# REPORT OF THE ELECTRICITY REGULATION COMMITTEE

This report provides a summary of significant decisions, orders, and rules issued by the Federal Energy Regulatory Commission (FERC) in the electricity regulation area during calendar year 2010, as well as regional developments during that period. The Electricity Regulation Committee, which prepared this report, has a broad focus and overlapping jurisdiction with certain other EBA committees. As these other committees have a more targeted focus, we have generally deferred to them as to their respective areas, including transmission reliability and planning; wholesale market-based rates; demand side management/renewable energy; enforcement actions/audits; and court appeals.

## I. RULEMAKINGS AND POLICY STATEMENTS

### *A. Order No. 697-D: Market Based Rates for Wholesale Sales of Electric Energy, Capacity, and Ancillary Services by Public Utilities*

On March 18, 2010, the FERC issued Order No. 697-D, *Market Based Rates for Wholesale Sales of Electric Energy, Capacity, and Ancillary Services by Public Utilities*.[1] Order No. 697-D granted rehearing and clarification of the FERC's determinations in Order No. 697-C.[2] Specifically, Order No. 697-D clarified and revised the reporting obligations imposed pursuant to 18 C.F.R. § 35.42 of the FERC's regulations, requiring that entities with market-based rate (MBR) authority file a notice of change in status with the FERC on acquiring sites for new generation capacity development.[3] Order No. 697-D also denied rehearing of requests regarding the provisions governing mitigated sales.[4]

The FERC first described its vertical market power analysis when granting MBR authority. In demonstrating a lack of vertical market power "through the affiliation, ownership or control of inputs to electric production," a seller must provide information on its sites for generation capacity development.[5] In addition, the regulations required sellers with MBR authority to report to the Commission

> any land it has acquired, taken a leasehold interest in, obtained an option to purchase or lease, or entered into an exclusivity or other arrangement to acquire for the purpose of developing a generation site and for which site control has not yet been demonstrated . . . during the prior three years (triggering event), and for which the potential number of megawatts that are reasonably commercially feasible on the land for new generation capacity development is equal to 100 megawatts or more.[6]

In Order No. 697-D, the FERC further clarified that "if no sites have been acquired during a quarter, then a seller should not file a report for that quarter."[7]

The FERC further stated that an MBR seller should submit a change in status notice only "if there is a change that may affect the conditions relied upon by the [FERC] since it initially granted the seller market-based rate authorization, or since the [FERC] accepted a seller's updated market power

1. Order No. 697-D, *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity, and Ancillary Services by Public Utilities*, 130 F.E.R.C. ¶ 61,206 (2010) [hereinafter Order No. 679-D].

2. Order No. 697-C, *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity, and Ancillary Services by Public Utilities*, F.E.R.C. STATS. & REGS. ¶ 31,291 (2009) [hereinafter Order No. 697-C].

3. 18 C.F.R. § 35.42 (2009) (regulation prior to revision). *See also* 18 C.F.R. § 35.42 (2011) (as revised).

4. Order No. 697-D, *supra* note 1, at P 1.

5. 18 C.F.R. § 35.37(e).

6. Order No. 697-C, *supra* note 2, at P 20 (providing prior 18 C.F.R. § 35.47(e), this language now repealed).

7. Order No. 697-D, *supra* note 1, at P 21.

analysis."[8] It also stated that it appreciated concerns regarding identifying potential development sites for thermal generation facilities and that reporting on sites where an entity has not demonstrated control over the past three years "could lead to a mistaken belief that [an entity] has more land under its control than is actually the case."[9] Therefore, the FERC reconsidered the requirement in 18 C.F.R. § 35.42(e), and eliminated the previous reporting requirement.[10] As a result, Order No. 697-D established that there is no obligation to report the acquisition of interests in sites where site control has not been demonstrated over the past three years.[11] The FERC did, however, reserve the right to require additional information from sellers at any time, including due to "a concern that a particular seller may be acquiring land for the purpose of preventing new generation capacity from being developed on that land . . . ."[12]

Order No. 697-D also addressed the FERC's tariff requirements stating "if the [s]eller wants to sell at the metered boundary of a mitigated balancing authority area at market-based rates, then neither it nor its affiliates can sell into that mitigated balancing authority area from the outside."[13] In Order No. 697-D, the FERC denied requests for rehearing and "re-affirm[ed] the [FERC's] determination to revise the mitigated sales tariff provision in Order No. 697-B to ensure that mitigated sellers making market-based rate sales at the metered boundary do not subsequently sell power into the mitigated market either directly or through their affiliates."[14] It also reiterated that if an MBR seller sells power at the metered boundary at market-based rates, the seller and its affiliates "may not sell power into the balancing authority area in which the seller is found, or presumed, to have market power, whether at cost-based or market-based rates."[15] The FERC later explained, though, that if the seller did not make MBR sales at the metered boundary then it and its affiliates can make cost-based sales into the balancing authority area where the seller is mitigated.[16] Finally, the FERC reaffirmed that the mitigated sales restrictions on MBR sales at metered boundaries only applies to agreements entered into after July 29, 2009.[17]

8. *Id.* at PP 21-22.

9. *Id.* at P 23.

10. *Id.*

11. *Id.*

12. Order No. 697-D, *supra* note 1, at PP 23-24.

13. *Id.* at P 28 (citing Order No. 697-A, *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity, and Ancillary Services by Public Utilities*, F.E.R.C. STATS. & REGS. ¶ 31,268 at P 336 (2008), *clarified*, *Market-Based Rate Affiliate Restrictions*, 124 F.E.R.C. ¶ 61,055 (2008), 76 Fed. Reg. 4,569 (2008) (to be codified at 18 C.F.R. pt. 35).

14. *Id.* at P 42. Mitigated area should be understood as the "'balancing authority area in which a seller is found, or presumed, to have market power.'" *Id.* at n.30 (citing Order No. 697-A at P 333).

15. *Id.* at P 44 (citing Order No. 697-A at n.464).

16. *Id.* at P 46.

17. *Id.* at P 50 (July 29, 2009, is the date on which Order No. 697-B became effective).

### B. *Order No. 676-F: Standards for Business Practices and Communication Protocols for Public Utilities*

On April 15, 2010, in Order No. 676-F, *Standards for Business Practices and Communication Protocols for Public Utilities*,[18] the FERC amended its regulations under 18 C.F.R. § 38.2,[19] to incorporate by reference the business practice standards adopted by the Wholesale Electric Quadrant of the North American Energy Standards Board (NAESB) for demand response services in organized wholesale markets administered by regional transmission organizations (RTOs) and independent system operators (ISOs). These standards are referred to as the "Phase I M&V Standards" and are referenced in 18 C.F.R. § 38.2.[20]

The FERC stated that the standards:

> [I]dentify operational information about demand response products that system operators need to make available to participants in markets where such products are offered and address . . . evaluation methods appropriate to use for demand response products. They also facilitate the ability of demand response providers to participate in electricity markets . . . . [and] provide a foundation for further business practice standardization efforts.[21]

The FERC urged NAESB to develop additional standards within one year, or submit a progress report by then if the additional standards have not been developed.[22] The FERC stated that the standards will assist in measuring demand response resource performance and monitoring potential manipulation.[23]

The standards incorporated into 18 C.F.R. § 38.2 through Order No. 676-F are business practices for Measurement and Verification of Wholesale Demand Response.[24] They include standards on the five performance methodologies set out (standards 015-1.16 through 015-1.30),[25] which are: (1) Maximum Base Load; (2) Meter Before/Meter After; (3) Baseline Type – I (Interval Meter); (4) Baseline Type – II (Non-Interval Meter); and Metering Generator Output.[26]

The FERC required that all RTOs and ISOs revise their Open Access Transmission Tariffs (OATTs) to include the NAESB standards approved in Order No. 676-F.[27] Compliance was required within 30 days.[28]

---

18. Order No. 676-F, *Standards for Business Practices and Communication Protocols for Public Utilities*, 131 F.E.R.C. ¶ 61,022 (2010) [hereinafter Order No. 676-F].

19. 18 C.F.R. § 38.2 (2009) (prior to revision); *see also* 18 C.F.R. § 38.2 (2011) (as revised).

20. Order No. 676-F, *supra* note 18, at P 13; 18 C.F.R. § 38.2(a)(10)-(12) (2011).

21. Order No. 676-F, *supra* note 18, at P 2.

22. *Id.* at P 13 nn.8, 32-37.

23. *Id.* at P 13.

24. *See* 18 C.F.R. § 18.2(a)(12) (2011).

25. *Id.* at P 11.

26. *Id.*

27. Order No. 676-F, *supra* note 18, at P 43.

28. *Id.*

### C. *Order No. 732: Revisions to Form, Procedures, and Criteria for Certification of Qualifying Facility Status for a Small Power Production or Cogeneration Facility*

On March 19, 2010, the FERC issued Order No. 732, *Revisions to Form, Procedures, and Criteria for Certification of Qualifying Facility Status for a Small Power Production or Cogeneration Facility* (Order No. 732).[29] Order No. 732 substantially revised Form No. 556, the form that cogeneration and small power production facilities must file to be certified or self-certified as qualifying facilities (QF), unless the FERC exempts the entity from submitting a filing.[30] The FERC stated it was revising and reformatting Form 556 to take advantage of new technologies and to clarify the content of the form.[31] In response to comments questioning whether there would be an opportunity to comment on future proposed changes to Form No. 556, the FERC responded, "parties will have an opportunity in response to a solicitation for comments under the Paperwork Reduction Act to comment on any future proposed revisions to the Form No. 556."[32]

The FERC also revised its regulations on the procedures, standards, and criteria for QF status in 18 C.F.R. Part 292.[33] The regulations were revised to include:

> (1) exemption of generating facilities with net power production capacities of 1 MW or less from the requirement that a generating facility, to be a QF, must file either a notice of self-certification or an application for [FERC] certification; (2) codification of the [FERC's] authority to waive the QF certification requirement for good cause; (3) extension to all applicants for QF certification the requirement ([previously] applicable only to applicants for self-certification of QF status) to serve a copy of a filed Form No. 556 on the affected utilities and state regulatory authorities; (4) elimination of the requirement for applicants to provide a draft notice suitable for publication in the *Federal Register*; and (5) clarification, simplification, or correction of certain sections of the regulations."[34]

---

29. Order No. 732, *Revisions to Form, Procedures, and Criteria for Certification of Qualifying Facility Status for a Small Power Production or Cogeneration Facility*, 130 F.E.R.C. ¶ 61,214 (2010) [hereinafter Order No. 732].

30. FERC, FORM NO. 556: CERTIFICATION OF QUALIFYING FACILITY (QF) STATUS FOR A SMALL POWER PRODUCTION OR COGENERATION FACILITY (2011), *available at* http://www.ferc.gov/docs-filing/forms/form-556/form-556.pdf; Order No. 732, *supra* note 29, at P 1 (Order No. 732 modified 18 C.F.R. § 131.80 by removing the contents and instructions previously contained therein and replaced them with the instruction that entities seeking QF status file the Form No. 556 in effect at time of filing).

31. Order No. 732, *supra* note 29, at P 1. The following changes were made to Form No. 556: the name of the form was shortened (*Id.* at PP 94-96); the form requires geographic coordinates (*Id.* at PP 97-100); the form clarified the ownership portion of the form so applicants only must provide information for direct owners holding at least 10% equity interest in the facility and upstream owners that hold at least a 10% equity interest and are electric utilities or holding companies (*Id.* at PP 101-106); the form now asks applicants to check the box on fuel use requirements rather than for a description on how the applicant will comply with fuel use requirements (*Id.* at PP 107-13); Form No. 556 now revised its language regarding Mass and Heat balance diagrams (*see* Order No. 732, *supra* note 29, at PP 114-21); and other changes were made related to cogeneration facilities, stemming from the Energy Policy Act of 2005 (*Id.* at PP 122-32; Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 985 (2005).

32. Order No. 732, *supra* note 29, at P 23.

33. 18 C.F.R. pt. 292.

34. Order No. 732, *supra* note 29, at P 3 (citing 18 C.F.R. pt. 292). The FERC later described its determination to make certain revisions to 18 C.F.R. § 292.204(a) (*Id.* at PP 42-45); 18 C.F.R. § 292.205(d)

In addition, the FERC changed the exemption of QFs from the Federal Power Act (FPA), the Public Utility Holding Company Act of 2005 (PUHCA), and certain state laws and regulations to clarify that certain small power production facilities satisfying the criteria in section 3(17)(E) of the FPA qualify for those exemptions.[35]

The FERC described its revisions to the QF requirements in 18 C.F.R. § 292.203: an amendment to section 292.203(b) to correct a prior error improperly referencing "operating and efficiency standards";[36] the addition of section 292.203(d) exempting small facilities from the requirement to make a filing to obtain QF status and making explicit the FERC's authority to waive the filing requirement for good cause;[37] and an amendment to section 292.203 adding an exemption for entities with a net power production capacity of 1 MW or less from making any filing to become a QF.[38] The FERC also declined to address requests that it modify 18 C.F.R. § 292.310, stating that these requests were outside of the scope of the proceeding.[39] The FERC stated, "[w]e find that a 1 MW threshold, consistent with PURPA's mandate, encourages QFs – both cogeneration and small power production – by eliminating the burden of filing."[40] It explained, that:

> QF certification filings from facilities 1 MW or smaller represented approximately 48 percent of all QF filings. The filings from these facilities, however, represented only a small percentage of the total capacity being certified as QFs; filings from facilities 1 MW or smaller represented only approximately one half of one percent of QF capacity certified."[41]

The FERC stated that exempting facilities larger than 1 MW would be a significant departure and that such facilities should not find the QF filing requirement unduly burdensome in comparison to their "significant capital outlay."[42]

### D. *Order No. 741: Credit Reform for Organized Markets*

On October 21, 2010, the FERC issued Order No. 741, a Final Rule on credit reform in electric markets designed to improve risk management and the use of credit in wholesale electric markets while ensuring just and reasonable rates.[43] Credit practices in organized wholesale markets have been developed within the markets through tariff revisions crafted through their stakeholder processes, which has led to varying practices among organized markets.[44]

---

(*Id.* at PP 46-50); 18 C.F.R. § 292.207 (*Id.* at PP 51-80); 18 C.F.R. §292.601 (*Id.* at PP 81-84); 18 C.F.R. § 292.602 (*Id.* at PP 85-87).

35. Order No. 732, *supra* note 29, at PP 4, 15 (citing 18 C.F.R. § 292.601-602).

36. *Id.* at PP 25, 33.

37. *Id*. at PP 26, 34.

38. *Id.* at PP 27, 34.

39. *Id.* at P 41.

40. Order No. 732, *supra* note 29, at P 35 (citing Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 824(a)-3(a) (2006)) (internal citations omitted).

41. *Id.*

42. *Id.*

43. Order No. 741, *Credit Reforms in Organized Wholesale Electric Markets*, 133 F.E.R.C. ¶ 61,060 (2010) [hereinafter Order No. 741].

44. *Id.* at P 3.

Because of the cross-market participation of many participants, a default in one market could also impact other markets, making all markets potentially susceptible to the credit practices in the market in which they are the weakest.[45] Thus, to establish uniformity and reduce market-wide risk, the FERC developed regulations of credit practices applicable to all markets.[46]

The Final Rule directs organized wholesale markets to implement seven different reforms as discussed below. Compliance filings are due on June 30, 2011, with tariff revisions to take effect October 1, 2011. Credit forms are as follows:

- Shorten the Settlement Cycle

Markets are to implement billing and settlement periods each of no more than seven days to reduce unpaid debt and the risk of default.[47]

- Use of Unsecured Credit

Markets are to reduce unsecured credit to no more than $50 million per market participant/$100 million per corporate family, which is designed to minimize the risk to markets of the inherent uncertainty in the credit analyses regarding unsecured credit.[48]

- Eliminate Unsecured Credit for FTR Markets

The FERC found that financial transmission rights (FTR) markets warrant risk management measures due to the uncertainty of the risk created by the variation in value over time of FTR rights, longer-dated obligations to perform, and the illiquidity of FTR rights. Thus, the FERC required tariff provisions that eliminate unsecured credit for financial FTR markets.[49]

- Enable ISOs/RTOs to Offset Market Obligations

ISOs and RTOs typically net transactions entered into between a market participant and themselves, but do not take title to the contractual position of a participant at the time of settlement, thus creating a risk that, if a participant files for bankruptcy, it will be argued that amounts owed and to be paid cannot be offset, which creates the potential for a larger default.[50] To avoid this risk, ISOs and RTOs must do one of the following:

1. Establish the ISO or RTO as the central counterparty to transactions with market participants;

2. Require participants to provide a security interest in their transactions;

3. Propose another alternative with as much protection as the previous two options; or

4. Establish credit requirements for participants based on gross obligations.[51]

- Minimum Criteria for Market Participation

To protect against under-capitalized market participants with inadequate risk management procedures, each ISO and RTO is required to specify minimum

45. *Id.* at PP 164-165.
46. *Id.* at PP 32-33.
47. *Id.*
48. *Id.* at PP 50-53.
49. *Id.* at P 70.
50. *Id.* at P 116.
51. *Id.* at P 117.

participation criteria for participation in the organized wholesale market.[52] The FERC did not specify criteria, and each ISO and RTO is to develop criteria through its stakeholder process.[53]

- Clarify "Material Adverse Change"

Concerned with the ambiguity as to when an ISO and RTO may find that there is a "material adverse change" for a change in the risk assessment of a market participant,[54] the FERC required ISOs and RTOs to develop and specify a non-exhaustive list of the circumstances when additional collateral will be required.[55]

- Grace Period to "Cure" Collateral Calls

The FERC set a standard time period to "cure" a collateral posting, not to exceed two days.[56]

### *E. ISO/RTO Performance Metrics Staff Report*

On October 21, 2010, FERC Staff issued its Report AD10-5-000, ISO/RTO Performance Metrics in response to the recommendations of the Government Accountability Office[57] to develop standardized measures of the performance of ISO/RTO operations and markets.[58] The Staff Report describes the performance metrics developed in collaboration with the ISOs and RTOs and stakeholders.[59]

These metrics fall into three general categories: reliability, market benefits, and organizational effectiveness.[60] Reliability metrics measure the reliability of day-to-day operations as well as long-term reliability. Market benefits metrics measure ISO/RTO performance based on market prices, congestion management, and resource availability, as well as the efficiency of the markets as to price convergence and competition. Finally, organizational effectiveness metrics measure the performance of ISOs/RTOs in cost-effectively accomplishing their goals while providing value to market participants.[61] The next steps are to develop operational and financial metrics for non-ISO/RTO regions in 2011, establish common metrics between ISOs/RTOs and non-ISO/RTO regions in 2012, monitor the implementation and performance using these metrics in 2013, and evaluate the metrics as applied and develop any necessary changes to the metrics in 2014.[62]

---

52. *Id.* at P 131.

53. *Id.*

54. *Id.* at P 136.

55. *Id.* at P 147.

56. *Id.* at P 160.

57. U.S. GOV'T ACCOUNTABILITY OFFICE, GAO-08-987, ELECTRICITY RESTRUCTURING: FERC COULD TAKE ADDITIONAL STEPS TO ANALYZE REGIONAL TRANSMISSION ORGANIZATIONS' BENEFITS AND PERFORMANCE (2008).

58. FERC STAFF REPORT AD10-5-000, ISO/RTO PERFORMANCE METRICS (Oct. 21, 2010), *available at* http://www.ferc.gov/legal/staff-reports/10-21-10-rto-metrics.pdf.

