

REPORT OF THE ELECTRICITY REGULATION COMMITTEE

This report provides a summary of the significant decisions, orders, or rules issued by the Federal Energy Regulatory Commission (the FERC or Commission) in 2011 in the electricity regulation area. The first part of the report addresses significant rulemaking orders issued in 2011, while the remainder of the report addresses Commission orders in individual cases.*

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I. INTRODUCTION

The Electricity Regulation & Compliance Committee, which prepared this report, has a broad focus and overlapping jurisdiction with several other EBA committees. As these other committees have a more targeted focus, we have generally deferred to those other committees for a summary of the Commission's activities in their respective areas. Thus, this report does not generally address transmission reliability and planning (System Reliability, Planning & Compliance Committee), wholesale market-based rates (Power Generation & Marketing Committee), enforcement issues (Compliance & Enforcement Committee) and demand-side management/renewable energy (Renewable Energy & Demand-Side Management Committees). In addition, this report does not generally address court appeals (Judicial Review Committee).

II. RULEMAKINGS AND POLICY STATEMENTS

A. *Order No. 1000, Transmission Planning and Cost Allocation By Transmission Owning and Operating Public Utilities*

On July 21, 2011, the FERC issued Order No. 1000, a Final Rule on *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*.¹ Order No. 1000 requires public transmission utility providers to engage in a regional planning process to develop a regional transmission plan, which specifies a regional cost allocation method for new transmission facilities selected in the regional transmission plan.² Additionally, Order No. 1000 imposes reforms with respect to nonincumbent developers, interregional transmission coordination, and cost allocation.³ Order No. 1000 seeks “to achieve two primary objectives: (1) ensure that [regional and interregional] transmission planning processes” identify and evaluate potential transmission alternatives and develop “a regional transmission plan that can meet transmission needs more efficiently and cost-effectively; and (2) ensure that the costs of [regional and interregional] transmission solutions [selected] to meet regional transmission needs are allocated fairly to those who . . . benefit[.]”⁴

Order No. 1000 prescribes three requirements for transmission planning.⁵ First, every public utility is required “to participate in a regional transmission planning process that [develops] a regional transmission plan and complies with existing Order No. 890 transmission . . . principles.”⁶ With respect to the regional transmission planning process, public utilities, in consultation with stakeholders, are directed to assess “transmission solutions that [may] meet the needs of the transmission planning region more efficiently or cost-effectively.”⁷

1. Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, F.E.R.C. STATS. & REGS. ¶ 31,323, 76 Fed. Reg. 49,842 (2011) (to be codified at 18 C.F.R. pt. 35) (FERC Docket No. RM10-23).

2. *Id.* at PP 6, 68.

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

4. *Id.* at P 4.

5. *Id.* at PP 6-8.

6. *Id.* at P 68.

7. *Id.* at P 148.

The second requirement for transmission planning is that local and regional transmission planning processes must consider transmission needs based on Public Policy Requirements established by state or federal laws or regulations.⁸ The third obligation for public transmission planning directs public utilities in each pair of neighboring transmission planning regions to undertake interregional coordination activities to determine if there are more efficient or cost-effective solutions to their mutual transmission needs.⁹ The FERC declined to require that a formal interregional transmission planning agreement be developed and filed with each pair of neighboring transmission planning regions.¹⁰ Instead, “each pair of neighboring transmission planning regions . . . must develop the same language to be included in each public utility transmission provider’s [Open Access Transmission, Energy and Operating Reserve Markets Tariff (OATT)],” which “describes the interregional transmission coordination procedures for that particular pair of regions.”¹¹

The Final Rule establishes two requirements for transmission cost allocation that cover: (1) the establishment of a cost allocation method for regional transmission planning; and (2) the establishment of a cost allocation method for interregional transmission planning.¹² Pursuant to Order No. 1000, public utilities are directed to establish “a method, or set of methods, for allocating the costs of new transmission facilities selected in the regional transmission plan for purposes of cost allocation.”¹³ Also, public utilities in neighboring transmission planning regions must develop a common interregional cost allocation method for new interregional transmission facilities that the regions determine to be efficient or cost-effective.¹⁴ Order No. 1000 specifies that regional and interregional transmission cost allocation methods must satisfy six similar cost allocation principles.¹⁵

Under Order No. 1000, public utilities are directed “to eliminate provisions in Commission-jurisdictional tariffs and agreements that [provide for] a federal right of first refusal for an incumbent transmission provider with respect to transmission facilities selected in a regional transmission plan for purposes of cost allocation” except under specified limited circumstances.¹⁶ The Commission observed that a failure to impose such a requirement could undermine the consideration and assessment “of more efficient or cost-effective solutions to regional transmission needs.”¹⁷

8. *Id.* at P 203. Order No. 1000 defines Public Policy Requirements as state or federal laws or regulations, which are enacted statutes “passed by the legislature and signed by the executive” and “regulations promulgated by a relevant jurisdiction, whether within a state or at the federal level.” *Id.* at P 2.

9. *Id.* at P 393.

10. *Id.* at P 475.

11. *Id.*

12. *Id.* at P 9.

13. *Id.* at P 558.

14. *Id.* at P 578.

15. *Id.* at PP 603, 622, 637, 646, 657, 668, 685.

16. *Id.* at P 313.

17. *Id.* at P 253.

B. Order No. 745, Demand Response Compensation in Organized Wholesale Energy Markets

The FERC issued Order No. 745 on March 15, 2011 and Order No. 745-A on December 15, 2011.¹⁸ In Order No. 745, the FERC amended its regulations to establish a uniform, nation-wide approach to compensating demand response resources (DRR) participating in markets administered by Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs).¹⁹ First, the FERC implemented a “net benefits test” designed to determine the cost-effectiveness of DRR.²⁰ The FERC concluded that when the net benefits test indicates that dispatch of a DRR is economical to the market, the DRR must be compensated for the service it provides at the market price for energy (the Locational Marginal Price, or LMP).²¹ The FERC then held that the requisite costs to appropriately compensate DRR must be allocated “proportionally to all entities that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy at the time when the demand response resource is committed or dispatched.”²² To achieve this standard, the FERC required each RTO and ISO “to make a compliance filing . . . that either demonstrates that its current cost allocation methodology appropriately allocates costs to those that benefit from the demand reduction or proposes revised tariff provisions that conform to this requirement.”²³ The FERC stated that this approach “allocate[es] the costs of demand response payments among all customers who benefit from the lower LMP resulting from the demand response.”²⁴

In Order No. 745-A, the FERC denied all requests for rehearing in the proceeding and granted in part and denied in part requests for clarification.²⁵ First, the FERC rejected a request for rehearing regarding its jurisdiction over demand response participation in wholesale energy markets and reaffirmed that regulation of such “participation is essential to the Commission fulfilling its statutory responsibility to ensure that jurisdictional rates are just and reasonable.”²⁶ In so holding, FERC explained that although “demand response does not involve the wholesale sale of energy, and that entities engaged solely in demand response are not public utilities,” participation of DRR in organized wholesale markets “has a direct and substantial effect on rates in those markets.”²⁷ The FERC distinguished its jurisdiction over demand response participants in organized wholesale energy markets from mere “inputs” to

18. Order No. 745, *Demand Response Compensation in Organized Wholesale Energy Markets*, F.E.R.C. STATS. & REGS. ¶ 31,322, 76 Fed. Reg. 16,658 (2011) (to be codified at 18 C.F.R. pt. 5) (FERC Docket No. RM10-17) [hereinafter Order No. 745], *order on reh'g and clarification*, Order No. 745-A, *Demand Response Compensation in Organized Wholesale Energy Markets*, 137 F.E.R.C. ¶ 61,215 (2011) [hereinafter Order No. 745-A].

19. Order No. 745, *supra* note 18, at P 2.

20. *Id.* at P 3.

21. *Id.* at PP 2-3.

22. *Id.* at P 102.

23. *Id.*

24. *Id.* at P 5.

25. Order 745-A, *supra* note 18, at P 1.

26. *Id.* at P 20.

27. *Id.* at PP 27, 31.

generation that may affect a wholesale rate, holding that its jurisdiction would not extend to regulation of such inputs.²⁸ The FERC then denied requests for rehearing regarding DRR compensation and affirmed its finding that the LMP is the proper compensation level for DRR because it corresponds to the “marginal value” of DRR and generation resources to the relevant market.²⁹ The FERC also denied requests for rehearing regarding the cost allocation of DRR compensation.³⁰

C. Order No. 741-A, Credit Reforms in Organized Wholesale Electric Markets

In Order No. 741-A, the Commission granted in part and denied in part requests for rehearing of certain credit reforms in organized wholesale electric markets.³¹ The Commission expressed concern that under the \$100 million corporate family cap on unsecured credit, the default of a single entity could result in significant exposure and, therefore, granted rehearing of the \$100 million corporate family cap.³² The Commission returned to its approach proposed in the Notice of Proposed Rulemaking “limit[ing] . . . the use of unsecured credit [to] . . . no more than \$50 million per entity, including the corporate family to which it belongs.”³³

The Commission denied rehearing with respect to proposals to eliminate unsecured credit in the financial transmission rights (FTR) markets.³⁴ Acknowledging the Commission’s “statutory directive to facilitate access to long term FTRs,” the Commission noted that load serving entities have the ability to seek another form of financing besides using unsecured credit and that there would be a reduction of risk to the market by eliminating unsecured credit.³⁵ The Commission also denied requests to allow netting of amounts owed to a market participant against amounts owed by that participant.³⁶ Regardless of whether netting is performed within or across market categories, the Commission remained concerned about the effect of default on a bankruptcy court decision that does not allow netting.³⁷ The Commission extended the deadline for complying with the requirement regarding the ability to offset market obligations to September, 30, 2011 with tariff provisions effective January 1, 2012.³⁸

D. Order No. 755, Frequency Regulation Compensation Final Rule

On October 20, 2011, the FERC issued Order No. 755, a final rule

28. *Id.* at P 31.

29. *Id.* at P 54.

30. *Id.* at P 111.

31. Order No. 741-A, *Credit Reforms in Organized Wholesale Electric Markets*, F.E.R.C. STATS. & REGS. ¶ 31,320 at P 1, 76 Fed. Reg. 10,492 (2011) (to be codified at 18 C.F.R. pt. 35) (FERC Docket No. RM10-13-001).

32. *Id.* at P 9.

33. *Id.*

34. *Id.* at P 14.

35. *Id.*

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

37. *Id.* at PP 17, 22-23.

38. *Id.* at P 25.

regarding compensation for frequency regulation services in ISO/RTO markets.³⁹ The FERC defined frequency regulation for the purposes of the order as “the capability to inject or withdraw real power by resources capable of responding appropriately to a system operator’s automatic generation control signal in order to correct for actual or expected Area Control Error needs.”⁴⁰ Under the current compensation system, frequency regulation providers (FRPs) are compensated by the relevant scheme adopted by the market they are located in, all of which generally pay a uniform amount per kW for electricity used for frequency regulation purposes regardless of the type and efficiency of the resource.⁴¹ In Order No. 755, the FERC concluded that the existing compensation system results in rates “that are unjust, unreasonable, and unduly discriminatory or preferential” because it “fail[s] to acknowledge the inherently greater amount of frequency regulation service being provided by faster-ramping resources” and can “result in economically inefficient dispatch of” resources.⁴²

Order No. 755 established a new two-part compensation structure for FRPs.⁴³ The first part consists of a market-based uniform clearing price, which must be derived from market-participant bids for the provision of frequency regulation capacity.⁴⁴ This price will take account of the resource’s lost opportunity costs, including cross-product opportunity costs, and inter-temporal opportunity costs.⁴⁵ The FERC determined that “[t]he capacity payment is necessary, because it exists in order to ensure that resources are indifferent between offering their capacity as a frequency regulation resource or as an energy resource.”⁴⁶ The second part of the FRP compensation will consist of a performance-based payment.⁴⁷ Acknowledging RTOs/ISOs’ differing operating arrangements, the FERC did not mandate the form or technical considerations of this payment.⁴⁸ The payment must, however, be based on services actually provided,⁴⁹ incorporate how accurately the resource follows a dispatch signal,⁵⁰ and be market-based “on resource bids that reflect the cost of providing the service.”⁵¹

39. Order No. 755, *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, F.E.R.C. STATS. & REGS. ¶ 31,324, 76 Fed. Reg. 67,260 (2011) (codified at 18 C.F.R. pt. 35) (FERC Docket No. RM11-7).

40. *Id.* at P 192.

41. *Id.* at P 6.

42. *Id.* at P 2.

43. *Id.* at P 77.

44. *Id.* at P 99.

45. *Id.* at PP 99-100.

46. *Id.* at P 101.

47. *Id.* at P 78.

48. *Id.* at P 130.

49. *Id.* at P 134.

50. *Id.* at P 151.

51. *Id.* at P 199.

III. RTO/ISO REGIONAL DEVELOPMENTS

A. *ISO New England*

1. Forward Capacity Market Auctions, Capacity-Related Market Rule

During 2011, a series of FERC orders reflected ISO New England's (ISO-NE or New England) continued focus on the implementation and refinement of the Forward Capacity Market (FCM). Under the FCM, an initial auction, referred to as a Forward Capacity Auction (FCA), is held three years in advance of identified capacity need, and subsequent auctions, referred to as reconfiguration auctions, that allow minor quantity adjustments and facilitate the trading of commitments, are held as the year of need approaches.⁵²

On October 20, the FERC accepted the results of the fifth FCA for the 2014/2015 Capacity Commitment Period, "except for the dynamic de-list bid submitted by Entergy Nuclear Power Marketing . . . for the Vermont Yankee Power Station," which the Commission set for hearing and settlement judge procedures.⁵³ The FERC directed

the presiding judge [to] consider the justness and reasonableness of Entergy's dynamic de-list bid for Vermont Yankee, with particular attention to the following issues: (1) whether, under ISO-NE's Tariff, Entergy would be responsible for replacement costs and if so, the likely amount of these costs; and (2) whether Entergy's going-forward costs properly include replacement cost risk and whether the expected replacement cost associated with this risk is accurately reflected in its dynamic de-list bid.⁵⁴

The FERC also continued to address on-going disputes with respect to New England's FCM and capacity-related market rules.⁵⁵ In its previous Order issued on April 23, 2010, the FERC set issues raised by the New England Power Generators Association and other generators in their complaints for a paper hearing.⁵⁶ Specifically, the FERC set for paper hearing issues related to the Alternative Pricing Rule (APR), capacity zones, and the proper value of the Cost of New Entry (CONE).⁵⁷

On April 13, 2011, the Commission issued its Order on Paper Hearing and Order on Rehearing.⁵⁸ In its Order, the Commission rejected the ISO's proposed two-tiered APR pricing mechanism on the basis that such a mechanism would result in capacity purchases in excess of the Installed Capacity Requirement.⁵⁹ However, the Commission stated that the benchmark pricing element of the ISO proposal "forms the basis for a just and reasonable buyer-side mitigation approach."⁶⁰ The Commission directed the ISO to work with stakeholders to develop and implement a buyer-side mitigation approach with specific features

52. *ISO New England Inc.*, 126 F.E.R.C. ¶ 61,115 at P 2 (2009).

