REPORT OF THE ELECTRICITY REGULATION COMMITTEE

This report covers significant calendar year 2013 electric regulatory orders of the Federal Energy Regulatory Commission (FERC).*

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I. INTRODUCTION

This report does not address transmission reliability, wholesale market-based rates, demand-side management/renewable energy, or enforcement matters. Likewise, this report does not address appellate decisions.

II. RULEMAKINGS AND POLICY STATEMENTS

A. Policy Statement re Allocation of Capacity on New Merchant Transmission Projects and New Cost-Based, Participant-Funded Transmission Projects

The FERC clarified its policy regarding "allocation of capacity for new merchant transmission projects and new nonincumbent, cost-based participant-funded transmission projects."[1] Generally, these policies allow developers of transmission projects to solicit interest from potential customers and negotiate directly with those customers.[2] The FERC clarified previous rules and regulations relating to solicitation for transmission project capacity.[3] The new policies adopt transparent, bilateral negotiation in lieu of formal open season solicitation processes, and a simpler reporting mechanism for FERC approval.[4]

B. Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies, *Order No. 784*

In Order No. 784,[5] the FERC: (1) reformed its policies requiring an explanation on how the transmission provider will determine service reserve requirements for transmission customers; (2) required that transmission providers take into account the speed and accuracy of the particular resources

1. *Allocation of Capacity on New Merchant Transmission Projects and New Cost-Based, Participant-Funded Transmission Projects, Priority Rights to New Participant-Funded Transmission*, 142 F.E.R.C. ¶ 61,038 at P 1 (2013).

2. *Id.* at P 16.

3. *Id.* at P 1.

4. *Id.* at P 23.

5. Order No. 784, *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, 144 F.E.R.C. ¶ 61,056 (2013).

used; and (3) modified its accounting and reporting regulations to increase the transparency for energy storage facilities.[6]

The FERC allowed sellers passing existing market power tests for energy and capacity to sell at market-based rates for energy imbalance and generator imbalance services when "those areas have implemented intra-hour scheduling for transmission service[s]."[7] With respect to operating reserve services, the FERC required sellers to explain in their application how the scheduling practice of their region handles operating reserves.[8] Apart from this change, the FERC required sellers to pass the standard screens for horizontal market power for energy and capacity services.[9] Because regulation and reactive power services and voltage control services have more stringent technical and geographic limitations associated with them and "are not simple combinations of basic energy and capacity products,"[10] the FERC stated that sellers "might need to enter into or facilitate special arrangements between neighboring balancing authorities . . . in order to make sales outside of their home balancing authority area."[11]

The FERC further considered whether or not to institute other alternative mitigation techniques for those sellers that either could not pass or would not conduct the market power studies for ancillary services in the form of price caps.[12] The FERC found the proposed single Open Access Transmission Tariff (OATT) market-rate cap to be just and reasonable because such a cap was essentially an extension of the FERC's preexisting mitigation measures, which sought to protect buyers from exercise of market power by sellers.[13] The FERC also allowed applicants to engage in sales to a public utility that purchases ancillary services to satisfy its OATT requirements where the sale is made pursuant to a competitive solicitation that meets the FERC's specified guidelines.[14]

The FERC additionally adopted its proposal to require each public utility transmission provider to submit OATT provisions that "take account of the speed and accuracy of regulation resources in determining its Regulation and Frequency Response reserve requirements."[15] The FERC stated this would allow self-supplying "with faster responding or more accurate resources . . . with a lower volume of regulation capacity, or vice versa."[16]

6. *Id.* at PP 9-11.
7. *Id.* at P 31.
8. *Id.* at P 58.
9. *Id.* at P 57.
10. *Id.* at P 59.
11. *Id.* at P 60.
12. *Id.* at P 75.
13. *Id.* at PP 82-83.
14. *Id.* at P 95.
15. *Id.* at P 102.
16. *Id.*

The FERC also revised its accounting and reporting requirements for energy storage projects.[17] According to the FERC, these changes were needed to better account for transactions associated with energy storage devices used in public utility operations.[18] The FERC also created the new Form Nos. 1 and 1-F schedules and amended existing schedules in Form No. 3-Q to report operational and statistical data for storage assets.[19] In support, it pointed out that when energy storage devices provide several services to customers, it is important to separate and account for these services so they are not cross-subsidizing each other.[20]

C. Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators, *Order No. 787*

In Order No. 787, the FERC addressed the communication of operational information between natural gas pipelines and electric transmission operators.[21] Order No. 787 revised parts 38 and 284 of the FERC's regulations to

> provide explicit authority to interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to share non-public, operational information with each other for the purpose of promoting reliable service or operational planning on either the public utility's or pipeline's system.[22]

As to the scope of information that can be shared, the FERC explained that the final rule "intentionally permit[s] the communication of a broad range of non-public, operational information to provide flexibility to individual transmission operators, who have the most insight and knowledge of their systems, to share that information which they deem necessary to promote reliable service on their system."[23] The FERC explained that the communications permitted by Order No. 787 are allowed in both emergency and non-emergency situations.[24]

To ensure that the information shared under Order No. 787 remains confidential and is shared "in a manner that is consistent with the prohibition on undue discrimination," the FERC adopted a No-Conduit Rule, which "prohibits all public utilities and interstate natural gas pipelines, as well as their employees, contractors, consultants, or agents, from disclosing, or using anyone as a conduit for the disclosure of, non-public, operational information they receive under this rule to a third party or to its marketing function employees."[25] The FERC

17. *Id.* at 122.

18. *Id.*

19. *Id.*

20. *Id.*

21. Order No. 787, *Communication of Operational Information Between Natural Gas Pipelines and Electric Transmission Operators*, 145 F.E.R.C. ¶ 61,134, 78 Fed. Reg. 70,163 (2013) (to be codified at 18 C.F.R. pts. 38, 284).

22. *Id.* at P 1.

23. *Id.* at P 41.

24. *Id.* at P 43.

25. *Id.* at P 77.

explained that the No-Conduit Rule only applies to the non-public, operational information an electric transmission operator provides to the interstate pipeline pursuant to this rule or vice versa.[26] Therefore, it does not affect: (1) the ability of interstate natural gas pipelines to exchange information among themselves or with local distribution companies (LDCs) regarding operational conditions affecting the gas flow between these physically interconnected parties; (2) the ability of an electric transmission operator to share its own information with an LDC; or (3) the ability of natural gas pipelines and gatherers to exchange information regarding operational conditions affecting the gas flows between these physically interconnected parties.[27] Moreover, this final rule does not prohibit electric transmission operators from sharing non-public, operational information received from a pipeline pursuant to this final rule with LDCs if the information sharing and appropriate safeguards to prevent inappropriate use or disclosure of shared information is separately authorized by the FERC, for example, pursuant to a Federal Power Act (FPA) section 205 tariff filing by an independent system operator (ISO) or regional transmission operator (RTO).[28] The FERC explained that the "communication and sharing of non-public, operational information is voluntary" and that it would consider requests for alternative information sharing procedures on a case-by-case basis.[29]

III. ORDER NO. 1000 REGIONAL COMPLIANCE PROCEEDINGS

A. *Transmission Planning Regions and Regional Transmission Plans*

Order No. 1000 requires public utility transmission providers to participate in regional transmission processes to develop regional transmission plans.[30]

In the case of Southeastern Regional Transmission Planning (SERTP), the filing proposes expansion of the original SERTP region with Central Public Power Partners, Louisville Gas and Electric Company and Kentucky Utilities Company (LG&E/KU), and Ohio Valley Electric Corporation to create a transmission planning region.[31] In response, LS Power argued that SERTP had not proven the proposed region to be integrated and that the participation of Tennessee Valley Authority is essential for the region to function.[32] The FERC determined the expanded SERTP region conditionally satisfied Order No. 1000's requirements.[33] However, some revisions were requested by the FERC, such as

26. *Id.* at PP 77-78.

27. *See generally id.* at PP 77-89 (rejecting arguments to expand the scope of the No-Conduit Rule).

28. *Id.* at P 77.

29. *Id.* at P 86.

30. Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, F.E.R.C. STATS. & REGS. ¶ 31,323, 76 Fed. Reg. 49,842 (2011) (to be codified at 18 C.F.R. pt. 35) [hereinafter Order No. 1000], *order on reh'g*, Order No. 1000-A, 139 F.E.R.C. ¶ 61,132 [hereinafter Order No. 1000-A], *order on reh'g*, Order No. 1000-B, 141 F.E.R.C. ¶ 61,044 (2012).

31. *Louisville Gas & Elec. Co*., 144 F.E.R.C. ¶ 61,054 at P 18 (2013).