59. *Id.* at 5-6.

60. *Id.* at 17.

61. *Id.*

62. *Id.* at 6.

### *F. Order No. 739: Price Caps for Reassigning Capacity*

On September 20, 2010, the FERC issued Order No. 739, *Promoting a Competitive Market for Capacity Reassignment*,[63] which lifts the price cap previously set for electric transmission customers that reassign transmission capacity. The FERC lifted the price cap to facilitate the development of a market for transmission capacity reassignment to compete against transmission capacity acquired from the transmission owner.[64]

The decision followed from Order No. 888, which permitted reassignment of point-to-point capacity, but capped rates for reassigned transmission capacity.[65] Order No. 890-A affirmed removal of the price cap, but limited the period during which capacity reassignments could occur above the cap to allow review of the actual operation of reassignments in the market, thus reinstating the price cap as of October 1, 2010.[66]

After reviewing a report by FERC Staff on reassignment transactions over a two-year period, the FERC lifted the price cap.[67] It lifted the cap to foster (1) a more robust secondary market for transmission capacity through an increased incentive for customers with point-to-point transmission service to resell the service when others place a higher value on the service, leading to more efficient use of existing transmission capacity, and (2) the development of new transmission capacity through price signals from the reassigned capacity market, which would also effectively cap the price of reassigned capacity at the cost of new transmission.[68] Transmission service provided under a pro forma OATT will continue to be offered at cost-of-service rates, unless a lack of market power can be demonstrated to justify market-based rates.[69]

## II. RTO/ISO/REGIONAL DEVELOPMENTS

### *A. California Independent System Operator Corporation (CAISO)*

#### 1. Station Power

On May 4, 2010, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) vacated and remanded a FERC decision requiring the CAISO to comply with the FERC's station-power netting requirements.[70] The central issue was the FERC's determination that generators may self-supply station power by netting consumption against generation output over any month in which the generating station's gross output is positive.[71] The D.C. Circuit found that the FERC had not adequately justified its determination

63. Order No. 739, *Promoting a Competitive Market for Capacity Reassignment*, 132 F.E.R.C. ¶ 61,238 (2010) [hereinafter Order No. 739].

64. *Id.* at P 1.

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

66. Order No. 890-A, *Preventing Undue Discrimination and Preference in Transmission Service*, F.E.R.C. STATS. & REGS. ¶ 31,261 at PP 388, 390 (2007).

67. Order No. 739, *supra* note 63, at P 32.

68. *Id.* at P 26.

69. *Id.* at P 27.

70. S. Cal. Edison Co. v. F.E.R.C., 603 F.3d 996 (D.C. Cir. 2010).

71. *Id.* at 997.

that no retail sale occurs when a generator self-supplies station power over a monthly netting period.[72] On August 30, 2010, the FERC issued its Order on Remand.[73] It determined that "the Commission and the states can use different methodologies when the Commission determines the amount of station power that is transmitted on the Commission-jurisdictional transmission grid and the states determine the amount of station power that is sold in state-jurisdictional retail sales."[74] On February 28, 2011, the Commission issued an Order Denying Rehearing of its Order on Remand.[75]

2. Standard Capacity Product

On May 20, 2010, the FERC issued two orders addressing a proposal by the CAISO to establish a resource adequacy Standard Capacity Product (SCP) and an ancillary services (A/S) must-offer obligation.[76] The SCP is intended to encourage the availability of resources by providing incentive payments and imposing non-availability charges for poor performance.[77] Underpinning the SCP is the development of monthly availability targets and comparing those targets with the monthly operating status of resource adequacy capacity resources.[78]

In its first order, the FERC denied rehearing of its June 26, 2009 Order, which largely found that the SCP and ancillary services (A/S) must-offer obligation proposal enhanced the CAISO's resource adequacy program and grid reliability.[79]

In the second order, the FERC addressed CAISO's August 10, 2009 filing in compliance with its June 26, 2009 Order, which required the CAISO to make certain modifications to its SCP mechanism.[80] It accepted the CAISO's compliance filing, but directed the CAISO to modify the calculation of SCP non-availability charges to: (1) eliminate the second portion of the formula proposed by the CAISO that would apply "when available capacity falls below a resource's minimum operating value" and retain only the first portion of the formula that should be revised to apply "across all levels of availability, including zero;" and (2) produce "a megawatt value rather than a percentage value for the availability level."[81]

72. *Id.* at 1002.

73. *Duke Energy Moss Landing LLC*, 132 F.E.R.C. ¶ 61,183 (2010).

74. *Id.* at P 16.

75. *Duke Energy Moss Landing LLC*, 134 F.E.R.C. ¶ 61,151 (2011).

76. *Cal. Indep. Sys. Operator Corp.*, 127 F.E.R.C. ¶ 61,298 (2009), *order on reh'g*, 131 F.E.R.C. ¶ 61,149 (2010); *Cal. Indep. Sys. Operator Corp.*, 131 F.E.R.C. ¶ 61,148 (2010).

77. *Cal. Indep. Sys. Operator Corp.*, 131 F.E.R.C. ¶ 61,149 at P 2.

78. *Id.* at P 15.

79. *Cal. Indep. Sys. Operator Corp.*, 127 F.E.R.C. ¶ 61,298 (2009), *order on reh'g*, 131 F.E.R.C. ¶ 61,149 (2010).

80. *Cal. Indep. Sys. Operator Corp.*, 131 F.E.R.C. ¶ 61,148 (2010).

81. *Id.* at PP 31, 32.

### 3. Transmission Planning Process and Generator Interconnection Procedures

On December 16, 2010, the FERC conditionally accepted, with modifications, the CAISO's Revised Transmission Planning Process (RTPP).[82] It found that the RTPP would be an important element in California's "development of transmission infrastructure . . . to meet [an] ambitious [state program of] renewable portfolio standards and other environmental goals."[83] It further determined that the RTPP encourages statewide stakeholder participation in transmission planning, is a more holistic rather than project-by-project approach, and furthers openness, transparency, and other Order No. 890 principles.[84]

Under the RTPP, the CAISO will identify particular network transmission facilities as "policy-driven elements."[85] These are facilities determined necessary to meet state or federal directives, including greenhouse gas reduction and renewable energy targets — the latter currently set at 33%.[86] Under the RTPP, the CAISO will also consider alternatives of demand response and storage to new transmission construction.[87] The FERC required that the CAISO clarify its tariff to provide that policy-driven elements identified in a later phase of the RTPP may supplant the need for reliability upgrades[88] or generator interconnection upgrades otherwise identified.[89]

The RTPP contains a competitive open bidding mechanism allowing all transmission developers to compete to plan, build, and own policy and economics-driven projects.[90] With limited exceptions, incumbent utilities will retain a first refusal right for reliability projects and projects necessary to meet generator interconnection requests.[91] The FERC noted that in the cost allocation and grid planning rulemaking, it is considering removing first refusal rights from transmission planning[92] and also that the final rule may require changes in CAISO rights of first refusal.[93]

In the same order the FERC denied a petition for declaratory order that sought to test CAISO interpretations of existing right of first refusal, CAISO tariff provisions on Large Generator Interconnection Procedure (LGIP) related network upgrades, and location-constrained resource interconnection facilities.[94] Planning for both types of facilities are within the RTPP. The FERC found that

82. *Cal. Indep. Sys. Operator Corp.*, 133 F.E.R.C. ¶ 61,224 (2010).

83. *Id.* at P 2.

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

85. *Id.* at P 2.

86. *Id.*

87. *Id.* at P 180.

88. *Id.* at P 60.

89. *Id.* at P 107.

90. *Id.* at PP 50, 102, 171.

91. *Id.* at P 68.

92. *Id.* at P 97; *see* Notice of Proposed Rulemaking, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities Notice of Proposed Rulemaking,* F.E.R.C. STATS. & REGS. ¶ 32,660, 75 Fed. Reg. 37,883 (2010).

93. 133 F.E.R.C. ¶ 61,224 at nn.6, 103.

94. *Id.* at P 12.

the petitioners failed to carry their burden of proof to show that the rights of first refusal provisions were not just or reasonable.[95]

In a separate order also issued December 16, 2010, the FERC conditionally accepted CAISO's proposal to merge small and large generator interconnection procedures.[96] Among other things, differences in the small and large generator procedures had caused the CAISO to be unable to meet study time lines.[97] Henceforth the CAISO will review both small and large projects using an integrated cluster approach, similar to the current LGIP, while retaining certain benefits to small generators.[98] These changes are expected to, among other things, reduce delays in the completion of studies relating to the increasing numbers of small generator interconnection requests.[99]

4. Scarcity Pricing

On June 29, 2010, the FERC accepted in part and rejected in part the CAISO's proposed Scarcity Reserve Pricing Mechanism.[100] The FERC allowed reserve power prices above CAISO price caps, in both day-ahead and real-time markets, when electric supplies are too low to meet CAISO's needs to meet its ancillary service obligations, including regulation up, regulation down, spinning reserves, and non-spinning reserves.[101] The pricing mechanism is intended to provide price incentives for generators to provide reserves or for demand response programs to be engaged when CAISO is unable to reach its target level of operating reserves.[102] Among other things, the FERC found that the pricing mechanism meets its Order No. 719[103] operating reserve shortage pricing requirements by ensuring that the price paid for energy is consistent with its value during such shortages.[104] The FERC rejected CAISO's proposal to make distinctions by subregion among prices levels during shortages.[105]

On November 1, 2010, the FERC accepted CAISO's June 29 Order compliance filing, finding the CAISO's request for clarification as to whether expanded system region and sub-regional prices should be added together when a shortage occurs in both areas has become moot because the FERC accepted CAISO's compliance filing that those prices not be additive, and granted the CAISO's request to delay implementation of scarcity pricing to December 14, 2010.[106]

95. *Id.* at P 96.

96. *Cal. Indep. Sys. Operator Corp.*, 133 F.E.R.C. ¶ 61,223 (2010).

97. *Id.* at PP 10, 67.

98. *Id.* at PP 70, 75.

99. *Id.* at PP 70.

100. *Cal. Indep. Sys. Operator Corp.*, 131 F.E.R.C. ¶ 61,280 (2010).

101. *Id.* at P 1.

102. *Id.* at P 71.

103. Order No. 719, *Wholesale Competition in Regions with Organized Electric Markets*, F.E.R.C. STATS. & REGS. ¶ 31,281 at P 208, 73 Fed. Reg. 64,100 (2010) (to be codified at 18 C.F.R. pt. 35).

104. 131 F.E.R.C. ¶ 61,280 at P 80.

105. *Id.* at PP 37-45.

106. *Cal. Indep. Sys. Operator Corp.*, 133 F.E.R.C. ¶ 61,113 (2010).

### *B. Electric Reliability Council of Texas (ERCOT)*

On December 1, 2010, ERCOT launched its new NODAL market design.[107] This market design replaces an existing market platform based upon four zones to manage congestion with a platform that performs this function and develops pricing at approximately 8000 nodes (i.e., locations in Texas where electricity is injected or removed from the transmission system).[108] The benefits of the new system are stated to be (i) improved generation dispatch and thus lower costs through unit-specific dispatch as compared to the prior platform's dispatch by defined generation portfolios; (ii) improved management of transmission congestion; and (iii) more accurate price signals as to where new generation and transmission is needed and should be located, which will improve the ability to connect increased quantities of renewables to the grid.[109] The new platform, which cost over $600 million and was developed over 7 years, was launched after almost 40 weeks of market trials, and is expected to produce cost savings of $5.6 billion for end-users over the next 10 years based upon a study commissioned by the Texas Public Utility Commission (PUCT).[110]

### *C. ISO New England, Inc. (ISO-NE)*

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

During 2010, a series of FERC orders reflected New England's continued focus on the implementation and refinement of the Forward Capacity Market (FCM).[111] 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.[112]

On February 26, the FERC accepted the results of the third FCA for the 2012/2013 Capacity Commitment Period.[113] On December 16, the FERC accepted the results of the fourth FCA for the 2013/2014 Capacity Commitment Period,[114] including ISO-NE's rejection of "two static de-list bids submitted by Dominion Resources Services, Inc. (Dominion) [on behalf of] Salem Harbor

107. Press Release, ERCOT, ERCOT Launches Improved Wholesale Market Design (Dec. 1, 2010), *available at* http://www.ercot.com/news/press_releases/2010/nr-12-01-10.

108. *Id.*

109. *Id.*

110. Proceeding to Consider Protocols to Implement a Nodal Market in the Electric Reliability Council of Texas Pursuant to PUC Subst. R 25.501, Doc. 31540 (PUCT Apr. 5, 2006) (final order), *available at* http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/31540_303_507517.PDF; CRA INT'L, UPDATE ON THE ERCOT NODAL MARKET COST-BENEFIT ANALYSIS (Dec. 18, 2008) (prepared for PUCT), *available at* http://www.puc.state.tx.us/electric/reports/31600/PUCT_CBA_Report_Final.pdf.

111. *See, e.g.*, *ISO New England Inc.*, 131 F.E.R.C. ¶ 61,042 at P 1 (2010) ("address[ing] the treatment of separate de-list bids submitted by resources at [multiple-unit generating] stations with common costs").

112. *See, e.g.*, *ISO New England Inc.*, 130 F.E.R.C. ¶ 61,145 at P 2 (2010) ("Under the FCM mechanism, ISO-NE will provide capacity payments to resources that provide capacity to the New England region, and capacity resources will compete through an annual Forward Capacity Auction to be selected to provide capacity on a three-year forward basis.").

113. *ISO New England Inc.*, 130 F.E.R.C. ¶ 61,145 (2010).

114. *ISO New England Inc.*, 133 F.E.R.C. ¶ 61,230 (2010).

Units 3 and 4."[115] The FERC approved ISO-NE's determination that Salem Harbor 3 and 4 would not be able to de-list because it was needed for reliability, but directed ISO-NE to make a compliance filing identifying an alternative to "the reliability need for Salem Harbor Units 3 and 4 and the tim[ing] to implement [the alternative]."[116]

Throughout 2010 the FERC also accepted a number of modifications to New England's FCM and capacity-related market rules. On April 15, 2010, for example, the FERC accepted ISO-NE and NEPOOL's proposed "revisions to the [FCM] market rules . . . that address the treatment of separate de-list bids submitted by resources at [multiple-unit generating] stations with common costs."[117] The revisions set forth the manner in which ISO-NE's Internal Market Monitor will evaluate de-list bids submitted by resources at stations with common costs as well as the appropriate compensation for resources that submit de-list bids that are rejected for reliability reasons in the FCA.[118]

On February 22, 2010, ISO-NE and NEPOOL proposed more sweeping changes to the FCM market rules "addressing the reliability criteria used for determining capacity zones and evaluating de-list bids, modifying the Alternative Capacity Price Rule (APR)," intended to prevent the price distortion through uneconomic Out-of-Market (OOM) bids, "changing the use of the Cost of New Entry (CONE) in determining the starting price for each . . . (FCA)," and extending the price floor for three additional commitment periods (i.e., FCA 4, 5, and 6).[119] While the FERC was considering the February 22 filing, the New England Power Generators Association (NEPGA) and a group of generators separately filed complaints against ISO-NE under section 206 of the FPA addressing the substance of the proposed FCM market rules.[120]

In an order issued on April 23, 2010, the FERC, while accepting the proposed FCM market rule revisions, set issues raised by NEPGA and other generators in their complaints for a paper hearing.[121] In the order, the FERC found some of the proposed changes just and reasonable and accepted them effective on the date of the order, including: (1) decoupling the auction starting price from CONE and revising rules that govern the review of offers below 75% of CONE; (2) a plan to develop requirements for import constrained capacity zones; (3) clarification of the obligations of resources without a capacity supply obligation; and (4) compensation for when a resource's election for pro-rationing is rejected due to reliability reasons.[122]

For purposes of the paper hearing, the FERC consolidated the February 22 filing with the complaints filed by NEPGA and PSEG, setting for paper hearing

115. *Id.* at P 7.

116. *Id.* at P 30.

117. *ISO New England Inc.*, 131 F.E.R.C. ¶ 61,042 at P 1 (2010).

118. *Id.* at P 5.

119. Various Revisions to FCM Rules Related to FCM Redesign at 2, *ISO New England Inc. and New England Power Pool*, No. ER10-787-000 (FERC Feb. 22, 2010), *available at* http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12271862 (internal quotation marks omitted).

120. Complaint, *New England Power Generators Ass'n Inc. v. ISO New England Inc.*, Docket No. EL10-50 (FERC Mar. 23, 2010), *available at* http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12298437.

121. *ISO New England Inc.*, 131 F.E.R.C. ¶ 61,065 (2010).

122. *Id.* at P 16.

issues related to the APR, capacity zones, and the proper value of the CONE.[123] Recognizing that ISO-NE would conduct the fourth FCA in August 2010, the FERC accepted the tariff provisions that related to the issues set for paper hearing.[124] The FERC noted that it anticipated that, if practicable, it would issue an order accepting revised market rules before March 1, 2011, in time to govern FCA # 5 (June 2011) and subsequent auctions.[125]

On August 12, 2010, the FERC issued an order denying in part, and granting in part, rehearing and clarification of its April 16 Order.[126] In the August 12 Order, the FERC clarified that the rules the FERC approved in the April 23 Order would remain in effect until new rules are approved.[127] However, the FERC denied ISO-NE's clarification request that any market rule changes would be implemented no earlier than FCA 6, stating that "[w]ith regard to whether design changes or new market rules will be in place in time for FCA # 5, the [FERC] will not at this time rule as to the effective date of such changes or new rules."[128] The FERC clarified that it intended "that any final determinations relating to the expiration of the price floor should be made after a new APR, the timing of its implementation, and its interrelationship with the price floor have been considered and determined."[129] Finally, the FERC also clarified "that only the value of CONE for future FCAs is at issue in the paper hearing,"[130] but rejected NEPGA's request for "information regarding ISO-NE's determinations as to what resources qualified for OOM treatment in the first three FCAs."[131] The issues set for paper hearing remain pending before the FERC in Docket Nos. ER10-787, EL10-50, and EL10-57.

2. SEMA Complaint

On September 21, 2010, the FERC issued an order on rehearing upholding its previous determinations that (1) "the Southeastern Massachusetts (SEMA) reliability region boundary continues to provide for a just [and] reasonable . . . allocation of . . . dispatch costs" associated with the out-of-merit operation of Mirant's Canal Units 1 and 2 in Cape Cod, Massachusetts for reliability reasons; and (2) "changes to the boundary were not justified either prospectively or retroactively."[132] In affirming its earlier decision, the FERC rejected arguments advanced by a group of municipal utilities in Massachusetts, concluding that a previous settlement they entered into regarding the allocation of uplift charges in SEMA "barred reallocation except: (1) based on the argument that the Transmission Owners could or should have implemented a switching arrangement, which was rejected in the Order on Complaint; and (2) through a change in the ISO-NE definition of the SEMA reliability region."[133]

123. *Id.* at P 18.
124. *Id.* at P 15.
125. *Id.* at P 23.
126. *ISO New England Inc.*, 132 F.E.R.C. ¶ 61,122 (2010).
127. *Id.* at PP 35-36.
128. *Id.* at P 36.
129. *Id.* at P 41.
130. *Id.* at P 46.
131. *Id.* at P 55.
132. *Braintree Elec. Light Dep't v. ISO New England Inc.*, 132 F.E.R.C. ¶ 61,248 at P 1 (2010).
133. *Id.* at P 34.

