Energy Company (MidAmerican) and Clipper Windpower Development Company, LLC (Clipper) of the cost allocation of certain facilities in a large generator interconnection agreement (LGIA).[319] MidAmerican asserted the facilities were retail distribution upgrades with costs to be assigned to Clipper. Clipper contended they were Network Upgrades, and, under the *pro forma* LGIA, it was to be reimbursed any such costs it was assigned.[320] The

308. *Public Serv. Co. of N.M.*, 140 F.E.R.C. ¶ 61,191 at P 24 (2012).

309. *Id.* at PP 29-38.

310. *Id.* at P 35.

311. *OREG 1, Inc.*, 138 F.E.R.C. ¶ 61,110 (2012) (denying rehearing and affirming its previous order in *OREG 1, Inc.*, 135 F.E.R.C. ¶61,150 (2011)).

312. *Id.* at P 5.

313. *Id.* at P 3 n.7 (quoting *Ashland Windfarm, LLC*, 124 F.E.R.C. ¶ 61,068 (2008)).

314. *Id.* at P 14.

315. *Id.* (comparing *WM Renewable Energy, L.L.C.*, 130 F.E.R.C. ¶ 61,268 (2010)).

316. *Id.* at P 15 (discussing *LG&E-Westmoreland Southampton*, 76 F.E.R.C. ¶ 61,116 (1996), *order on clarification and reh'g*, 83 F.E.R.C. ¶ 61,182 (1998)).

317. *Niagara Wind Power, LLC*, 141 F.E.R.C. ¶ 61,179 at P 14 (2012).

318. *Id.* at PP 23-28.

319. *MidAmerican Energy Co.*, 138 F.E.R.C. ¶ 61,028 (2012).

320. *MidAmerican Energy Co.*, 136 F.E.R.C. ¶ 63,016 at P 3 (2011).

FERC discussed the *Mobile-Sierra*[321] public interest standard of review, finding *Mobile-Sierra* did not apply because large generator interconnection service was provided under MidAmerican's OATT, and, when non-"contract rates" are involved, the FERC has discretion whether to apply the *Mobile-Sierra* standard and compelling circumstances typically required for application were not present.[322]

PNM owned 60% of the Eastern Interconnection Project (EIP), but leased 40% from Tortoise Capital Resources Corp. (Tortoise), expiring April 1, 2015.[323] PNM operated all of the capacity under its OATT, but under the lease could not offer leased capacity beyond that expiration.[324] TGP Granada, LLC and Roosevelt Wind Ranch, LLC (collectively, TGP) sought transmission over the EIP for a wind project. PNM advised TGP it could accommodate only 25 MW due to the lease limitations. PNM suggested TGP either fund a transmission line or buy-out the lease.[325] On March 2, 2012, TGP filed a complaint alleging this PNM response violated Order No. 888.[326] It asserted undue discrimination by PNM and Tortoise against certain transmission customers by their unwillingness to process transmission service requests for the leased capacity beyond April 1, 2015.[327] The FERC granted the complaint, observing leases cannot circumvent open access requirements.[328] TGP also sought a ruling that changing its receipt point was allowed under PNM's tariff, or that the FERC waive PNM's tariff to allow the change. The FERC ruled to the contrary, stating PNM's tariff, which is based on the FERC *pro forma* OATT, treats such changes as new service requests; other parties might be reluctant to commit to the queue if their priority could be lost to last minute waivers.[329]

PNM, Power Network New Mexico, LLC, and New Mexico Renewable Energy Transmission Authority requested a waiver of queue provisions of PNM's OATT to speed construction of approximately 200 miles of 345 kV transmission facilities from eastern and central New Mexico to Rio Puerco (Power Network Project).[330] The waiver applicants argued waiver should be granted because the queue hindered renewable generation in New Mexico and would be limited to one project.[331] On September 20, 2012, the FERC found no good cause for waiver, expressing concern that waiver contravened Order Nos.