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

33. *Id.* at P 27.

including a list of all utility transmission providers enrolled in the region, adjusting the effective date of the proposal, identifying relevant transmission facilities, and elaborating upon evaluation processes for transmission projects currently under construction.[34]

The Midwest Independent Transmission System Operator, Inc. (MISO)[35] proposed to be considered as a transmission planning region.[36] In order to fully satisfy Order No. 1000's requirements, MISO proposed to adjust and clarify the enrollment process.[37] The FERC approved MISO's proposal, considering it to be in compliance with Order No. 1000.[38] It declared that the revised transmission planning process would begin June 1, 2013.[39]

For its transmission planning region, PJM Interconnection, L.L.C. listed a number of public and non-public utilities who are currently integrated or integrating into PJM.[40] The filing also stated its intent to fully implement revisions in the next twelve- and twenty-four-month planning cycles.[41] The FERC partially accepted PJM's filling—accepting the area of the RTO, but directing PJM to provide more detail regarding its proposed transmission planning processes.[42]

B. Consideration of Transmission Needs Driven by Public Policy Requirements

Companies such as Southern Company, LG&E, the Southwest Power Pool, Inc. (SPP), MISO, and PJM filed transmission plans addressing how they will incorporate Order No. 1000's public policy requirements.[43]

Southern Company and LG&E attempted to satisfy Order No. 1000's public policy requirements by identifying transmission planning processes.[44] The FERC found Southern Company's filing did not comply with Order No. 1000 and directed it to submit further filings with explanation and elaboration of how public policy requirements will be considered.[45] It found LG&E's proposal partially complied with Order No. 1000 but requested revisions to take account

34. *Id.* at P 33.

35. Effective April 26, 2013, the MISO changed its name from "Midwest Independent Transmission System Operator, Inc." to "Midcontinent Independent System Operator, Inc." *Entergy Arkansas, Inc*., 143 F.E.R.C. ¶ 61,259 at P 2 n.4 (2013). In this report, "MISO" will be used as the short form for both names.

36. *Midwest Indep. Transmission Sys. Operator, Inc*., 142 F.E.R.C. ¶ 61,215 at P 33 (2013).

37. *Id.* at P 35.

38. *Id.* at P 38.

39. *Id.* at P 39.

40. *PJM Interconnection, L.L.C.*, 142 F.E.R.C. ¶ 61,214 at P 26 (2013).

41. *Id.* at P 27.

42. *Id.* at PP 30-34.

43. *Southwest Power Pool, Inc.*, 144 F.E.R.C. ¶ 61,059 at P 64 (2013); *Louisville Gas & Elec. Co*., 144 F.E.R.C. ¶ 61,054 at P 1 (2013); *Midwest Indep. Transmission Sys. Operator, Inc*., 142 F.E.R.C. ¶ 61,215 at P 88 (2013); *PJM Interconnection, L.L.C.*, 142 F.E.R.C. ¶ 61,214 at P 73 (2013).

44. 144 F.E.R.C. ¶ 61,054 at P 120 (2013).

45. *Id.* at P 124.

of local laws and eliminate requirements that proposals must prove current procedures do not meet proposed goals.[46]

SPP proposed to retain its existing processes in order to comply with Order No. 1000's public policy requirements.[47] However, SPP proposed to define public policy requirements and clarify transmission needs driven by public policy requirements.[48] SPP's filing was partially approved by the FERC subject to the condition that SPP provide further detail about solicitation of input for identification of transmission needs driven by public policy requirements.[49]

MISO argued it is already in compliance with Order No. 1000's public policy requirements due to the MISO Transmission Expansion Plan Transmission Issues criteria and that it currently analyzes many scenarios, including public policy needs.[50] MISO's proposed definition of public policy requirements was found to be partially compliant by the FERC.[51] The FERC required MISO to clarify its filing to specify that local laws and regulations will be considered in determining public policy requirements.[52]

PJM stated that its integrated market design and transmission planning procedures, which identify and allow input regarding public policy concerns, satisfied Order No. 1000's public policy requirements.[53] PJM pointed to its energy efficiency and renewable resources as support for its current focus on public policy.[54] The FERC found PJM partially complied with Order No. 1000 and directed it to submit additional detail regarding non-discriminatory and transparent processes through which public policy requirements can be solicited.[55]

C. *Elimination of Federal Right of First Refusal and* Mobile-Sierra

In Order No. 1000, the FERC directed "transmission providers to remove from their OATTs or other Commission-jurisdictional tariffs and agreements any provisions that grant a federal right of first refusal to transmission facilities that are selected in a regional transmission plan for purposes of cost allocation."[56] In response to the argument that this requirement amends existing contractual provisions and is thus "subject to the *Mobile-Sierra* doctrine,"[57] the FERC found the record in that generic proceeding was insufficient to address the specific

46. *Id.* at P 126.
47. 144 F.E.R.C. ¶ 61,059 at P 64.
48. *Id.* at P 65.
49. *Id.* at P 73.
50. *Midwest Indep. Transmission Sys. Operator, Inc*., 142 F.E.R.C. ¶ 61,215 at P 88 (2013).
51. *Id.* at P 95.
52. *Id.* at P 96.
53. *PJM Interconnection, L.L.C.*, 142 F.E.R.C. ¶ 61,214 at P 73 (2013).
54. *Id.* at P 74.
55. *Id.* at P 118.
56. Order No. 1000, *supra* note 30, at P 7.
57. *Id.* at P 283.

issues presented and issues regarding the applicable standard of review were better addressed as part of the proceeding on the compliance filing.[58]

In its compliance filing, ISO New England Inc. (ISO-NE) argued the *Mobile-Sierra* doctrine protects the obligation and right of the Participating Transmission Owners in the Transmission Operating Agreement to build transmission upgrades and that the public interest does not demand confiscation of this right.[59] The FERC found that these provisions "are prescriptions of general applicability rather than negotiated rate provisions" and, therefore, they are not "necessarily entitled to a *Mobile-Sierra* presumption."[60] It also found that "[u]nlike circumstances in which the FERC can presume that the resulting rate is the product of negotiations between parties with competing interests, the negotiation that led to the provisions at issue here was primarily among parties with the same interest."[61] It further found that the *Mobile-Sierra* doctrine does not bar its abrogation of contracts in a generic proceeding, "particularly in response to changed circumstances or in order to remedy serious harm to the public interest caused by anticompetitive provisions."[62] It explained that "changes in the electric industry driving the demand for new transmission, coupled with the advent of nonincumbent transmission developers, led the FERC to reexamine the effect of federal rights of first refusal on customers and nonincumbent transmission developers."[63]

As to the PJM region, the Indicated PJM Transmission Owners argued that the PJM Consolidated Transmission Owners Agreement and the PJM Amended and Restated Operating Agreement provide the PJM Transmission Owners with a right of first refusal, which was entitled to the protection of the *Mobile-Sierra* public interest presumption.[64] The FERC found the applicable provisions conferring a federal right of first refusal lacked "the characteristics that justify the *Mobile-Sierra* presumption,"[65] constituted "prescriptions of general applicability rather than negotiated rate provisions,"[66] and "arose in circumstances that do not provide the assurance of justness and reasonableness on which the *Mobile-Sierra* presumption rests."[67]

MISO, in filing in compliance with Order No. 1000, argued that its Transmission Owners Agreement is protected by the *Mobile-Sierra* doctrine, which MISO suggested the FERC had not satisfied and was unlikely to satisfy.[68]

58. *Id.* at P 292.

59. *ISO New England Inc*., 143 F.E.R.C. ¶ 61,150 at 154 (2013).

60. *Id.* at P 166.

61. *Id.* at P 169.

62. *Id.* at P 173.

63. *Id.* at P 198.

64. *PJM Interconnection, L.L.C.*, 142 F.E.R.C. ¶ 61,214 at P 155 (2013).

65. *Id.* at P 185.

66. *Id.* at P 186.

67. *Id.* at P 188.

68. Midwest Independent Transmission System Operator, Inc.'s and MISO Transmission Owners' Compliance Filing for Order No. 1000, Regarding Regional Planning and Cost Allocation of Transmission

The FERC disagreed,[69] reasoning that the "Transmission Owners Agreement formulates a rule that is a prescription of general applicability rather than a negotiated rate provision,"[70] and the "right of first refusal [provision] in the MISO Transmission Owners Agreement . . . arose in circumstances that do not provide the assurance of justness and reasonableness on which the *Mobile-Sierra* presumption rests."[71]

D. Regional Cost Allocation

In July 2013, the FERC issued initial compliance orders addressing compliance filings submitted by California Independent System Operator Corporation (CAISO), MISO, ISO-NE, New York System Operator, Inc. (NYISO), and PJM.[72] The FERC found that, by and large, the proposed cost allocation approaches for these regions complied with the six cost allocation factors identified by Order No. 1000.[73] While the FERC found that the proposals were largely compliant, finding that the five proposals appropriately required the allocation of costs solely within the planning region unless another entity outside the region voluntarily agrees to be allocated some portion of costs, it also found that the proposals did not address the consequences of upgrades for other transmission planning regions or whether those regions have agreed to bear the costs of any associated upgrades in another region.[74]

E. Waivers of Order No. 1000

The FERC granted a number of waivers of the Order No. 1000 transmission planning and cost allocation requirements, noting that Order No. 1000 specified the criteria for waiver of the final rule are unchanged from those used to evaluate requests for waiver under Order Nos. 888, 889, and 890.[75] The FERC explained that it would grant requests for waiver "by public utilities that could show that they own, operate, or control only limited and discrete transmission facilities

Projects with Regional Benefits (Part 1 of 2) at 4-5, *Midwest Indep. Transmission Sys. Operator, Inc*., 142 F.E.R.C. ¶ 61,215 (2013) (Docket No. ER13-187-000).