The FERC further determined that the "[m]unicipals have not provided sufficient support to demonstrate that their proposed alternative reallocation, based on hypothetical or after-the-fact bifurcation of the SEMA region, would be just and reasonable."[134] Ultimately, the FERC affirmed its earlier conclusion that "running the Canal units as required by NERC and NPCC criteria was a pragmatic practice until new facilities could be constructed to ensure reliable electrical service in SEMA."[135]

3. PSEG Complaint

On July 9, 2010, the FERC issued an order granting an April 2, 2010 complaint, filed by PSEG Power Connecticut LLC (PSEG) against ISO-NE, "challenging the justness and reasonableness of ISO-NE's actions with respect to the Capacity Network Resource . . . Capability [CNRC] ratings capacity resources owned by PSEG."[136] In its complaint, PSEG alleged that ISO-NE was "violating its Tariff by effectively applying a cap on the [CNRC] ratings of the PSEG [Bridgeport Harbor Units 3 and 4], limiting PSEG's available Qualified Capacity eligible to participate in the . . . fourth [FCA to the MW values specified in Pre-Order No. 2003] interconnection agreement for these units."[137] PSEG argued that the higher historical MW values determined by the ISOs, based on actual unit testing, should control.[138]

In its July 9 Order, the FERC found that ISO-NE's Tariff was ambiguous, and, given extrinsic evidence, directed ISO-NE to use the historical capability levels for PSEG's Bridgeport Harbor Units 3 and 4 for the fourth FCA.[139] The FERC reasoned:

> [The] ISO-NE already has allowed PSEG to use a megawatt output consistent with PSEG's historical output in previous Forward Capacity Auctions, the parties do not dispute the documented historical capability of the units, and there is no basis in the Tariff or extrinsic evidence to interpret section 5.2.3 to allow ISO-NE to now reduce that CNR Capability rating for the PSEG units by insisting that the interconnection agreement alone must control.[140]

The FERC noted, however, that "[i]f [the ISO] wants to establish a hierarchy procedure, it may seek to make a section 205 filing proposing to modify section 5.2.3 of the LGIP."[141] On November 30, 2010, ISO-NE submitted proposed Tariff changes to clarify mechanisms that ISO-NE will utilize to determine the CNRC ratings of existing generating resources, which were accepted by the FERC by Order dated January 28, 2011.[142]

134. *Id.* at P 46.
135. *Id.* at P 73.
136. *PSEG Power Conn., LLC v. ISO New England Inc.*, 132 F.E.R.C. ¶ 61,022 at P 1 (2010).
137. *Id.* at P 6.
138. *Id.* at P 11.
139. *Id*. at P 40.
140. *Id.* at P 39.
141. *Id.* at P 39 n.46.
142. *ISO New England Inc.*, 134 F.E.R.C. ¶ 61,057 (2011).

### *D. Midwest Independent Transmission System Operator, Inc. (MISO)*

1. Regional Cost Allocation for "Multi-Value Projects"

On December 16, 2010, the FERC accepted, with conditions, a joint Midwest ISO and Midwest ISO Transmission Owners' filing to amend the Midwest ISO Tariff, to provide a regional cost allocation for large transmission lines designated "multi-value projects" (MVPs).[143] The filing also provided for Generator Interconnection Projects (GIP) arising within defined time periods to share the costs of Network Upgrades mutually relied upon, and proposed to retain the cost allocation for Network Upgrades for GIPs that had been accepted in a October 23, 2009 Order on Midwest ISO Regional Expansion Criteria and Benefits (RECB) standards.[144]

MVPs were newly defined in the tariff as projects "determined to enable the reliable and economic delivery of energy in support of documented energy policy mandates or . . . that address . . . multiple reliability and/or economic issues affecting multiple transmission zones."[145] The cost of such projects was proposed to "be allocated to all load in, and exports from, the Midwest ISO on a postage-stamp" and system usage bases.[146] Each element of the MVP filing was conditionally accepted by the December 16 Order, except that the FERC rejected the allocation of MVP costs to, and the collection of such costs in usage rates on, exports to load in the neighboring PJM. Instead, the FERC accepted the MVP charge for all export and wheel-through transactions except for transactions "sinking" in PJM. The FERC reasoned that for non-PJM export and wheel-through transactions "[m]ajor integrated facilities such as MVPs support all uses of the system, including transmission on the system . . . used to deliver to an external load." [147] It found there was "no involuntary assignment of costs . . . given that . . . an external entity taking no service or buying no energy from Midwest ISO, . . . would not be charged.[148]

The FERC also determined that "the MVP proposal does not violate the [FERC's] OASIS posting requirements," because the proposal "does not create a new transmission product, and . . . that the proposed MVP charge merely recovers transmission revenue requirements." [149] However, the FERC found that the filing parties had not shown that assessing the MVP usage rate on exports and wheel-through transactions that sink in PJM "does not constitute a resumption of rate pancaking along the Midwest ISO-PJM seam," which had been found to be unjust and unreasonable in prior, now-final, orders.[150] Thus,

143. *Midwest Indep. Transmission Sys. Operator, Inc*., 133 F.E.R.C. ¶ 61,221 (2010).

144. *Midwest Indep. Transmission Sys. Operator, Inc*., 129 F.E.R.C. ¶ 61,060 (2009), discussed in *Report of the Electricity Regulation & Compliance Committee*, 31 ENERGY L.J. 219, 240-241 (2009).

145. 133 F.E.R.C. ¶ 61,221 at P 1.

146. *Id.*

147. *Id.* at P 439.

148. *Id.*

149. *Id.* at P 444.

150. *Id.* at P 440 (citing *Midwest Indep. Transmission Sys. Operator, Inc*., 104 F.E.R.C. ¶ 61,105 at P 35 (2003)). *See also id.* at P 441 (citing *Midwest Indep. Transmission Sys. Operator, Inc*., 109 F.E.R.C. ¶ 61,168 at P 60 (2004)).

the FERC required a compliance filing within 60 days to exclude wheel-through and export transactions to PJM from MVP charges.[151]

The FERC also required a compliance filing to add tariff language: 1) that a portfolio approach would be used to identify MVPs;[152] 2) that annual informational reports of the selection of MVPs be made;[153] 3) clarifying the definition of "Monthly Net Actual Energy Withdrawal," to ensure that there is no "double netting;"[154] and 4) clarifying that the formula for the MVP usage rate includes MWhs of grandfathered services to reflect cost allocation of MVPs to such services.[155] The FERC found that changes to the existing allocations' congestion rights were likely necessary to reflect the allocation of MVP costs and, thus, required a delayed compliance filing by June 1, 2011, to describe those changes.[156] The FERC also noted[157] that this order precedes any rulings in *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*,[158] so the MVP proposal was reviewed under current FERC policies, and is subject to any future rulemakings.

2. Dairyland Power and Big Rivers Join the Midwest ISO

In 2010, Dairyland Power Cooperative (Dairyland) and Big Rivers Electric Corporation (Big Rivers) integrated into the Midwest ISO markets as transmission owners.[159] Dairyland's service territory is situated between other Midwest ISO members in Iowa, Minnesota, and Wisconsin. Big Rivers, based in Henderson, Kentucky, is the thirty-fourth transmission owner whose systems are integrated into Midwest ISO and the RTO's fifth new transmission-owning member since November 2009.[160]

3. Treatment of Grandfathered Agreements

On October 16, 2009, the Midwest ISO filed Tariff revisions in Docket No. ER10-73-000 proposing to eliminate Carved-Out Grandfather Agreement (GFA) treatment, between a Transmission Owner and an Affiliate, a voting and/or owner member company or another Transmission Owner for any GFA added to Attachment P of its Tariff effective on or after November 1, 2009.[161] In a related filing in Docket No. ER10-74-000, the Midwest ISO applied its proposed Tariff changes (1) in declining to include a number of GFAs Dairyland Power Cooperative sought to have included in Attachment P and carved-out from the

151. *Id.* at P 441.

152. *Id.* at P 223.

153. *Id.* at P 243.

154. *Id.* at P 389.

155. *See id.* at P 451. The FERC "accept[ed] the proposal to exclude grandfathered [transmission] agreements from the regional allocation of MVP costs . . . [as] consistent with the existing exclusion of grandfathered agreements from regional allocations of the costs of other network upgrades." *Id.* at P 450.

156. *Id.* at P 395.

157. *Id.* at n.5.

158. *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, F.E.R.C. STATS. & REGS. ¶ 32,660, 75 Fed. Reg. 37,884 (2010) (to be codified at 18 C.F.R. pt. 35).

159. *Midwest Indep. Transmission Sys. Operator, Inc.*, 131 F.E.R.C. ¶ 61,187 (2010).

160. *Big Rivers Electric Corp.*, 133 F.E.R.C. ¶ 61,175 (2010).

161. Amendment to the Open Access Transmission, Energy, and Operating Reserve Markets Tariff, *Midwest Indep. Transmission Sys. Operator, Inc.*, No. ER10-73 (Oct. 16, 2009).

Midwest ISO markets upon its integration on June 1, 2010; and (2) revising Attachment P of its Tariff to remove four existing Dairyland GFAs in accordance with the proposed changes to the GFA eligibility criteria.[162]

On October 30, 2009, Dairyland filed a Complaint against the Midwest ISO in Docket No. EL10-9-000 challenging the Midwest ISO's proposed Tariff changes and alleging that the Midwest ISO violated its Tariff by failing to revise Attachment P to include certain Carved-Out GFAs. Dairyland requested that the FERC direct the Midwest ISO to include the thirty GFAs in Attachment P as Carved-Out GFAs.

In an order issued on December 15, 2009, the FERC accepted Midwest ISO's proposal to prospectively limit the availability of carved-out treatment for agreements between the new transmission owner and an affiliate or owner-member, but rejected Midwest ISO's proposal to eliminate the availability of carved-out GFA status for existing agreements between a prospective new member and another transmission owner.[163] Accordingly, the FERC rejected Midwest ISO's proposal to delete four Dairyland GFAs with other Transmission Owners that were already listed in Attachment P.[164] On January 14, 2010, Dairyland filed a request for rehearing, and Great River Energy (Great River) filed a request for clarification or rehearing of the December 15 Order.

On May 20, 2010, the FERC issued an Order on Rehearing and Compliance Filing[165] denying rehearing of its December 15, 2009 Order.[166] In denying rehearing, the FERC rejected arguments by Dairyland that the December 15 Order unduly discriminates between existing and prospective transmission owners by precluding Transmission Owners that joined Midwest ISO on or after November 1, 2009, from designating certain of their existing contracts as GFAs in the same manner as existing Transmission Owners.[167] The FERC determined that "Dairyland can analyze the costs of converting its GFAs to tariff service prior to fully integrating into Midwest ISO, and weigh those costs against the benefits of Midwest ISO membership."[168] Therefore, Dairyland is not similarly situated to the transmission-owning members who were already a part of Midwest ISO at the time of energy market start-up.

### 4. Revenue Sufficiency Guarantee

On June 3, 2010, the FERC issued an order denying rehearing of its November 2010 Order commencing a paper hearing to investigate the Midwest ISO's Revenue Sufficiency Guarantee (RSG) cost allocation methodology.[169] In issuing its order, the FERC rejected arguments that it should have ordered a trial type hearing and arguments relating to the scope of the ordered paper hearing.[170]

162. Midwest Independent Transmission System Operator, Inc. Section 205 Filing to Revise Attachment P, *Midwest Indep. Transmission Sys. Operator, Inc.*, Docket No. ER10-74-000 (Oct. 16, 2009).

163. *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 F.E.R.C. ¶ 61,221 (2009).

164. *Id.* at P 49.

165. *Midwest Indep. Transmission Sys. Operator, Inc.*, 131 F.E.R.C. ¶ 61,163 (2010).

166. *Midwest Indep. Transmission Sys. Operator, Inc.*, 129 F.E.R.C. ¶ 61,221 (2009).

167. *Id.* at P 23.

168. *Id.* at P 40.

169. *Midwest Indep. Transmission Sys. Operator, Inc.*, 131 F.E.R.C. ¶ 61,214 (2010).

170. *Id.* at PP 11-13.

On August 30, 2010, the FERC issued an order relating to the Midwest ISO's proposal to redesign the manner in which Revenue Sufficiency Guarantees would be allocated to market participants.[171] The August 30 Order partly accepted and partly rejected the proposed Tariff provisions, and required, among other things, a 30-day compliance filing reflecting the revisions that the FERC accepted.[172] In particular, the August 30 Order accepted the RSG Redesign proposal to the extent that it conformed to the features of an indicative proposal that the FERC previously found to be just and reasonable.[173] However, the August 30 Order rejected the elements of the RSG Redesign proposal that substantially departed from the Indicative Proposal.[174] The FERC required the Midwest ISO to delete the rejected provisions of the RSG Redesign, without prejudice to their subsequent submission under section 205 of the Federal Power Act, to conform particular aspects of the RSG Redesign to related features of the Indicative Proposal, and to clarify certain provisions of the RSG Redesign.[175]

### *E. PJM Interconnection LLC (PJM)*

#### 1. Cost-of-Service Based Transmission Expansion

In *Primary Power, LLC* and *Central Transmission LLC v. PJM Interconnection LLC*,[176] the FERC determined that PJM may permit non-utility applicants to construct transmission facilities that will receive cost-of-service rate treatment and that may qualify for incentive return on equity (ROE) adders. In *Primary Power,* a start-up Transco advised the FERC that it was seeking inclusion of the "Grid Plus Transmission System," a series of four MVAr Static Var Compensators (SVCs) to be installed on three different utility systems at a cost of approximately $200 million, in PJM's Regional Transmission Expansion Plan. Grid Plus stated that it offered economic advantages in reactive power, voltage control and operating flexibility that will reduce the cost of transmission (i.e., $45 to $485 million annually) and expand capacity for west to east transfers. It requested that the FERC issue a declaratory order establishing the above interpretation of PJM's OATT and Operating Agreement, designating it as the entity to construct and own the SVCs and permitting Grid Plus to receive 300 basis points of incentive ROE adders, granting authority to recover project development costs through a regulatory asset amortized over 5 years including if the project were abandoned due to reasons beyond its control, and establishing a capital structure and 12.75 ROE.[177]

The FERC granted the Declaratory Order, but denied the request that Primary Power be designated as constructor and operator of Grid Plus and also granted the requested rate incentives except for the requested 12.75 ROE, reducing the ROE incentive to 200 basis points should PJM include the project

171. *Midwest Indep. Transmission Sys. Operator, Inc.*, 132 F.E.R.C. ¶ 61,186 (2010).

172. *Id.* at P 3.

173. *Id.* at P 63.

174. *Id.* at P 28.

175. *Id.* at P 35.

176. *Primary Power, LLC*, 131 F.E.R.C. ¶ 61,015 (2010); *Cent. Transmission, LLC v. PJM Interconnection, LLC*, 131 F.E.R.C. ¶ 61,243 (2010).

177. *Primary Power*, 131 F.E.R.C. ¶ 61,015 at PP 1-14.

in its RTEP as a baseline project and designate Primary Power to construct it. The FERC thus reserved to PJM the ultimate decision of both whether Grid Plus is a desirable addition to the PJM transmission system (noting that competing projects also exist), whether Primary Power is the appropriate entity to construct the project, and whether Grid Plus should receive cost-based rates (i.e., its entitlement to do so depends upon its designation as a “baseline project” by PJM).[178] However, if PJM makes these determinations, the FERC agreed that the non-routine character of the Project and the financial risk and burden of its development would entitle Primary Power to the requested rate incentives under FPA § 219 and Order No. 679.[179]

In *Central Transmission*, referencing its decision in *Primary Power*, the FERC held that Central Transmission, a member of the LS Power Group and not a traditional transmission owning utility, could be designated by PJM to construct and own a 160 mile, double circuit 345 kv transmission line connecting three PJM 345 kv substations in Illinois and Indiana and designed to interconnect 27,000 MW of wind generation to the grid.[180]

2. PJM/MISO Joint Operating Agreement

On June 29, 2010, the FERC issued an Order establishing hearing and settlement judge procedures, and consolidating three Complaints filed by MISO and PJM respecting alleged violations by each in implementation of those provisions of their Joint Operating Agreement (JOA) that provide for joint management of transmission congestion between their two systems to achieve more efficient and lower cost operations.[181] Total damages claimed in the three complaints equals approximately $160 million.[182]

The JOA provides a process for employing generation redispatch to reduce congestion at the transmission seams between the two systems and to compensate the redispatched generators affected, including payments to defray costs of the redispatch between the two RTOs.[183] In the Redispatch Complaint, filed by MISO on March 9, 2010, MISO contends that PJM has been achieving the objectives of the JOA redispatch process by other means (i.e., internal PJM redispatch) and has therefore cost MISO generators revenues (in excess of $5 million) that they would have received had the required JOA procedures been properly implemented.[184] In the Billing Complaint, also filed by MISO on March 9, MISO claims that PJM, from 2005-2009 and following the integration of AEP into PJM, erroneously calculated its market flows in its dispatch flow model by omitting thirty-four Com Ed area generators (6,100 MW) from the software used in that calculation, resulting in as much as $130 million of reduced flows and injury to MISO generators. Although PJM concedes the error asserted in the Billing Complaint, it denies liability under both Complaints under the JOA’s liability provisions which it asserts limits damages to malicious or

178. *Id.* at PP 62-73.

179. *Id.*

180. *Cent. Transmission, LLC*, 131 F.E.R.C. ¶ 61,293 (2010).

181. *Midwest Indep. Transmission Sys. Operator, Inc*. *v. PJM*, 131 F.E.R.C. ¶ 61,284 (2010).

182. *Id.* at PP 1, 5 & 12.

183. *Id.* at P 2.

184. *Id.* at PP 5-15.

reckless conduct and further asserts the OATT's two-year and Delaware's three year statute of limitations.[185] In the third Complaint, filed April 12, 2010, PJM asserts that MISO has improperly designated substitute or proxy flowgates (i.e., transmission asserted to experience constrained conditions) under the JOA resulting in approximately $25 million of PJM overpayments to MISO. MISO denies the allegation.[186] On January 4, 2011, a Settlement Agreement was filed, which is pending before the FERC.

Under the Agreement,[187] MISO and PJM agree to the dismissal of their Complaints with prejudice and to the release and discharge of all liabilities, known or unknown, that could arise from operation of the JOA prior to the date of the Settlement Agreement. It is further agreed that there shall be a review by an independent third party of the procedures for implementing the JOA immediately and every two years thereafter, that recommendations from that review shall be jointly considered and acted upon, that procedures shall be established for joint agreement to effecting changes in such implementation procedures, that such reviews and all matters for decision shall be posted on the parties website and communicated to stakeholders through their established stakeholder consultation processes, and that each party shall have enhanced access to the data of the other to permit verification of market-to-market settlements. Six guiding principles are provided for JOA administration, and it is further agreed that no rebilling of JOA charges shall be made after the elapse of one year from the initial billing.

3. PJM Expansion

In late 2009, the FERC approved a request from American Transmission Systems, who operates the transmission assets of the First Energy System located largely in Ohio, that, if it satisfies its exit obligations to MISO and receives all required regulatory approvals, it may transfer operation of its assets and its membership in an RTO to PJM.[188] In October 2010, the FERC similarly granted such approvals to Duke Energy for its Ohio and Kentucky operations (Indiana will remain with MISO).[189] In each case, the FERC applied the standards developed in its 2003 *Louisville Gas & Electric* Order[190] to approve the requested transfer, including acceptance that RTO membership is voluntary and not mandatory for transmission owning entities.