53. *ISO New England Inc.*, 137 F.E.R.C. ¶ 61,056 at P 1 (2011).

54. *Id.* at P 27.

55. *Id.* at P 15.

56. *ISO New England Inc.*, 131 F.E.R.C. ¶ 61,065 at P 1 (2010).

57. *Id.* at P 18.

58. *ISO New England Inc.*, 135 F.E.R.C. ¶ 61,029 at P 1 (2011).

59. *Id.* at P 164.

60. *Id.* at P 165.

outlined by the Commission.⁶¹ In its Order, the Commission also accepted the ISO's proposal regarding the treatment of historical out-of-market (OOM) capacity finding that it should not be subject to mitigation.⁶² The Commission indicated that the FCA price floor should be extended for at least the fifth and sixth FCAs and that the ISO is required to make a filing with the Commission if it is necessary to "extend the price floor beyond the sixth FCA."⁶³

With regard to zonal modeling, the Commission accepted the ISO's proposal to "model all zones all the time" to determine the appropriate capacity zones prior to the FCA but "use the eight energy load zones as [the] initial capacity zones."⁶⁴ The Commission also accepted the ISO's proposal that capacity zones to be used after the sixth FCA would be developed in conjunction with stakeholders in the system planning process.⁶⁵ Finally, the Commission approved replacing the current dynamic de-list bid threshold (*i.e.*, the level below which offers can be submitted in an FCA without review by the Internal Market Monitor) of 0.8 times the CONE with a lower threshold of \$1.00/kW-month.⁶⁶ Multiple parties have requested rehearing of the Commission's April 13 Order.⁶⁷

2. *Devon Power LLC*, Remand of *Mobile-Sierra* Issues from FCM Settlement

On October 20, 2011, the FERC issued an Order Denying Rehearing⁶⁸ affirming its determinations set forth in its previously issued Order on Remand from the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit).⁶⁹ The Commission affirmed its previous determinations that (1) "the auction results and transition payments arising from [the FCM Settlement] were tariff rates, not contract rates,"⁷⁰ and (2) that the Commission nevertheless "had discretion to approve a settlement provision imposing a more stringent application of the statutory just and reasonable standard of review, [*i.e.*,] *Mobile Sierra* 'public interest' standard of review."⁷¹ In particular, the Commission found that it is "appropriate to accept the *Mobile-Sierra* 'public interest' language, in part because of the similarities between the Settlement rates and contract rates" in the FCM context.⁷²

3. Order on Tie Benefits

On December 30, 2010, the ISO filed revisions to Market Rule 1 of its Tariff to revise the methodology for calculating tie benefits, which "are an input

61. *Id.* at P 169.

62. *Id.* at P 21.

63. *Id.* at P 22.

64. *Id.* at P 272.

65. *Id.* at P 278.

66. *Id.* at PP 313, 315.

67. *See generally* Requests for Rehearing filed in FERC Docket Nos. ER10-787, EL10-50, and EL10-57, available at <http://www.ferc.gov/docs-filing/elibrary.asp> (last visited Mar. 7, 2012).

68. *Devon Power LLC*, 137 F.E.R.C. ¶ 61,073 (2011).

69. *Devon Power LLC*, 134 F.E.R.C. ¶ 61,208 (2011) (FERC Docket No. ER03-563-066).

70. 137 F.E.R.C. ¶ 61,073 at PP 1, 21.

71. *Id.* at PP 1, 32.

72. *Id.* at P 32.

into the Installed Capacity Requirement calculation needed to conduct [FCAs] and subsequent annual reconfiguration auctions.”⁷³ On February 28, 2011, the Commission issued an order in which it accepted the ISO’s proposed tariff revisions, subject to the condition that the ISO file with the Commission “revised tariff sheets that directly state the methodology for determining transfer capabilities for the purpose of establishing tie benefits in section III.12.1 of Market Rule 1.”⁷⁴ In addition, the Commission rejected arguments by protesters that the ISO had failed to sufficiently explain the manner by which the transfer capability of an interconnection is determined for use in calculating tie benefits but agreed that the details of the transfer capability determination should be included in the tariff rather than in existing planning and operating procedures.⁷⁵ Specifically, the Commission directed the ISO to file “revised tariff sheets that directly state the methodology for determining transfer capabilities for the purpose of establishing tie benefits in section III.12.1 of Market Rule 1.”⁷⁶ A Request for Rehearing submitted by the Long Island Power Authority and Cross-Sound Cable Company, LLC remains pending before the Commission as of the date of publication.⁷⁷

4. Opinion No. 513, Order Accepting ISO-NE’s Proposed Installed Capacity Credits and Related Values

On May 6, 2011, the FERC issued Opinion No. 513, affirming an Administrative Law Judge’s finding that the Attorney General of Connecticut, the Connecticut Department of Public Utility Control, and the Connecticut Office of Consumer Counsel (Complainants) failed to show that Brookfield Energy Marketing Inc., Constellation Energy Commodities Group, Inc., and Shell Energy North America (US), L.P. (Respondents) engaged in market manipulation during the “Transition Period” leading up to the implementation of the ISO-NE FCM.⁷⁸

In its Order, the FERC affirmed an Administrative Law Judge’s Initial Decision finding that Complainants failed to show that Respondents – suppliers of capacity in ISO-NE – acted with the requisite scienter when making energy supply offers at or near the \$1,000/MWh price cap set forth in ISO-NE’s tariff for capacity-backed energy during the Transition Period.⁷⁹ The Complainants alleged “that Respondents were paid at least \$50.9 million for capacity over the Northern New York AC interface, energy which Respondents . . . never intended to provide.”⁸⁰ However, the FERC found “that Respondents fully intended to deliver their capacity-backed energy in the unlikely event ISO-NE called on it, and that each [Respondent] had procedures in place to ensure the energy actually

73. *ISO New England Inc.*, 134 F.E.R.C. ¶ 61,144 at P 1 (2011) (FERC Docket No. ER11-2580).

74. *Id.* at P 61.

75. *Id.*

76. *Id.*

77. Request for Rehearing of the Long Island Power Authority, LIPA and Cross-Sound Cable Company, LLC at 1, FERC Docket No. ER11-2580-000 (Mar. 3 2011).

78. *Blumenthal v. ISO New England, Inc.*, 135 F.E.R.C. ¶ 61,117 at P 1 (2011) (FERC Docket No. ER11-3048).

79. *Id.* at PP 8, 25.

80. *Id.* at P 10.

could be delivered if necessary.”⁸¹ Ultimately, the Commission concluded that

[h]aving found adequate record evidence that Respondents purposefully, but legitimately, offered their capacity-backed energy to ISO-NE at or near the price cap in consideration of various risks and could and would have delivered on those offers if called upon, the Initial Decision found Complainants did not support their allegations of market manipulation, and, most specifically, did not show the requisite scienter.⁸²

The Complainants requested rehearing of the May 6 Order.

B. *New York Independent System Operator*

On August 2, 2011, the FERC re-affirmed its prior approval of proposals by New York Independent System Operator (NYISO) to (1) allow a generator to request an exemption from an offer floor (Offer Floor Mitigation) after construction of the generator’s project has begun; and (2) revise the criteria for granting a request for offer floor mitigation by requiring the generator to demonstrate that the Installed Capacity (ICAP) spot auction price in New York City (In-City ICAP) three years after the generator’s Class Year will be higher than the offer floor during that same period (the Three-Year Rule).⁸³

1. NYISO Proposals – Timing of Exemption Decision

On September 27, 2010, NYISO filed at the FERC certain proposed revisions to NYISO’s in-City mitigation measures that would involve determining whether a capacity supplier qualifies for an Offer Floor exemption “before the capacity resource obtains authority to sell its capacity in the ICAP market.”⁸⁴ A contentious component of NYISO’s proposal was to allow a generator that has not obtained authority to sell capacity in the ICAP market to request a re-evaluation by NYISO of a prior decision by NYISO rejecting the generator’s request for an Offer Floor exemption.⁸⁵ The proposed tariff language (1) stated “that ‘Examined Facilities’ are analyzed when they enter the Class Year cost allocation process under Attachment S and seek [Capacity Resource Interconnection Service (CRIS)] rights without further conditions,” and (2) provided “for a re-evaluation for an exemption if the Category I Examined Facility satisfies certain criteria” and either [(a)] enters a new Class Year to seek CRIS rights or [(b)] intends to receive transferred CRIS rights at the same location without [additional] conditions.”⁸⁶ NYISO evaluates all Class Year projects together “to determine any necessary generator interconnection costs.”⁸⁷ Thus, these provisions do not require that exemption testing occur prior to the generator’s decision to invest or to commence construction of its project. In

81. *Id.* at P 36.

82. *Id.* at P 52.

83. Order on Rehearing and Clarification, *New York Indep. Syst. Operator, Inc.*, 136 F.E.R.C. ¶ 61,077 (2011).

84. *Id.* at P 3; *see also* NYISO 205 Filing – ICAP In-City Buyer Side Mitigation Measures at 1-2, FERC Docket No. ER10-3042-000 (Sept. 27, 2011) [hereinafter NYISO filing], *available at* http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/09/NYISO_205_Flng_FID_69_ICAP_Buyer_Side_Mitigation_09_27_10.pdf.

85. 136 F.E.R.C. ¶ 61,077 at P 3.

86. *Id.* at P 23; *see also* NYISO Filing, *supra* note 84, at 46-49.

87. 136 F.E.R.C. ¶ 61,077 at P 24 n.17.

either situation, the mitigation exemption determination will be made before the project enters the capacity market. Consequently, these provisions allow a Category I facility that previously was determined by NYISO not to qualify for an Offer Floor exemption to receive a re-evaluation of the exemption determination if the economics of the project change.⁸⁸

2. The Three-Year Rule

NYISO's pre-existing tariff said that

a new generator could be granted an exemption from [O]ffer [F]loor mitigation by showing that the ICAP spot market auction price for the two capability periods beginning with the first capability period in which an ICAP supplier "is reasonably anticipated to offer to supply [unforced capacity (UCAP)]" is projected to be higher than the [O]ffer [F]loor for the same two periods (Reasonably Anticipated Entry Date Rule),⁸⁹

a Capability Period is approximately six months.⁹⁰ In its September 27, 2010 filing, "NYISO proposed to modify this rule to, instead, require . . . that the exemption test economic analysis . . . assume that a project[']s in-service] date will be three years after the project's Class Year (Three-Year Rule)," regardless of the project's actual in-service date.⁹¹ NYISO argued that the Three-Year Rule is justified because (1) three years is a "reasonable approximation of both the length of time between the Class Year cost allocation process when the developer is making an investment decision and when the developer can reasonably be expected to enter the market;"⁹² (2) the ambiguity inherent in the Anticipated Entry Date rule allows a generator to claim an anticipated entry date based on the generator's view of a date that will increase the generator's chances of obtaining an offer floor exemption;⁹³ and (3) the in-service dates identified by generators typically change significantly throughout the period when the project is in the queue.⁹⁴ This proposal was protested by several parties, including the New York City Suppliers.⁹⁵

3. The FERC's November 2010 and February 2011 Decisions

"In [its] November 26, 2010 Order, the [FERC] accepted, in part, and rejected, in part, NYISO's proposed revisions to the mitigation exemption test."⁹⁶ The FERC "found that NYISO failed to provide sufficient support for the Three-Year Rule;" the FERC told NYISO that in its upcoming compliance filing, NYISO should either justify or withdraw its proposal to adopt the Three-Year Rule.⁹⁷ The FERC approved NYISO's proposals regarding the timing of

88. *Id.* at P 24.

89. *Id.* at P 4.

90. NYISO Filing, *supra* note 84, at 12.

91. 136 F.E.R.C. ¶ 61,077 at P 29.

92. NYISO Filing, *supra* note 84, at 3.

93. 136 F.E.R.C. ¶ 61,077 at P 30.

94. *Id.*

95. *Id.*; *see also* Request for Leave to Answer and Answer of the NYISO at 1, FERC Docket No. ER10-3043-001 (2011).

96. 136 F.E.R.C. ¶ 61,077 at P 5 (citing *New York Indep. Sys. Operator, Inc.*, 133 F.E.R.C. ¶ 61,178 (2010)).

97. *Id.*

the exemption test, along with a generator's right to request a re-evaluation, even after the generator has started construction of its project.⁹⁸ The FERC said that if NYISO grants a generator an Offer Floor exemption, NYISO cannot repeal the exemption if, during construction of the project, market conditions change in a manner that are not consistent with the exemption.⁹⁹ On December 6, 2010, NYISO filed its support of the Three-Year Rule.¹⁰⁰ On February 2, 2011, the FERC accepted, subject to conditions, the Three-Year Rule, but the FERC ruled "that projects in NYISO's [Class Year 2008] should be evaluated under the existing" timing standard.¹⁰¹

In their request for clarification or, alternatively, rehearing, NYC Suppliers said they were concerned that a generator could abuse the exemption process to increase the generator's likelihood of getting an exemption.¹⁰² In the Rehearing Order, the FERC re-affirmed its findings in its November 2010 decision that (1) NYISO can make an exemption determination before the generator decides whether to move forward with a project but that NYISO can also make "an exemption determination after the project [is] constructed;" and (2) "a mitigation exemption [that is] granted cannot be revoked, but an exemption" request that was rejected can be re-examined in the circumstances proposed by NYISO.¹⁰³ The FERC also rejected the NYC Suppliers' request that the FERC clarify that any Offer Floor exemption granted pursuant to the Three Year Rule would begin to apply in the "year tested," which is the future year whose market factors are utilized in evaluating whether an exemption is justified.¹⁰⁴ In addition, a group of generators in New York City, which included Ravenswood, asked the FERC for clarification or, in the alternative, rehearing of FERC's November 2010 decision regarding the timing of exemption testing; the group is referred to by the FERC as the New York City Suppliers).¹⁰⁵ However, in the Rehearing Order, the FERC re-affirmed its approval of the Three Year Rule.¹⁰⁶ The FERC said that this Rule is appropriate because "it is more transparent, predictable, and less prone to manipulation by the project developer" as compared to the Anticipated Entry Date rule.¹⁰⁷

98. 133 F.E.R.C. ¶ 61,178 at P 71.