69. *Midwest Indep. Transmission Sys. Operator, Inc*., 142 F.E.R.C. ¶ 61,215 at P 175.

70. *Id.* at P 180.

71. *Id.* at P 182.

72. *Southwest Power Pool, Inc*., 144 F.E.R.C. ¶ 61,059 (2013); *ISO New England, Inc*., 143 F.E.R.C. ¶ 61,150 (2013); *California Indep. Sys. Operator Corp*., 143 F.E.R.C. ¶ 61,057 (2013); *PJM Interconnection, L.L.C.*, 142 F.E.R.C. ¶ 61,214 (2013); *Midwest Indep. Transmission Sys. Operator, Inc.*, 142 F.E.R.C. ¶ 61,215 (2013).

73. 144 F.E.R.C. ¶ 61,059 at P 354; 143 F.E.R.C. ¶ 61,150 at P 352; 143 F.E.R.C. ¶ 61,057 at P 301; 142 F.E.R.C. ¶ 61,214 at P 422; 142 F.E.R.C. ¶ 61,215 at P 440.

74. 144 F.E.R.C. ¶ 61,059 at P 355; 143 F.E.R.C. ¶ 61,150 at P 357; 143 F.E.R.C. ¶ 61,057 at P 302; 142 F.E.R.C. ¶ 61,214 at P 422; 142 F.E.R.C. ¶ 61,215 at P 441; *see also* Order No. 1000, *supra* note 30, at P 657.

75. *Electric Energy, Inc.*, 144 F.E.R.C. ¶ 61,028 at P 7 (2013); *SU FERC, L.L.C.*, 143 F.E.R.C. ¶ 61,139 at P 8 (2013); *Lockhart Power Co*., 143 F.E.R.C. ¶ 61,040 at P 12 (2013); *Alcoa Power Generating Inc. (Long Sault Division)*, 143 F.E.R.C. ¶ 61,038 at P 10 (2013).

(facilities that do not form an integrated transmission grid), until such time as the public utility receives a request for transmission service."[76]

Entertaining requests on a case-by-case basis, the FERC determined waiver of Order No. 1000 is appropriate given the specific unique circumstances presented in the waiver requests.[77] In particular, it found that the entities control limited and discrete transmission facilities that do not form an integrated transmission grid[78] or that the entities only provide transmission service based on pre-OATT agreements.[79] However, the FERC explained that while it granted the entities a waiver, it does not mean that the entities are "immune from the potential of being allocated costs of regional transmission facilities that are selected in a regional transmission plan for purposes of cost allocation."[80] The FERC added that "public utility transmission providers in each transmission planning region, in consultation with their stakeholders, may consider proposals to allocate costs directly to entities (for example, generators or network customers) as beneficiaries that could be subject to regional or interregional cost allocation."[81]

IV. OTHER RTO/ISO DEVELOPMENTS

A. ISO New England, Inc.

On January 14, 2013, the FERC accepted in part, and rejected in part, changes proposed by ISO-NE to make New England's Forward Capacity Market (FCM) rules consistent with those for the full integration of price-responsive demand.[82] Specifically, the FERC accepted a proposal to require demand response resources to supply capacity in the FCM,[83] apply to those resources mechanisms designed to curb market power, hedge against high energy market prices, and mitigate economic incentives to overstate available capacity.[84] The FERC rejected ISO-NE's proposal to re-classify the treatment of demand response resources that provide capacity through both demand reductions and behind-the-meter generation, noting deficiencies on the record before it with the calculation of capacity values and the results that could be produced.[85]

76. *Alcoa*, 143 F.E.R.C. ¶ 61,038 at P 11 (citing *Black Creek Hydro, Inc.*, 77 F.E.R.C. ¶ 61,232 (1996)); *see also Electric Energy*, 144 F.E.R.C. ¶ 61,028 at P 8; *SU FERC*, 143 F.E.R.C. ¶ 61,139 at P 9; *Lockhart*, 143 F.E.R.C. ¶ 61,040 at P 13.

77. *E.g.*, *SU FERC*, 143 F.E.R.C. ¶ 61,139 at P 10.

78. *Id.*; *Electric Energy*, 144 F.E.R.C. ¶ 61,028 at P 9.

79. *Lockhart*, 143 F.E.R.C. ¶ 61,040 at P 14; 143 F.E.R.C. ¶ 61,038 at P 12.

80. *Lockhart*, 143 F.E.R.C. ¶ 61,040 at P 14; *see also Electric Energy*, 144 F.E.R.C. ¶ 61,028 at P 9; *SU FERC*, 143 F.E.R.C. ¶ 61,139 at P 11; *Alcoa*, 143 F.E.R.C. ¶ 61,038 at P 12.

81. *Lockhart*, 143 F.E.R.C. ¶ 61,040 at P 14 (citing Order No. 1000-A, *supra* note 30, at P 680); *see also Electric Energy, Inc*., 144 F.E.R.C. ¶ 61,028 at P 9; *SU FERC*, 143 F.E.R.C. ¶ 61,139 at P 11; *Alcoa*, 143 F.E.R.C. ¶ 61,038 at P 12.

82. *ISO New England, Inc*., 142 F.E.R.C. ¶ 61,027 at PP 1-2 (2013).

83. *Id.* at PP 27-31.

84. *Id.* at P 55.

85. *Id.* at PP 43-45.

Identifying its concerns with other aspects of the proposal, the FERC conditioned its acceptance on the submission of further explanation.[86]

On June 14, 2013, in response to a filing by Dominion Energy Marketing, Inc., seeking recovery for a portion of the costs associated with the operation of certain generating units beyond their schedules for reliability reasons, the FERC not only granted the requested cost recovery, but instituted a section 206 proceeding finding unjust and unreasonable a portion of the New England market rule "because it does not provide resources an adequate opportunity to recover costs incurred to comply with ISO-NE directives to ensure reliability in instances when their supply offers were not mitigated."[87] Accordingly, the FERC directed ISO-NE to submit revisions that

> allow resources to submit a section 205 filing for cost recovery, including fuel and variable operation and maintenance costs for the resource, in circumstances where for reliability reasons a resource is dispatched: (1) beyond its day-ahead schedule, where there is no opportunity to refresh the offer price to reflect current costs; or (2) after the results of the day-ahead market schedule are published, where the resource did not receive a day-ahead market schedule.[88]

It subsequently accepted revisions proposed by ISO-NE that would "help ensure that necessary cost recovery will be available when appropriate, and only when appropriate."[89] The FERC rejected requests for broader opportunities for cost recovery.[90]

On September 16, 2013, the FERC conditionally accepted ISO-NE's and New England Power Pool's (NEPOOL) proposed revisions to Market Rule 1 to aid ISO-NE in maintaining reliability during the 2013-2014 winter (Winter Reliability Program).[91] The Winter Reliability Program consisted of four components: (1) a demand response program open both to market participants with new demand response assets that are not otherwise participating in the wholesale markets and market participants participating in the FCM that have capacity in excess of that needed to meet their Capacity Supply Obligations;[92] (2) an "oil inventory service" program in which selected oil-fired and dual-fuel generators take on obligations, including the injection of fuel oil into their storage tanks prior to December 1, 2013, in exchange for monthly payments;[93] (3) a dual-fuel testing program in which participating dual-fuel resources are compensated for successfully testing their ability to switch fuels within five hours;[94] and (4) market monitoring changes intended to improve resources' flexibility to switch fuels by removing the requirement that resources seek the market monitor's approval prior to switching, and instead requiring resources to

86. *Id.* at P 45.

87. *Dominion Energy Mktg., Inc.*, 143 F.E.R.C. ¶ 61,233 at P 25 (2013).

88. *Id.* at P 26.

89. *Dominion Energy Mktg., Inc.*, 145 F.E.R.C. ¶ 61,110 at P 35 (2013).

90. *Id.* at P 37.

91. *ISO New England, Inc.*, 144 F.E.R.C. ¶ 61,204 at P 1 (2013).

92. *Id.* at P 4.

93. *Id.* at P 9.