4. Order No. 719 Compliance

Order No. 719, issued in 2008, imposed four requirements upon RTOs, including PJM, as follows: i) expanded DSM participation in ancillary service markets and the development of "scarcity pricing" for periods when load approaches resource constraints; ii) expanded availability of long-term contracts for energy supply; iii) modifications in the role of RTO Market Monitors to

185. *Id.* at PP 19-29.

186. *Id.* at PP 40-46.

187. Settlement & Explanatory Statement, *Midwest Indep. Sys. Operator, Inc. v. PJM*, No. EL10-45-000 (FERC Jan. 4, 2011), *available at* http://www.ferc.gov/docs-filing/elibrary.asp.

188. *Am. Transmission Systems, Inc.*, 129 F.E.R.C. ¶ 61,249 (2009).

189. *Duke Energy Ohio, Inc.*, 133 F.E.R.C. ¶ 61,058 (2010).

190. *Louisville Gas & Electric*, 114 F.E.R.C. ¶ 61,282 (2003).

assure their independence, to establish their required functions, to define the tools that they need to perform those functions, and to assure that that they do not perform direct market administration roles inconsistent with their monitoring functions and independence; and iv) development of RTO performance metrics.[191]

PJM was unable to develop a consensus scarcity pricing mechanism through its stakeholder collaborative process and filed its proposal with the FERC in June of 2010.[192] It proposes to establish new ten-minute reserve markets for all operating reserves; an integrated, optimized energy and reserve dispatch procedure operating every five minutes; demand curve pricing based on one of the FERC-suggested scarcity pricing mechanisms in Order 719; separate reserve price caps for each reserve type (i.e., "synchronized" and "total" ten minute reserves); and an overall cap on energy and reserve prices of $2700/MWh.[193] A four-year transition is proposed to implement the new pricing system, and revenues obtained from it are to be credited against Reliability Pricing Model capacity charges. The FERC has not yet acted upon the proposal. In a late 2009 Order, the FERC approved PJM's compliance filing respecting Market Monitor roles and functions with certain modest revisions.[194] On October 21, 2010, the FERC issued an order finding that PJM satisfies Order No. 719's four responsiveness criteria, i.e., that its governance processes permit inclusiveness, fairness in balancing diverse interests, representation of minority positions, and ongoing responsiveness to market stakeholders.[195]

5. Transmission Rights

On September 16, 2010, the FERC approved a contested settlement that two transmission service agreements should be "rolled over" and continued in force pursuant to PJM's OATT.[196] The settlement was between PJM, NYISO, Con Ed, and PSE&G, and was supported by the NY PSC and New York City, but was opposed by the NRG Companies. The settlement involved two 1970s agreements pursuant to which Con Ed had agreed to supply PSE&G service territory in northern New Jersey with up to 1000 MW of electricity essentially in return for the latter supplying an equal amount of power to New York City from PSE&G generation. These agreements, which predated Order No. 888 and had been grandfathered to continue in effect following the pro forma OATT's

191. Order No. 719, *Wholesale Competition in Regions with Organized Electric Markets*, F.E.R.C. STATS. & REGS. ¶ 31,281 (2008), *order on reh'g*, F.E.R.C. STATS. & REGS. ¶ 31,292 (2009), 73 Fed. Reg. 64,100 (2008) (to be codified at 18 C.F.R. pt. 35), *reh'g denied*, 129 F.E.R.C. ¶ 61,252 (2009). The FERC approved PJM's proposal to encourage long-term power contracting through creation and operation of an electronic bulletin board on its website upon which offers to buy and sell long-term energy will be publicized in a late 2009 Order. *See PJM Interconnection LLC*, 129 F.E.R.C. ¶ 61,250 at PP 101-04 (2009).

192. *PJM Interconnection, LLC*, No. ER09-1063-004, at p. 3 (FERC June 18, 2010), *available at* http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx [hereinafter *PJM Compliance Filing*].

193. *Id.* PJM proposals to expand integration of DR into its ancillary service markets and FERC Orders approving the same are described in the Smart Grid & Demand Resource Committee Report published in this same volume of the Energy Bar Journal. *PJM*, 132 F.E.R.C. ¶ 61,123 (2010); *PJM*, 129 F.E.R.C. ¶ 61,250 (2009).

194. *PJM*, 129 F.E.R.C. ¶ 61,250 at PP 105-213 (2009).

195. *PJM Interconnection, LLC*, 133 F.E.R.C. ¶ 61,071 (2010).

196. *PJM Interconnection, LLC*, 132 F.E.R.C. ¶ 61,221 (2010) (*PJM Transmission Rights*); *PJM Interconnection, LLC*, 130 F.E.R.C. ¶ 61,126 (2010). Rehearing has been granted of the September 16 Order.

adoption, were due to expire in 2015.[197] In the view of the NY PSC, New York City (NYC) and the settling parties, they remained critical to the provision of reliable and low cost service to NYC. However, their required flows of electricity restricted sales, and thus revenue opportunities, from NRG's Arthur Kill Generating Station. Since the settlement was contested, the FERC was required to adjudicate whether its terms were just and reasonable, non-discriminatory, and in the public interest. After a paper hearing, in which it decided that the agreements created firm transmission service to which OATT roll-over rights applied, the FERC approved continued provision of the service as an OATT non-conforming agreement.[198]

6. Market Manipulation Associated with Virtual Transmission

On September 17, 2010, the FERC approved a PJM filing establishing a temporary solution to a certain manipulation of PJM markets.[199] PJM market rules require that transmission service (typically non-firm) be purchased in "up-to congestion transactions" (many of which are financial transactions not involving actual transmission of electricity), and such purchases (made using a marginal line loss valuation methodology) are entitled to receive a credit to the extent that total transmission service purchases exceed associated costs.[200] PJM requested that its market rules be modified such that transmission service need not be obtained in connection with "up-to congestion" transactions.[201] The FERC approved the modification.[202]

7. Creation of PJM Settlement

On May 5, 2010, PJM submitted a tariff filing to create a new non-profit, wholly-owned entity, called "PJM Settlement." PJM Settlement is to have two functions: i) to serve as the designated counterparty for all transactions in all PJM markets, but not in bi-lateral transactions between PJM market participants; and ii) to perform all settlement and billing transactions related to PJM market transactions previously performed by PJM. However, PJM Settlement is to have no employees or assets separate from PJM, though it will have a separate Board of Directors none of whom will be PJM officers or directors, though they will be PJM employees, and will pay PJM for all services provided from the revenues it

197. *PJM Transmission Rights*, *supra* note 196, at PP 2-7 & 16-17.

198. *Id.* at PP 22-81.

199. *PJM Interconnection, LLC*, 132 F.E.R.C. ¶ 61,244 (2010) (*PJM Virtual Transmission Manipulation*). On April 15, 2010, the FERC denied all requests for rehearing (filed principally in connection with virtual transactions) respecting its 2009 Order adopting the marginal line loss rate methodology. *Black Oak Energy, LLC v. PJM Interconnection, LLC*, 131 F.E.R.C. ¶ 61,024 (2010). The FERC also dismissed a second Complaint, *EPIC Merchant Energy NJ/PA, L.P. v. PJM Interconnection, LLC*, 131 F.E.R.C. ¶ 61,130 (2010), asserting the same matter as the Black Oak Complaint, i.e., that virtual market transactions should not be assessed marginal line loss charges or deserve greater refunds from the surplus recovery as they do not in fact incur transmission service costs and thus disproportionately create the cost recovery surplus being distributed.

200. *PJM Virtual Transmission Manipulation, supra* note 199, at PP 2-11.

201. *Id.* at P 12.

202. *Id.* at PP 42-49.

collects through its billing of PJM market members, including billing for all PJM administrative services.[203]

In two orders, the FERC approved the creation of PJM Settlements despite Protests from several PJM market participants questioning whether PJM Settlements could properly perform its market counter-party functions separate from PJM itself, and based upon unconditional guarantee agreements between the two entities filed with the FERC.[204] FERC waived certain of its reporting and other requirements reflecting the close relationship between PJM and PJM Settlements, but it required that separate rate schedules applicable to PJM Settlements be filed.[205] The FERC also required a further compliance filing by PJM to identify PJM Settlements counterparty functions in its OATT, to respond to the continued Protests that PJM Settlements is not able to perform as a true counterparty or to explain why further tariff modifications are not needed.[206]

8. Reliability Pricing Model

On May 20, 2010, the FERC issued an order largely accepting PJM's compliance filing respecting pricing and auction procedures for its Reliability Pricing Model (RPM or capacity market).[207] The principal issues addressed related to pricing of capacity required to be purchased in RPM incremental auctions where load or the reliability requirement has increased since the original base auction (i.e., three years before the service year) and whether the sell-back of capacity should be required if load or the requirement has decreased since that base auction and too much capacity was purchased. The FERC required PJM to eliminate a proposed fixed price increment for additional capacity purchases, viewing it as unnecessary and inconsistent with the administratively determined pricing curve otherwise used in such auctions, and determined not to require a mechanism in incremental auctions to sell-back capacity required in excess of needs as destructive of base auction result certainty and providing an opportunity for improper gaming. [208]

9. SECA

On May 21, 2010, the FERC issued two orders[209] completing its adjudication of a series of transmission rate issues surrounding its 2003 decision to eliminate "through and out" rates in the PJM and MISO footprints. The first order denied rehearing petitions filed on eight 2003-2005 orders which had directed the elimination and implemented replacement rates (i.e., Seams Elimination Charge/Cost Adjustment/Assignment (SECA)).[210] "Through and Out" rates were transmission rates which were intended to recover the costs of transmission within an RTO where the transmitted supply was being purchased

203. *PJM Interconnection, LLC*, 133 F.E.R.C. ¶ 61,277 at PP 4-13 (2010) (*PJM Settlements I*).

204. *Id.*; *PJM Interconnection, LLC*, 132 F.E.R.C. ¶ 61,205 (2010) (*PJM Settlements II*).

205. *PJM Settlements I*, *supra* note 203, at PP 51-61.

206. *PJM Settlements II*, *supra* note 204 at P 33.

207. *PJM Interconnection, LLC*, 131 F.E.R.C. ¶ 61,168 (2010).

208. *Id*. at PP 27, 35-39 & 75-86.

209. *Midwest Indep. Transmission Sys. Operator, Inc*, 131 F.E.R.C. ¶ 61,174 (2010) (*Midwest SECA I*); *Midwest Indep. Transmission Sys. Operator, Inc*., 131 F.E.R.C. ¶ 61,173 (2010) (*Midwest SECA II*).

210. *Midwest SECA I*, *supra* note 209, at PP 2-3 & 9.

from a generator in one RTO and would be delivered to end-users in a second RTO. Two such rates would apply to such a transaction, one imposed by each RTO to obtain a contribution to the costs of each RTO's separate transmission facilities used in providing the service. The FERC concluded that application of the two rates to the single transmission was discriminatory and unlawful, and refused to rehear that issue. [211]

Under the SECA mechanism, which was replaced with a new rate structure in 2007, transmission investment and operating costs previously collected from "through and out" rates (which were sizeable) was instead recovered through a cost adjustment applied to all load in each RTO served by inter-RTO transactions in proportion to the level of such transactions to the sub-zone in which the load was located in a 2002 or 2003 test year. As the SECA charge applied regardless of current individual inter-RTO transactions, the FERC stated that the discrimination and illegality was corrected. The FERC denied a series of rehearing requests seeking the adoption of alternatives to or modifications of this charge.[212]

The second order adjudicated issues respecting how the SECA rates should be developed, accepting in part and revising in part recommendations in Administrative Law Judge Initial Decisions from March and April 2006.[213] Also, in response to the 7th Circuit's reversal and remand of the FERC's earlier approval of PJM's proposal that new large capacity transmission lines (i.e., 500 kv & above) have their costs allocated 100% regionally through a postage stamp rate, the FERC ordered a paper hearing and substantial data filing on comparable benefits and costs by PJM.[214] The court had found the FERC's adopted allocation method to be arbitrary and capricious as no showing was made in the order that large transmission's regional benefits approximated the FERC's ordered allocation of costs amongst transmission users, but the court's mandate permits the FERC to reaffirm its original order if it can develop a satisfactory evidentiary basis for doing so. [215]

### *F. New York Independent System Operator, Inc. (NYISO)*

#### 1. Declaratory Order

On January 8, 2010, the NYISO submitted a petition for a declaratory order seeking a ruling from the FERC concerning whether the New York Power Authority's (NYPA) ownership of certain Grandfathered Transmission Congestion Contracts (Grandfathered TCCs) terminated when the original generating unit at the Charles Poletti Power Plant in Astoria, Queens, in New York stopped operating on January 31, 2010.[216] In an order issued on April 15,

---

211. *Id.* at PP 1, 150-153.

212. *Id.* at PP 1, 35-49.

213. *Midwest SECA II, supra* note 209.

214. Ill. Commerce Comm. v. FERC, 576 F.3d 470 (7th Cir. 2009); *PJM Interconnection, LLC*, 130 F.E.R.C. ¶ 61,052 (2010). The FERC has permitted, subject to refund, PJM assignments of cost allocation for its 2010 Regional Transmission Expansion Plan based upon the Court rejected region-wide allocation principles. *PJM Interconnection, LLC*, 131 F.E.R.C. ¶ 61,235 (2010); *PJM Interconnection, LLC*, 130 F.E.R.C. ¶ 61,103 (2010).

215. *Ill. Commerce Comm.*, 576 F.3d at 482.

216. Petition for Declaratory Order, *N.Y. Indep. Sys. Operator, Inc*, No. EL10-33 (FERC Jan. 8, 2010).

2010, the FERC granted NYISO's petition, finding that NYPA's ownership of the Grandfathered TCCs did not terminate when the original Poletti generating unit ceased to operate.[217] The FERC found that "the construction of a new generating unit on the same site as the original unit did not terminate the NYPA Agreements."[218] In reaching this conclusion, the FERC rejected arguments that the NYPA Agreements terminated when original Poletti unit was retired on January 31, 2010.[219]

2. Rejection of Elimination of Network Integration Transmission Service

On April 27, 2010, the FERC rejected NYISO's proposal to eliminate Network Integration Transmission Service (NITS) from its OATT.[220] NYISO's request was prompted by the new rules being developed by the North American Energy Standards Board (NAESB) and the North American Electric Reliability Corporation (NERC), which would require NYISO to develop a new online functionality to support NITS, entailing a potentially expensive software upgrade.[221] Without quantifying the cost of the upgrade, NYISO claimed that the expense was not justified.[222] While the FERC requires that both Point-to-Point and NITS pro forma tariff provisions be included in the OATT, to date no market participant had requested NITS under the NYISO OATT.[223]

Pointing to inherent differences between NITS (which provides for scheduling service from a single generator to a variety of loads, or from a variety of generators to a single load, without securing physical transmission reservations for each transaction) and Point-to-Point service (which provides for the reservation and transmission of capacity and energy from particular point(s) of receipt to particular point(s) of delivery), the FERC held that even though NYISO customers do not currently avail themselves of NITS, the choice should still be available.[224] Rejecting the proposal, the FERC also noted that NYISO failed to provide (1) the cost estimated for complying with the NITS-related proposed NAESB/NERC standards, and (2) the time line in which those proposed NAESB/NERC standards were expected to become effective.[225]

3. Market Power Mitigation

The FERC revisited the issue of mitigating generation owners' exercise of market power in the New York City (NYC) Installed Capacity (ICAP) market in an order issued on May 20, 2010.[226] In two orders issued in 2008, the FERC had accepted NYISO's proposed NYC mitigation plan, subject to NYISO's

217. Order Granting Petition for Declaratory Order, *N.Y. Indep. Sys. Operator, Inc.*, 131 F.E.R.C. ¶ 61,032 (2010).

218. *Id.* at P 39.

219. *Id.* at P 40.

220. *N.Y. Indep. Sys. Operator, Inc*., 131 F.E.R.C. ¶ 61,074 (2010).

221. *Id.* at P 4.

222. *Id.* at PP 4, 19.

223. *Id.* at P 3.

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

225. *Id.* at P 19.

226. *N.Y. Indep. Sys. Operator, Inc.*, 131 F.E.R.C. ¶ 61,170 (2010).

submission of a compliance filing.[227] The May 20, 2010 Order addressed that compliance filing, as well as requests for rehearing and clarification of the FERC's 2008 actions.[228]

With regard to the requests for rehearing and clarification, the FERC first re-affirmed its rejection on procedural grounds of NYISO's attempt to expand the definition of "control" of a generation resource to include the retention of revenue or other financial benefits from Unforced Capacity.[229] Second, the FERC ruled that in setting the offer floor for new generation – applicable to new generator entrants for three years – equal to 75% of the net CONE, NYISO had not used the definition of CONE specified by the FERC.[230] Third, the FERC ruled that "NYISO's [proposed] penalty for economic withholding . . . [of] capacity is excessive and should be the same as the penalty for physical withholding through uneconomic exports."[231] Fourth, the FERC denied a request to relieve mitigated pivotal suppliers from penalties where their failure to offer capacity into the spot market was inadvertent.[232] Fifth, the FERC rejected a request that a change in contractual or financial arrangements for a generating unit in existence on March 7, 2008, should be deemed to transform that unit into a new unit subject to the new entry mitigation rules.[233] Sixth, the FERC affirmed its ruling that the market mitigation rules should apply to certain demand response resources (special case responses or SCRs) in the same manner, but not necessarily in the identical form, as they apply to other participants.[234]

The FERC rejected NYISO's compliance filing in the following respects. First, the FERC found that NYISO had not complied with the FERC's order regarding the pivotal supplier withholding conduct threshold, which the FERC had intended be the same as the impact threshold.[235] Second, the FERC ruled that the mitigation for SCRs "should be limited to the initial participation of [such resources] in the marketplace."[236] Third, the FERC rejected NYISO's proposal to terminate mitigation for SCRs after twelve consecutive months, and instead required mitigation to apply to the SCRs for a total of twelve, but not necessarily consecutive, months.[237] Fourth, the FERC directed NYISO to give SCRs certain mitigation exemptions similar to those provided to new generation.[238] The FERC also directed NYISO to make certain other conforming or clarifying tariff changes.[239]

227. *N.Y. Indep. Sys. Operator, Inc.*, 122 F.E.R.C. ¶ 61,211, *order on reh'g*, 124 F.E.R.C. ¶ 61,301 (2008). That mitigation plan, as originally proposed, stemmed from Consolidated Edison's divestiture of most of its in-city generation to two generation owners. *Consol. Edison Co. of N.Y., Inc.*, 84 F.E.R.C. ¶ 61,287 (1998).

228. *N.Y. Indep. Sys. Operator, Inc.*, 131 F.E.R.C. ¶ 61,170 at P 1.

229. *Id.* at PP 21-23.

230. *Id.* at P 31.

231. *Id.* at P 38.

232. *Id.* at P 39.

233. *Id.* at P 43.

234. *Id.* at PP 47-48, 97.

235. *Id.* at P 74.

236. *Id.* at P 106.

237. *Id.* at P 107.

238. *Id.* at P 108.

239. *Id.* at PP 108, 135, 137, 138 & 145.