99. *Id.*

100. NYISO Compliance Filing – In-City Buyer Mitigation Measures at 1, FERC Docket No. ER10-3043-000 (Dec. 6, 2010), available at http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/12/BSM_Cmplnc_all_12610.pdf.

101. *New York Indep. Sys. Operator*, 134 F.E.R.C. ¶ 61,083 at PP 1, 25 (2011).

102. 136 F.E.R.C. ¶ 61,077 at P 10; *see also* Request for Clarification or, in the Alternative, Rehearing of the New York City Suppliers, FERC Docket No. ER10-3043-001 (Dec. 22, 2010).

103. 136 F.E.R.C. ¶ 61,077 at P 20.

104. *Id.* at P 39.

105. *Id.* at P 3.

106. *Id.* at P 1.

107. *Id.* at P 38.

C. *PJM Interconnection*

1. Order Accepting and Suspending Proposed Changes to the PJM Tariff Dealing with Demand Response, OA and RAA, Subject to Refund and the Outcome of a Technical Conference

On January 31, 2011, the Commission accepted PJM Interconnection, L.L.C.'s (PJM) proposal to add two additional demand resource products that market participants could offer in the PJM Reliability Pricing Model (RPM) capacity market.¹⁰⁸ The new demand resource products provided for load reductions for longer periods than the existing product.¹⁰⁹ The Commission accepted PJM's filing, subject to PJM's submission of a compliance filing establishing demand resource targets.¹¹⁰ On March 2, 2011, PJM submitted that filing, which the Commission accepted.¹¹¹ That order also denied a PSE&G request for rehearing of the Commission's January 31, 2011 order because it was beyond the scope of the filing, as "PJM [had] not proposed to modify its existing [demand resource] safeguard provisions."¹¹² The Commission also ruled that the existing safeguards were "sufficient for the new demand resource products."¹¹³

On April 7, 2011, PJM submitted a filing proposing to revise the PJM rules regarding the "values recognized for certain load reductions made during emergency and testing conditions by demand response resources" in PJM's RPM capacity market.¹¹⁴ PJM believed that the existing rules gave certain market participants an incentive to offer load reduction capability that might not actually be present in a given year.¹¹⁵ To remove this incentive, PJM proposed that, when an end-use customer was called upon to reduce load, PJM would only recognize the reduction below the customer's "Peak Load Contribution."¹¹⁶ The Commission stated that it agreed with PJM's goals but that questions remained regarding PJM's proposal.¹¹⁷ The Commission directed Commission Staff to conduct a technical conference on PJM's proposal, which convened on July 29, 2011.¹¹⁸ The Commission issued an Order on November 4, 2011 accepting PJM's April 7, 2011 filing, subject to conditions.¹¹⁹ The Commission directed PJM to: (1) explain how aggregation of customer load will be handled under PJM's new rules and how penalties would apply to aggregators;¹²⁰ (2) explain how demand resources would be compensated for load reductions above the Peak Load Contribution;¹²¹ and (3) provide clarification on how it would

108. *PJM Interconnection, L.L.C.*, 134 F.E.R.C. ¶ 61,066 at P 1 (2011).

109. *PJM Interconnection, L.L.C.*, 135 F.E.R.C. ¶ 61,102 at PP 2-3 (2011).

110. *Id.* at P 4.

111. *Id.* at P 24.

112. *Id.* at P 15.

113. *Id.* at P 16.

114. *PJM Interconnection, L.L.C.*, 135 F.E.R.C. ¶ 61,212 (2011).

115. *Id.* at P 2.

116. *Id.* at PP 2, 12.

117. *Id.* at PP 67, 72.

118. *Id.* at P 67; Technical Conference, FERC Docket No. ER11-3322-000 (July 29, 2011).

119. *PJM Interconnection, L.L.C.*, 137 F.E.R.C. ¶ 61,108 at P 1 (2011).

120. *Id.* at P 69.

121. *Id.* at P 78.

calculate comparison loads.¹²² In addition, the Commission directed PJM to include an interim mechanism that would accommodate commitments that Curtailment Service Providers already entered into.¹²³ On December 15, 2011, the Commission approved PJM's proposal to compensate demand resources at LMP when the resources met the Order No. 745 requirements but rejected PJM's elimination of an alternative compensation mechanism under circumstances not addressed by the rule as beyond the scope of the rule.¹²⁴

2. Order on Joint ATSI/PJM Integration Filing

On May 31, 2011, the Commission issued an order ruling on PJM's and American Transmission System, Inc.'s (ATSI) proposed changes to the PJM OATT and other PJM documents related to ATSI's proposed move from Midwest ISO (MISO) to PJM.¹²⁵ In a prior order, the Commission had authorized ATSI to terminate its obligations to MISO and thus move to PJM.¹²⁶ The Commission's May 31, 2011 order permitted ATSI to utilize its then-existing formula rate in PJM, but found that ATSI's proposed changes to that formula rate that would allow ATSI to "recover the costs of the RTO realignment decision through its formula rate" had not been shown to be just and reasonable.¹²⁷ The Commission ruled that in order to include these costs in its rates, ATSI would have to "specifically identify the benefits of the RTO realignment decision with respect to its wholesale transmission customers and include a cost-benefit analysis showing that the benefits to wholesale transmission customers exceed the costs of the realignment."¹²⁸

3. Order Addressing PJM's Proposed Tariff Changes Relating to the Minimum Offer Price Rule

On April 12, 2011, the Commission accepted PJM's proposed changes to the capacity procurement minimum offer price mechanism (MOPR), subject to conditions.¹²⁹ The MOPR was established in 2006, and included three screens: 1) a conduct screen – "a benchmark price used to" assess whether an offered selling price is too low; 2) an impact screen – "a test . . . compar[ing] capacity clearing price[s] with and without mitigation" of the buyer's market power; and (3) an incentive test – a test to assess whether net buyers had an incentive to underprice their bids.¹³⁰ Under the then-existing MOPR, where a seller failed all three screens, its price was generally increased to 90% of the Net Asset Class

122. *Id.* at P 79.

123. *Id.* at P 81.

124. *PJM Interconnection, L.L.C.*, 137 F.E.R.C. ¶ 61,216 at P 2 (2011).

125. *PJM Interconnection, L.L.C.*, 135 F.E.R.C. ¶ 61,198 at P 1 (2011).

126. *PJM Interconnection, L.L.C.*, 129 F.E.R.C. ¶ 61,249 at PP 4-5 (2009).

127. 135 F.E.R.C. ¶ 61,198 at PP 1, 59. These costs included the charges that PJM assessed ATSI in connection with the move to PJM, internal costs that ATSI incurred in connection with the move to PJM and which ATSI had deferred, and the fees that MISO charged ATSI in connection with its exit from MISO, which the Commission stated included the cost of legacy Midwest Transmission Expansion Plan (MTEP) projects in MISO, the cost of which ATSI remained responsible following its exit from MISO. *Id.* at P 1.

128. *Id.* at P 60.

129. *PJM Interconnection, L.L.C.*, 135 F.E.R.C. ¶ 61,022 at P 3 (2011).

130. *Id.* at P 6.

cost of new entry (Net CONE).¹³¹ In certain situations, the price was increased to 80% of Net CONE, and there were certain exemptions and waivers.¹³²

PJM submitted several changes to these rules. The Commission accepted the majority of them, subject to conditions in certain instances. First, the Commission approved the five changes that PJM made to the reference requirements used to calculate Net CONE.¹³³ These changes made the Net CONE calculation consistent with other calculations under the OATT, specified the use of the Handy-Whitman pricing index, clarified the pricing of ancillary services, provided for locational differences to be taken into account, and replaced the then-existing real levelized calculations with nominal levelized calculations (typical of a mortgage).¹³⁴ The Commission found these to be reasonable changes for purposes of the Net CONE calculations.¹³⁵ Second, the Commission accepted PJM's proposal to increase the percentage factor used for combined cycle (CC) and combustion turbine (CT) units in the conduct screen from 80-90% (while lowering certain other percentages).¹³⁶ The Commission found that this level "reasonably balances the need to prevent uneconomic entry, the inherent vagaries of cost estimation, and the administrative burdens entailed by having to provide data to justify a generator-specific lower threshold."¹³⁷ Third, the Commission accepted PJM's proposal that all sellers, not only those in a substantially net-short position, be subject to the MOPR.¹³⁸ The Commission stated that entities not in a substantially net-short position may require price mitigation as well.¹³⁹ Fourth, the Commission approved PJM's proposal to eliminate the impact screen.¹⁴⁰ The Commission found that the screen "allows offers that are indisputably uneconomic to escape mitigation."¹⁴¹ Fifth, the Commission rejected PJM's proposal that a seller that seeks to demonstrate that its offer is justified, notwithstanding the fact that it is subject to price mitigation, must make such showing to the Commission in a section 206 filing.¹⁴² The Commission ruled that such requests should first be submitted to PJM and the Independent Market Monitor.¹⁴³ Sixth, the Commission approved PJM's proposal to eliminate the exemption from MOPR for resources "being developed in response to a state regulatory or legislative mandate to resolve a projected capacity shortfall."¹⁴⁴ Seventh, the Commission approved PJM's proposal to add wind and solar facilities to the list of resources for which zero price offers may be submitted and to eliminate the exemption for upgrades to existing capacity

131. *Id.*

132. *Id.*

133. *Id.* at P 43.

134. *Id.* at PP 29-34, 51.

135. *Id.* at PP 43-51.

136. *Id.* at PP 66-74.

137. *Id.* at P 66.

138. *Id.* at P 76.

139. *Id.* at PP 86-90.

140. *Id.* at PP 92-93.

141. *Id.* at P 101.

142. *Id.* at P 118.

143. *Id.*

144. *Id.* at P 124.

resources.¹⁴⁵ The Commission determined that wind and solar resources “are a poor choice if a developer’s primary purpose is to suppress capacity market prices.”¹⁴⁶ The Commission added that upgraded CC or CT capacity could be a means of pursuing a price suppression strategy, so such resources should continue to be subject to MOPR.¹⁴⁷ Eighth, the Commission modified PJM’s proposal to apply mitigation until the second successive auction in which a resource clears the market.¹⁴⁸ The Commission ruled that the mitigation “should apply to each new resource in the base residual and each incremental auction until the resource demonstrates that its capacity is needed by the market at a price near its full entry cost.”¹⁴⁹ Finally, the Commission generally accepted certain other clarifying and administrative changes to the MOPR.¹⁵⁰

On November 17, 2011, the Commission issued an order generally denying the parties’ requests for rehearing and accession of the Commission’s April 12, 2011 order accepting PJM’s compliance filing.¹⁵¹ The primary change ordered by the Commission was its directive that PJM expand the group of generation resources subject to the MOPR offer floor and that PJM apply the MOPR to upcoming auctions more quickly.¹⁵²

4. Order on Rehearing and Motion in the ConEd MW Wheel Proceeding

On April 8, 2011, the Commission denied the NRG Companies’ request for rehearing of the Commission’s September 16, 2010 order approving “a contested settlement that two transmission service agreements should be “rolled over” and continued in force pursuant to PJM’s OATT.”¹⁵³ The settlement was between Consolidated Edison and PSE&G, among others, and involved two longstanding transmission agreements under which power was delivered to PSE&G into New Jersey, in exchange for PSE&G’s delivery of the same amount of energy into New York City.¹⁵⁴ The Commission affirmed its earlier ruling that a firm pre-Order 888 transmission agreement qualified for roll-over rights and that the replacement transmission did not have to be OATT service.¹⁵⁵ The Commission recognized that continuation of the transaction may result in uneconomic flows in some hours, but that in the great majority of hours flows would be improved, and that “the perfect cannot be the enemy of the good.”¹⁵⁶

145. *Id.* at P 145.

146. *Id.* at P 153.

147. *Id.*

148. *Id.* at P 173.

149. *Id.* at P 176.

150. *Id.* at PP 182, 191, 205, 211.

151. *PJM Interconnection, L.L.C.*, 137 F.E.R.C. ¶ 61,145 at P 1 (2011).

152. *Id.* at P 256.

153. *Report of the Electricity Regulation Committee*, 32 ENERGY L.J. 265, 288 (2011) [hereinafter *2011 Report*]; see also, *PJM Interconnection, L.L.C.*, 135 F.E.R.C. ¶ 61,018 at PP 1, 7 (2011).

154. *2011 Report*, *supra* note 152, at 288-89.

155. 135 F.E.R.C. ¶ 61,018 at PP 26-30 (2011).

156. *Id.* at PP 34, 35.

D. Midwest Independent System Operator

1. Order on Dispatchable Intermittent Resources

On February 28, 2011, the FERC conditionally accepted in part updates to the MISO Tariff that created a new category of resources named Dispatchable Intermittent Resources (DIR).¹⁵⁷ The Tariff changes gave intermittent resources up to two years to register as DIRs but allowed them to begin participating in the real-time energy market beginning June 2011.¹⁵⁸ The FERC accepted in part and rejected in part MISO's proposal that DIRs (i) "be subject to Excessive/Deficient Energy Deployment Charges;" (ii) "be eligible to receive real-time make whole credits (i.e., Real-Time Revenue Sufficiency Guarantee [(RSG)] credits, Real-Time Offer [RSG] Payments, and Day-Ahead Margin Assurance Payments);" and (iii) "be allocated [RSG] charges in a manner similar to Generation Resources."¹⁵⁹ It conditionally accepted the proposal to allocate RSG costs to DIRs, requiring MISO to explain in a thirty-day compliance filing how those charges will be assessed.¹⁶⁰ It rejected proposed tariff revisions that deleted language regarding the RSG Constraint Management Charge.¹⁶¹

The FERC rejected MISO's proposal to apply the tariff changes to intermittent resources that use energy sources other than wind, finding that MISO's arguments were focused primarily on wind and did not address whether the same reasoning applied to non-wind resources.¹⁶² However, the FERC accepted MISO's proposal to allow intermittent wind resources that commenced commercial operations before April 2005 as well as intermittent resources that have 100% of their capacity covered by long-term firm point-to-point service, network integration service, or network integration transmission service to remain categorized as non-dispatchable resources (and thus not obligated to register as DIRs).¹⁶³ It also barred DIRs from reverting back to non-dispatchable status because switching would "defeat the significant reliability and market transparency reasons for requiring Intermittent Resources to register as [DIRs] in the first place."¹⁶⁴

The FERC found several deficiencies in MISO's proposal, which it directed MISO to correct in a 30-day compliance filing.¹⁶⁵ Among these were MISO's failure to adequately demonstrate "how existing tariff provisions for Generation Resources will apply to [DIRs] without modification;"¹⁶⁶ its failure to adequately "explain the methods [it] will permit [DIRs] to use when determining their Forecast Maximum Limits;"¹⁶⁷ and its method for determining default Forecast

157. *Midwest Indep. Transmission Sys. Operator, Inc.*, 134 F.E.R.C. ¶ 61,141 at P 1, *reh'g denied*, 136 F.E.R.C. ¶ 61,100 (2011).