321. United Gas Pipe Line Co. v. Mobile Gas Serv. Corp., 350 U.S. 332 (1956); FPC v. Sierra Pac. Power Co., 350 U.S. 348 (1956).

322. 138 F.E.R.C. ¶ 61,028 at PP 4-7 (citing *Devon Power LLC*, 134 F.E.R.C. ¶ 61,208, *order on reh'g*, 137 F.E.R.C. ¶ 61,073 (2011)).

323. *TGP Granada, LLC v. Pub. Serv. Co. of New Mexico*, 140 F.E.R.C. ¶ 61,005 at P 3 (2012).

324. *Id.*

325. *Id.* at P 9.

326. *Id.* at PP 1, 10.

327. *Id.* at P 12.

328. *Id.* at P 19; *see also TGP Granada, LLC v. Pub. Serv. Co. of New* Mexico, 141 F.E.R.C. ¶ 61,094 (2012) (FERC order on PNW and Tortoise filings on progress in meeting July 15 order requirements).

329. 140 F.E.R.C. ¶ 61,005, at PP 31-32, 44.

330. *Public Serv. Co. of N.M.*, 140 F.E.R.C. ¶ 61,230 at P 1 (2012).

331. *Id.* at P 17.

888 and 890, which require long-term firm point-to-point service requests be processed first-come, first-serve.[332]

VIII. Other Orders on Complaints, Petitions, and Applications

FERC Opinion No. 521 determined excess energy sales to third-party marketers not members under a FERC-approved generation and transmission pooling agreement did not violate the agreement, but the energy allocation made to the particular sales did.[333]

On June 21, 2012, the FERC denied rehearing[334] of its March 15 denial of Powerex Corporation's complaint against the Western Area Power Administration (Western), where it had found Western complied with its tariff in accepting a long-term firm service application by fax from Morgan Stanley Capital Group.[335] On rehearing, Powerex sought a ruling that requests via fax could not be accepted without notice to customers or disregard of rules requiring public posting of available transfer capacity.[336] The FERC explained its prior order was fact specific and did not allow broad acceptance of off-the-record negotiations and/or preferential treatment.[337]

On July 16, 2012, the FERC approved MidAmerican Energy Company's re-delineation and re-classification of non-radial 69 kV facilities and non-radial 161 kV facilities connecting to 69 kV facilities from distribution to transmission[338] on the grounds they now serve a broader area.[339] It applied the Order No. 888[340] seven-factor jurisdictional test,[341] deferring to Illinois and Iowa commission 2011 delineations. It noted that facilities used for interstate wholesale purchases would be FERC-jurisdictional.[342]

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332. *Id.* at PP 60-61.

333. *Louisiana Pub. Serv. Comm'n v. Entergy Corp.*, 139 F.E.R.C. ¶ 61,240 at PP 107-34 (2012), *aff'g in part and rev'g in part, Louisiana Pub. Serv. Comm'n v. Entergy Corp.*, 133 F.E.R.C. ¶ 63,008 (2010).

334. *Powerex Corp. v. United States Dep't of Energy, Western Area Power Admin. – Sierra Nevada Region*, 139 F.E.R.C. ¶ 61,226 at P 1 (2012).

335. *Powerex Corp. v. United States Dep't of Energy, Western Area Power Admin. – Sierra Nevada Region*, 138 F.E.R.C. ¶ 61,188 (2012).

336. 139 F.E.R.C. ¶ 61,226, at P 9.

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

338. *MidAmerican Energy Co.*, 141 F.E.R.C. ¶ 61,028 at P 6 (2012).

339. *Id.* at P 15.

340. *See generally* Order No. 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, FERC STATS. & REGS. ¶ 31,036, 31,771 (1996), *order on reh'g*, Order No. 888-A, FERC STATS & REGS. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 F.E.R.C. ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 F.E.R.C. ¶ 60,046 (1998), *aff'd in relevant part sub nom.* Transmission Access Policy Study Grp. v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom.* New York v. FERC, 535 U.S. 1 (2002).

341. 140 F.E.R.C. ¶ 61,028, at P 19.

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

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