On November 26, 2010, the FERC ruled upon NYISO's proposed revisions to its buyer-side market power mitigation measures applicable to the NYC ICAP market.[240] NYISO proposed revisions to the method for determining "offer floor mitigation durations" and to the process for determining offer floor exemptions.[241] With respect to offer floor mitigation durations, the FERC ruled that NYISO's proposal "potentially may over- or under-mitigate the exercise of buyer-market power."[242] The FERC rejected the first of two mitigation proposals NYISO made,[243] and modified the second to provide that the offer floor mitigation "will be lifted only for the minimum . . . portion of a supplier's resource capacity" that clears in 12 monthly auctions.[244] The FERC also rejected NYISO's three-year minimum and fifteen-year maximum mitigation.[245] With respect to the offer floor exemption process, the FERC generally approved NYISO's proposed changes to the process for making exemption determinations.[246]

On May 20, 2010, the FERC approved market mitigation measures for three generators located outside of NYC and Long Island.[247] NYISO argued that the three generators in question exhibited bidding behavior that departed from what "would be expected under competitive market conditions."[248] The proposed mitigation measures would apply in specified situations.[249] In these situations, NYISO proposed to substitute a default bid.[250] The FERC found that the three generators "engaged in conduct that departed significantly from that which would be expected under competitive conditions,"[251] and generally approved NYISO's proposal.[252]

On October 12, 2010, the FERC approved market mitigation measures to apply to generators outside of NYC and Long Island ("rest-of-state").[253] NYISO's proposal was similar to the one it proposed earlier with respect to the three rest-of-state generators, which the FERC had accepted earlier that year.[254] The FERC generally accepted them on the same grounds it had relied upon with respect to the three generators.[255]

240. *N.Y. Indep. Sys. Operator, Inc.*, 133 F.E.R.C. ¶ 61,178 (2010).
241. *Id.* at P 5.
242. *Id.* at P 47.
243. *Id.* at P 48.
244. *Id.* at P 49.
245. *Id.* at P 51.
246. *Id.* at PP 71-73.
247. *N.Y. Indep. Sys. Operator, Inc.*, 131 F.E.R.C. ¶ 61,169 (2010).
248. *Id.* at P 7.
249. *Id.* at P 12.
250. *Id.* at P 12.
251. *Id.* at P 89.
252. *Id.* at P 66.
253. *N.Y. Indep. Sys. Operator, Inc.*, 133 F.E.R.C. ¶ 61,030 at P 1 (2010).
254. *N.Y. Indep. Sys. Operator, Inc.*, 131 F.E.R.C. ¶ 61,169 (2010).
255. *Id.* at P 43.

4. Lake Erie Loop Flow

On July 15, 2010, the FERC accepted NYISO's January 12, 2010 report on Lake Erie region loop flows.[256] The FERC had first addressed this issue in a 2008 order that accepted NYISO's temporary solution to the loop flow problem,[257] and revisited the issue in a 2009 order.[258] NYISO submitted its January 12, 2010 report in compliance with the FERC's 2009 Order.[259]

NYISO's report stated that relays for new phase angle regulators (PARs) were being installed to mitigate loop flow,[260] and that it recommended a series of market initiatives to be implemented by NYISO and neighboring RTOs and ISOs.[261] NYISO recommended the implementation of "four, broad-based market initiatives: (i) the buy-through congestion proposal; (ii) the congestion management/market-to-market coordination proposal; (iii) interface pricing revisions; and (iv) enhanced interregional transaction coordination."[262] The FERC agreed that these initiatives, "taken as a whole," appeared to be constructive,[263] but directed NYISO and the parties to address additional issues raised by the parties, and to submit comments on those issues to the FERC.[264] On December 30, 2010, the FERC addressed those comments, and imposed specific deadlines for the implementation of the interface pricing revisions and congestion management/market-to-market coordination, and, following the implementation of those two initiatives, required NYISO to submit semi-annual reports on the implementation of the other two market initiatives.[265]

5. Order No. 719 Compliance

On June 4, 2010, the FERC issued a second order regarding NYISO's compliance with the FERC's directives in Order No. 719 regarding market monitoring.[266] NYISO had submitted an initial compliance filing in 2009, which the FERC acted on in an order issued November 20, 2010.[267] The FERC's November 20, 2009 Order directed NYISO to revise its compliance filing,[268] and that compliance filing was the subject of the FERC's June 4, 2010 Order.[269] The order accepted all of NYISO's proposed revisions, except NYISO's proposal that it not forward what it characterized as sixteen "traffic ticket" market violations to the FERC.[270] The FERC accepted three of NYISO's proposals on the ground that the activities were set forth in the tariff, involve "objectively

256. *N.Y. Indep. Sys. Operator, Inc.*, 132 F.E.R.C. ¶ 61,031 (2010). Loop flows refer to physical flows that differ from scheduled flows, which can cause congestion on transmission lines.

257. *N.Y. Indep. Sys. Operator, Inc.*, 125 F.E.R.C. ¶ 61,184 at P 20 (2008).

258. *N.Y. Indep. Sys. Operator, Inc.*, 128 F.E.R.C. ¶ 61,049 (2009).

259. *N.Y. Indep. Sys. Operator, Inc.*, 132 F.E.R.C. ¶ 61,031 at P 1 (2010).

260. *Id.* at P 7.

261. *Id.* at P 11.

262. *Id.*

263. *Id.* at P 40.

264. *Id.* at PP 41-43.

265. *N.Y. Indep. Sys. Operator, Inc.*, 133 F.E.R.C. ¶ 61,276 at PP 31-33 (2010).

266. *N.Y. Indep. Sys. Operator, Inc.*, 131 F.E.R.C. ¶ 61,225 (2010).

267. *N.Y. Indep. Sys. Operator, Inc.*, 129 F.E.R.C. ¶ 61,164 (2009).

268. *Id.* at P 1.

269. *Id.* at P 3.

270. *Id.* at P 98.

identifiable behavior," and do not subject the actor to other sanctions,[271] but rejected the other thirteen on the ground they failed to meet one or more elements of this test.[272]

The FERC issued another order regarding NYISO's compliance with Order No. 719 on October 21, 2010.[273] This order addressed an issue that the FERC had reserved for judgment in its November 20, 2009 Order on NYISO's May 15, 2009 Order No. 719 compliance filing.[274] The reserved issue involved the reforms that regional organizations needed to take to ensure their boards of directors were responsive to customer and stakeholder needs.[275] The FERC addressed this issue generically in a technical conference, and then applied the knowledge it gained in that process to NYISO specifically.[276] The FERC determined that NYISO's government and stakeholder processes were compliant with Order No. 719, but that ideas presented in the proceeding, while not required by Order No. 719, should be considered by NYISO.[277]

6. Recovery of Deliverability Upgrade Costs

On June 17, 2010, the FERC ruled upon NYISO's and the New York Transmission Owners' joint compliance filing that provided a mechanism to recover the certain costs of Highway System Deliverability Upgrades constructed by the Transmission Owners to provide Capacity Resource Interconnection Service.[278] Under NYISO rules, if the size of upgrade required for deliverability for such service was less than 90% of the minimum expansion, the developer would pay a prorated share of the cost based on the MW required for deliverability, and the balance of the cost would be allocated to load.[279] In this filing, NYISO proposed that in such situations each load serving entity would share this cost based on its "proportionate share of the installed capacity [ICAP] requirement in the statewide capacity market . . . as adjusted to subtract locational capacity requirements."[280] The FERC accepted the parties' filing.[281]

*G. Southwest Power Pool (SPP)*

1. SPP Highway/Byway Cost Allocation Plan

By Order dated June 17, 2010, the FERC approved the Highway/Byway transmission cost-allocation methodology proposed by SPP.[282] This new methodology assigns the costs of the base plan upgrades in the SPP region based on the operating voltage levels of the transmission projects and their primary

271. *Id.*
272. *Id.* at P 17.
273. *N.Y. Indep. Sys. Operator, Inc.*, 133 F.E.R.C. ¶ 61,072 (2010).
274. *N.Y. Indep. Sys. Operator, Inc.*, 129 F.E.R.C. ¶ 61,164 at P 19 (2009).
275. *Id.*
276. *N.Y. Indep. Sys. Operator, Inc.*, 133 F.E.R.C. ¶ 61,072 at PP 19, 26.
277. *Id.* at P 26.
278. *N.Y. Indep. Sys. Operator, Inc.*, 131 F.E.R.C. ¶ 61,242 at PP 1, 4-6.
279. *Id.* at P 5.
280. *Id.* at P 10.
281. *Id.* at P 29.
282. *Sw. Power Pool, Inc*., 131 F.E.R.C. ¶ 61,252 (2010).

regional or local use.[283] Specifically: (1) for high voltage transmission projects (300 kV and above) – 100% of the costs will be allocated to the electric utilities' load across SPP's entire system; (2) for lower voltage transmission projects (between 100 kV and 300 kV) – 33% of the costs will be allocated to the electric utilities' load across SPP's entire system and 67% will be allocated to the local utilities; and (3) for small voltage transmission projects (below 100 kV) – 100% of the costs will be allocated to the local utilities.[284] Multiple requests for rehearing of the June 17 Order are currently pending.[285]

2. SPP Transmission Planning Proposal

On July 15, 2010, the FERC conditionally accepted the SPP transmission planning proposal, the Integrated Transmission Plan (ITP).[286] The ITP is a planning process that includes: (1) 20-year assessments, focusing on higher-voltage (300 kV and above) solutions necessary to develop the EHV backbone; (2) 10-year assessments, focusing on lower voltage (between 100 kV and 300 kV) solutions not resolved in the 20-year assessment, as well as such issues as elimination of violations, mitigation of congestion, improved access to markets, backbone expansion staging, and improved interconnections; and (3) near-term assessments, focusing on solutions needed to comply with NERC reliability standards.[287] The near-term assessments will occur annually and the 20-year and 10-year assessments will be performed every three years.

The SPP will conduct transmission planning forums to define the scope of each assessment, announcing at the beginning of each calendar year which part(s) of the ITP cycle will be covered during that year.[288] Each type of assessment will involve (1) a study scope; (2) evaluation of alternative solutions (i.e., generation options, demand response programs, "smart grid" technologies, and energy efficiency programs) against each other on the basis of their relative effectiveness of performance and economics; and (3) evaluation of the cost-efficiency of every proposal quantifying the costs and benefits modeled on a 40-year time frame.[289] After SPP completes its studies and analyses, SPP will present a list of proposed projects (along with a description of all alternatives considered and an explanation for choosing the presented solutions) for review and approval to SPP's decisions makers.[290] Once the ITP process identifies the facilities to be built, the costs will be recovered through the Highway/Byway cost allocation plan approved by the FERC on June 17, 2010, in Docket No. ER10-1069.[291] The ITP process is expected to be implemented on a "compressed" schedule, with intention to present the first 20-year transmission plan in January 2011, and the first 10-year transmission plan in January 2012.[292]

283. *Id.* at P 10.
284. *Id.*
285. Order Granting Rehearing for Further Consideration, No. ER10-1069 (FERC Aug. 9, 2010).
286. *Sw. Power Pool, Inc*., 132 F.E.R.C. ¶ 61,042 (2010).
287. *Id.* at P 8.
288. *Id.* at P 9.
289. *Id.*
290. *Id.* at P 15.
291. *Id.*
292. *Id.* at P 16.

Multiple parties timely requested rehearing of the July 15 Order, which remain pending.[293]

3. Entergy/SPP Relationship Matters

In December, the FERC issued an order accepting a filing made by Entergy Corp. which amended its OATT to empower the Entergy-Regional State Committee (E-RSC), an organization representing Entergy's State Regulators, to direct Entergy to make a FPA § 205 filing to (1) change its transmission cost allocation methodology for upgrades or to alter its Base Plan time horizon, and (2) to add transmission projects to its Construction Plan.[294] The E-RSC was formed in late 2009 with the purpose, amongst others, to address concerns expressed in previous years with the state and adequacy of the Entergy transmission system as well as a desire to proactively evaluate whether an RTO or other alternative structure would reduce end-user costs.[295] Immediately following its formation, the E-RSC joined with the FERC in sponsoring an independent study of the cost-benefit of alternative transmission system governance structures (including joining SPP) for Entergy.[296]

An initial such study was completed in Fall 2010 and indicated that a $1.3 billion cost savings could be achieved from Entergy and Cleco Power joining SPP over the 10 year period 2013 to 2022, but that cost savings varied for the three entities (and could be rendered significantly negative) depending upon how transmission costs would be allocated in the future.[297] In November, at Entergy's request and with the support of E-RSC, the FERC approved the extension of SPP as Entergy's Independent Coordinator of Transmission (ICT) for an additional two years (through November 2012) or until a decision is made on joining SPP or continuing the ICT as permanent.[298]

## III. TRANSMISSION RATES

### *A. Cost Based*

In a December 16, 2010 Order,[299] the FERC denied the petition of Grasslands Renewable Energy, LLC (Grasslands), for a declaratory order that its proposal to construct a network transmission system that assigned priority transmission rights to customers who agreed to pay the entire cost of the system (by contracting for service at cost-based rates in advance of construction) would satisfy the FERC's open access transmission requirements, finding that the proposal would improperly grant an undue preference to certain transmission customers in contravention of section 205 of the FPA and the FERC's open

293. Order Granting Rehearing for Further Consideration, *supra* note 285.

294. *Entergy Ark., Inc.*, 133 F.E.R.C. ¶ 61,211 (2010).

295. *Id.* at P 3.

296. *Id.*

297. CHARLES RIVER ASSOC. & RESERO CONSULTING, COST-BENEFIT ANALYSIS OF ENTERGY AND CLECO POWER JOINING THE SPP RTO (Sept. 30, 2010), *available at* http://www.spp.org/publications/FERC%20SPP%20Entergy%20CBA%20Report%20Final.pdf.

298. *Entergy Servs. Inc.*, 133 F.E.R.C. ¶ 61,136 (2010).

299. *Grasslands Renewable Energy, LLC*, 133 F.E.R.C. ¶ 61,225 (2010).

access principles.[300] Grasslands' proposal is to develop the Wind Spirit Project (WSP) in the Northern Plains region through three affiliated entities, WSP Poolco, WSP Firmco, and WSP Transco, through which it will:

1. aggregate wind resources at dispersed locations in the Northern Plains region;

2. "firm up" or shape the variable wind power through the utilization of storage assets; and

3. deliver this firm wind energy product to load centers in the Southwest and West.[301]

Wind generators participating in WSP Poolco would earn revenues through a "netback" model, in which payments would be made based on downstream firm energy sales less firming service, transmission service, and administrative costs and fees.[302] Grasslands proposed to engage in a two-phase process to identify those entities willing to participant-fund the WSP collector system. In Phase One, Grasslands would identify wind developers willing to make their output available to WSP Poolco for aggregation and firming services.[303] Noting that the full benefits of the WSP would be achieved only if wind power was acquired at diverse locations, Grasslands proposed that, if the project was oversubscribed by interested wind generators, it would prioritize applicants objectively based on:

1. projects that are being developed by experienced and creditworthy wind developers;

2. projects further along in the development process;

3. projects likely to be able to interconnect with the WSP Collector System at a reasonable cost; and

4. projects that are geographically dispersed.[304]

The FERC did not directly comment on this particular prioritization aspect of Grassland's proposal.

In Phase Two, Grasslands would provide public notice to potentially interested non-WSP Poolco generators and offer transmission rights on the WSP Collector System to those willing to participant-fund a share of the project at cost-based rates, with terms comparable to those provided to WSP Poolco.[305] Noting that the economics of the WSP, i.e., optimizing the profitability of wind generation for WSP wind generators, would not work if it was required to build a WSP collector system oversized relative to the initial demand, Grasslands proposed to reserve the right to decline to provide transmission services to non-WSP participants while still providing them an option of paying the full incremental cost of adding their projects to the system.[306]

The FERC denied Grasslands' proposal, finding that it granted preferential treatment to WSP Poolco participants and thus was inconsistent with section 205 of the FPA and the FERC's open access policies. Specifically, the FERC found

300. *Id.* at P 20.
301. *Id.* at P 3.
302. *Id.* at PP 5-6.
303. *Id.* at P 9.
304. *Id.* at P 10.
305. *Id.* at P 11.
306. *Id.* at P 12.

that the proposal created two classes of customers — (1) those who agree to take not only transmission service from WSP Transco, but also agree to take the aggregating and marketing service from WSP Poolco and balancing service from WSP Firmco, and (2) those who agree to take only transmission service — and granted undue preference to the former by guaranteeing only to them the right to receive preferential embedded cost rate treatment, as opposed to incremental cost rates.[307]

The FERC offered two suggestions for Grasslands to modify its proposal to comport with the FERC's open access policies. The first suggestion was to consider using an open season to identify potential customers (in addition to those interested in participating in WSP Poolco) interested in participant-funding the WSP collector system.[308] The second suggestion was to consider using clustering procedures to determine a set of facilities that would efficiently meet the needs of customer requests, which could include identification of a subset of customers for which embedded cost rates would be offered and those that would be charged incremental rates, provided the criteria used for distinguishing between classes of customer is nondiscriminatory and transparent.[309]

### *B. Incentive Rates*

#### 1. Great River Energy

Great River Energy (GRE) and the Midwest ISO requested approval of revisions to the Midwest ISO's Open Access Transmission, Energy, and Operating Reserve Markets Tariff (Tariff) and authorization from the FERC pursuant to sections 205 and 219 of the FPA for certain transmission rate incentives for three proposed transmission projects that are part of a comprehensive regional planning initiative by eleven utilities in the Midwest region known as the Transmission Capacity Expansion Initiative by the Year 2020 (CapX2020 Project).[310] The three CapX2020 projects for which GRE sought incentive rates include: (1) a 240-mile, 345 kV transmission line with a 10-mile, 230 kV line for which GRE will fund approximately $131 million of the total $794 million cost; (2) a 250-mile, 345 kV transmission line for which GRE will fund approximately $165 million of the total $659 million cost; and (3) a 68-mile, 230 kV transmission line for which GRE will fund $13 million of the total $102 million cost.

Specifically, GRE sought approval for recovery of 100% of prudently-incurred Construction Work in Progress (CWIP), recovery of 100% of prudently-incurred costs if a project is abandoned for reasons beyond GRE's control and a hypothetical capital structure of 20% equity and 80% debt.[311] The FERC held that despite GRE's status as a non-jurisdictional entity it has the statutory authority to consider and grant GRE's application because the FERC has the authority to consider whether non-jurisdictional rates are just and reasonable to the extent it is necessary to determine that jurisdictional rates —

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

308. *Id.* at P 22.

309. *Id.* at P 23.

310. *Great River Energy*, 130 F.E.R.C. ¶ 61,001 at PP 1, 4 (2010).