94. *Id.* at P 12.

provide an ex post justification for switching to the higher cost fuel.[95] ISO-NE proposed to "allocate the costs of the Winter Reliability Program to Regional Network Load, which is paid for by transmission owners, rather than to Real-Time Load Obligation, which is paid for by load-serving entities."[96] However, the FERC directed that ISO-NE allocate the program's costs to Real-Time Load Obligation "[b]ecause real-time load is the primary beneficiary, and the primary cost-driver, of the Winter Reliability Program."[97]

On April 24, 2013, the FERC accepted changes proposed by NEPOOL to accelerate the clearing of ISO-NE's day-ahead energy market and the completion of ISO-NE's analytical process for ensuring adequate resources are committed for reliability purposes.[98] The changes, which increase the time gas-fired generation resources have to make fuel arrangements based upon their commitments, were proposed as part of a broader effort to improve natural gas and electric market coordination and resource performance.[99] The FERC chose the earlier timeframes proposed by NEPOOL, rather than those proposed by ISO-NE, finding "the NEPOOL Proposal has the potential to not only enhance reliability but also better account for market efficiency."[100]

B. New York Independent System Operator, Inc.

On June 6, 2013, the FERC conditionally approved a NYISO proposal to implement buyer- and seller-side market power mitigation measures for new capacity zones.[101] This proposal involves revisions to market power mitigation measures similar to the installed capacity (ICAP) market measures currently in place in New York City.[102] The proposal differs from ICAP by restricting supply-side measures to Pivotal Suppliers who control at least the megawatts of unforced capacity.[103] Additionally, the proposal grandfathers projects that have commenced construction as of March 31 from the buyer-side provisions.[104] The FERC noted the market power mitigation measures would reduce risk and delay from uncertainty in mitigation policy.[105]

C. PJM Interconnection, L.L.C.

On June 5, 2013, the FERC dismissed a FirstEnergy Solutions Corp. and Allegheny Energy Supply Company, LLC (together, FirstEnergy) complaint requesting modification of the PJM tariff and operating agreement to prevent

95. *Id.* at P 14.
96. *Id.* at P 55.
97. *Id.* at P 70.
98. *ISO New England, Inc.*, 143 F.E.R.C. ¶ 61,065 at P 1 (2013).
99. *Id.* at PP 35-36.
100. *Id.* at P 36.
101. *New York Indep. Sys. Operator, Inc*., 143 F.E.R.C. ¶ 61,217 at P 1 (2013).
102. *Id.* at PP 9-10.
103. *Id.* at P 12.
104. *Id.* at P 13.
105. *Id.* at P 40.

underfunding of Financial Transmission Rights (FTRs).[106] FirstEnergy alleged that pro rata discounts to FTR payments caused by under-collection of congestion charges from the day-ahead and real-time energy markets require FTR holders to bear the risk of FTR underfunding associated with, and pay increased costs to make up for, real-time market congestion.[107] The FERC found that FirstEnergy failed to demonstrate that the relevant PJM Tariff provisions are unjust and unreasonable and dismissed the complaint.[108] It noted that while full funding of FTRs is a goal, the PJM Tariff does not guarantee it.[109] The FERC also found that neither FirstEnergy nor any commenter identified any party that causes FTR underfunding or demonstrated that allocating the costs of FTR underfunding to all transmission customers in PJM would provide a better incentive to remedy the underlying causes of FTR underfunding.[110] In addition, the FERC found FirstEnergy failed to show that reallocating real-time congestion costs would benefit the PJM market overall—rather than only FTR holders—or allocate such costs to those who cause or would benefit from reducing them.[111]

On March 22, 2013, the FERC denied a rehearing concerning its 2012 order on remand issued in response to a remand by the United States Court of Appeals for the Seventh Circuit regarding cost allocation for new transmission facilities that operate at or above 500 kilovolts (kV).[112] The FERC affirmed its prior finding that using the static distribution factor modeling for PJM transmission facilities operating at 500 kV and above is unjust and unreasonable and using a postage stamp allocation of the costs of those facilities is a just and reasonable alternative.[113]

On May 2, 2013, the FERC conditionally accepted in part and rejected in part PJM's proposed tariff changes to its minimum offer price rule (MOPR) for generating resources seeking to participate in its capacity market auctions.[114] In December 2012, PJM proposed to replace its unit-specific review process with two broad exemptions: competitive entry and self-supply Load Serving Entities (LSEs).[115]

Under the competitive entry exemption, the following units would be exempt from the price floor: a unit that does not receive out-of-market funding and a unit that receives outside funds only as a result of participating in a competitive auction open to all available resources.[116] Under the self-supply

106. *FirstEnergy Solutions Corp. v. PJM Interconnection, L.L.C.*, 143 F.E.R.C. ¶ 61,209 at P 3 (2013).

107. *Id*. at P 3.

108. *Id.* at P 40.

109. *Id*. at P 41.

110. *Id.* at P 43.

111. *Id.* at P 44.

112. *PJM Interconnection, L.L.C.*, 142 F.E.R.C. ¶ 61,216 at P 1 (2013).

113. *Id.* at PP 66-87.

114. *PJM Interconnection, L.L.C.*, 143 F.E.R.C. ¶ 61,090 at P 3 (2013).

115. *Id.* at PP 13, 27, 63.

116. *Id.* at P 24.

exemption, an LSE that owns or contracts for a "large proportion," based on specified thresholds for LSEs that are net-short and net-long, of the capacity needed to meet its load would not be subject to the price floor.[117] PJM also proposed to limit the MOPR to gas-fired combustion turbine, combined-cycle, and integrated gasification combined-cycle (IGCC) resources, to exempt incremental capacity increases of less than 20 MW, and to apply the MOPR to the entire PJM region rather than just constrained Local Deliverability Areas.[118] Under the PJM proposal, a resource would be subject to the MOPR unless it fit within one of the exemptions.[119]

The FERC rejected PJM's proposal to eliminate the unit-specific review.[120] It reasoned that resources that are ineligible for the MOPR exemptions should have the opportunity to demonstrate that their entry costs are competitive.[121]

D. Midwest Independent Transmission System Operator, Inc./Midcontinent Independent System Operator, Inc.

On May 16, 2013, the FERC found pro forma formula rate protocols under the MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff (Tariff) and individual MISO transmission owners' filed formula rate protocols did not ensure just and reasonable rates.[122] It found the protocols generally excluded state commissions and other interested parties from the exchange of information and review process and should be amended to include all customers, commissions, consumer advocacy agencies, and state attorney generals.[123] It also found that the rate protocols required insufficient transparency as to costs and revenue requirements, reasoning both the rate formula and its inputs must be revealed and supported.[124] It further found the procedures for challenging formula rates were insufficiently clear and inadequate, and did not provide access to sufficient information.[125] It ordered changes to eliminate each deficiency.[126]

On July 18, 2013, the FERC heard a complaint from the Interstate Power and Light Company (IPL) that ITC Midwest, LLC's (ITCM) interconnection reimbursement policy, in the context of MISO's zonal rate structure, resulted in an improper subsidy.[127] ITCM customers could receive reimbursement of 100% of their interconnection-related network upgrade costs.[128] Applying Order No.

117. *Id.* at P 25.
118. *Id.* at PP 146-47.
119. *Id.* at PP 145-47.
120. *Id.* at P 26.
121. *Id.*
122. *Midwest Indep. Transmission Sys. Operator, Inc.*, 143 F.E.R.C. ¶ 61,149 at P 1 (2013).
123. *Id*. at P 34.
124. *Id.* at PP 81, 83.
125. *Id.* at PP 113-23.
126. *Id.* at P 123.
127. *Interstate Power & Light Co. v. ITC Midwest, LLC*, 144 F.E.R.C. ¶ 61,052 at P 1 (2013).
128. *Id.* at P 39.

2003 policies, the FERC ordered tariff revisions to provide that ITCM generator interconnection customers may receive up to a 10% reimbursement, consistent with tariff provisions for other MISO pricing zones.[129]

On June 20, 2013, the FERC conditionally accepted tariff revisions proposed by MISO for the merger of the transmission facilities of Entergy Corporation (Entergy) to ITC Midsouth LLC and the integration of these transmission facilities, along with the load and generation in Entergy's footprint, into MISO's footprint.[130] Under proposed Module B-1, MISO sought to establish terms and conditions for transmission service over Entergy's transmission facilities during Entergy's integration into MISO.[131]

According to Module B-1, during the six-month interim, MISO will have functional control of all of ITC Midsouth transmission.[132] "Thus, MISO will provide 'Order Nos. 888 and 890-compliant open access transmission service on these facilities,' and Module B-1 will operate in substantially the same fashion as the MISO tariff operated prior to the April 2005 start-up of the MISO energy markets . . . ."[133] MISO stated that differences existed between Module B-1 and the existing provisions of the MISO tariff were the result of MISO's market services being unavailable to ITC Midsouth's customers until after the interim period.[134] However, MISO proposed to adopt, among other things, Entergy's methodology for calculating Available Flowgate Capability (AFC); Entergy's automated preemption and competition software used to maximize the use of Available Transfer Capability (ATC); and ancillary services available under Entergy's tariff (except that scheduling, system control, and dispatch service are now provided under Schedule 1 of the MISO Tariff).[135] MISO proposed to treat integrating grandfathered agreements comparably to other grandfathered agreements in the MISO region.[136]

The FERC found that the Module B-1 tariff was just and reasonable,[137] noting, among other things, that MISO's proposal appropriately enabled ITC Midsouth's customers to use a single de-pancaked rate for the entire MISO region.[138] However, the FERC found that MISO failed to address important topics such as the transition of customers to MISO tariff Module B-1 service and the treatment of interconnection service requests.[139]

129. *Id.* at P 42.
130. *Midwest Indep. Transmission Sys. Operator, Inc.*, 143 F.E.R.C. ¶ 61,258 at P 1 (2013).
131. *Id.* at P 3.
132. *Id.* at P 6.
133. *Id.*
134. *Id.*
135. *Id.* at PP 8-9.
136. *Id.* at P 9.
137. *Id.* at P 26.
138. *Id.* at P 34.
139. *Id.* at P 29.