158. *Id.* at PP 3-5.

159. *Id.* at PP 5, 15.

160. *Id.* at P 14.

161. *Id.* at P 15.

162. *Id.* at P 34.

163. *Id.* at P 37.

164. *Id.* at P 41.

165. *Id.* at P 63.

166. *Id.* at P 61.

167. *Id.* at P 64.

Maximum Limits.¹⁶⁸ It also directed MISO within one year to prepare (i) an analysis of whether it was appropriate to subject DIRs to Excessive/Deficient Energy Deployment Charges on the same basis as other generation resources for deviations in energy output that vary from dispatch targets,¹⁶⁹ and (ii) an explanation of whether, based on operational experience, DIRs “should be eligible to provide supplemental, spinning, and/or operating reserves.”¹⁷⁰

On August 12, 2011, the FERC denied requests for rehearing relating to the bar on switching between DIR and non-DIR status and to the allocation of RSG costs.¹⁷¹ As to the former, the FERC held that the rehearing request raised no new arguments not already considered in the original order and that the original order was the result of reasoned decision-making.¹⁷² As to the latter, the FERC rejected arguments that “the allocation of RSG costs to [DIRs was] unduly discriminatory vis-à-vis virtual traders.”¹⁷³ The FERC noted that treating DIRs differently from virtual traders was justified since virtual supply offers, unlike bids of DIRs, “are made and accepted in financially binding transactions in the day-ahead market.”¹⁷⁴ In addition, the FERC pointed out “that [DIRs] avoid paying RSG charges only to the extent that they avoid causing the incurrence of RSG costs,” so the RSG allocation to DIRs does not result in cost shifts to virtual offers.¹⁷⁵

2. MISO MVP Rehearing Order

On October 21, 2011, the FERC issued an order denying in part and granting in part rehearing, conditionally accepting compliance filing, and directing further compliance filings with respect to its 2010 approval of revisions to the MISO Tariff addressing cost allocation for “multi-value [transmission] projects” (MVPs) and related issues.¹⁷⁶ MVPs are projects that “enable the reliable and economic delivery of energy in support of documented energy policy mandates or laws that address, through the development of a robust transmission system, multiple reliability and/or economic issues affecting multiple [MISO] transmission zones.”¹⁷⁷ The Tariff revisions approved in 2010 provided for recovery of MVP costs “through a system usage (i.e., a per-MWh) charge allocated to all load within, and exports from, [MISO].”¹⁷⁸

In support of requests for rehearing, parties argued that the allocation of MVP costs to all load and exports violated the requirement to allocate costs based on cost-causation principles, as directed by the Seventh Circuit in *Illinois*

168. *Id.* at P 65.

169. *Id.* at P 81.

170. *Id.* at P 107.

171. *Midwest Indep. Transmission Sys. Operator, Inc.*, 136 F.E.R.C. ¶ 61,100 at P 1 (2011).

172. *Id.* at PP 21, 24.

173. *Id.* at P 26.

174. *Id.*

175. *Id.* at P 28.

176. *Midwest Indep. Transmission Sys. Operator, Inc.*, 137 F.E.R.C. ¶ 61,074 at PP 2, 28 (2011) (FERC Docket No. ER10-1791).

177. *Id.* at P 9 (quoting *Midwest Indep. Transmission Sys. Operator, Inc.*, 133 F.E.R.C. ¶ 61,221 at P 1 (2010)).

178. *Id.* at P 13.

Commerce Commission v. FERC.¹⁷⁹ The FERC rejected this argument, holding that the parties “misapprehend[ed] the holding of *Illinois Commerce Commission*, which faulted the [FERC] for an evidentiary failure, not an analytical one.”¹⁸⁰ According to the FERC, the question under *Illinois Commerce v. FERC* is “not whether the MVP Proposal matches costs to benefits on a utility-by-utility basis, but whether it will provide sufficient benefits to the entire [MISO] region to justify a regional allocation of costs.”¹⁸¹ While acknowledging that

the benefits of integrated regional planning may be more appreciated to greater or lesser degrees at different times by different customers with respect to different groups of transmission projects, these benefits are nevertheless experienced by all [MISO] members and accrue over time. Too granular a focus would undermine the benefits and advantages provided by membership in [MISO].¹⁸²

The FERC also found that the procedures and criteria for approval of an MVP ensured that they will provide regional benefits.¹⁸³

The FERC required MISO to conduct reviews at least every three years of the costs and benefits of MVPs.¹⁸⁴ The FERC also rejected rehearing requests relating to generator interconnection issues.¹⁸⁵ In its prior order, the FERC approved MISO’s decision to make permanent the “Interim Cost Allocation Proposal,” under which interconnection customers were “responsible for 100 percent of the costs of generator interconnection projects below 345kV,” and for 90 percent of the cost of projects rated above 345kV, “with the remaining 10 percent recovered on a system-wide basis.”¹⁸⁶ The FERC rejected arguments on rehearing that this approach was unfair to interconnecting generators, stating that “[a]rguments that the Interim Cost Allocation Proposal discriminates against location-constrained resources or fails to address free-rider issues fail to consider the benefits . . . under the other elements of the MVP Proposal. The intent of the overall proposal is to send a price signal that encourages developers to site efficiently.”¹⁸⁷ The FERC also rejected challenges on rehearing to its approval of a tariff provision that limited the conditions under which generator interconnections could become eligible for designation as MVPs (thereby absolving generators of cost responsibility), holding that the conditions provided “enough flexibility to ensure that transmission expansion projects that may be categorized as MVPs are appropriately categorized as MVPs.”¹⁸⁸

3. *Edison Mission v. MISO*

On July 15, 2011, the FERC issued an order granting a complaint by Edison Mission Energy that MISO violated its own Tariff and a 2008 FERC Order on

179. *Id.* at P 28 (citing *Illinois Commerce Comm’n v. FERC*, 576 F.3d 470 (7th Cir. 2009)).

180. *Id.* at P 123.

181. *Id.*

182. *Id.* at P 126 (footnotes omitted).

183. *Id.* at PP 132-82.

184. *Id.* at PP 190-91.

185. *Id.* at PP 198-201.

186. *Id.* at P 198.

187. *Id.* at P 219.

188. *Id.* at P 232.

“queue reform by requiring two Edison [Mission w]ind [p]rojects to meet the M3 milestone in section 8.2 of [MISO’s] Generator Interconnection Procedures (GIP).”¹⁸⁹ Edison Mission had submitted interconnection requests for the projects to MISO in 2006, and they were included in a System Impact Study for a cluster of projects (Group 5) that was completed in 2007.¹⁹⁰ Edison Mission executed Facilities Study Agreements (FSAs) with MISO, also in 2007.¹⁹¹

In 2009, the FERC conditionally accepted a Generator Interconnection Agreement (GIA) for another Group 5 project but required MISO to remove language from the agreement relating to the project’s responsibility for a certain transmission line because there was no evidence the line would not have been built “but for” the Group 5 projects.¹⁹² This led MISO to undertake a new System Impact Study for the Group 5 projects, which it completed in 2011.¹⁹³ MISO then notified the Edison Mission project and others “that they would need to enter into another [FSA] and meet the M3 milestone within 30 days or be removed from the . . . queue.”¹⁹⁴ Edison Mission filed its complaint, alleging that MISO violated Tariff and FERC order requirements that exempted projects with pre-existing FSAs from the milestones in the revised queue procedures.¹⁹⁵

In response to the complaint, MISO argued that subjecting pre-existing projects to the M3 milestone requirement was necessary to preserve order in the queue process and was consistent with language from another part of the queue reforms that required all pending projects to transition to the new queue procedures within sixty days.¹⁹⁶ It claimed that acceptance of Edison Mission’s position would unfairly subject some Group 5 projects to the milestone requirement while exempting others and that a new FSA was needed for the Edison Projects in light of the revised Group 5 System Impact Study.¹⁹⁷ The FERC based its decision to grant the complaint on the tariff language relied on by Edison Mission, ruling that MISO’s reliance on a different provision was misplaced.¹⁹⁸ While Edison Mission’s position would discriminate between projects that had executed FSAs and those that did not, the FERC held that such discrimination was not undue.¹⁹⁹

4. MISO’s Waiver Request for Entergy

On September 27, 2011, the FERC denied MISO’s request for a waiver of tariff provisions “regarding the planning and cost allocation of network upgrades, in order to establish a transition for the integration of [Entergy] and its

189. *Edison Mission Energy v. Midwest Indep. Transmission Sys. Operator, Inc.*, 136 F.E.R.C. ¶ 61,035 at P 1 (2011) (FERC Docket No. EL11-43).

190. *Id.* at PP 2-3.

191. *Id.* at P 3.

192. *Id.* at P 6 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 F.E.R.C. ¶ 61,019 at P 24 (2009)).

193. *Id.*

194. *Id.* at P 7.

195. *Id.* at PP 8-13.

196. *Id.* at PP 21, 23.

197. *Id.* at PP 25, 28.

198. *Id.* at PP 39, 41.

199. *Id.* at P 44.

operating companies (collectively Entergy) into MISO.²⁰⁰ MISO stated that a transition was necessary because it and Entergy had not yet studied the differences between their systems and that if the systems were found to be non-comparable, subsidization could occur between the existing MISO system (the Northern Planning Region) and the portion of MISO to be represented by Entergy facilities (the Southern Planning Region) following its becoming a MISO member.²⁰¹

MISO proposed that the transition period consist of a five to ten year study period, during “which the cost of network upgrades terminating [in] one planning [area] would be allocated only within that [area].”²⁰² The transition period would end when comparability of the systems of the two planning areas had been achieved.²⁰³ If comparability was not achieved within ten years, MISO would propose cost allocation approaches appropriate for the circumstances prevailing at that time.²⁰⁴ After the transition period, the “existing regional cost sharing rules would apply to Baseline Reliability Projects, Market Efficiency Projects, and Generator Interconnection Projects . . . , and regional sharing of MVP costs would be phased in over the following four years.”²⁰⁵ Numerous parties opposed the request, raising a wide range of objections, including that MISO had “failed to identify a concrete problem that need[ed] to be remedied;”²⁰⁶ the project failed to adequately specify the Tariff provisions for which it sought a waiver;²⁰⁷ the transition period was too long,²⁰⁸ and the request gave MISO too much discretion.²⁰⁹

In denying the waiver request, the FERC agreed with many of the arguments of the intervenors. It held that MISO needed to seek relief under section 205 of the Federal Power Act (FPA) because the “proposal would alter the existing cost allocation . . . for the existing MISO footprint and apply a new cost allocation methodology to Entergy during the transition period.”²¹⁰ It also held that the proposed waiver was “not limited in scope and lack[ed] specificity” and that it “fails to provide a sufficient explanation of the concrete problem being remedied and how progress toward addressing the problem would be measured.”²¹¹ However, the FERC left open the possibility that elements of the proposed transition might be upheld if properly supported in the context of a section 205 filing.²¹²

200. *Midwest Indep. Transmission Sys. Operator, Inc.*, 136 F.E.R.C. ¶ 61,212 at P 1 (2011) (FERC Docket No. ER11-3728) (footnote omitted).

201. *Id.* at PP 2-3.

202. *Id.* at P 4.

203. *Id.*

204. *Id.*

205. *Id.*

206. *Id.* at P 16.

207. *Id.* at P 17.

208. *Id.* at P 18.

209. *Id.*

210. *Id.* at P 28.

211. *Id.* at P 29.

212. *Id.* at PP 27-28.

5. Order on MISO's Interpretation of the SPP-MISO JOA Regarding the Sharing of Transmission Capacity on a Common Path

On July 1, 2011, the FERC granted MISO's request for a declaratory order that section 5.2 of the Joint Operating Agreement (JOA) between Southwest Power Pool (SPP) and MISO, which addresses the sharing of transmission capacity on a common path, "will remain in effect and applicable to Entergy Arkansas . . . in the event it becomes a transmission-owning member of MISO."²¹³

Entergy Arkansas interconnects with the MISO transmission system

in New Madrid, Missouri, where Ameren . . . , Associated Electric Cooperative . . . and Entergy Arkansas share the capacity of 500/345kV transformers. The direct contiguous tie capability between Entergy Arkansas and Ameren is approximately 1,000 MW of the 1,500 MW total capability of the interconnection. The tie is governed by a 1977 Interchange Agreement, which was amended in 1996²¹⁴

to comply with the Order No. 888 requirement to ensure open access. "SPP and MISO entered into the . . . JOA as part of SPP's application to become an RTO."²¹⁵ Section 5.2 of the JOA states that "[i]f the Parties have contract paths to the same entity, the combined contract path capacity will be made available for use by both Parties."²¹⁶

The dispute arose in the context of discussions between SPP, MISO, Entergy, and Entergy's retail regulators over whether Entergy Arkansas should continue to operate under an existing arrangement with the Independent Coordinator of Transmission (ICT), join the SPP, or join MISO.²¹⁷ Parties to the discussions asked MISO "to confirm the availability of transmission path sharing under section 5.2 of the" JOA if Entergy Arkansas joined MISO.²¹⁸ "MISO's counsel prepared a legal analysis" that provided that confirmation, to which SPP took exception.²¹⁹ MISO asked the FERC to resolve the dispute.²²⁰

The primary area of disagreement between MISO and SPP concerned the meaning of "the same entity" in section 5.2.²²¹ MISO stated that because SPP and MISO both "have contract paths to Entergy Arkansas," the latter is "the same entity" under section 5.2 and those paths must therefore be shared.²²² SPP countered "that if Entergy Arkansas joins MISO, . . . neither MISO nor SPP would have a contract path to the same entity."²²³ Instead, SPP would have a contract path "with MISO, not Entergy Arkansas, and MISO could not have a contract path with itself."²²⁴ SPP and intervenors also urged the FERC to deny

213. *Midwest Indep. Transmission Sys. Operator, Inc.*, 136 F.E.R.C. ¶ 61,010 at P 1 (2011) (FERC Docket No. EL11-34), *petitions for reh'g pending*.

214. *Id.* at P 3 (footnote omitted).

215. *Id.* at P 8 n.17.

216. *Id.* at P 11.

217. *Id.* at P 7.

218. *Id.* at P 8.