311. *Id.* at P 5.

here, Midwest ISO's rates — are just and reasonable.[312] GRE stated, and the FERC held, that GRE is entitled to the rebuttable presumption that the projects meet the incentive eligibility requirements because the projects have each received certificates of need from the Minnesota Public Utilities Commission.[313] The FERC also held that GRE met the requirements that there be a nexus between the incentives sought and the investment being made because the FERC had previously found that the projects are not routine and present special risks.[314] The FERC granted GRE's requested rate incentives and found that the proposed changes to its formula rate are just and reasonable, subject to certain modifications.[315]

2. Pioneer Transmission, LLC

On March 27, 2009, the FERC approved certain transmission rate incentives for Pioneer Transmission, LLC's (Pioneer) 765 kV transmission line in Indiana that will connect the transmission systems operated by PJM and the Midwest ISO.[316] On January 21, 2010, the FERC issued an order denying multiple requests for rehearing and granting clarification with respect to certain issues.[317]

Specifically, the FERC clarified that the FERC "approved the rate incentives for the Pioneer project that were addressed in the March 27 Order," but "did not 'approve' the project itself," and therefore, neither Pioneer's "authority to construct the project nor the timing of such construction is affected by the March 27 Order."[318] The FERC also clarified that certain of the incentives granted (i.e., ROE adder and recovery of 100% of construction work in progress) were explicitly conditioned "upon either the project being placed under operational control of PJM and Midwest ISO or upon the approval of the project by the regional transmission planning processes of PJM and Midwest ISO."[319]

The FERC stated that if the project is abandoned, it "will require Pioneer to make a showing in a section 205 filing that abandonment costs were prudently incurred, propose a rate and cost allocation method to recover the abandonment costs in a just and reasonable manner, and received authorization from the Commission for the recovery of its costs" and that customers that are concerned about their potential exposure to such costs may protest such filing.[320] The FERC also clarified that its "approval of incentives for the Pioneer project does not prejudge any other project, does not indicate a preference of one particular project over another, nor does it impact the tariff criteria by which PJM and/or Midwest ISO will evaluate the project(s)."[321] The FERC noted that any changes

312. *Id.* at P 25.
313. *Id.* at PP 7, 29.
314. *Id.* at PP 30-32.
315. *Id.* at PP 40-47.
316. *See* generally *Pioneer Transmission, LLC*, 126 F.E.R.C. ¶ 61,281 (2009) (Mar. 27 Order).
317. *Pioneer Transmission, LLC*, 130 F.E.R.C. ¶ 61,044 (2010).
318. *Id.* at P 19.
319. *Id.* at PP 19-20.
320. *Id.* at PP 20, 27.
321. *Id.* at P 21.

to the project through the regional planning processes "will not necessarily alter the basis upon which the Commission granted transmission incentives."[322] The FERC held that if a third party "believes that the Pioneer project has been modified in a manner that renders the basis for the transmission incentives . . . to be invalid, that entity may file a complaint under section 206 of the [Federal Power Act]."[323] Finally, the FERC clarified that "approval of the regulatory asset incentive is not a Commission assurance that the costs will be recovered in future rates, but only an indication that the Commission will allow the utility's authorized rates to include the relevant costs."[324]

3. Western Grid Development, LLC

Western Grid Development, LLC (Western Grid) requested a declaratory order "finding that its proposed energy storage device projects (Projects) are wholesale transmission facilities, as well as Commission approval of certain incentive rate treatments for the Projects under FPA section 219 and Order No. 679.[325] The Projects are energy storage devices using sodium sulfur batteries that will be constructed and operated at specific sites along the transmission system operated by the CAISO to "solve existing reliability problems at a lower cost than traditional transmission upgrades."[326] Given the manner in which Western Grid proposed to operate the Projects and the cost recovery proposals, the FERC found that the Projects would be wholesale transmission facilities subject to FERC jurisdiction.[327] The FERC granted approval for recovery of 100% of prudently-incurred CWIP, a fifty basis point ROE adder for participation in CAISO, a 100 basis point ROE adder for being a stand-alone transmission company, a forty-five basis point ROE adder (conditioned on approval in the CAISO transmission planning process and the overall ROE within the zone of reasonableness), creation of a regulatory asset to recover pre-commercial costs (conditioned on approval in the CAISO transmission planning process) and a hypothetical capital structure of 50% equity and 50% debt (conditioned on approval in the CAISO transmission planning process).[328]

The FERC denied approval for recovery of 100% of prudently-incurred costs for the Projects if they are abandoned for reasons outside of Western Grid's control, noting that "Western Grid has failed to adequately demonstrate that it faces adequate risk factors beyond its control that would endanger the completion of the Projects."[329] The FERC held that because Western Grid did not make "the necessary FPA section 219 demonstration that the Projects ensure reliability and/or reduce the price of delivered power by reducing congestion, we are conditioning the grant of the requested incentives on CAISO's approval of the Projects in its transmission planning process."[330] The FERC also held that

322. *Id.*
323. *Id.*
324. *Id.* at P 28.
325. *W. Grid Dev., LLC*, 130 F.E.R.C. ¶ 61,056 at P 1 (2010) (citations omitted).
326. *Id.* at PP 3-4.
327. *Id.* at P 43.
328. *Id.* at PP 81, 95-98, 102 & 105.
329. *Id.* at PP 87, 89.
330. *Id.* at P 16.

Western Grid met the requirements that there be a nexus between the incentives sought and the investment being made.[331]

4. Baltimore Gas & Electric Company

On May 29, 2009, the FERC authorized a 150 basis point ROE adder and an abandonment transmission rate incentive for the portion of the Mid-Atlantic Power Pathway (MAPP) owned by Baltimore Gas and Electric Company (BG&E).[332] On March 18, 2010, the FERC denied requests for rehearing of the May 29 Order filed by the Maryland Office of People's Counsel (OPC) and the Maryland Public Service Commission (PSC). Specifically, the FERC denied the OPC's request for rehearing that the project rates with the ROE adder will be excessive.[333] The FERC also denied OPC and PSC requests for rehearing based on the standard of review and rejected the OPC's argument that no incentives may be granted absent a showing that all four goals identified in section 219 of the FPA.[334] The FERC also found "that the cumulative effects of the 150-basis point ROE [adder], the abandonment incentive and the formula rate are not mutually exclusive but together will encourage investors to invest in transmission projects and particularly, this one."[335]

5. Primary Power, LLC

Primary Power, LLC (Primary Power), filed a petition for declaratory Order requesting approval of certain transmission rate incentives pursuant to FPA sections 205 and 219 and Order No. 679 and "seek[ing] assurances that it is eligible to propose and be designated to build a project under the PJM . . . Regional Transmission Expansion Plan (RTEP), and will thereby be eligible for cost-based rates."[336] The FERC granted in part and denied in part Primary Power's petition. FERC's order is discussed in Section III.E.1 above.

6. Public Service Electric and Gas Company

On March 13, 2009, the FERC granted Public Service Electric and Gas Company (PSEG) incentive rates, including a 150-basis point ROE adder, in connection with its portion of the Mid-Atlantic Power Pathway (MAPP) project, contingent on the project's approval as part of PJM's regional planning process.[337] On April 15, 2010, the FERC denied requests for rehearing of the March 13 Order filed by the Maryland OPC and the Maryland PSC. Among others, the FERC rejected arguments that it should have evaluated the rate incentive request with respect to PSEG's portion of the MAPP project (rather than the project as whole) and that it "should adopt standards for determining whether a project is routine or bears a sufficient nexus to the incentives being sought."[338]

331. *Id.* at P 107.

332. *Balt. Gas & Elec. Co.*, 127 F.E.R.C. ¶ 61,201 (2009) (May 29 Order).

333. *Balt. Gas & Elec. Co.*, 130 F.E.R.C. ¶ 61,210 at P 14 (2010).

334. *Id.* at PP 19-20, 27 & 39.

335. *Id.* at P 31.

336. *Primary Power LLC*, 131 F.E.R.C. ¶ 61,015 at P 1 (2010).

337. *Pub. Serv. Elec. and Gas Co.*, 126 F.E.R.C. ¶ 61,219 at PP 1-2 (2009) (Mar. 13 Order).

338. *Pub Serv. Elec. and Gas Co.*, 131 F.E.R.C. ¶ 61,028 at PP 15-17, 25 (2010).

7. Western Grid Development, LLC[339]

On January 21, 2010, the FERC granted Western Grid Development, LLC's (Western Grid) request for declaratory order, holding "that operation of its proposed sodium sulfur storage projects (Projects) in the manner it proposed would make the Projects wholesale transmission facilities, and conditionally granting the requested transmission rate incentives, with the exception of the abandoned plant incentive."[340] On October 12, 2010, the FERC rejected intervenors' requests for rehearing that battery storage facilities, like the Projects, cannot be considered transmission facilities.[341]

8. Southern California Edison Company[342]

Southern California Edison Company (SoCal Edison) filed a petition for declaratory order requesting FERC approval of certain rate incentives for two transmission projects under section 219 of the FPA and Order No. 679.[343] Specifically, SoCal Edison sought a 150-basis point ROE adder for one project and a 100-basis point ROE adder for the other project, recovery of 100% of CWIP in rate base, and recovery of 100% of prudently-incurred costs if a project is abandoned for reasons beyond SoCal Edison's control.[344] Despite SoCal Edison's arguments that the large generator interconnection study process provided sufficient basis to support the section 219 and Order No. 679 standard of review, the FERC held that SoCal Edison did not make sufficient showing that the projects would improve reliability or reduce the cost of delivered power by reducing congestion and declined to approve the requested incentives under Order No 679.[345] However, the FERC did approve the requested CWIP and abandoned plant incentives under its "inherent authority under section 205 of the FPA to allow rate treatments that promote public policy goals."[346]

9. The Nevada Hydro Company, Inc.

On March 24, 2008, the FERC granted The Nevada Hydro Company, Inc.'s (Nevada Hydro) request for certain transmission rate incentives for its proposed transmission line connecting San Diego Gas & Electric Company's (SDG&E) and Southern California Edison Company's (SoCal Edison) transmission systems (TE/VS Interconnect) and the Lake Elsinore Advanced Pump Storage project.[347] SDG&E, SoCal Edison, and Pacific Gas & Electric Company filed requests for rehearing arguing that the FERC "erred by: (1) directing Nevada Hydro to use a proxy group excluding utilities located outside of the WECC; and (2) mandating the use of an up-front ROE determination methodology in Nevada Hydro's subsequent FPA section 205 filing to implement rates for the TE/VS

339. *W. Grid Dev., LLC*, 133 F.E.R.C. ¶ 61,029 (2010).
340. *Id.* at P 1 (citing *W. Grid Dev., LLC*, 130 F.E.R.C. ¶ 61,056 (2010)).
341. *Id.* at PP 11-22.
342. *S. Cal. Edison Co.*, 133 F.E.R.C. ¶ 61,107 (2010).
343. *Id.* at P 1.
344. *Id.* at P 7.
345. *Id.* at PP 43-44.
346. *Id.* at P 62.
347. *The Nev. Hydro Co., Inc.*, 122 F.E.R.C. ¶ 61,272 (2008) (2008 Order).

Interconnect."[348] The FERC denied rehearing on both issues, clarifying that "Nevada Hydro will not be limited to using a region-wide proxy group" in a subsequent rate filing and the FERC does not require up-front ROE determinations in all cases and made no such determination with respect to Nevada Hydro's projects.[349]

10. Startrans IO, LLC

On March 31, 2008, the FERC granted Startrans IO, LLC (Startrans), certain transmission rate incentives and accepted Startrans' proposed ROE.[350] On November 18, 2010, the FERC denied request for rehearing, but clarified it is "not mandating the use of regional proxy groups in this or in other cases" and its "decision to make an up-front ROE determination will depend on the facts and circumstances of individual cases."[351]

11. Potomac-Appalachian Transmission Highline, LLC

On February 29, 2008, the FERC granted Potomac-Appalachian Transmission Highline, LLC's (PATH) incentive rate treatment pursuant to Order No. 679 for its transmission project and set PATH's proposed formula rate for hearing and settlement judge procedures.[352] On November 19, 2010, the FERC granted in part and denied in part requests for rehearing and set PATH's proposed ROE for hearing and settlement judge procedures.[353] The FERC granted requests for rehearing finding that PATH's proposed ROE should be set for a full evidentiary hearing because the "parties raised several issues of material fact" that "could not be decided based on the written record."[354] The FERC generally denied requests for rehearing relating to the incentives granted, but clarified that the project was entitled to a 200-basis point ROE adder.[355] The FERC also approved the proposed offer of settlement regarding PATH's formula rate that had previously been set for hearing.[356]

12. PJM Interconnection, LLC

PJM submitted for PSEG a request pursuant to sections 205 and 219 of the FPA for transmission rate incentives for four projects.[357] Specifically, PSEG sought recovery of 100% of construction work in progress, recovery of 100% of prudently-incurred costs if any project is abandoned for reasons beyond PSEG's control, as well as authority to assign the incentives to an affiliate if a project is assigned to such affiliate.[358] The FERC held that each project satisfied Order No. 679's rebuttable presumption that the section 219 requirements are met

348. *The Nev. Hydro Co., Inc.*, 133 F.E.R.C. ¶ 61,155 at P 4 (2010).

349. *Id.* at P 1.

350. *Startrans IO, LLC*, 122 F.E.R.C. ¶ 61,306 (2008).

351. *Startrans IO, LLC*, 133 F.E.R.C. ¶ 61,154 at P 1 (2010).

352. *Potomac-Appalachian Transmission Highline, LLC*, 122 F.E.R.C. ¶ 61,188 (2008).

353. *Potomac-Appalachian Transmission Highline, LLC*, 133 F.E.R.C. ¶ 61,152 at P 2 (2010).

354. *Id.* at P 55.

355. *Id.* at PP 80-89.

356. *Id.* at P 98.

357. *PJM Interconnection, LLC*, 133 F.E.R.C. ¶ 61,273 at P 1 (2010).

358. *Id.* at P 1.

because each project has been "vetted and approved" as part of PJM's regional planning process.[359] However, the FERC clarified that "in this and future cases involving application of Order No. 679 the Commission will require each applicant to demonstrate that there is a nexus between the incentive sought and the specific investment being made" and found that PSEG had "provided insufficient information for the Commission to determine if each project meets the nexus requirement."[360] The FERC "den[ied] the requested incentives without prejudice to [PSEG] refiling to demonstrate how each project meets the nexus requirement."[361]

### *C. Negotiated Rates*

#### 1. Tres Amigas

In a March 18, 2010 Order, the FERC granted the request of Tres Amigas, LLC (Tres Amigas) to sell transmission service on the project at negotiated rates,[362] subject to a number of conditions designed to ensure that the goals of open access are protected and that rates for transmission service on its project remain just and reasonable. The Tres Amigas Superstation is designed to be a three-way alternating current/direct current transmission interconnection superstation in Clovis, New Mexico, that will link the Eastern Interconnection, ERCOT, and the Western Electric Coordinating Council.[363] The March 18 Order evaluated Tres Amigas' request for negotiated rate authority pursuant to the approach explained in detail in *Chinook Power Transmission, LLC*[364] In *Chinook*, the FERC refined and clarified its methodology for evaluating merchant transmission provider requests for negotiated rate authority to focus on the following four areas of concern: "(1) the justness and reasonableness of rates; (2) the potential for undue discrimination; (3) the potential for undue preference, including affiliate preference; and (4) regional reliability and operational efficiency requirements."[365] The FERC found that Tres Amigas had demonstrated that it met these criteria, subject to its abiding by the commitments made in its pleadings, including the following:

1. Tres Amigas would file an OATT (setting forth the terms of the open season) and establish an OASIS prior to holding its first open season;

2. Tres Amigas and its owners and affiliates would not sell power that is delivered through the project without first obtaining the FERC's approval;

3. Tres Amigas would seek FERC authorization before permitting purchasers of transmission service on the project or any utility with captive customers to acquire an equity interest in Tres Amigas; and

4. Tres Amigas would expand its facilities at cost-based rates (if the market would not support an upgrade on a merchant basis).366

359. *Id.* at P 41.

360. *Id.* at PP 45-46.

361. *Id.* at P 49.

362. *Tres Amigas LLC*, 130 F.E.R.C. ¶ 61,207 (2010).

363. *Id.* at P 4.

364. *Chinook Power Transmission, LLC*, 126 F.E.R.C. ¶ 61,134 (2009).

365. *Id.* at P 37.

366. *Tres Amigas LLC*, 130 F.E.R.C. ¶ 61,207 at P 80.

The FERC also granted Tres Amigas's request to allocate 50 percent of its initial capacity to anchor customers, subject again to a number of conditions, including:

- Tres Amigas must offer "the same rate and terms as the anchor shipper received to any customer in an open season willing to commit to the same terms, consistent with Chinook;"
- Tres Amigas must seek FERC authorization for the anchor customer transaction in a subsequent section 205 filing;
- Tres Amigas must not withhold any capacity (it had proposed to withhold 20% of the project's initial capacity) that is not committed to an anchor customer during the open season process; and
- Tres Amigas must seek approval of its open season through the filing of an independently audited post-open season report to ensure the overall allocation of initial capacity was conducted in a fair, open, and nondiscriminatory manner.[367]

In its Order on Motion for Clarification,[368] the FERC clarified that Tres Amigas' obligation to offer the anchor customer rates and terms to non-anchor customers need not be open-ended but could be offered on a one-time basis, provided that the one-time offer satisfies the FERC's fair, open, and non-discriminatory requirements.

2. SunZia Transmission

In a May 20, 2010 Order,[369] the FERC denied the request of SunZia Transmission, LLC (SunZia), for (1) allocation of firm transmission rights to some owners of the proposed project and (2) negotiated rate authority. SunZia's proposed project is for two 500 kV transmission lines running 460 miles from New Mexico to Arizona, with an expected capacity of 3,000 or 4,500 MW.[370]

In denying SunZia's request that each SunZia owner be allocated firm transmission rights representing 100% of its pro rata investment in the project's transmission capacity, the FERC disagreed with SunZia that owners could enjoy exclusive firm transmission service rights based on the project's use of participant funding.[371] Rather, the FERC stated that each owner must provide access to firm transmission service rights on their respective allotted portion of the project consistent with Order No. 888 and the FERC's open access policies.[372]

Similarly, the FERC denied SunZia's request that three of the owners be authorized under the FERC's generator tieline precedents to use up to 100% of their pro rata share of capacity on the project to serve affiliated generators that are qualifying facilities (QFs) or eligible facilities of exempt wholesale generators (EWGs).[373] The FERC explained that the project, with its multiple points of interconnection, could not be considered a generator tieline for some

367. *Id.* at PP 61, 88.

368. *Tres Amigas LLC*, 131 F.E.R.C. ¶ 61,281 at P 14 (2010).

369. *SunZia Transmission, LLC*, 131 F.E.R.C. ¶ 61,162 (2010).

370. *Id.* at P 2.

371. *Id.* at P 24.

372. *Id.*

373. *Id.* at PP 33-34.

affiliates while simultaneously serving as a network transmission facility for one owner and a transmission line providing service to other owners' anchor customers.[374]

Finally, the FERC denied SunZia's request for negotiated rates, finding that the proposal failed the first three prongs of *Chinook*'s four prong test. First, the FERC found that the proposal failed the "just and reasonable rates" prong because the owners did not demonstrate that they would hold a fair, open, and transparent open season for the initial allocation of capacity.[375] Second, although the FERC refused to address whether the 50% pre-subscription amount approved in *Chinook* should be considered a ceiling, it found that SunZia's request that certain owners be allowed to allocate up to 100% of their respective shares of project capacity to anchor customers through negotiated rate agreements violated the "undue discrimination" prong.[376] The FERC further disapproved of the absence of SunZia's commitment to offer the same terms found in agreements with anchor customers to customers seeking capacity in an open season.[377] Third, the FERC found that the proposal that certain SunZia owners be allowed to make all of their capacity available for use by affiliated generation in the region violated the "undue preference and affiliate concerns" prong of *Chinook*.[378] The petition was denied without prejudice to SunZia modifying its proposal to conform to FERC precedents and policy regarding open access to transmission service.[379]

## IV. CORPORATE ACTIVITIES

### *A. PPL Acquisitions*

PPL Corporation (PPL) requested the FERC's approval under FPA § 203[380] of its acquisition of all E.ON U.S. indirect limited liability company interests in the two regulated utilities (Louisville Gas & Electric Co. (LG&E) and Kentucky Utilities Co. (KU)), in certain merchant generation and a power marketer. The merger adds 8,000 MW of mostly coal-fired generation to PPL's existing generating fleet of 12,000 MW, and adds 900,000 customers to the 1.4 million to which it provides distribution service in Pennsylvania. The acquisition is valued at $7.6 billion.[381] Applying the three-part standard established in its 1990s Merger Policy Statement,[382] the FERC concluded that the proposed transaction was in the public interest as it would not improperly affect competition or service rates, or adversely affect FERC or state regulation.[383]

374. *Id.* at P 34.