E. Southwest Power Pool, Inc.

On March 21, 2013, the FERC granted and denied requests for rehearing and/or clarification of its October 18, 2012 order conditionally accepting SPP's Integrated Marketplace.[140] It upheld its prior acceptance of SPP's limited day-ahead must-offer obligation, noting that in other RTOs it has denied any must-offer obligation where there is no capacity payment to generators and pointed out that SPP does not include a resource adequacy capacity payment.[141] It clarified its directive that the market monitor check for manipulation in the day-ahead market and requested that SPP file a tariff revision to specifically state that certain activities without a legitimate business purpose undertaken to manipulate the market are prohibited.[142] It deemed concerns about whether resources offered would be deliverable to be speculative, indicating they would be addressed in response to SPP's compliance filing regarding verification of deliverability.[143] As to the requirement imposed on SPP to file an information report in fifteen months, the FERC denied a request that it formally notice and act upon the informational filing but said it would take action under FPA section 206 if necessary and market participants could use the report as a basis for complaints.[144]

The FERC denied requests to allocate day-ahead make-whole payment cost to supply-increasing transactions because they do not increase the commitment costs incurred in the day-ahead market.[145] It explained that supply-increasing transactions receive day-ahead make-whole payments because they are part of the minimized costs to serve cleared bids, so they should not in turn have to pay their own compensation.[146] The FERC clarified that low voltage resources committed by SPP to address reliability are eligible for make-whole payments.[147]

The FERC denied rehearing of its decision to allow SPP to calculate losses on a marginal cost basis without a transition period; however, it clarified that parties may comment on the refund method for marginal losses in SPP's compliance filing proceeding.[148] It granted SPP rehearing for more time to meet the Order No. 755 implementation requirement concerning procurement of frequency regulation to allow implementation based upon actual experience with the market.[149]

As to long-term market-based congestion management tools, the FERC rejected rehearing of its decision to allow SPP 180 days after market start-up to submit its Order No. 681 long-term firm transmission rights compliance filing,

140. *Southwest Power Pool, Inc.*, 142 F.E.R.C. ¶ 61,205 at P 1 (2013).
141. *Id.* at P 11.
142. *Id.* at P 15.
143. *Id.* at P 19.
144. *Id.* at P 22.
145. *Id.* at P 26.
146. *Id.*
147. *Id.* at P 27.
148. *Id.* at P 36.
149. *Id.* at P 40.

noting SPP will provide a hedge for congestion during the first year.[150] It clarified that incremental auction revenue rights are to be allocated to customers whose transmission service requests resulted in network additions.[151] It denied expansion of cost hedges because proponents did not show that they were needed to serve native load as distinguished from the situation in MISO.[152]

The FERC denied requests for clarification of the allocation of costs to serve existing grandfathered agreements, emphasizing SPP still must undertake a stakeholder process and file a report on this topic.[153] As to seams and reserve sharing, in response to SPP's requests for clarification, the FERC stated SPP is not precluded from proposing tariff provisions that apply to external market participants if those entities choose to engage in transactions in the Integrated Marketplace, including participating in reserve sharing agreements with SPP.[154] The FERC denied SPP's contention that a need for market-to-market coordination had not been demonstrated.[155] However, it clarified SPP is not required to implement its market-to-market mechanism until one year following market start-up.[156]

The FERC upheld conditional acceptance of SPP's market power mitigation plan, denying generator requests for rehearing that such mitigation would deny them fixed costs recovery.[157] It reiterated that mitigation only applies when there are constraints and the generator crosses conduct and impact thresholds and has a significant Resources-to-Load distribution factor and that the conduct test prevents mitigation below unit marginal cost.[158] It noted when the generation offer exceeds the conduct or impact test, but not both, no mitigation applies, and where the unit provides an infra-marginal offer "(i.e., when it is not the [highest cost] unit selected in the supply stack)," it receives a fixed costs contribution.[159] It added that where there are operating reserves shortages, scarcity prices allow additional fixed costs recovery.[160]

F. California Independent System Operator Corp.

On June 15, 2013, the FERC approved implementation of a process to resettle certain bid recovery costs.[161] CAISO's tariff provides a make-whole provision for "bid cost recovery" under which resources committed will recover their bid costs, including start-up and minimum load costs, even if not actually

150. *Id.* at P 49.
151. *Id.* at P 54.
152. *Id.* at P 65.
153. *Id.* at P 70.
154. *Id.* at P 78.
155. *Id.* at P 85.
156. *Id.*
157. *Id.* at P 96.
158. *Id.*
159. *Id.* at P 98.
160. *Id.* at P 99.
161. *California Indep. Sys. Operator Corp.*, 143 F.E.R.C. ¶ 61,211 at P 1 (2013).

placed in service.[162] In initially accepting the mechanism, the FERC required that bid cost recovery payments be based on actual delivered energy.[163]

Once in place, however, CAISO determined the business practice manual formula implementing bid cost recovery did not properly account for payments when a generator provided less real-time energy than scheduled and that certain bidding practices could exacerbate this problem.[164] CAISO filed tariff revisions to eliminate the flaw and close the bidding practice loophole.[165] CAISO then issued a technical bulletin explaining it would recalculate previously settled bid cost recovery payments to account for the actual payments received for reduced power delivery.[166] When the FERC stated that CAISO could not resettle bid cost recovery payments without its authorization, CAISO filed for authorization.[167]

The FERC granted CAISO that authority.[168] It found resettlements necessary to give effect to CAISO's filed rate, which, since April 1, 2009, required it to account for "all revenues earned by a resource for energy actually delivered when it calculates a bid cost recovery payment. The purpose of the bid cost recovery mechanism is to make resources whole by permitting a resource to recover bid costs that were not fully recovered through market revenues."[169] Because the filed rate requires that CAISO "determine and net out all market revenues earned for delivered energy" and because the flawed formula in the business practice manuals previously had led to overpayments, the FERC found resettlement necessary to give effect to the express language and intent of the tariff.[170] The FERC rejected the arguments resettlement was unnecessary, noting the previous payments did not account for all "delivered" market revenues because of the improper formula[171] and rejected laches arguments CAISO had delayed too long from the time it realized resettlement was necessary to seek resettlement approval.[172] It distinguished CAISO's petition from a MISO petition where it denied resettlement authorization.[173] It stated it refused MISO resettlements because the MISO tariff did not require them while the original CAISO bid cost recovery payments were made pursuant to a flawed formula contained in a business practice manual inconsistent with the CAISO tariff.[174]

162. *Id.* at P 2.

163. *Id.*

164. *Id.* at P 3.

165. *Id.*; *see generally California Indep. Sys. Operator Corp.*, 135 F.E.R.C. ¶ 61,110 (2011) (accepting the revised tariff*), order on reh'g*, 137 F.E.R.C. ¶ 61,180 (2011).

166. *California Indep. Sys. Operator Corp.*, 143 F.E.R.C. ¶ 61,211 at P 4.

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

168. *Id.* at P 21.

169. *Id.* at P 16.

170. *Id.*

171. *Id.* at PP 18-19.

172. *Id.* at P 17.

173. *Id.* at P 20 (distinguishing *Midwest Indep. Transmission Sys. Operator, Inc.*, 115 F.E.R.C. ¶ 61,108 (2006), *order on reh'g*, 117 F.E.R.C. ¶ 61,212 (2007)).

174. *Id.* at P 20.

On January 4, 2013, the FERC determined CAISO did not need consent from a project operator to convert idle generating resources into synchronous condensers and designate them as Reliability Must-Run (RMR) assets.[175] Each fall, CAISO reviews the amount of local capacity available under certain simulated scenarios to plan system operations and what resources it will require to run to prevent outages during the following year.[176] In its 2012 review, CAISO determined, because San Onofre Nuclear Generating Station remained offline, certain peak load required further voltage support in Southern California.[177] CAISO determined two Huntington Beach Generating Station units needed to be converted into synchronous condensers and shunt capacitors installed at three substations because solutions could not be implemented before summer peak loads.[178] Thus, CAISO designated the two units RMR units and entered a non-conforming RMR Agreement with the plant operator AES, whereby AES would convert those units to condensers.[179] However, the entire Huntington Beach Generating Station is subject to a Tolling Agreement, filed with the FERC, and a contemporaneous Supplemental Agreement, each between AES and BE CA LLC, a subsidiary of JP Morgan Ventures Energy Corporation (collectively, JP Morgan).[180] The Supplemental Agreement required the other party's consent before either party could add generating infrastructure within a defined geographic area.[181] CAISO petitioned that the FERC declare that JP Morgan's consent was not needed to convert units to synchronous condensers, stating JP Morgan had been unwilling to either provide consent or stipulate its consent was not required.[182]

The FERC held JP Morgan did not have consent rights.[183] It found it had jurisdiction over the dispute, even though the Supplemental Agreement was not filed with it.[184] It noted the Supplemental Agreement incorporated by reference large parts of the Tolling Agreement and expressly stated, "together with the Tolling Agreement, [it] constitutes the entire agreement between the [p]arties hereto."[185] It found splitting a functionally unified agreement into multiple agreements cannot avoid FERC jurisdiction.[186] Having found jurisdiction, it parsed the language of the agreements.[187] It looked to the definition of

175. *California Indep. Sys. Operator Corp.*, 142 F.E.R.C. ¶ 61,016 at P 1 (2013).