219. *Id.*

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

221. *Id.* at PP 11, 24.

222. *Id.* at P 11.

223. *Id.* at P 24.

224. *Id.*

MISO's petition as premature, both because MISO failed to exhaust informal dispute resolution procedures under the JOA and because the issue might become moot if the parties renegotiated the JOA to reflect the changes in the parties' systems.²²⁵ The FERC examined how the term "entity" was used in the JOA and concluded that it was "sufficiently broad to encompass Energy Arkansas, regardless of whether it is a member of MISO, SPP, or neither."²²⁶ It also rejected as unsupported SPP's argument that MISO cannot have a contract path with one of its members:

Since the term "contract path" is not defined in the SPP JOA, the context of section 5.2 and how it has been used by MISO and SPP suggests that the term was intended to encompass transmission capacity on physical or contractual interconnections – not just the narrow "point-to-point" transmission service definition SPP argues for.²²⁷

The FERC also noted that MISO's interpretation of section 5.2 was "consistent with the course of performance of parties to the SPP JOA."²²⁸ However, the FERC agreed with SPP that the JOA imposed a duty on the parties to renegotiate the JOA's terms in good faith in response to changing circumstances.²²⁹ Finally, the FERC rejected the argument that the petition should be denied due to MISO having failed to exhaust the JOA informal dispute resolution provisions, finding that there was no evidence that the parties would benefit by doing so.²³⁰

E. Southwest Power Pool

1. Transmission Cost Allocation Rehearing Order

On June 17, 2010, the FERC accepted SPP's Highway/Byway methodology for allocating the cost of new transmission facilities in SPP.²³¹ This methodology allocates costs for new transmission facilities based on a facility's voltage.²³² Specifically,

the costs of facilities operating at 300 kV and above[, which SPP refers to as Extra High Voltage facilities, are] allocated 100 percent across the SPP region on a postage stamp basis; . . . the costs of facilities operating above 100 kV and below 300 kV [are] allocated one-third on a regional postage stamp basis and two-thirds to the zone in which the facilities are located; and . . . the costs of facilities operating at or below 100 kV [are] allocated 100 percent to the zone in which the facilities are located.²³³

Several parties requested rehearing of the Highway/Byway Order.²³⁴

On October 20, 2011, the Commission issued an order on rehearing

225. *Id.* at PP 33-39.

226. *Id.* at P 61.

227. *Id.* at P 62.

228. *Id.* at P 63.

229. *Id.* at P 64.

230. *Id.* at P 66.

231. *Southwest Power Pool, Inc.*, 131 F.E.R.C. ¶ 61,252 (2010) (FERC Docket No. ER10-1069).

232. *Id.* at P 10.

233. *Id.*

234. *See, e.g.*, Request for Rehearing of Nebraska Public Power District, FERC Docket No. ER10-1069-000 (July 9, 2010).

affirming its earlier order.²³⁵ The Commission stated that “[u]nder the cost causation principle,” the Commission and courts have “traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them”²³⁶ but “that cost allocation is ‘not a matter for the slide-rule.’”²³⁷ The Commission found that the Seventh Circuit’s *Illinois Commerce Commission v. FERC* decision does not alter this analytical framework, which has been employed by the Commission to ensure that transmission cost allocation methodologies are consistent with the cost causation principle, and does not require a utility-by-utility or zone-by-zone cost-benefit analysis.²³⁸

The Commission affirmed that SPP provided sufficient evidence to demonstrate that the Highway/Byway methodology is just and reasonable and not unduly discriminatory or preferential.²³⁹ The Commission also found that SPP’s analysis demonstrated that Extra High Voltage facilities in the SPP region are used more for regional purposes and that lower voltage facilities are more local in nature.²⁴⁰ In addition, the Commission found that SPP operates its transmission system and energy market on a single-system regional basis to reliably and efficiently integrate resources to serve loads throughout its entire footprint and that the strong regionally-integrated Extra High Voltage transmission network that results from this process provides benefits to all that are interconnected to it. As a result, the fundamental benefit of the Extra High Voltage facilities supporting regional power flows is the flexibility they provide to deliver energy and operating reserves more efficiently and reliably within and between balancing areas throughout the SPP footprint, even if such benefits may be more appreciated at different times by different customers.²⁴¹

The Commission concluded that by distinguishing between the types of facilities that are used on a regional and zonal basis, the Highway/Byway methodology would ensure that allocations of costs are roughly commensurate with associated benefits.²⁴² Accordingly, the Order on Rehearing affirmed the Commission’s finding that SPP provided probative evidence to support a determination that the Highway/Byway Methodology is just and reasonable and not unduly discriminatory and denied rehearing.²⁴³

2. Integrated Transmission Plan Rehearing Order

On July 15, 2010, the FERC accepted SPP’s proposal to implement the Integrated Transmission Plan (ITP), a modified transmission planning process, into Attachment O of SPP’s tariff.²⁴⁴ The ITP provides for Near Term Assessments, which are conducted annually and designed to meet reliability

235. *Southwest Power Pool, Inc.*, 137 F.E.R.C. ¶ 61,075 (2011).

236. *Id.* at P 20 (quoting *KN Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992)).

237. *Id.* (quoting *Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 589 (1945)).

238. *Id.* at PP 21, 29, 47 (citing *Illinois Commerce Comm’n v. FERC*, 576 F.3d 470 (7th Cir. 2009)).

239. *Id.* at PP 34, 52-55.

240. *Id.* at PP 47-48.

241. *Id.* at P 53.

242. *Id.* at PP 36, 47.

243. *Id.* at P 84.

244. *Southwest Power Pool, Inc.*, 132 F.E.R.C. ¶ 61,042 (2010) (FERC Docket No. ER10-1269).

needs and comply with NERC standards; 10-year Assessments “initiated every three years” and focused on developing needed transmission facilities of 100-300 kV; and 20-year Assessments “initiated every three years” and focused on developing needed transmission facilities of 300 kV and above.²⁴⁵ Under the ITP, “SPP will assess the cost-effectiveness of proposed [transmission] solutions” on a forty-year “financial modeling time frame,” and the cost-effectiveness analysis “will include quantif[ication of the] benefits resulting from dispatch savings, loss reductions, avoided projects, applicable environmental impacts, reduction in required operating reserves, interconnection improvements, congestion reduction, and other benefit metrics” developed through the SPP stakeholder process.²⁴⁶ Several parties requested rehearing of the Commission’s order accepting the ITP.²⁴⁷

On July 21, 2011, the Commission issued an order on rehearing affirming its earlier order, denying requests for rehearing and granting clarification.²⁴⁸ On rehearing, the Commission affirmed that the ITP tariff “provisions detail a comprehensive, iterative process for transmission planning” that satisfies the Order No. 890 requirements of transparency, comparability and openness.²⁴⁹ The Commission noted that “[t]he transparency principle does not require that all rules and practices related to the details of transmission planning be included in a transmission provider’s tariff or filed with the Commission.”²⁵⁰ The Commission affirmed that SPP’s approach is acceptable because the SPP tariff provides sufficient guidance and details,²⁵¹ because the ITP Assessments will be implemented through an open and transparent stakeholder process,²⁵² and “because some of the details [of cost-effectiveness analyses] are not ‘realistically susceptible of specification.’”²⁵³ Accordingly, the Commission found that it has properly applied the “rule of reason,” as required by the courts, when implementing its statutory duty to ensure that rates are just and reasonable and not unduly discriminatory.²⁵⁴ The Commission granted limited clarification to clarify that the determinations in the instant proceeding

do[es] not limit a party’s ability to file a complaint under section 206 of the FPA relating to practices in the ITP Manual if it believes that the implementation processes detailed in the ITP Manual, when put into practice, have an unjust, unreasonably or unduly discriminatory effect on SPP’s rates or services.²⁵⁵

245. *Id.* at P 8.

246. *Id.* at P 14.

247. Request for Rehearing by the Empire Dist. Elec. Co., Omaha Pub. Power Dist., City Utils. of Springfield, Mo. and Lincoln Elec. Sys., FERC Docket No. ER10-1269-001 (Aug. 13, 2010).

248. *Southwest Power Pool, Inc.*, 136 F.E.R.C. ¶ 61,050 (2011).

249. *Id.* at PP 18, 20.

250. *Id.* at P 22.

251. *Id.* at P 34.

252. *Id.* at P 35.

253. *Id.* at P 37 (quoting *City of Cleveland v. FERC*, 773 F.2d 1368, 1376 (D.C. Cir. 1985)).

254. *Id.* at PP 32, 34.

255. *Id.* at P 64 (citing *California Indep. Sys. Operator Corp.*, 133 F.E.R.C. ¶ 61,224 at P 159 n.138 (2010)).

J. California Independent System Operator Corporation

1. Start-Up and Minimum Load Amendment

On January 26, 2011, the California Independent System Operator Corporation (CAISO) filed with the FERC an amendment to the CAISO tariff “to allow scheduling coordinators to make independent elections for start-up and minimum load cost compensation,” and to allow scheduling coordinators “to submit daily bids for start-up and minimum load costs for resources subject to the proxy cost option” for start-up and minimum load cost compensation.²⁵⁶ In the tariff amendment, the CAISO also proposed “to codify in [its] tariff its longstanding practice of temporary suspension of the daily master file updates when necessary to accommodate system upgrades and perform system maintenance.”²⁵⁷ On March 31, 2011, the FERC issued an order accepting the tariff amendment effective as of April 1, 2011.²⁵⁸

2. Order Denying Complaint Regarding *Critical Path Transmission & Clear Power*

On December 14, 2010, Critical Path Transmission, LLC and Clear Power, LLC jointly filed a complaint against the CAISO.²⁵⁹ They alleged that the CAISO “violated its tariff and the filed rate doctrine by failing to adhere to the transmission planning process . . . in effect in the CAISO . . . [t]ariff . . . at the time when [the complainants] submitted proposed economic transmission projects for consideration” in the CAISO’s 2008-2009 transmission planning request windows.²⁶⁰ On April 14, 2011, the FERC issued an order denying the complaint.²⁶¹ No party filed a request for rehearing of the April 14, 2011 order. Therefore, the FERC proceeding has concluded.

3. Order Denying Complaint Regarding *Transmission Technology Solutions v. CAISO*

On November 29, 2010, Transmission Technology Solutions, LLC (TTS) and Western Grid Development, LLC (WGD) jointly filed a complaint against the CAISO.²⁶² They alleged that the CAISO violated the FPA by engaging in unjust, unreasonable, and discriminatory decisions and actions with respect to “TTS’s proposed projects in the CAISO’s 2008-2009 transmission planning process . . . and [with respect to] WGD’s proposed projects in the CAISO’s

256. CAISO Start-up and Minimum Load Tariff Amendments at 1, FERC Docket No. ER11-2760-000 (Jan. 26, 2011).

257. *Id.*

258. *California Indep. Sys. Operator Corp.*, 134 F.E.R.C. ¶ 61,257 at P 1 (2011) (FERC Docket No. ER11-2760).

259. Complaint and Request for Refund Effective Date and Conditional Motion for Consolidation of Critical Path Transmission, LLC and Clear Power, LLC Against the California Indep. Sys. Operator Corp., FERC Docket No. EL11-11-000 (Dec. 14, 2010).

260. *Id.* at 2; *Critical Path Transmission, LLC v. California Indep. Sys. Operator Corp.*, 135 F.E.R.C. ¶ 61,031 (2011).

261. 135 F.E.R.C. ¶ 61,031 (2011).

262. Complaint and Request for Expedited Action, FERC Docket No. EL11-8-000 (Nov. 29, 2010).

2009-2010 [transmission planning process].”²⁶³

On April 27, 2011, the FERC issued an order denying the complaint.²⁶⁴ No party filed a request for rehearing of the April 27, 2011 order. Therefore, the FERC proceeding has concluded.

4. Order on Compliance and Rehearing Regarding PDR Amendment

On February 16, 2010, the CAISO submitted a tariff amendment to include provisions in its tariff to implement a new type of resource capable of providing demand response services, “the proxy demand resource.”²⁶⁵ The FERC, on July 15, 2010, issued an order conditionally accepting the February 16, 2010 tariff amendment “with a July 19, 2010 effective date for the *pro forma*” proxy demand resource agreement included in the tariff amendment “and an August 10, 2010 effective date for the remaining tariff provisions” included in the tariff amendment, subject to a compliance filing to be submitted by the CAISO.²⁶⁶

On August 16, 2010, the CAISO submitted the compliance filing and a request for clarification or, in the alternative, request for rehearing of the July 15, 2010 order asserting that the CAISO should not be obligated to include in its tariff a methodology for verifying proxy demand resource ancillary services capacity for periods “longer than one hour.”²⁶⁷ On January 4, 2011, the FERC issued an order accepting the August 16 compliance filing and granting the CAISO’s request for rehearing.²⁶⁸

5. Order on Rehearing Regarding Self-Supply of Station Power

On November 20, 2007, the [FERC] issued an order that, among other things, granted rehearing of [a previous FERC order] regarding the categorization of the South of Lugo Transmission Path (South of Lugo) [in California] for purposes of allocating minimum load compensation costs under the [CAISO] tariff.²⁶⁹ In granting rehearing, the November [20,] 2007 order found that the constraint on South of Lugo should be categorized as a zonal, rather than a local, constraint.²⁷⁰ The effect of this decision [was] that minimum load compensation cost responsibility associated with the . . . must-offer obligation [under the CAISO tariff] would not be allocated entirely to the local load serving entity Instead, [the] cost responsibility [would be] allocate[d] to a number of load serving entities . . . located in the SP-15 zone [in California].²⁷¹

On December 19, 2007, the Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California (collectively, Southern Cities) filed a request for

263. *Id.* at 2; *Transmission Tech. Solutions, LLC v. California Indep. Sys. Operator Corp.*, 135 F.E.R.C. ¶ 61,077 at P 1 (2011).

264. 135 F.E.R.C. ¶ 61,077 (2011).

265. CAISO Tariff Amendment to Implement Proxy Demand Resource Product, FERC Docket No. ER10-765-000 (Feb. 16, 2010).

266. *California Indep. Sys. Operator Corp.*, 132 F.E.R.C. ¶ 61,045 at P 1 (2010) (emphasis in original).

267. Motion for Clarification or, in the Alternative, Rehearing of the California Indep. Sys. Operator Corp., FERC Docket No. ER10-765-001 (Aug. 16, 2010).

268. *California Indep. Sys. Operator Corp.*, 134 F.E.R.C. ¶ 61,004 (2011) (FERC Docket Nos. ER10-765 and ER10-2621).

269. *California Indep. Sys. Operator Corp.*, 136 F.E.R.C. ¶ 61,197 at P 1 (2011) (citing *California Indep. Sys. Operator Corp.*, 121 F.E.R.C. ¶ 61,193 (2007)).