375. *Id.* at P 42.

376. *Id.* at PP 53, 57 & 61.

377. *Id.* at P 58.

378. *Id.* at P 53.

379. *Id.* at P 61.

380. 16 U.S.C. § 824b (2006); *PPL Corp. & E.ON US, LLC*, 133 F.E.R.C. ¶ 61,083 (2010).

381. *PPL Corp.*, 133 F.E.R.C. ¶ 61,083 at PP 2-6 (2010).

382. *See generally* Order No. 592, *Inquiry Concerning the FERC's Merger Policy Under the FPA: Policy Statement*, F.E.R.C. STATS. & REGS. ¶ 31,044 (1996), 61 Fed. Reg. 68,595 (1996) (to be codified at 18 C.F.R. pt. 2), *reh'g denied*, Order No. 592, 79 F.E.R.C. ¶ 61,321 (1997); *FPA Section 203 Supplemental Policy Statement*, F.E.R.C. STATS. & REGS. ¶ 31,111 (2000).

383. *PPL Corp.*, 133 F.E.R.C. ¶ 61,083 at PP 11-34.

In particular, horizontal competition was not affected as no competitor was eliminated from any market and further as the effect on market concentration was de minimis (i.e., Herfindahl-Hirschman Index (HHI) values increased by only between 45-61 points, less than the 100 point minimum specified in the Policy Statement). This resulted from the fact that PPL generation is largely in PJM, whereas LG&E/KU serve in parts of the Midwest not in the PJM footprint. Vertical market power is not present as both PPL and LG&E/KU transmission are operated by independent transmission operators (i.e., PJM & SPP), owned natural gas facilities are not connected to generation or are regulated as common carriers, and rail equipment is used only to serve owned generating plants.[384] Applicants committed to hold transmission and wholesale customers harmless from costs related to the transaction for five years, and, after imposing special filing requirements should Applicants seek to revise this commitment, the FERC concluded that no adverse effect on rates would occur. The FERC also determined that no adverse effect on its or state regulator jurisdiction would occur, and that no cross-subsidization or encumbrance of utility assets for the benefit of an associate company would occur. [385]

### *B. First Energy Corp. & Alleghany Energy, Inc.*

First Energy owns seven electric utility operating companies serving 4.7 million customers in restructured, competitive markets within or soon to be within the PJM RTO.[386] Its generation subsidiaries control approximately 14,800 MW whose output is sold at market-based rates. Allegheny delivers electric service to 1.5 million customers employing 7000 MW of generation through subsidiaries in four states, two of which have restructured competitive markets (Pennsylvania & Maryland) and two of which provide bundled, regulated service (Virginia & West Virginia). The transaction, with a value of $8.5 billion, has First Energy acquiring Alleghany as a subsidiary through a stock for stock transaction. As both First Energy and Alleghany primarily provide service in PJM, the merger's potential to increase horizontal market power was analyzed. Applicants performed a Delivered Price Test Analysis of Economic and Available Economic Capacity which showed that in three of ten market analyses performed "screen failures" occurred, i.e., the market was shown to be impermissibly concentrated under the FERC's Merger Policy Statement standards. The FERC, however, concluded, over consumer interest protests, that "there is no indication that the proposed transaction will create or enhance Applicants' ability to exercise market power", explaining as follows:

> Applicants have shown that there are three screen failures in this case out of the ten time periods. They occur in off-peak periods where Applicants have relatively low market shares involving comparatively small HHI increases. While we have stated that as a general matter off-peak screen failures should not be disregarded, they do not by themselves establish that a proposed transaction will adversely affect competition. Our concern normally is with cases in which there are systematic screen failures, i.e., failures that "present a consistent pattern across time periods

384. *Id.* at PP 11-19.

385. *Id.* at PP 20-34.

386. *First Energy Corp.*, 133 F.E.R.C. ¶ 61,222 at PP 2-27 (2010).

> and/or markets," in markets that are highly concentrated, and where the entity seeking the approval has a significant share of the market.[387]

The FERC went on to note that market concentrations as measured by the HHI barely exceeded the Merger Policy Statement's minimum 1000 level to indicate undesired concentration (i.e., ranging from 1000 to 1059) and with HHI increases from the transaction generally (but not always) below the minimum 100 level.[388]

Accordingly, and as provided for in the Statement, the FERC held that screen violations in this case did not indicate the creation or presence of impermissible horizontal market power. Vertical market power was also missing, the FERC noted, as neither First Energy nor Alleghany owned significant generation inputs (such as natural gas or other fuels) and as each company's transmission was controlled by the FERC-approved RTOs or Independent Transmission Operators. [389] As with PPL, Applicants committed to hold transmission and wholesale customers harmless from costs related to the transaction for five years, and, after imposing special filing requirements should Applicants seek to revise this commitment, the FERC concluded that no adverse effect on rates would occur. The FERC also determined that no adverse effect on its or state regulator jurisdiction would occur, and that no cross-subsidization or encumbrance of utility assets for the benefit of an associate company would occur.[390] The merger has also been approved by state regulators in Pennsylvania, Maryland, and West Virginia.[391]

### *C. Northeast Utilities Inc. & NStar Inc.*

In October, a third merger between regulated energy service providers was announced. NStar and Northeast Utilities are both located in New England with six electric and gas distribution subsidiaries serving 3.5 million customers in Massachusetts, New Hampshire, and Connecticut.[392] NStar and Northeast Utilities filed an application with the FERC on January 7, 2011, for authorization and approval of a two-step merger transaction by which NSTAR will become a

---

387. *Id.* at P 49.

388. *Id.* at PP 48-55.

389. *Id.* at PP 56-57.

390. *Id.* at PP 58-70.

391. Commission Order, *Monongahela Power Co.*, No. 10-07-13-E-PC (W.Va. Pub. Serv. Comm'n Dec. 16, 2010). The Maryland PSC required as conditions of its approval that estimated merger savings of $6.5 million be credited against current customer service rates, that over $1 million of contributions be made to Maryland universal service and energy efficiency programs, that one or more renewable energy projects with output of 13,000 MWH per year be placed in service in Maryland within forty-five months of the merger and that a regional headquarters staffed by a regional president be maintained in Maryland. Order No. 83788, *In re the Application of the Merger of FirstEnergy Corp. and Allegheny Energy, Inc.*, No. 9233 (Md. Pub. Serv. Comm'n Jan. 18, 2011), *available at* http://webapp.psc.state.md.us/Intranet/Casenum/CaseAction_newcfm?CaseNumber+9233. On February 24, 2011, by a 3-2 vote, the PA PUC approved the merger subject to a number of conditions including that a statewide investigation be initiated to ensure that a properly functioning and workable competitive electricity market exists in the state. Press Release, PUC, PUC Approves Merger of Allegheny Power, TRAILCO and First Energy (Feb. 24, 2011), *available at* http://www.puc.state.pa.us/General/press_releases/Press_Releases.asp?ShowPR+2727.

392. Press Release, Ne. Utilities, Northeast Utilities and NSTAR Agree to $17.5 Billion Merger of Equals, Forming New England's Premier Utility (Oct. 18, 2010), *available at* http://www.nu.com/media/news_netscape.asp.

wholly-owned subsidiary of Northeast Utilities in Docket No. EC11-35-000, and must also obtain approval from the Massachusetts DPU.[393]

### *D. Mirant & RRI and Dynegy*

In separate transactions, merchant generators Mirant Corp. and RRI Energy, Inc. combined in December to form GenOn Energy, Inc., and Dynegy Corp. agreed to be acquired by two different investment groups. The FERC approved the Mirant/RRI merger.[394] To evaluate horizontal market power concerns, Applicants performed a delivered price test using economic and installed capacity and further studied market concentration in capacity and ancillary services markets where their operations overlapped, i.e., PJM and CAISO. In PJM, Applicants generation constitutes only 7.4% of total resources and the effect of their merger did not exceed an 88 point increase in the HHI (in most sub-markets less than 30 points) which is below the minimum threshold for concern of 100 points defined in the Merger Policy Statement. In CAISO, Applicants own 9.35% of generation and the merger causes at most a 41 point increase in the HHI, again below the minimum threshold.

The FERC determined that the merger raised no issues of vertical market power as Applicants own no transmission or significant fuel supply infrastructure, that rates will not be affected in light of Applicants primary sales at market based rates and 5-year hold harmless commitment, that its and state regulator jurisdiction will not be adversely affected, and that no cross-subsidization will occur as the result of the merger.[395]

With respect to Dynegy, it agreed in August to be acquired by Blackstone Group in a $4.7 billion deal, who would then sell one third of Dynegy's generation to NRG Energy. Although approved by the FERC,[396] the transaction was rejected by Dynegy shareholders in a November vote as providing insufficient compensation for the assets acquired. In December, a new agreement was signed with a major shareholder, Icahn Enterprises, providing for acquisition at a higher price per share, but permitting Dynegy to pursue superior all-cash offers until January 24. The transaction remains pending.[397]

### *E. Ameren, Constellation/EDF & Entergy*

In June 2010, the FERC approved a request from Ameren Corp. that its three utility subsidiaries (Ameren CILCO, Ameren IP, & Ameren CIPS) be combined into a single Company (Ameren Illinois Company). Ameren explained that the combination would reduce costs and ensure continued high quality customer service through consolidation of separate operations. Ameren

---

393. NSTAR, Application of NSTAR and Northeast Utilities and Their Respective Public Utility Subsidiaries Under Sections 203(a)(1) and 203(a)(2) of the Federal Power Act for Authorization of Disposition of Jurisdictional Assets and Merger, No. EC11-35-000 (FERC Jan. 7, 2011).

394. *Mirant Corp.*, 132 F.E.R.C. ¶ 61,096 at PP 15-26 (2010).

395. *Id.* at PP 27-35.

396. *Dynegy Inc.*, 133 F.E.R.C. ¶ 62,107 (2010).

397. Press Release, Dynegy, Dynegy Enters into Agreement to Be Acquired by Icahn Enterprises LP for $5.50 Per Share in Cash (Dec. 15, 2010), *available at* http://phx.corporate-ir.net/phoenix.zhtml?c=147906&p=RssLanding&cat=news&id=1507915; Jeffrey Ryser, *Icahn Makes $5.50/Share Bid for Dynegy; Analyst Reaction Mixed*, ELECTRIC POWER DAILY, Dec. 16, 2010.

UE also changed its name to Ameren Missouri. In August, as part of a request for incentive rate treatment on $3 billion of planned transmission investment to improve reliability, reduce congestion, and permit interconnection of up to 25,000 MW of wind generation, Ameren advised of the creation of Ameren Transmission Company of Illinois which would exclusively focus on owning and developing a major new transmission system that will quadruple Ameren transmission investment once completed.[398]

### *F. Generation, Transmission & Other Acquisitions*

Numerous smaller distribution business sales and generation or transmission plant acquisitions also occurred in 2010. For example, in Maine, Emera Inc., the owner of Bangor Hydro-Electric and Nova Scotia Power, has acquired Maine Public Service, a small distributor in northernmost Maine which is not interconnected with the U.S. grid. In addition, Southwestern Electric Power Co. has purchased the transmission and distribution assets of Valley Electric Membership, a Louisiana cooperative, thereby doubling the size of its service territory in Louisiana.[399] In two other transactions, the FERC approved the sale and transfer of a specific transmission plant and nine generation facilities.[400]

In 2010, the FERC also approved PEPCO Holdings sale of the fossil generation fleet of its Delaware subsidiary and former utility, Connective Energy (4,490 MW for $1.65 billion), to Calpine Corporation;[401] Exelon Corporation's acquisition of 966.5 MW of wind energy resources from John Deere Renewables;[402] and Constellation Holdings' acquisition of 2,154 MW of generation from Boston Generating.[403] Finally, two retail power marketers were sold during the year, with NRG Company acquiring Green Mountain Energy[404] and Sempra Energy transferring its retail marketer to Noble Americas Energy Solutions.[405]

## V. RESOLUTION OF WESTERN ELECTRICITY MARKETS

Four principal activities occurred in the FERC's efforts in 2010 to complete enforcement and refund proceedings respecting the 2000-01 California energy crisis. First, an additional four settlements were approved between California parties seeking refunds and generators participating in the markets in that

398. *Ameren Corp.*, 131 F.E.R.C. ¶ 61,240 (2010); Letter from Alan J. Statman, Counsel, Ameren Services Co., to Kimberly D. Bose, Secretary, FERC (Aug. 2, 2010), *available at* http://www.windforillinois.org/storage/ATX%20FERC%20Filing%20package.pdf.

399. *BHE Holdings Inc.*, 133 F.E.R.C. ¶ 61,231 (2010); *Sw. Elec. Power Co.*, 132 F.E.R.C. ¶ 62,148 (2010); Mary Powers, *Australian Group Sells Duquesne Interest to Singapore Entity*, ELECTRIC POWER DAILY, Dec. 7, 2010; Lisa Wood, *National Grid Sells N.H. Units to Canadian Concern*, ELECTRIC POWER DAILY, Dec. 10, 2010.

400. *ITC Midwest LLC*, 133 F.E.R.C. ¶ 61,169 (2010); *Am. Transmission Co.*, 130 F.E.R.C. ¶ 62,153 (2010).

401. *New Dev. Holdings, LLC*, 131 F.E.R.C. ¶ 62,266 (2010).

402. *Exelon Corp.*, 133 F.E.R.C. ¶ 62,174 (2010).

403. *Fore River Dev., LLC*, 133 F.E.R.C. ¶ 61,248 (2010).

404. *Green Mountain Energy Co.*, 133 F.E.R.C. ¶ 62,082 (2010).

405. *Sempra Energy Solutions LLC*, 133 F.E.R.C. ¶ 62,083 (2010).

period.[406] An additional approximate $350 million was made available for refund.[407]

Second, an ALJ Initial Decision was issued adjudicating whether additional refunds were required under the terms of the Ninth Circuit Court of Appeals Remand in *State of California ex rel. Lockyer v. FERC*.[408] The Court had held that market-based rates were permissible under the FPA but only when supported by the FERC's requirement of pre-approval to assure the absence of market power and adequate post-approval reporting of actual transactions. The Complaint alleged, among other things, that generators failed to comply with the FERC's required post-approval reporting, and that if such reports had been filed they would have shown the market prices to be unjust and unreasonable due to sellers' accumulation of undue market power following the FERC's pre-approval Order, and thus refunds to be required.

In its remand Order, the FERC directed the ALJ to examine in an evidentiary hearing whether "any individual public utility seller's violation of the FERC's market-based rate quarterly reporting requirement led to an unjust and unreasonable rate for that particular seller in California during the 2000-2001 period."[409] The Initial Decision concludes that, while there may have been violations of the reporting requirements, no actual accumulation of market power occurred, and thus no further refunds are proper. Accordingly, it grants generators' requested summary disposition of the Complaint.[410] The FERC itself has not yet acted upon this matter.

Third, in late 2009, the FERC issued an *Order on Remand* in response to the Ninth Circuit's remand in *Public Utility Commission of the State of California v. FERC.*[411] The Court there ruled that the FERC had erred in failing to provide in its enforcement proceedings a "market-wide refund remedy" for transactions occurring prior to October 2, 2000, and for excluding "block forward market transactions" and "energy exchange transactions" from refund entitlements. The FERC responded by establishing a second evidentiary hearing before an ALJ to examine if further refunds were proper for these periods and

406. The four principal proceedings initiated by the FERC to investigate and value refund entitlements to which these settlements relate and the history of their prosecution are described in prior Committee Reports. As there noted, most generator specific proceedings have ended by settlement with over $6 billion returned to ratepayers. *See Report of the Electricity Regulation & Compliance Committee*, 31 ENERGY L.J. 221, 260-261 (2010).

407. *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Servs.*, 131 F.E.R.C. ¶ 61,082 (2010); *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Servs.*, 131 F.E.R.C. ¶ 61083 (2010); *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Servs.*, 131 F.E.R.C. ¶ 61,259 (2010); *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Servs.*, 133 F.E.R.C. ¶ 61,249 (2010).

408. Cal. Pub. Utils. Comm'n v. FERC, 383 F.3d 1006 (9th Cir. 2004), *cert denied*, Coral Power, LLC v. Cal. ex rel. Brown, 551 U.S. 1140 (2007).

409. *Cal. ex rel. Lockyer v. B.C. Power Exch. Corp.*, 122 F.E.R.C. ¶ 61,260 at P 32 (2008).

410. *Cal. ex rel. Lockyer v. B.C. Power Exch. Corp.*, 130 F.E.R.C. ¶ 63,017 (2010) (Initial Decision). In evaluating the presence of undue market power, the FERC directed use of the hub and spoke analysis method used for this purpose during the period rather than more sophisticated evaluation methods used today, and particularly whether a 20% generation market share threshold was reached. The FERC also rejected requests of the California Parties to address broader issues and possible causes of unjust and unreasonableness in market prices as a part of this evidentiary analysis. *See* Initial Decision at PP 6-21.

411. Cal. Pub. Utils. Comm'n v. FERC, 462 F.3d 1027 (9th Cir. 2006). For a full description of this decision, *see Report of the Electricity Regulation Committee*, 28 ENERGY L.J. 269, 333-334 (2007).

transactions, but directed that the hearing be held in abeyance to provide time for settlement efforts.[412] The FERC ruled that only violations of then existing tariff rules and laws could be the basis of further refunds, and provided a listing of improper activities prohibited at that time if not pursued for legitimate business purposes which were to be examined. California Parties filed a *Request for Rehearing and Clarification* in which they requested that no advance limitation be placed upon what could be considered improper activities for evidentiary examination, and further that refunds be permitted from improper market prices whether caused by a particular sellers activity or that of other sellers (who may have previously settled and no longer be subject to refund orders) for all market transactions.[413]

By mid-2010, no progress had been made in settling the additional, potential refund liabilities created by the Court's remand and the Chief ALJ initially ordered that hearing procedures initiate, but then suspended such procedures temporarily "until the Commission determines the scope of the issues and the parties to the case" which would only occur once the rehearing petitions were decided.[414] On September 7, 2010, the FERC issued a *Supplemental Order Soliciting Comments* in which it provided potential parties to the evidentiary hearing a further opportunity to advise it of their positions on what issues should be addressed in the evidentiary hearing.[415] The FERC has yet to issue a further order clarifying these matters.

Fourth, the FERC has issued several orders denying rehearing requests respecting individual generator settlements[416] and several other matters but most significantly its June 2009 adjudication of requests for cost offsets from potential refunds by sellers under its adopted Mitigated Market Clearing Price methodology.[417] Also, in April, the Cal-ISO submitted its Updated Compliance Report on the methods used to calculate refund amounts and obligations.[418]

412. *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Servs.*, 129 F.E.R.C. ¶ 61,147 (2009).

413. Order on Remand, *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Servs.*, Docket No. EL00-95-184 (FERC Dec. 22, 2009); California Parties' Comments on the Scope of this Proceeding, *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Servs.*, No. EL00-95-236 (FERC Sept. 22, 2010).