176. *Id.* at P 2.

177. *Id.*

178. *Id.* at P 4.

179. *Id.* at P 5. The two units, initially built and installed as natural gas generators, had their emission rights sold to Edison Mission Huntington Beach and may not be operated. *Id*.

180. *Id.* at P 4. The original agreements were executed between AES and the Williams Energy Services Company, but Williams later assigned its interest to JP Morgan. *Id*.

181. *Id.* at PP 12, 15, 47.

182. *Id.* at P 6.

183. *Id.* at P 49.

184. *Id.* at PP 44-46.

185. *Id.* at P 45.

186. *Id.* at P 46 (citing *Natural Gas Pipeline Co. of Am*., 85 F.E.R.C. ¶ 61,322, at p. 62,262 (1998)).

187. *Id.*

"capacity" in the agreements and determined that was defined in terms of generating capacity.[188] Because the synchronous condensers provide ancillary services and do not generate additional megawatts, the FERC held that JP Morgan did not have to consent for conversion of units to synchronous condensers.[189]

On January 29, 2013, the FERC accepted CAISO tariff revisions to clarify what circular scheduling practices are prohibited.[190] Under the CAISO tariff, such schedules "have a source and sink in the same balancing authority area with transmission segments in a second balancing authority area."[191] These schedules can create operational difficulties and market efficiencies by introducing power schedules that create no actual power flows, which mislead the day-ahead system planning process, and can lead to, when the market is actually operated, congestion, interference with congestion relief practices, and sub-optimal unit commitment.[192]

CAISO proposed to prohibit individual scheduling coordinators from submitting bids that result in awarded schedule with an "e-Tag" where the source and sink are in the same balancing authority area.[193] This would be enforced by settling bids at the lower of the locational marginal price for the interties where the bids would take power.[194] CAISO proposed those submitting prohibited circular schedules would be unable to receive congestion revenue rights payments.[195] The prohibition would not apply to schedules from multiple "e-Tags" or submitted by multiple scheduling coordinators.[196] Bids from multiple scheduling coordinators would still be reviewed by the Market Monitor and the FERC's Office of Enforcement if warranted.[197] Other exceptions to the prohibition of circular scheduling were:

> (1) schedules that include a transmission segment on a direct current (DC) intertie; (2) schedules involving a pseudo-tie unit delivering energy to its attaining balancing authority area; (3) schedules used to serve temporarily stranded generation or load; and (4) schedules using wheel-through transactions to serve load outside a Participating Transmission Owner's system.[198]

However, if the circumstances that triggered one of these four exceptions were disregarded in the transaction and the schedule still has a source and sink in the same balancing authority area, the bid would be prohibited.[199]

188. *Id.* at P 47.
189. *Id.* at P 51.
190. *California Indep. Sys. Operator Corp.*, 142 F.E.R.C. ¶ 61,072 at P 1 (2013).
191. *Id.* at P 2.
192. *Id.* at PP 3-4.
193. *Id.* at P 8.
194. *Id.* at P 13.
195. *Id.* at P 16.
196. *Id.* at P 8.
197. *Id.*
198. *Id.* at P 10 (footnotes omitted).
199. *Id.* at P 12.

The FERC accepted CAISO's proposal,[200] finding CAISO's concerns valid and that creation of market rules that establish objective criteria would reduce the incentive to create circular schedules and aid in relief of real-time system congestion.[201] It rejected arguments that CAISO's tariff was unclear or inhibited efficient market behavior in the day-ahead or hour-ahead markets.[202] It directed CAISO to publish in the business practice manual how a company is to demonstrate load is being served outside the Participating Transmission Owner's system.[203]

On May 2, 2013, the FERC conditionally approved CAISO's elimination of convergence bidding at intertie scheduling points.[204] Convergence bidding involves bids to buy or sell electric energy in the day-ahead market, without any obligation to consume or provide electricity.[205] Such bids at intertie scheduling points were settled at the day-ahead price and then automatically liquidated with the opposite buy or sell position at the Hour-Ahead Scheduling Process price.[206] Based on information provided, it found that "due to the [CAISO's] dual real-time market structure, virtual transactions at CAISO interties did not improve market efficiency" and that "[r]ather than efficiently committing resources, . . . intertie convergence bidding led to increased costs to ratepayers,"[207] among other things, as the result of net virtual supplies developing at intertie scheduling points, which tended to reduce physical supply scheduled and to increase real-time imbalance energy offset costs, which CAISO handles in an uplift account.[208] It directed that CAISO attempt to "develop[] a solution to the dual real-time market structure that would permit reinstatement of intertie convergence bidding with just and reasonable outcomes," including "expected benefits, such as increased competition, reduced market power, and increased day-ahead to real-time price convergence."[209]

G. Electric Reliability Council of Texas

In *Blue Summit Wind, LLC*, the FERC disclaimed jurisdiction over facilities interconnecting a wind farm that is located in the SPP region but that would be connected to the Electric Reliability Council of Texas (ERCOT).[210] The wind farm and interconnection facilities would be located entirely within Texas, and configured to prevent the flow of electric energy to the SPP.[211] Station power

200. *Id.* at P 22.
201. *Id.* at PP 22-23.
202. *Id.* at PP 30-34.
203. *Id.* at P 38.
204. *California Indep. Sys. Operator Corp.*, 143 F.E.R.C. ¶ 61,087 at P 2 (2013).
205. *Id.* at P 5.
206. *Id.*
207. *Id.* at P 62.
208. *Id.* at P 66.
209. *Id.* at PP 75-76.
210. *Blue Summit Wind, LLC*, 142 F.E.R.C. ¶ 61,031 at P 1 (2013).
211. *Id.*

would be supplied by an ERCOT retail provider, but if that power was unavailable from ERCOT, backup power would be provided by an SPP provider.[212] This backup configuration would include an automatic transfer switch that would prevent any commingling of electric energy from ERCOT.[213] The FERC determined that pursuant to *Cross Texas Transmission LLC*[214] and *Cottonwood Energy Co., LP*,[215] it should disclaim jurisdiction over the interconnection facilities because (1) the facilities will be located entirely within Texas and all energy produced, transmitted, and consumed solely therein and (2) the configuration ensured no wind farm energy will be commingled with that in interstate commerce, except as a result of FPA section 210, 211, or 212 orders.[216]

On January 17, 2013, the FERC granted a petition for declaratory order filed by Electric Transmission Texas, LLC (ETT), a transmission owner with facilities located in the ERCOT region, disclaiming jurisdiction over (1) its ERCOT region transmission facilities; (2) transmission service over those facilities; and (3) sales of electricity over those facilities.[217] ETT filed its petition to comply with a 2008 Public Utilities Commission of Texas (PUCT) order establishing five Competitive Renewable Energy Zones (CREZ).[218] The PUCT required that generators located outside of ERCOT but interconnecting into ERCOT through a CREZ facility, or the transmission services provider operating that CREZ transmission facility, seek a FERC order disclaiming jurisdiction as a condition precedent a certificate of convenience and necessity for the CREZ line.[219] ETT argued each of its CREZ projects is located entirely within ERCOT, none would interconnect with transmission facilities of any non-ERCOT regions, and none would be used to provide transmission service in interstate commerce.[220] The FERC found ETT's CREZ facilities would not be used for transmission or sales for resale of electric energy in interstate commerce, including the commingling of electric energy between ERCOT and non-ERCOT regions.[221] It disclaimed jurisdiction under FPA sections 210, 211, and 212, reliability jurisdiction under FPA section 215, and any other FPA provisions.[222]

212. *Id.* at PP 6-10.
213. *Id.* at P 7.
214. *Cross Tex. Transmission LLC*, 129 F.E.R.C. ¶ 61,106 (2009).
215. *Cottonwood Energy Co., LP*, 118 F.E.R.C. ¶ 61,198 (2007).
216. *Blue Summit Wind*, 142 F.E.R.C. ¶ 61,031 at PP 17-22.
217. *Electric Transmission Tex., LLC*, 142 F.E.R.C. ¶ 61,032 at P 15 (2013).
218. *Id.* at PP 1-4.
219. *Id.* at P 3.
220. *Id.* at P 6.
221. *Id.* at P 13.
222. *Id.* at P 15.