270. *Id.* (citing 121 F.E.R.C. ¶ 61,193 at PP 2-9).

271. *Id.*

rehearing of findings in the November 20, 2007 order.²⁷² On September 16, 2011, the FERC issued an order denying the Southern Cities' request for rehearing.²⁷³ On November 14, 2011, the Six Cities filed a petition for review of the November 20, 2007 and September 16, 2011 orders in the D.C. Circuit.²⁷⁴ The case is pending before the court.

G. ERCOT

1. Nodal Market Revision Requests

The Electric Reliability Council of Texas (ERCOT) has implemented a series of revisions to its Nodal Protocols. Many of the approved change provide fine tuning to the protocols to reflect experience since the December 1, 2010 nodal market implementation. ERCOT is also considering revisions to certain protocols affecting ancillary services. In December, ERCOT approved a change concerning section 6.4.3.2, Energy Offer Curve for Responsive Reserve Service and Regulation Up Service Capacity.²⁷⁵ That revision

adds a requirement for the Energy Offer Curve to be set at the System-Wide Offer Cap . . . for the capacity reserved for Responsive Reserve . . . Service Ancillary Service Resource Responsibility and Regulation Up . . . Ancillary Service Resource Responsibility because of the Day-Ahead Market . . . or Supplemental Ancillary Services Market Ancillary Service awards, or Self-Arranged Ancillary Service Quantity.²⁷⁶

2. Non-Spinning Reserve Pricing Proposal

At its October 27 open meeting, the PUCT provided guidance concerning the appropriate price floor for non-spinning reserve (Non-Spin).²⁷⁷ That action was the first of a series of steps that the PUCT anticipates must be taken “to ensure that [the] ERCOT[] energy-only market sends . . . correct price signals, particularly when shortage[s] occur.”²⁷⁸ ERCOT implemented the PUCT guidance by approving Nodal Protocol Revision Request (NPRR) 428 concerning section 6.4.3.1, Energy Offer Curve Requirements for Generation Resources Assigned Non-Spin Responsibility.²⁷⁹ That NPRR “adds a

272. Request for Rehearing on Behalf of the Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California, FERC Docket Nos. EL04-103-003 & ER04-835-008 (Dec. 19, 2007).

273. *California Indep. Sys. Operator Corp.*, 136 F.E.R.C. ¶ 61,197 (2011).

274. Petition for Review of the Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California, No. 11-1422 (D.C. Cir. Nov. 14, 2011).

275. See generally Nodal Protocol Revision Request No. 427, Energy Offer Curve Requirements for Generation Resources Assigned Reg-Up and RRS, Project No. 37,897 (ERCOT Oct. 27, 2011), available at http://www.ercot.com/content/mktrules/issues/npr/426-450/427/keydocs/427NPRR-01_Energy_Offer_Curve_Requirements_for_Generation_Re.DOC.

276. See generally, *Approved Nodal Protocol Revision Requests (NPRRs)*, ERCOT, http://www.ercot.com/mktrules/issues/reports/nprr_approved (last visited Mar. 8, 2012) [hereinafter *Approved NPRRs*].

277. Memorandum from Commissioner Kenneth W. Anderson, Jr., Pub. Util. Comm'n of Tex., on Dec. 8, 2011 Open Meeting, Item No. 25, Project No. 37,987, to Chairman Donna L. Nelson, Pub. Util. Comm'n of Tex., at attachment A, at 1 (Dec. 7, 2011), available at http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/37897_67_712836.PDF.

278. *Id.*

279. *Approved NPRRs*, *supra* note 276.

requirement for the Energy Offer Curve to be at or above \$120 for On-Line Non-Spinning Reserve . . . capacity and at or above \$180 for Off-Line Non-Spin capacity.²⁸⁰

IV. TRANSMISSION RATES

A. Cost Based Rates

1. *Southern California Edison, Rehearing*

On October 6, 2011, the Commission denied Southern California Edison's (SCE) request for rehearing of the Commission's April 15, 2010 order, as well as two other related requests.²⁸¹ The primary issue in the case was whether to use the median or the midpoint of the range of reasonableness of the comparable group in setting SCE's rate of return on equity (ROE).²⁸² The Commission rejected SCE's argument that the Commission's use of the midpoint of the range of reasonableness when setting the ROE for the members of an ISO as a group while using the median of the range of reasonableness while setting the ROE for an individual member of that group unfairly discriminated against ISO members that filed their ROE requests on an individual basis.²⁸³ The Commission ruled that the purpose of its analysis in these two situations was different and that the difference justified the different approaches.²⁸⁴ The Commission stated that when it was setting the ROE for members of a ISO, it was important to select an ROE that considered the full range of reasonableness.²⁸⁵ The Commission contrasted this with setting the ROE for an individual utility, where the Commission stated its primary focus was selecting the ROE that provided the best measure of central tendency.²⁸⁶ The Commission also rejected SCE's rehearing request on a second issue: whether to update the ROE to reflect changes in the yield on ten-year Treasury bonds between the time period used for the discounted cash flow (DCF) analysis that set the ROE and the Commission's April 15, 2010 order.²⁸⁷ SCE had also argued that the Commission's use of the change in Treasury ten-year bond yields as a proxy for the change in SCE's cost of capital was inappropriate in light of current financial conditions.²⁸⁸ The Commission ruled that its policy was well-established and that it was not persuaded that SCE should be exempt from this policy.²⁸⁹

B. Incentive Rates

1. Ameren Grand Rivers

On May 19, 2011, the Commission issued an order on transmission rate

280. *Id.*

281. *Southern Cal. Edison Co.*, 137 F.E.R.C. ¶ 61,016 (2011) (FERC Docket No. ER08-375-004).

282. *Id.* at P 2.

283. *Id.* at PP 3, 12.

284. *Id.* at P 17.

285. *Id.* at P 14.

286. *Id.* at P 23.

287. *Id.* at PP 7, 30.

288. *Id.* at PP 10, 28.

289. *Id.* at P 31.

incentives for a portfolio of projects referred to as the “Grand Rivers” transmission projects.²⁹⁰ The Commission conditionally granted transmission rate incentives with respect to the Illinois Rivers and Big Muddy River projects but denied rate incentives for the Spoon River and Wabash River projects.²⁹¹ The approval of rate incentives for Illinois Rivers and Big Muddy River are conditioned on those projects being approved in the MISO’s Transmission Expansion Planning Process (MTEP) as providing reliability benefits and/or economic benefits from congestion reduction.²⁹²

The Commission found “that receiving approval in the MTEP as an MVP under Criterion 1 [of MISO’s tariff] establishes eligibility for the Order No. 679 rebuttable presumption.”²⁹³ The Commission further found that a sufficient nexus had been shown between the incentives sought and the investment being made for the Illinois River and Big Muddy River projects due to the significant scope and effect of those projects.²⁹⁴ The Commission pointed to (i) the size and estimated cost of these projects; (ii) the fact that they each will span multiple states and cross the Mississippi River, implicating major Mississippi River shipping channels and creating unusual construction risk; (iii) a comparison of the project costs to Ameren’s current net transmission plant; and (iv) the fact that these projects are expected to mitigate NERC contingencies, integrate new renewable generation, enhance transfer capability, and improve reliability.²⁹⁵ The Commission found that the scope and effect of the Spoon River and Wabash River projects was significantly smaller and thus denied incentives for those projects without prejudice to the filing of a new application for them.²⁹⁶

The Commission went on to conditionally grant the following transmission rate incentives for the Illinois River and Big Muddy River projects: (1) inclusion of 100% of construction work in progress (CWIP) in rate base;²⁹⁷ (2) an abandoned plant incentive so that it will have the opportunity to recover prudently incurred costs if the Projects are abandoned due to forces outside of the project developer’s control;²⁹⁸ (3) “a hypothetical capital structure of 56 percent equity and 44 percent debt;”²⁹⁹ and (4) authorization “to expense and recover on a current basis”, rather than capitalizing, all prudently incurred costs for planning, regulatory, and related approvals during the Projects’ pre-commercial operations period, including legal, engineering, environmental, and consulting services and other development expenses that are not captured in

290. *Ameren Servs. Co.*, 135 F.E.R.C. ¶ 61,142 at P 1 (2011) (FERC Docket No. EL10-80).

291. *Id.* at PP 1, 42.

292. *Id.* at P 31.

293. *Id.* Order No. 679 establishes a rebuttable presumption that the requirements for incentive rate treatment under section 219 of the Federal Power Act (FPA) are met if (1) the “project results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found acceptable by the Commission; [and] (2) the . . . project [receives] construction approval from [the] appropriate state commission or . . . siting authority.” *Id.* at P 22; *see also* Order No. 679, *Promoting Transmission Investment Through Pricing Reform*, F.E.R.C. STATS. & REGS. ¶ 31,222 at P 58, 71 Fed. Reg. 43,294 (2006) (to be codified at 18 C.F.R. pt. 35).

294. 135 F.E.R.C. ¶ 61,142 at PP 38-39.

295. *Id.* at P 39.

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

297. *Id.* at P 48.

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

299. *Id.* at P 69.

CWIP accounts.³⁰⁰

2. PSE&G Rate Incentive Rehearing and Changes of Project Order

On October 4, 2011, the Commission issued an order addressing the status of the Branchburg Project and dismissing as moot a request for rehearing of the Commission's December 30, 2009 Order (Incentives Order),³⁰¹ which granted PSE&G a package of transmission rate incentives for the project.³⁰² The Commission noted that following the issuance of its Incentives Order, the original Branchburg Project was removed from the PJM regional transmission expansion plan (RTEP) and replaced by another PSE&G project.³⁰³ The Commission held that this substitution was more than a mere reconfiguration of the original project in that the new project (1) will be a 230 kV project, not a 500 kV project; (2) "will convert existing 138 kV circuits between Roseland and Hudson County, New Jersey into 230 kV operation; (3) will expand [an] existing . . . 230 kV substation" and reconfigure another 230 kV substation; (4) "will include the construction of two 230 kV underground cables;" and (5) will cost an estimated \$700 million, not \$1.1 billion.³⁰⁴ Accordingly, the Commission held that the transmission incentives approved in its Incentives Order are not transferable to the new project.³⁰⁵ The Commission found that the only still-effective incentive granted in the Incentives Order is the opportunity for PSE&G to seek recovery of prudently incurred abandonment costs from the original project.³⁰⁶

3. RITELine Incentive Order

On October 14, 2011, the Commission issued an order conditionally approving in part and rejecting in part the rate incentives sought by the RITELine Companies for their Reliability Interregional Transmission Extension Project, a proposed 420-mile, 765 kV electric transmission project designed to serve new wind generation resources that would extend from the Indiana/Ohio border, through Indiana, and into Illinois.³⁰⁷ The Commission noted that the RITELine Project has not been approved in PJM's RTEP regional planning process and has not received siting approval from the state siting authorities.³⁰⁸ The FERC further determined that RITELine failed to adequately demonstrate that it would ensure reliability or reduce delivered power costs by reducing congestion because (i) the claimed congestion reductions were predicated on the addition of 5,000 MW of wind generation that might not get built;³⁰⁹ (ii) the RITELine Companies failed to provide the basis for certain modeling assumptions made in its congestion study "regarding the amounts, types, and

300. *Id.* at P 77.

301. *Public Serv. Elec. & Gas Co.*, 129 F.E.R.C. ¶ 61,300 (2009).

302. *Public Serv. Elec. & Gas Co.*, 137 F.E.R.C. ¶ 61,010 (2011) (FERC Docket No. ER10-159-001).

303. *Id.* at P 21.

304. *Id.* at P 24.

305. *Id.* at P 26.

306. *Id.*

307. *RITELine Illinois, LLC*, 137 F.E.R.C. ¶ 61,039 at PP 1-4 (2011) (FERC Docket Nos. ER11-4069 & ER11-4070).

308. *Id.* at P 34.

309. *Id.* at P 36.

location of new renewable” resources,³¹⁰ and (iii) PJM’s RTEP process is working on the reliability issues the RITELine Companies raised and may be able to resolve them before the RITELine Project is completed.³¹¹ Nonetheless, the Commission approved incentive rate treatment for the project, conditioned upon the RITELine Project being included in PJM’s RTEP as a project that “will ensure reliability or reduce the cost of delivered power by reducing congestion.”³¹²

The Commission found that a sufficient nexus had been shown between the substantial risks and challenges being undertaken and the incentives requested.³¹³ The Commission noted the RITELine Project’s size and \$1.6 billion cost, the fact that it would “permit the integration of approximately 5,000 MW of new wind generation,” the risks attributable to the lack of a formal siting process in Indiana, and the risks and challenges involved in using advanced technologies.³¹⁴

The Commission granted the RITELine Companies their requested 50-basis-point ROE adder for transferring functional control to PJM, subject to (i) the RITELine Project being included in PJM’s RTEP; (ii) the RITELine Companies taking all necessary steps to grant operational control to PJM; and (iii) “the RITELine Companies becom[ing] Participating Transmission Owners” in PJM.³¹⁵ However, the FERC denied the RITELine Companies their requested 50-basis-point adder for the use of an advanced technology and held that the RITELine Companies failed to show that using the two technologies in combination “is sufficiently novel or innovative . . . to warrant a separate . . . ROE adder.”³¹⁶ The Commission also granted two-thirds of the 150-basis point adder that the RITELine Companies requested based on the risks and challenges associated with investing in the project.³¹⁷ The Commission reduced the RITELine Companies’ proposed base ROE from 10.7% to 9.93%.³¹⁸ The FERC held that in applying a DCF methodology to the proxy group, the RITELine Companies failed to comply with the FERC policy requiring that they eliminate both the low-end cost of equity for PPL Corporation and the corresponding high-end ROE for that company.³¹⁹

4. *Green Power Express* Rehearing

On May 19, 2011, the Commission issued an order denying requests for rehearing of its April 10, 2009 Order (April 10 Order)³²⁰ in which the Commission conditionally approved certain transmission rate incentives for the *Green Power Express* project.³²¹ The Commission denied claims that the April 10 Order’s approval of rate incentives was premature, noting that there is no

310. *Id.*

311. *Id.* at P 37.

312. *Id.* at P 38.

313. *Id.* at P 52.

314. *Id.* at P 53.

315. *Id.* at P 60.

316. *Id.* at P 61.

317. *Id.* at P 63.

318. *Id.* at PP 65, 73.

319. *Id.* at P 72.

320. *Green Power Express LP*, 127 F.E.R.C. ¶ 61,031 (2009).