414. Order of Chief Judge Ending Stay of Litigation, Continuing Settlement Judge Procedures, Designating Presiding Administrative Law Judge, and Instituting Track II Procedural Time Standards, *San Diego Gas & Electric Co. v. Sellers of Energy & Ancillary Servs.*, Nos. EL00-95-184 & EL00-95-248 (FERC July 16, 2010); Order of Chief Judge Temporarily Suspending Modified Track II Procedures, *San Diego Gas & Electric Co. v. Sellers of Energy & Ancillary Servs.*, Docket No. EL00-95-248 (FERC Aug. 19, 2010).

415. Supplemental Order Soliciting Comments, *San Diego Gas & Electric Co. v. Sellers of Energy & Ancillary Servs.*, 132 F.E.R.C. ¶ 61,209 (2010).

416. *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Servs.*, 130 F.E.R.C. ¶ 61,199 (2010); *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Servs.*, 130 F.E.R.C. ¶ 61,198 (2010); *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Servs.*, 130 F.E.R.C. ¶ 61,197 (2010); *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Servs.*, 130 F.E.R.C. ¶ 61,183 (2010). These Orders generally rejected assertions that the settlement process and particularly treatment of non-settling municipal interests to whom refund liabilities and entitlements were netted was improper and discriminatory.

417. *See San Diego Gas & Electric Co. v. Sellers of Energy & Ancillary Servs.*, 131 F.E.R.C. ¶ 61,144 (2010); *San Diego Gas & Electric Co. v. Sellers of Energy & Ancillary Servs.*, 131 F.E.R.C. ¶ 61,062 (2010) (i.e., designation of Arizona Elec. Power Coop. as a non-public utility for refund purposes).

418. Updated Compliance Report of the Cal-ISO Concerning Preparatory Rerun Activity, *San Diego Gas & Electric Co. v. Sellers of Energy and Ancillary Servs.*, No. ER03-746-000 (FERC Apr. 16, 2010).

## VI. PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 (PURPA) DEVELOPMENTS

### *A. Termination of Purchase Obligations*

On April 15, 2010, the FERC granted an application under PURPA section 210(m)[419] by Detroit Edison Company (Detroit Edison) for termination of its PURPA obligation to enter into new power purchase contracts to purchase electric energy and capacity from QFs with net capacity in excess of 20 MW (Large QFs) for Detroit Edison's interconnected system under the control of the Midwest ISO.[420] PURPA section 210(m) provides for termination of PURPA mandatory purchase requirement if the FERC finds that the QFs have nondiscriminatory access to markets, and the FERC's regulations establish a rebuttable presumption that the markets administered by the Midwest ISO provide QFs with non-discriminatory access to markets. The application relied on this rebuttable presumption, and no party to the docket attempted to rebut the presumption.[421]

On March 18, 2010, the FERC granted in part and denied in part an application under PURPA section 210(m) by New York Electric & Gas Corporation and Rochester Gas and Electric Corporation for termination of their PURPA obligation to enter into new power purchase contracts to purchase electric energy and capacity from Large QFs for the applicants' interconnected system under the control of the NYISO.[422] The FERC's regulations establish a rebuttable presumption that the markets administered by NYISO provide Large QFs with non-discriminatory access to markets, and the application relied on this rebuttable presumption.[423] Based on that rebuttable presumption, the FERC granted the application with respect to all Large QFs with the exception of Cornell University (Cornell).[424] The FERC found that Cornell had successfully rebutted the presumption by demonstrating that Cornell is effectively denied nondiscriminatory access to NYISO's markets by virtue of the demonstrated high variability in the need for Cornell's thermal output and the manner in which NYISO's markets operate; specifically, with respect to penalties for under-generation associated with variability from bids in the day-ahead market that are waived for some resources but not for Cornell.[425]

On April 15, 2010, the FERC granted in part and denied in part an application under PURPA section 210(m) by Public Service Company of New Hampshire (PSNH) for termination of its PURPA obligation to enter into new power purchase contracts to purchase electric energy and capacity from Large QFs and from QFs with a net capacity of 5 MW through 20 MW for PSNH's interconnected system under the control of the ISO-NE.[426] The FERC's

419. Public Utility Regulatory Policies Act of 1978, 16 U.S.C. § 824a-3(h) (2006).

420. *Detroit Edison Co.*, 131 F.E.R.C. ¶ 61,039 (2010).

421. *Id.* at PP 15-18.

422. *N.Y. State Electric & Gas Corp. and Rochester Gas and Electric Corp.*, 130 F.E.R.C. ¶ 61,216 (2010).

423. *Id.* at P 4.

424. *Id.* at P 16.

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

426. *Pub. Serv. Co. of N.H.*, 131 F.E.R.C. ¶ 61,027 (2010).

regulations establish a rebuttable presumption that the markets administered by ISO-NE provide Large QFs with non-discriminatory access to markets, and the application relied on that rebuttable presumption.[427] Based on that rebuttable presumption, the FERC granted the application with respect to all Large QFs.[428] The FERC's regulations also establish a rebuttable presumption that QFs with net capacity less than or equal to 20 MW do not have nondiscriminatory access to markets. The FERC rejected PSNH's attempt to rebut this latter presumption because PSNH attempted to show generally that all QFs with net capacity of 5 MW or more have access to ISO-NE's markets rather than make facility-specific showings with respect to individual QFs as required by Order No. 688; consequently, the FERC denied without prejudice PSNH's application with respect to QFs with net capacity from 5 MW through 20 MW.[429] At 2010 year end the case was pending on rehearing.

### *B. CPUC Declaratory Order*

The California Public Utilities Commission (CPUC) filed a petition for declaratory order requesting that the FERC find that sections 205 and 206 of the FPA,[430] section 210 of PURPA,[431] and Commission regulations do not preempt the CPUC's decision (referred to as its AB 1613 Decision) to require California utilities to file feed-in tariffs and offer ten-year contracts at a certain price to combined heat and power (CHP) generating facilities of 20 MW or less that meet energy efficiency and environmental compliance requirements. Feed-in tariffs encourage certain types of generation resources by offering a guaranteed purchase price for electricity generated from those resources under a long-term contract. The CPUC took this action in response to an amendment to California law requiring utilities to buy power from CHPs to reduce greenhouse gas emissions. Three utilities (Joint Utilities) regulated by the CPUC filed a separate petition for declaratory order arguing that the CPUC's action is preempted by the FPA to the extent the CPUC is setting rates for wholesale sales of electric energy. The two proceedings were consolidated. The petitions were granted and denied, in part, as the FERC held that under certain conditions the CPUC's decision is not preempted by the FPA, PURPA, or Commission regulations.

The FERC held that the CPUC's decision and feed-in tariff proposal is not preempted by the FPA, PURPA, or Commission regulations as long as: (1) the CHP generators from which the CPUC is requiring the Joint Utilities to purchase energy and capacity are QFs pursuant to PURPA; and (2) the rate established by the CPUC does not exceed the avoided cost of the purchasing utility.[432] The FERC also held that if a CHP generator is not a QF, the CPUC's action is not preempted by the FPA if the CPUC is only ordering the utilities to purchase capacity and energy from certain resources, but the CPUC's action is preempted

---

427. *Id.* at P 4.

428. *Id.* at P 16.

429. *Id.* at PP 20-22.

430. 16 U.S.C. §§ 824d-824e (2006).

431. *Id.* § 824a-3; *see generally id.* §§ 2601-2603.

432. *Cal. Pub. Utils. Comm'n*, 132 F.E.R.C. ¶ 61,047 (2010); *order granting clarification and dismissing reh'g*, 133 F.E.R.C. ¶ 61,059 (2010).

if the CPUC is setting wholesale rates for such transactions.[433] The FERC cited to past precedent under PURPA rejecting state proposals that required sales by QFs to be made at rates in excess of the purchasing utilities' avoided cost, and to the extent they set rates for wholesale sales of electric energy by non-QF public utilities.[434] The FERC cautioned that there was no record in these proceedings on which it may determine whether the CPUC's offer price is consistent with the avoided cost rate requirements of section 210 of PURPA, and this order does not address whether the CPUC's offer price is consistent with PURPA's avoided cost requirements.[435] The FERC also held that arguments concerning the environmental considerations underlying the CPUC's feed-in tariff program do not excuse the Commission of these statutory obligations.[436]

Subsequently, the CPUC sought clarification that it could reexamine its implementation of its decision by implementing it under section 210 of PURPA by requiring utilities to consider different factors in the avoided cost calculation, and that full avoided cost need not be the lowest cost in order to promote CHP facilities. The FERC clarified that the concept of a multi-tiered avoided cost rate structure can be consistent with avoided cost requirements in section 210 of PURPA and the FERC's regulations, and overruling *Southern California Edison*[437] to the extent its broader language is inconsistent with this decision. The FERC also clarified that, while an avoided-cost rate may not include a bonus or adder above calculated full avoided cost to compensate for environmental items, real environmental costs that could be incurred by a utility may be a component in determining avoided cost rates.[438] On January 20, 2011, the FERC issued an Order Denying Rehearing of its July 15, 2010 clarification Order.[439]

### *C. JD Wind 1, LLC*

After the failure of negotiations with a utility, JD Wind entities (JD Wind), which entities had self-certified as QFs under PURPA,[440] filed a complaint with the Public Utility Commission of Texas seeking a legally enforceable obligation from the utility seeking rates based on the avoided costs calculated at the time that obligation was incurred. The Texas Commission upheld that part of an ALJ determination that JD Wind did not offer firm power, and, thus, a legally enforceable obligation requiring a showing that the QF is capable of providing firm power could not be satisfied. JD Wind sought relief from the FERC.

In an initial Order, the FERC declined to initiate a requested enforcement action under section 210(h) of PURPA.[441] The FERC also declared as inconsistent with PURPA and FERC regulations the decision by the Texas

433. *Id.* at P 69.

434. *Id.* at P 70.

435. *Id.* at P 68.

436. *Id.* at P 70.

437. *S. Cal. Edison Co.*, 70 F.E.R.C. ¶ 61,215 (1995), *reconsideration denied*, 71 F.E.R.C. ¶ 61,269, at p. 62,080 (1995).

438. *Cal. Pub. Utils. Comm'n*, 133 F.E.R.C. ¶ 61,059 at P 31 (2010).

439. *Cal. Pub. Utils. Comm'n*, 134 FERC ¶ 61,044 (2011).

440. 16 U.S.C. § 824a-3(h) (2006).

441. *JD Wind 1, LLC*, 129 F.E.R.C. ¶ 61,148 (2009), *order denying requests for reh'g, reconsideration or clarification*, 130 F.E.R.C. ¶ 61,127 (2010).

Commission, and its attempt to limit the requirement to provide a QF with a legally enforceable obligation only to those that provide firm power.[442] Two parties sought rehearing, reconsideration, or clarification, which the FERC denied.[443] Since this proceeding arises under section 210 (h) of PURPA, rehearing does not lie, but the FERC chose to address the requests.

The FERC rejected arguments that it has changed its interpretation of 18 C.F.R. § 292.304(d) (2009) stating that the regulation's express language provides a QF, including non-firm resources, the option of selling on an as available basis, or pursuant to a legally enforceable obligation, and with the latter a right to choose a rate based on avoided costs at the time of delivery, or at the time the obligation is incurred.[444] The FERC rejected the argument that the legislative history of PURPA does not support the FERC's finding, and reasoned that the legislative history allows for consideration of the firmness of the power when determining the capacity component of the rate.[445] The FERC also rejected the argument that an avoided cost rate cannot be accurately calculated for intermittent resources at the time the obligation is incurred.[446] The FERC also noted that while it did not undertake an enforcement action under PURPA as requested by JD Wind, that JD Wind can bring its own enforcement action directly against the state regulatory authority or electric utility in United States district court.[447]

## VII. GENERATOR INTERCONNECTION

### A. *Tatanka Complaint*

On August 4, 2010, the FERC issued an order dismissing a complaint filed by Tatanka Wind Power, LLC (Tatanka), against Montana-Dakota Utilities Company, a division of MDU Resources Group, Inc. (Montana-Dakota), relating to a dispute over payment for certain Network Upgrades constructed by Tatanka pursuant to a Large Generator Interconnection Agreement (LGIA) with Montana-Dakota.[448] According to the FERC, the dispute centered around "Tatanka's obligation to build and Montana-Dakota's obligation to pay for Network Upgrades that Tatanka has constructed at its Dakota Wind facility under the option to build."[449]

In dismissing the complaint, the FERC determined that because Tatanka conceded that it did not build the Network Upgrades to the specifications contained in the LGIA, Montana-Dakota was not required to repay Tatanka for the costs incurred.[450] Although the FERC dismissed Tatanka's complaint, it also concluded:

442. *Id.* at P 22.
443. 130 F.E.R.C. ¶ 61,127.
444. *Id.* at P 16.
445. *Id.* at P 20.
446. *Id.* at PP 22-23.
447. *Id.* at P 25.
448. *Tatanka Wind Power, LLC v. Montana-Dakota Utils. Co.*, 132 F.E.R.C. ¶ 61,103 (2010).
449. *Id.* at P 29.
450. *Id.*

> that Montana-Dakota is obligated to repay Tatanka for the entire cost of the Network Upgrades, plus applicable interest, at such time as Tatanka submits a final invoice for the total cost of the Network Upgrades built in accordance with the specifications set forth in the Amended and Restated Tatanka LGIA.[451]

The FERC noted, however, Montana-Dakota "under section 206 of the FPA to file a complaint with the Commission if, in its opinion, any part of the final cost of the Network Upgrades, built to the agreed upon specifications, was imprudently incurred."[452]

### *B. Puget Declaratory Order*

On November 18, 2010, the FERC issued an order denying Puget Sound Energy Inc.'s (Puget) petition for a declaratory order seeking priority to 1,250 MW of interconnection capacity that would eventually serve the Lower Snake River Project wind farm.[453] In its order, the FERC found that interconnection lines at issue are used to serve Puget's native load and is governed by Puget's existing OATT. In particular, the FERC found that "where an applicant's generation project is serving its native load customers and where the applicant has an OATT on file with the [FERC], we find that generator lead lines to support such a project are properly governed by the terms and conditions of that existing OATT."[454] The FERC further stated that

> [b]y adhering to this process, Puget may reserve transmission capacity on the Lead Lines if needed to serve native load, based on a reasonable forecast over Puget's planning horizon. However, consistent with Order No. 888, transmission capacity reserved for future native load growth must be posted and made available until such time as the capacity is needed.[455]

## VIII. OATT ISSUES

### *A. WECC Price Caps*

On May 20, 2010, the FERC issued an order instituting an FPA section 206 investigation into the energy price cap in the Western Electricity Coordinating Council (WECC) outside of the CAISO.[456] On October 8, 2010, the FERC issued an order modifying (1) the energy price cap on spot market sales in the WECC from $400/MWh to $750/MWh, effective upon issuance of this order; and (2) the price cap in the WECC outside of the CAISO to $1000/MWh, effective April 1, 2011.[457] In modifying the price caps, the FERC found that given the interdependency between the WECC and the CAISO markets, "it is unjust and unreasonable to have inconsistent bid caps in the CAISO and the rest of the WECC."[458]

451. *Id.* at P 35.
452. *Id.* at P 36 (internal citation omitted).
453. *Puget Sound Energy Inc.*, 133 F.E.R.C. ¶ 61,160 (2010).
454. *Id.* at P 11.
455. *Id.* at P 12.
456. *Cal. Indep. Sys. Operator Corp.*, 131 F.E.R.C. ¶ 61,145 (2010).
457. *Cal. Indep. Sys. Operator Corp.*, 133 F.E.R.C. ¶ 61,026 (2010).
458. *Id.* at P 14.

### *B. Southern Montana Complaint*

On November 18, 2010, the FERC issued an order accepting the August 20, 2010 complaint filed by Southern Montana Electric Generation & Transmission Cooperative, Inc. (Southern Montana), against NorthWestern Corporation (NorthWestern) alleging that NorthWestern is violating FERC orders and its OATT by billing Southern Montana for long-term firm point-to-point transmission service without a valid service agreement.[459] In granting the complaint, the FERC noted that the only matter at issue was whether "NorthWestern has properly complied with its OATT and [FERC] policy on entering into a contract for long-term firm transmission service for the particular 65 MWs of service at issue."[460] In determining that NorthWestern violated its OATT and FERC policy, the FERC found that NorthWestern could not bill Southern Montana in the absence of "a separate, transaction-specific service agreement for a long-term firm point-to-point request once the request is accepted."[461]

## IX. NON-RTO COMPLAINTS

On September 22, 2010, the FERC reversed an administrative law judge's finding in an initial decision[462] that costs associated with the Spindletop natural gas storage facility regulatory asset are not production costs and for that reason should be excluded from the bandwidth calculation used to maintain rough production cost equalization among Entergy Corporation's utility subsidiaries.[463] The FERC found that the Spindletop regulatory asset reflects deferred actual costs associated with actual service for the production of electricity.[464] The FERC rejected arguments that the Spindletop regulatory asset costs represent out-of-period costs that would justify their exclusion from the bandwidth calculation,[465] that inclusion of the costs would encourage manipulation of the bandwidth calculations,[466] and that inclusion of the costs would subsidize Louisiana jurisdictional customers at the expense of Texas wholesale and retail customers.[467] From this analysis the FERC concluded that the Spindletop regulatory asset should be included in the bandwidth calculation.[468] At 2010 year end the case was pending on rehearing.[469]

459. *S. Mont. Electric Generation & Transmission Coop., Inc. v. Nw. Corp.*, 133 F.E.R.C. ¶ 61,163 (2010).

460. *Id.* at P 65.

461. *Id.* at P 66.

462. *La. Pub. Serv. Comm'n v. Entergy Corp.*, 127 F.E.R.C. ¶ 63,021 (2009).

463. *La. Pub. Serv. Comm'n v. Entergy Corp.*, 132 F.E.R.C. ¶ 61,253 (2010).

464. *Id.* at P 37.

465. *Id.* at P 38.

466. *Id.* at P 39.

467. *Id.* at P 40.

468. *Id.* at P 41.

469. Order Granting Rehearing for Further Consideration, No. EL08-51 (FERC Nov. 11, 2010).

# ELECTRICITY REGULATION COMMITTEE

Gary A. Morgans, Chair
Brian M. Meloy, Vice-Chair

Glenn S. Benson
Candice Castaneda
Heather L. Curlee
Melinda J. Davison
Romulo L. Diaz, Jr.
Richard A. Drom
Russell A. Feingold
James G. Flaherty
David E. Fleming
Daniel E. Frank
Jeffrey A. Franklin
Caileen N. Gamache
Natasha Gianvecchio
Lisa A. Gilbreath
Marvin T. Griff
John Wyeth Griggs
Walter R. Hall, II
Laurel Heacock
Sheila S. Hollis
Dong Hong
Marcia C. Hooks
Michael L. Kessler
Kurt L. Krieger
Jody M. Kyler
James R. Lacey
Melissa G. Liazos
Diana M. Liebmann
Tamara L. Linde
Tracy J. Logan
Roxane E. Maywalt
Maureen C. McLaughlin
Lopa B. Parikh
Stephen R. Pelcher
Mark L. Perlis
Raymond V. Petniunas
Emily R. Pitlick
Michael Postar
John P. Ratnaswamy
John J. Schulze, Jr.
Steven A. Shapiro
John A. Shope
Noha Sidhom
Douglas W. Smith
Regina Y. Speed-Bost
Philip E. Stoffregen
Channing D. Strother, Jr.
Karen S. White