V. TRANSMISSION RATES

A. Cost-Based Rates

In its June 20, 2013, order, the FERC accepted San Diego Gas & Electric Company's (SDG&E) tariff revisions to implement a new Transmission Owner formula rate mechanism (TO4).[223] The TO4 formula made four changes:

> (1) [It] shifts the rate-effective period for each cycle from September 1 to January 1 following an initial transition period; (2) [it] incorporates special ratemaking incentives for transmission projects, pursuant to Order No. 679 . . . ; (3) [it] permits SDG&E to allocate and/or directly assign costs for certain categories of administrative and general and intangible plant costs . . . to the transmission function as opposed to solely utilizing a labor ratio allocation . . . ; and (4) the TO4 formula has no sunset date.[224]

SDG&E requested an increase in transmission service rates, and a return on equity (ROE) of 11.3%, comprised of a base return of 10.3% plus a 50 basis point incentive adder for its continued participation in CAISO and a 50 basis point adder for its increased investment risk.[225] SDG&E also requested new transmission depreciation rate.[226]

The FERC approved continued use of the 50 basis-point incentive adder as consistent with FPA section 219 because it encourages SDG&E's continued participation in CAISO.[227] It rejected protesters' requests for summary disposition of the proposed ROE but found that SDG&E violated FERC precedent by using a twelve-month weighted average for transmission rate base.[228] It ordered the average thirteen-monthly balances be used for SDG&E's transmission rates.[229] It imposed a five-month suspension subject to refund[230] but on rehearing granted intervenors' request that the rates be suspended for a nominal period.[231]

B. Incentive Rates

On November 9, 2012, Dairyland Power Cooperative (Dairyland) petitioned the FERC in connection with its investment in the Hampton-Rochester-La Crosse Project (the Project), which is planned to consist primarily of a double-circuit-capable 345 kV transmission line and related 161 kV lines, requesting a hypothetical capital structure of 35% equity and 65% debt (hypothetical capital structure) and recovery of 100% of prudently-incurred costs

223. *San Diego Gas & Elec. Co.*, 143 F.E.R.C. ¶ 61,246 at P 1 (2013), *reh'g granted*, 144 F.E.R.C. ¶ 61,078 (2013).

224. *San Diego Gas & Elec.*, 143 F.E.R.C. ¶ 61,246 at P 4.

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

226. *Id.* at P 6.

227. *Id.* at P 23.

228. *Id.* at P 24.

229. *Id.*

230. *Id.* Ordering Paragraph (A).

231. *San Diego Gas & Elec. Co.*, 144 F.E.R.C. ¶ 61,078 at P 9 (2013).

of transmission facilities abandoned for reasons beyond the control of Dairyland (abandoned plant recovery).[232]

As to FPA section 219(a) and Order No. 679 requirements, Dairyland stated the Project ensures reliability or reduces the cost of delivered power by reducing transmission congestion, as is supported by the Minnesota Public Utilities Commission's Certificate of Need, as well as by the Public Service Commission of Wisconsin's Certificate of Public Convenience and Necessity, thus is entitled to the rebuttable presumption that it meets the requirements of FPA section 219(a).[233] Dairyland also stated the Project is not routine (first 345 kV owned by Dairyland uses advanced technology) and faces significant hurdles and associated risks (planned regionally and crosses several state borders, thus giving Dairyland limited control of cancellation or costs), so it meets the Nexus Requirement of Order No. 679.[234]

In terms of abandoned plant recovery, Dairyland stated that as a minority owner it has little control over decisions related to cancellation, and key approvals from both federal and state agencies still need to be obtained, which may threaten the Project's progress.[235] It asserted lack of recovery may affect its credit rating and increase financing costs.[236] As to hypothetical capital structure, Dairyland argued issues related to joint ownership, limited control as a minority owner, outstanding permits and rights-of-way, and use of advanced technologies created risks Dairyland might not otherwise face with internal projects.[237] It asserted that a 35% equity ratio would provide a return commensurate with risk and that denial of such compensation would adversely affect its credit rating.[238]

The FERC accepted Dairyland's reasoning, finding that the total package of incentives requested by Dairyland was tailored to the project risks and challenges Dairyland faces.[239]

VI. MERGERS AND ACQUISITIONS

On September 24, 2012, ITC Holdings Corporation (ITC) and Entergy Corporation (Entergy) requested FPA section 203 authorization[240] to merge FERC-jurisdictional transmission facilities of the Entergy Operating Companies[241] into a new ITC subsidiary.[242] They averred the transaction

232. *Dairyland Power Coop.*, 142 F.E.R.C. ¶ 61,100 at P 1 (2013).

233. *Id.* at P 10.

234. *Id.* at P 14.

235. *Id.* at PP 16-17.

236. *Id.* at PP 16-18.

237. *Id.* at P 21.

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

239. *Id.* at P 30.

240. 16 U.S.C. § 824b(a)(1) (2012).

241. The "Entergy Operating Companies are vertically integrated electric utilities" in Arkansas, Louisiana, Mississippi, and Texas that "own approximately 15,800 miles of transmission lines and provide transmission service to an area of almost 114,000 square miles." *ITC Holdings Corp.*, 143 F.E.R.C. ¶ 61,256 at P 14 (2013).

> will consist of the separation of the transmission assets of the Entergy Operating Companies into separate transmission companies that will be owned by the new Entergy intermediate holding company, . . . which will then be distributed to Entergy's shareholders in a spin-off or split-off and subsequently merged with the new . . . intermediate public utility holding company.[243]

The ITC subsidiary would own the "wires-only" transmission assets of the Entergy Operating Companies while Entergy would continue to own the Entergy Operating Companies and their electric generation and distribution assets.[244]

In approving the transaction, the FERC noted it "will benefit customers in the Entergy footprint and bring an independent transmission company to a region that has not experienced the benefits of independent transmission ownership."[245] It listed the Entergy Operating Companies' ability to focus on generation and distribution as one benefit.[246] Additionally, it noted "[b]y eliminating competition for capital between generation and transmission functions and thereby focusing only on transmission investment, the Transco model responds more rapidly and precisely to market signals indicating when and where transmission investment is needed."[247]

VII. COMPLAINTS

A. Rail Splitter Wind Farm, LLC v. Ameren Services Co.

On January 17, 2013, the FERC denied the challenge of a wind energy developer, Rail Splitter Wind Farm, LLC (Rail Splitter), against Ameren Services Company (Ameren) and MISO, alleging Ameren's assessment of a monthly services charge for its 107 MW wind farm in Illinois was unreasonable.[248] Under a Large Generator Interconnection Agreement (LGIA), Rail Splitter committed to fund upfront, without reimbursement, 100% of the costs—$2.7 million—to construct the necessary network upgrades to accommodate the interconnection of the Rail Splitter facility to the Ameren system.[249]

When construction on the facility was nearly complete and Rail Splitter had paid Ameren $2.3 million of the total costs of network upgrades, Ameren notified Rail Splitter of its decision to invoke Option 1 of section III.A.d of Attachment FF of the MISO tariff in order to recover the costs of network

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

243. *Id*. at P 20 (quoting Joint Application for Authorization of Acquisition and Disposition of Jurisdictional Transmission Facilities, Approval of Transmission Service Formula Rate and Certain Jurisdictional Agreements, and Petition for Declaratory Order on Application of Section 305(a) of the Federal Power Act at 12, (*ITC Holdings Corp*., 143 F.E.R.C. ¶ 61,256 (2013) (Docket Nos. EC12-145-000, ER12-2681-000, EL12-107-000)).

244. *Id.* at P 2.

245. *Id.* at P 124.

246. *Id.*

247. *Id.* at P 125 (quoting *Startrans IO, L.L.C*., 122 F.E.R.C. ¶ 61,307 at P 27 (2008)).

248. *Rail Splitter Wind Farm, LLC v. Ameren Servs. Co.*, 142 F.E.R.C. ¶ 61,047 at P 1 (2013).

249. *Id*. at PP 2-5, 8.

upgrades, instead of accepting the remaining balance from Rail Splitter.[250] Under Option 1, the interconnection customer funds the network upgrades initially but receives 100% reimbursement from the transmission owner for those funds after the facility achieves commercial operations.[251] The interconnection customer then pays a percentage of reimbursed funds back to the transmission owner over time as a monthly services charge.[252] Accordingly, Ameren reimbursed Rail Splitter the cost for 100% of the network upgrades financed by Rail Splitter and imposed a monthly services charge based on Ameren's revenue requirement.[253] Rail Splitter raised concerns informally about Ameren's election of Option 1 but entered into a Facilities Service Agreement (FSA) with Ameren, which formalized the monthly services charge obligation and was filed with and accepted by the FERC in January 2010.[254] Under the FSA, the total amount that Rail Splitter would pay Ameren would be $9.8 million more than the actual cost of network upgrades.[255] The FERC denied the complaint, noting that Rail Splitter failed to bring its concerns to it before executing the FSA.[256] Finding the FSA was not protected by the *Mobile-Sierra* standard, the FERC held that Rail Splitter had not met the less stringent just and reasonable standard that would justify amending the terms of an executed agreement and would outweigh the FERC's interests in promoting stability and regulatory certainty.[257]