321. *Green Power Express LP*, 135 F.E.R.C. ¶ 61,141 (2011) (FERC Docket No. ER09-681-001).

requirement that a project must first complete the regional transmission planning process or have “been approved by a state regulatory or siting commission.”³²² The Commission further denied challenges to the project’s eligibility for transmission rate incentives, pointing out that the project will “(1) reduce congestion . . . by facilitating integration and delivery of low-cost wind energy in the upper Midwest; (2) ensure reliability by providing a robust transmission backbone . . . capable of moving large amounts of power and handling unscheduled flows; and (3) improve the voltage profile of underlying lower voltage networks.”³²³ The Commission also denied rehearing with respect to the whether Green Power had shown a sufficient “nexus between each requested incentive and the risks and challenges associated with the project.”³²⁴ The Commission pointed to the size of the project and the need to lower borrowing costs and “offset numerous regulatory and governmental risks.”³²⁵ The Commission also denied “requests for rehearing regarding the ROE and ROE incentive adders” approved in the April 10 Order, finding that the protesters had failed to specify “what issues of material fact should have been sent to hearing.”³²⁶ Finally, the Commission approved a settlement between Green Power and certain parties which provides for, among other things, certain changes to the formula rate template and Protocols that the Commission had set for hearing in the April 10 Order.³²⁷ The FERC’s acceptance of the settlement is subject to the conditions in the April 10 Order.³²⁸

5. *Desert Southwest Power*

On May 20, 2011, the Commission issued an order granting Desert Southwest the following “transmission rate incentives for its proposed 118 mile single-circuit 500 kV transmission project”³²⁹ that “will enable power from location-constrained wind resources . . . to be transported from eastern Riverside County, California to load pocket areas in southern California.”³³⁰ (1) 100% recovery of its prudently incurred CWIP costs in rate base; (2) 100% recovery of its prudently-incurred transmission related costs if the project is abandoned due to forces outside the developer’s control; (3) a combined 150-basis point ROE adder based on the size, scope benefits, and the risks and challenges of the Project; and, (4) “a hypothetical capital structure of 50 percent equity and 50 percent debt . . . until the Project is placed in service.”³³¹

The Commission found that, although Desert Southwest did not qualify for a Order No. 679 rebuttable presumption, the “project is needed to ensure

322. *Id.* at P 17.

323. *Id.* at P 32 (quoting 127 F.E.R.C. ¶ 61,031 at P 41).

324. *Id.* at P 41.

325. *Id.*

326. *Id.* at PP 46-47.

327. *Id.* at PP 64, 75.

328. *Id.* at P 75.

329. *Desert Southwest Power, LLC*, 135 F.E.R.C. ¶ 61,143 at P 1 (2011) (FERC Docket No. EL10-54-000).

330. *Id.* at P 3.

331. *Id.* at P 6. “Desert Southwest requested a total of 200 basis points of incentive ROE adders.” *Id.* at P 91.

reliability or reduce congestion”³³² and qualified for incentives by demonstrating that “the Project will enhance the economic efficiency of the operating the CAISO system by reducing congestion” based on an Economic Benefit Analysis “that included twelve months of congestion data, contingency data for over 140 contingencies at over 65 junctions, power flow under various scenarios, and a table of locational marginal price data for the area with or without the project.”³³³

6. Atlantic Wind Connection

On May 19, 2011, the Commission issued an order granting in part and denying in part a petition for transmission rate incentives for the proposed Atlantic Wind Connection project, which “will include four 320 kV direct current cables (two circuits of 1,000 MW each) [running] parallel to the Mid-Atlantic coast approximately 20 miles offshore for 250 miles, interconnecting with the existing land-based transmission system in New Jersey, Delaware, Maryland, and Virginia.”³³⁴ The Commission held that the applicants failed to qualify for the “rebuttable presumption that the Project satisfies the requirements of section 219” of the FPA or to demonstrate that the project will “ensure[] reliability or reduce[] the price of delivered power by reducing congestion.”³³⁵ Nonetheless, the Commission approved certain transmission rate incentives for the project, “conditioned upon the project being included in . . . PJM[’s] RTEP.”³³⁶ The Commission found that the project is non-routine based on the fact that it “will be constructed underwater, extend along the Mid-Atlantic coast for 250 miles, . . . interconnect with the existing land-based transmission system in four states, . . . cost an estimated \$5 billion, involve the use of multiple advanced technologies, and require various regulatory approvals.”³³⁷

7. Central Transmission

On May 19, 2011, the Commission issued an order granting in part and denying in part a petition for declaratory order filed by Central Transmission, LLC seeking transmission rate incentives for its proposed Valley Project, a thirty to fifty mile, “single circuit 345 kV transmission line and associated equipment.”³³⁸ The Commission conditionally granted the Valley Project “(i) recovery of pre-commercial costs through a regulatory asset, (ii) recovery of abandonment costs, (iii) a 50 basis point [ROE] adder for [RTO] participation, and (iv) a 30-year depreciable life,” subject to PJM “including the project as an economic enhancement in . . . its [RTEP] regional planning process.”³³⁹ The Commission determined that the Valley Project is not routine based on its scope, effects, risks, and challenges, “including those posed by potentially being the first transmission line approved as an economic enhancement through PJM’s

332. *Id.* at P 40.

333. *Id.* at P 41.

334. *Atlantic Grid Operations A LLC*, 135 F.E.R.C. ¶ 61,144 at P 5 (2011) (FERC Docket No. EL11-13).

335. *Id.* at PP 57, 60.

336. *Id.* at P 62.

337. *Id.* at P 69.

338. *Central Transmission, LLC*, 135 F.E.R.C. ¶ 61,145 at P 4 (2011) (FERC Docket No. EL11-21).

339. *Id.* at P 2.

RTEP process.”³⁴⁰ However, the Commission rejected, without prejudice, “Central Transmission’s request for authorization to use a forward-looking formula rate, subject to a true-up” because Central Transmission has not yet filed the tariff provisions or demonstrated that the formula rate will be just and reasonable.³⁴¹

V. CORPORATE ACTIVITIES

A. Mergers and Acquisitions

1. Duke Energy and Progress Energy

In September 2011, the Commission issued an order on the request by Duke Energy Corporation to acquire Progress Energy, Inc.³⁴² Duke proposed to acquire Progress Energy’s direct and indirect ownership interests in Carolina Power & Light Company, d/b/a Progress Energy Carolinas, and Florida Power Corporation, d/b/a Progress Energy Florida, Inc.³⁴³ The transaction adds approximately 12,500 MWs of generation capacity and “more than 70,000 miles of distribution and transmission lines” to Duke’s existing generation capacity and electric transmission facilities in parts of North Carolina and South Carolina and approximately 3.1 million customers in North Carolina, South Carolina, and Florida.³⁴⁴ The transaction is valued at \$13.7 billion.³⁴⁵

Applying the Merger Policy Statement, the Commission determined that the Applicants had not shown that the transaction, as currently proposed, would not have an adverse impact on competition due to the significant screen failures in the horizontal market power analysis.³⁴⁶ Therefore, the Commission directed the Applicants to propose market power mitigation measures to remedy the screen failures, including but not limited to, joining an RTO, implementing “an ICT arrangement, generation divestiture, virtual divestiture,” and/or building transmission upgrades “to provide greater access to third party suppliers.”³⁴⁷

The Commission’s focus on the horizontal market power analysis was based on two factors. First, the only relevant markets examined were the regions where Duke’s and Progress Energy’s generation overlap.³⁴⁸ The results of the DPT showed that the proposed transaction would increase the already excessive pre-merger market share in certain seasonal/load periods for both the Duke Energy Carolinas BAA and Progress Energy Carolinas-East BAA and result in “systematic screen failures.”³⁴⁹ For the Duke Energy Carolinas BAA, the screen failures had changes in the Herfindahl-Hirschman Index (HHI) that were greater than the HHI changes that are “presumed likely to create or enhance market

340. *Id.* at P 40.

341. *Id.* at P 2.

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

343. *Id.* at PP 15, 18.

344. *Id.* at PP 15, 16.

345. *Id.* at P 18 n.25.

346. *Id.* at P 117.

347. *Id.* at PP 145-146.

348. *Id.* at PP 124, 131-133.

349. *Id.* at PP 134, 139-140.

power” in multiple seasonal/load periods.³⁵⁰ For the Progress Energy Carolinas-East BAA several of the screen failures had changes in the HHI that were significantly “greater than [the] HHI changes that ‘potentially raise significant market power concerns’” in multiple seasonal/load periods.³⁵¹ In contrast, the Commission found that there were no screen failures for the Progress Energy Carolinas – West BAA.³⁵²

The Commission determined that the proposed transaction raised no vertical market power issues because the Applicant’s transmission facilities were either controlled by a FERC-approved RTO or subject to open-access tariffs on file with the Commission.³⁵³ Next, the Commission found that the proposed transaction would not have an adverse effect on rates because of the “Applicants’ commitment to hold transmission and wholesale customers harmless [from transaction-related costs] for five years”³⁵⁴ and imposing special filing requirements should the Applicants seek to revise this commitment.³⁵⁵

In December 2011, the Commission rejected the Applicant’s proposed mitigation plan.³⁵⁶ Under the plan, the Applicants proposed the virtual divestiture of between 225 and 500 MW of Available Economic Capacity (AEC) in each hour in the Duke Energy Carolinas and Progress Energy Carolinas – East BAAs for certain seasons.³⁵⁷ The Applicants also proposed to offer the AEC for a term of eight years and to engage an independent market monitor to oversee the compliance with these mitigation measures.³⁵⁸ In examining the proposal, the Commission found that the Applicant’s supporting analysis was based on the flawed assumption “that all of the [AEC would] be sold in equal amounts to two entities that do not currently control any capacity” in the relevant BAAs and, therefore, could not “demonstrate that the [m]itigation [measures would] have the intended remedial effect.”³⁵⁹ The Commission also found that the Applicants’ mitigation plan had other shortcomings, including the failure to relinquish operational control over the divested generation from the merged company.³⁶⁰ These restrictions “narrow[ed] the pool of eligible buyers” for the AEC.³⁶¹ Further, the Commission found that the Applicants’ proposed eight year term was arbitrary as it could not demonstrate “that the adverse . . . effects of the [p]roposed [t]ransaction would be remedied within [that period].”³⁶² Finally, the Commission determined that the independent market monitor “would not provide sufficient oversight of the” Applicants’ compliance.³⁶³ Therefore, the

350. *Id.* at P 135 (citing Order No. 592, *Inquiry Concerning the Federal Power Act: Policy Statement*, F.E.R.C. STATS. & REGS. ¶ 31,044, at p 30,134, 61 Fed. Reg. 68,595 (1996) (codified at 18 C.F.R. pt. 2)).

351. *Id.* at P 137.

352. *Id.* at P 133.

353. *Id.* at P 161.

354. *Id.* at P 169.

355. *Id.* at P 170.

356. *Duke Energy Corp.*, 137 F.E.R.C. ¶ 61,210 (2011).

357. *Id.* at P 15.

358. *Id.* at PP 16, 21.

359. *Id.* at PP 68-74.

360. *Id.* at PP 75-77.

361. *Id.* at P 76.

362. *Id.* at P 86.

363. *Id.* at P 89.

Commission concluded that the proposed transaction, as supplemented by the mitigation plan, failed to adequately remedy the previously identified negative effects on competition.³⁶⁴ As a result, the proposed merger remains conditionally authorized until the Applicants offer mitigation measures that address the Commission's competitive concerns.³⁶⁵

2. *AES Corporation and DPL Inc.*

In November 2011, the Commission approved the request by AES Corporation (AES) to acquire DPL Inc. (DPL).³⁶⁶ AES proposed to acquire DPL's indirect ownership interests in Dayton Power & Light Company, DPL Energy LLC, and DPL Energy Resources, Inc. The merger adds 3,929 MW of electric generating capacity to AES's existing 1,967 MW of electric generation in PJM.³⁶⁷ The transaction is valued at \$4.7 billion.³⁶⁸

Applying the Merger Policy Statement, the Commission determined that the proposed transaction was consistent with the public interest because it would not have an adverse effect on competition, rates, and regulation.³⁶⁹ In evaluating the effect on horizontal market power, the Commission recognized that PJM was the relevant geographic market because it is the only location where the AES and DPL generation assets overlap.³⁷⁰ In PJM, the combination of the Applicant's generation assets constituted 3.3% of PJM's installed capacity.³⁷¹ Moreover, "the majority of AES's generation is committed under long-term contracts to third parties."³⁷² Accordingly, the Commission found that the proposed transaction would have a *de minimis* impact on horizontal market power in the non-firm energy, capacity product, and ancillary services markets in the PJM market and any relevant submarket within PJM.³⁷³ The Commission also found no vertical market power because AES's and DPL's transmission facilities are operated by MISO and PJM, respectively.³⁷⁴ Next, the Commission found that due to the "Applicant's commitment to hold transmission and wholesale customers harmless [from transaction-related costs] for five years"³⁷⁵ and that, after imposing special filing requirements should Applicants seek to revise this commitment,³⁷⁶ the proposed transaction would not have an adverse effect on rates.³⁷⁷ The proposed transaction was consummated on November 28, 2011.³⁷⁸

364. *Id.* at P 92.

365. *Id.*

366. *AES Corp.*, 137 F.E.R.C. ¶ 61,122 (2011).

367. *Id.* at PP 3, 6-9, 17.

368. *Id.* at P 11.

369. *Id.* at P 1, 15 (citing Order No. 592, *Inquiry Concerning the Federal Power Act: Policy Statement*, F.E.R.C. STATS. & REGS. ¶ 31,044, 61 Fed. Reg. 68,595 (1996) (codified at 18 C.F.R. pt. 2)).

370. *Id.* at P 17.

371. *Id.*

372. *Id.*

373. *Id.* at P 24.

374. *Id.* at P 28.

375. *Id.* at P 41.

376. *Id.* at P 42.

377. *Id.* at P 44.

378. *The AES Corporation Finalizes Acquisition of DPL Inc.*, REUTERS, Nov. 28, 2011, <http://www.reuters.com/finance/stocks/AES/key-developments/article/2441077>.

3. *NSTAR and Northeast Utilities*

In January 2011, Northeast Utilities Inc. and NSTAR sought the Commission's approval of a two-step merger, pursuant to "which NSTAR would become a wholly-owned subsidiary of Northeast Utilities."³⁷⁹ Through their electric and gas distribution subsidiaries, NSTAR and Northeast Utilities provide service to nearly 3.5 million customers in Massachusetts, New Hampshire, and Connecticut.³⁸⁰ Applying the three-part standard established in the Merger Policy Statement,³⁸¹ the Commission concluded that the proposed merger was consistent with the public interest.³⁸² The Commission determined that the proposed transaction would not adversely affect competition in New England.³⁸³ Due to the fact that there was "no overlap of supply of wholesale electricity in any market," the Commission observed that the merger "result[ed] in an HHI change of zero."³⁸⁴ The Commission further concluded that the applicants could not artificially decrease demand because, as the provider of last resort in parts of the region, the applicants are obligated to purchase sufficient electricity in the wholesale energy market.³⁸⁵ As a result, the merger did not raise concerns of buyer market power.³⁸⁶ Finally, issues regarding vertical market power were not of concern because the applicants had turned over operational control of their transmission facilities to ISO-NE.³⁸⁷ In addition, the Commission accepted the applicants' commitment to hold wholesale requirements and transmission customers harmless from the effects of the merger for a period of five years.³⁸⁸

4. *Exelon Corp. and Constellation Energy Group, Inc.*

In April, a fourth merger between regulated service providers was announced.³⁸⁹ Pursuant to the proposed merger, Constellation will become a wholly-owned subsidiary of Exelon Generation.³⁹⁰ The combined entity will "control approximately 43,000 MW of generation capacity . . . across ten different geographic markets in the United States" and serve over 100 TWh of wholesale load annually.³⁹¹ The applicants have also sought approval of the New York Public Service Commission, the Maryland Public Service Commission, and the Public Utility Commission of Texas.³⁹²

379. *NSTAR*, 136 F.E.R.C. ¶ 61,016 at P 1 (2011) (FERC Docket No. EC11-35).

380. *Id.* at PP 2, 7.

381. Order No. 592, *Inquiry Concerning the Federal Power Act: Policy Statement*, F.E.R.C. STATS. & REGS. ¶ 31,044, 61 Fed. Reg. 68,595 (1996) (codified at 18 C.F.R. pt. 2).

382. 136 F.E.R.C. ¶ 61,016 at P 1.

383. *Id.* at P 47.

384. *Id.* at P 48.

385. *Id.* at PP 50-51.

386. *Id.* at P 51.

387. *Id.* at P 56.

388. *Id.* at P 62.

389. News Release, Exelon, Exelon and Constellation Energy to Merge (Apr. 28, 2011), available at http://www.exelonconstellationmerger.com/sites/default/files/NEWS_RELEASE.pdf.

390. *Id.*

391. Joint Application for Authorization of Disposition of Jurisdictional Assets and Merger Under Sections 203(a)(1) and 203 (a)(2) of the Federal Power Act at 2, FERC Docket No. EC11-83-000 (May 20, 2011).

392. *Id.* at Exhibit L.

VI. PURPA DEVELOPMENT

A. *Termination of Purchase Obligations*

1. PG&E, SDG&E, and SCE

On June 16, 2011, the FERC granted an application under PURPA section 210(m) jointly filed by Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (jointly, Applicants) for termination of their PURPA obligation to enter into new power purchase contracts “to purchase electric energy and capacity from [QFs] with net capacity in excess of 20MW on a service territory-wide basis” for the interconnected systems of each of the Applicants under the control of the CAISO.³⁹³ The Applicants’ filing was “the first time an application for relief from the mandatory purchase obligation has been filed with the Commission under section 210(m)(1)(C) of PURPA, instead of sections 210(m)(1)(A) or (B).”³⁹⁴ The FERC found that the four components of the California market, namely: “(1) California’s Combined Heat and Power . . . Program; (2) California’s Renewable Portfolio Standard . . . Program; (3) California’s Resource Adequacy . . . requirements and (4) the [CAISO’s] . . . implementation of the Market Redesign and Technology Upgrade . . . day-ahead market” taken together contain competitive qualities comparable to those identified in PURPA sections 210(m)(1)(A) and (B).³⁹⁵ Therefore, the FERC found “that QFs will have non-discriminatory access to wholesale markets” for the sale of capacity and electric energy that are “comparable to those identified in PURPA sections 210(m)(1)(A) and (B).”³⁹⁶ The FERC found that under PURPA section 210(m)(1), when it analyzes whether an electric utility should be relieved of the mandatory purchase obligation, it must focus on the seller’s perspective – that is, whether markets provide QFs an opportunity to sell capacity and electric energy – and not on the buyer’s perspective.³⁹⁷

2. NSP Companies

On August 10, 2011, the FERC granted an application under PURPA section 210(m) by Northern States Power Company, a Minnesota corporation, and Northern States Power Company, a Wisconsin corporation, (jointly, the NSP Companies) for termination of their PURPA obligation to enter into new power purchase contracts “to purchase energy and capacity from [qualifying facilities (QFs)] that have a net capacity greater than 20 MW” (Large QFs) for the NSP Companies interconnected system under the control of the [MISO].³⁹⁸ The FERC’s regulations establish a rebuttable presumption that the markets administered by the MISO provide Large QFs with non-discriminatory access to markets, and the application relied on this rebuttable presumption.³⁹⁹ The FERC

393. *Pacific Gas & Elec. Co.*, 135 F.E.R.C. ¶ 61,234 at PP 1-2 (2011).

394. *Id.* at P 6.

395. *Id.* at P 7.

396. *Id.* at P 24.

397. *Id.* at P 26.

398. *Northern States Power Co.*, 136 F.E.R.C. ¶ 61,093 at P 1 (2011).

399. *Id.* at PP 2, 14.

rejected protestors, stating that they failed to rebut the presumption that Large QFs have nondiscriminatory access to the MISO market.⁴⁰⁰ The FERC stated that it “found that the existence of bilateral long-term contracts for long-term sales of capacity and energy within markets, such as MISO, is a sufficient indication of a market to satisfy the statutory requirement.”⁴⁰¹ The FERC also found that the Joint Protesters had not provided sufficient evidence to show “that there are transmission constraints that would deny the Joint Protesters’ QFs nondiscriminatory access to the MISO markets.”⁴⁰²

3. *Idaho Wind Partners 1, LLC*

Idaho Wind Partners 1, LLC (Idaho Wind) filed a petition for declaratory order concerning a proposed transaction of the

bundled sale of energy and renewable energy credits (RECs) from Idaho Wind-owned QFs to a third-party with an instantaneous buy-back of only the energy (so that the RECs can then be sold separately in California markets) and a subsequent sale of that energy to the local Idaho utility.

Idaho Wind ask[ed] the [FERC] to declare that [the proposed] transaction: (1) will not adversely affect the QF status of the QFs; (2) does not preclude the subsequent sale of the energy produced by the QFs to the local Idaho utility at avoided cost rates pursuant to the [PURPA] mandatory purchase obligation; and (3) does not violate the FERC’s anti-manipulation rule.⁴⁰³

On March 17, 2011, the FERC issued an order dismissing without prejudice Idaho Wind’s petition because the petition does not identify who the third-party purchaser/seller is, particularly whether the third party is or is not itself a QF, and that information may be relevant to the FERC’s determination.⁴⁰⁴ In an order issued on May 19, 2011, the Commission clarified that any QF, regardless of relative size or affiliation or physical location, may be the third party to the sale and buy-back proposed.⁴⁰⁵ On September 15, 2011, the Commission dismissed a request for clarification or rehearing of the May 19, 2011 Order.⁴⁰⁶

VII. GENERATION INTERCONNECTIONS

A. *E.ON v. MISO*

The Commission issued an order granting a complaint filed by the Midwest Generation Development Group (Development Group) against MISO, in which the Development Group alleged that a provision of Attachment FF of the MISO’s OATT “governing the treatment of costs associated with generat[ion] interconnection network upgrades . . . [was] unjust, unreasonable, and unduly discriminatory.”⁴⁰⁷ The Commission ordered the MISO to remove the provision

400. *Id.* at P 19.

401. *Id.* at P 18.

402. *Id.* at P 21.

403. *Idaho Wind Partners 1, LLC*, 134 F.E.R.C. ¶ 61,217 at PP 1-2 (2011).

404. *Id.* at P 26.

405. *Idaho Wind Partners 1, LLC*, 135 F.E.R.C. ¶ 61,154 at P 5 (2011).

406. *Idaho Wind Partners 1, LLC*, 136 F.E.R.C. ¶ 61,174 at P 1 (2011).

407. *E.ON Climate & Renewables N.A., LLC v. Midwest Indep. Transmission Sys. Oper., Inc.*, 137 F.E.R.C. ¶ 61,076 at P 1 (2011).

from its OATT effective March 22, 2011.⁴⁰⁸

The provision permitted transmission owners constructing network upgrades to elect “Option 1” payment for the cost of network upgrades associated with generation interconnection.⁴⁰⁹ Under Option 1, the interconnection customer provided the funding for the network upgrades up-front.⁴¹⁰ The transmission owner would construct the upgrades and “refund 100 percent of the cost . . . to the interconnection customer” and, then, “charge the interconnection customer . . . through a monthly Network Upgrade Charge over time based on a formula contained in Attachment GG” of the OATT.⁴¹¹ Under Option 2, the transmission owner does not refund the payment to the interconnection customer, and the interconnection customer pays no further charges.⁴¹²

“The Development Group claim[ed] that the election of Option 1 significantly increases the cost of interconnection.”⁴¹³ It argued “that the interconnection customer is not causing any financing costs, and, since the interconnection customer is required to fund the construction of network upgrades up-front, the transmission owner and its customer are protected against having to pay any costs associated with the construction of network upgrades.”⁴¹⁴ The Development Group stated that the operation and maintenance costs associated with the network upgrades should “be recovered from transmission customers under the transmission [owner’s] tariff rates,” rather than from the interconnection customer.⁴¹⁵ It further argued that Option 1 pricing is unduly discriminatory in that it imposes different costs on interconnection customers depending on whether the transmission elects Option 1 or Option 2 cost recovery.⁴¹⁶ The MISO argued that the Commission had previously accepted Option 1⁴¹⁷ and that it was “consistent with Order No. 2003 . . . cost causation principles because interconnection customers benefit from network upgrades and Option 1 ensures that interconnection customers make efficient, cost-effective siting decisions.”⁴¹⁸ The MISO Transmission Owners opposed the complaint and argued that Option 1 allows for the recovery of legitimate costs of providing interconnection service.⁴¹⁹ The Commission held that allowing transmission owners to select between repayment under Option 1 and Option 2 is unjust, unreasonable and unduly discriminatory because it “increases the costs that are directly assigned to the interconnection customer, but there is no difference in the interconnection service provided.”⁴²⁰ It further held that the transmission owners’ sole discretion to choose between Option 1

408. *Id.*

409. *Id.* at P 4.

410. *Id.*

411. *Id.*

412. *Id.*

413. *Id.* at P 8.

414. *Id.* at P 10.

415. *Id.*

416. *Id.* at P 11.

417. *Id.* at P 20 (citing *Midwest Indep. Transmission Sys. Oper., Inc.*, 114 F.E.R.C. ¶ 61,106 (2006)).

418. *Id.* at P 22.

419. *Id.* at P 31.

420. *Id.* at P 37.

and Option 2 “creates opportunities for undue discrimination.”⁴²¹ The MISO Transmission Owners and the Organization of MISO States have requested rehearing of the decision.⁴²²

VIII. ORDER GRANTING AND DENYING COMPLAINTS (EXCLUDING COMPLAINTS BY AND AGAINST RTOS)

A. Louisiana Public Service Commission v. Entergy Services, Inc.

Post Order Nos. 480 and 480-A, Entergy filed a motion requesting the Commission hold additional proceedings to establish a record on whether under FPA section 206(c) “Entergy will . . . experience any reduction in revenues as a result of [any] refunds” from a retroactive reallocation of costs among the Entergy Operating Companies.⁴²³ In the alternative, Entergy asked the Commission to consider exercising its equitable discretion and not order such refunds.⁴²⁴ In responding to Entergy’s request, the Commission deferred action in this complaint proceeding subject to the outcome of a paper hearing for another remand proceeding involving the Commission’s Opinion Nos. 468 and 468-A.⁴²⁵ In that proceeding, the Commission was examining similar issues on the applicability of FPA section 206(c) and whether refunds were legal and appropriate.⁴²⁶ In the Order on Remand, the Commission’s recent order on the paper hearing addressed the issues presented in this case⁴²⁷ and affirmed its finding that FPA section 206(c) does not bar the Commission’s authority to order prospective refunds.⁴²⁸ Moreover, like in the order on the paper hearing, “the Entergy system as a whole collected the proper level of revenues, but” it was later determined to have incorrectly allocated the production costs “among the various Entergy Operating Companies.”⁴²⁹ Therefore, because Entergy was not unjustly enriched by over-collecting revenues, the Commission invoked its equitable discretion and did not order refunds.⁴³⁰ The Commission, however, held its rulings regarding refunds in abeyance pending the additional proceedings established in the remand of the Opinion No. 468 and 468-A proceeding.⁴³¹ The Commission also determined that it would be arbitrary and capricious to allow Entergy to phase-in the implementation of the bandwidth remedy after it had found that Entergy’s rates were unjust and unreasonable and directed Entergy to make a compliance filing to implement the bandwidth remedy on June 1, 2005 and calculate bandwidth payments and receipts through

421. *Id.* at P 39.

422. Request for Rehearing of the Organization of MISO States, FERC Docket No. EL11-30-001 (Nov. 21, 2011).

423. *Louisiana Pub. Serv. Comm’n v. Entergy Servs., Inc.*, 137 F.E.R.C. ¶ 61,047 at P 8 (2011).

424. *Id.* at PP 9-12.

425. *Louisiana Pub. Serv. Comm’n v. FERC*, 129 F.E.R.C. ¶ 61,238 at P 8 (2009).

426. *Louisiana Pub. Serv. Comm’n v. Entergy Servs., Inc.*, 137 F.E.R.C. ¶ 61,047 at P 4 (2011) (citing *Louisiana Pub. Serv. Comm’n v. Entergy Corp.*, 132 F.E.R.C. ¶ 61,133 (2010), *order granting reh’g in part and denying reh’g in part*, 135 F.E.R.C. ¶ 61,218 (2011)).

427. *Id.* at P 27.

428. *Id.* at P 30.

429. *Id.*

430. *Id.* at P 31.

431. *Id.* at P 32.

December 31, 2005.⁴³² Entergy made the required compliance filing on December 19, 2011. Finally, the Commission's Order on Rehearing denied the challenges to the Commission's decision to defer action in this proceeding pending the outcome of the paper hearing in the Opinion No. 468 proceeding.⁴³³ The Commission found that by requiring Entergy to implement the bandwidth from June 1, 2005, through December 31, 2005, the arguments for immediate action on the court remand were now moot.⁴³⁴

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432. *Id.* at P 34.

433. *Id.*

434. *Id.* at P 5.

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