Finally, the FERC declined to apply its holding in *E.ON Climate & Renewables North America, LLC v. MISO*[258] to the FSA, emphasizing that its decision in *E.ON* would not apply to FSAs that were effective prior to March 22, 2011.[259]

B. New England States Committee on Electricity v. ISO New England, Inc.

On February 12, 2013, the FERC denied the New England States Committee on Electricity's (NESCOE) December 28, 2012, complaint alleging that ISO-NE's proposed tariff revisions implementing buyer-side mitigation in the FCM "without an exemption for state-sponsored public policy resources" are unjust and unreasonable.[260]

In its complaint, NESCOE argued if ISO-NE implements its minimum offer price rule (MOPR) without an exemption for "state-sponsored public policy resources," the MOPR will "result in an over-procurement of capacity and will

250. *Id.* at P 4.
251. *Id.* at P 3.
252. *Id.* at PP 3-5.
253. *Id.* at PP 6-7.
254. *Id.* at P 4.
255. *Id.* at P 8.
256. *Id.* at P 32.
257. *Id.* at PP 30-31.
258. *E.ON Climate & Renewables North America, LLC v. MISO*, 137 F.E.R.C. ¶ 61,076 (2011).
259. *Rail Splitter Wind Farm*, 142 F.E.R.C. ¶ 61,047 at P 33.
260. *New England States Comm. on Elec. v. ISO New England, Inc.*, 142 F.E.R.C. ¶ 61,108 at P 1 (2013).

unreasonably undermine state laws supporting the development of renewable resources."[261] NESCOE asserted, "the MOPR will likely completely exclude many, if not all, new renewable resources from the FCM" despite that states in the region have codified policies supporting new renewable resources, which "will be placed in service irrespective of the MOPR's exclusion."[262] As an alternative to ISO-NE's proposed MOPR, NESCOE offered an alternative—a categorical exemption from the MOPR for certain statutorily-defined renewable resources—NESCOE asserts would allow renewable resources to clear in the FCM[263] and is "based on the overarching principle that legitimate state statutory goals can and must be integrated within a competitive market structure."[264]

In denying NESCOE's complaint, the FERC explained NESCOE had not supported that ISO-NE's proposal is unreasonable without "a categorical exemption for state-sponsored resources"[265] or that "the MOPR undermines state policies or deters states from continuing their renewable resource policies."[266] It explained, "even with an exemption for state-sponsored resources, the FCM cannot and will not procure more than the [Installed Capacity Requirement (ICR)]," and "[b]ecause nothing in the proposed FCM rules require nor cause the purchase of capacity in excess of the ICR, NESCOE's argument does not persuade us to find the proposed rules to be unjust and unreasonable."[267] It explained it must balance two considerations in assessing NESCOE's proposed exemption: "The first is [the FERC's] responsibility to promote economically efficient markets and efficient prices, and the second is [the FERC's] interest in accommodating the ability of states to pursue other legitimate state policy objectives."[268] It stated that although it had accepted PJM's proposal to exempt renewable resources from its MOPR, "there are differences between PJM and ISO-NE that affect the balancing of the above considerations."[269] Specifically, the "effect of an exemption for renewables would likely be much greater in New England than in PJM"[270] because "the ISO-NE capacity market relies on a vertical demand curve while PJM's capacity market relies on a sloped demand curve" and because the New England market is "substantially smaller than the PJM market."[271] The FERC explained that these aspects of the FCM make it likely that an exemption for renewables will "have a greater depressing effect on capacity prices in New England than in PJM."[272] It stated, "[a]ny new proposal

261. *Id.* at P 8.
262. *Id.*
263. *Id.* at PP 13-14.
264. *Id.* at P 14.
265. *Id.* at P 33.
266. *Id.* at P 36.
267. *Id.* at P 34.
268. *Id.* at P 35.
269. *Id.*
270. *Id.*
271. *Id.*
272. *Id.*

must do more than rely on findings specific to PJM and address the above-described characteristics of ISO-NE's market."[273]

C. New England Power Generators Ass'n v. ISO New England Inc.

On August 27, 2013, the FERC denied in part and granted in part a New England Power Generators Association (NEPGA) complaint ISO-NE "impermissibly reinterpreted its Transmission, Markets and Services Tariff (Tariff) to impose a firm fuel obligation on all resources with Capacity Supply Obligations (capacity resources) through the [FCM]."[274] In addressing the tariff requirements for capacity resources, the FERC identified the most relevant tariff provisions[275] and explained that

> [a] plain reading of these provisions imposes on capacity resources straightforward requirements to: (1) offer into both the day-ahead and real-time energy markets a MW amount equal to or greater than its Capacity Supply Obligation when the resource is physically available; (2) respond to ISO-NE's directives to start, shutdown or change output levels; and (3) keep supply offers open throughout the operating day.[276]

It then rejected NEPGA's assertion that ISO-NE "impermissibly 'stretches' these requirements to make a capacity resource's failure to comply with dispatch instructions based on fuel procurement reasons a Tariff violation,"[277] stating "[a]lthough the [FERC] agrees with NEPGA (as conceded by ISO-NE) that there is not a per se firm fuel requirement in the Tariff," the Good Utility Practice standard in Tariff section III.1.11.3(d) does not extend to fuel procurement activities.[278]

The FERC found that section III.1.11.3(d) concerns how a market participant "manages the physical operation of a resource in order to respond to its dispatch instructions as closely as practical," and does not concern "how the resource submits or manages its offers or how it procures fuel, nor does it concern whether a resource will operate at all due to fuel procurement issues."[279] Similarly, it explained that Tariff sections III.13.6.1.1.1 and III.13.6.1.1.2 "which describe the formation and submission of supply offers, do not apply to fuel procurement activities" and that "the Good Utility Practice clause applies to the physical, mechanical operations of the unit—not fuel procurement."[280] It explained "the Tariff excuses nonperformance by a capacity resource in only limited circumstances, and merely exercising Good Utility Practice in an effort

273. *Id.* at P 37.

274. *New England Power Generators Ass'n v. ISO New England, Inc.*, 144 F.E.R.C. ¶ 61,157 at P 1 (2013).

275. *Id.* at P 48 (identifying Tariff §§ III.1.7.20(b), III.1.10.1A(d)(vi), and III.13.6.1.1.1 as the most relevant provisions in this context).

276. *Id.* at P 49.

277. *Id.* at PP 50, 53.

278. *Id.* at P 53.

279. *Id.*

280. *Id.* at P 54.

to procure fuel is not one of them."[281] The FERC found that "[f]or these reasons, . . . Tariff sections III.1.11.3(d) and III.13.6.1.1.2 do not apply to fuel procurement or transportation activities."[282]

While the FERC denied NEPGA's complaint with respect to the application of Good Utility Practice to fuel procurement, it granted, in part, NEPGA's complaint that ISO-NE's Tariff interpretation "impermissibly narrowed the circumstances under which a capacity resource may be excused from its performance obligation."[283] It explained it agreed with ISO-NE "that the Tariff imposes a strict performance obligation on capacity resources and that capacity resources may not take economic outages, including outages based on economic decisions not to procure fuel or transportation[,]"[284] but there is "an important distinction between being *unable* to procure fuel or transportation and *making an economic determination* not to procure fuel or transportation."[285] The FERC found that

> under the [t]ariff, a *demonstrated* inability to procure fuel or transportation for a resource to run beyond (in terms of hours and/or incremental MWs) its day-ahead commitment, or when not scheduled in the day-ahead market, may legitimately affect whether a resource is physically available. If a capacity resource cannot procure fuel or transportation in real time in order to run at dispatch levels beyond its day-ahead commitment (or when not scheduled in the day-ahead market), then the resource is not physically available to perform for a reason beyond the resource's control for those additional hours and/or MWs; thus the resource may be excused for non-performance.[286]

The FERC also found, "economic considerations are irrelevant to determining whether a unit is 'physically available,' based upon a natural interpretation of the term 'physical,' as pertaining to that which is material or mechanical," and "a capacity resource that fails to comply with dispatch instructions when it is physically available but has determined not to procure fuel or transportation due to economic considerations is in violation of the Tariff."[287] The FERC explained that it "will not pursue any pending enforcement referrals from the [internal market monitor (IMM)] that are based solely on an alleged inability to procure natural gas,"[288] but "will review such subsequent referrals consistent with the factors identified in the *Revised Policy Statement on Enforcement*."[289] The FERC explained that "[d]etermining whether a capacity resource was unable to obtain fuel and/or transportation will . . . be a fact-specific inquiry," and that the IMM "will need to make such

281. *Id.*

282. *Id.*

283. *Id.* at P 47.

284. *Id.*

285. *Id.* at P 56.

286. *Id.*

287. *Id.* at P 58.

288. *Id.* at P 60.

289. *Id.* at P 61 (citing *Enforcement of Status, Regulations and Orders*, 123 F.E.R.C. ¶ 61,156 at PP 23-26 (2008)).

determinations on a case-specific basis . . . and will refer the cases to the Commission . . . if the IMM has reason to believe that the resource's action is a [t]ariff violation."[290]

D. Prairie Power, Inc. v. Ameren Services Co.

In response to a complaint filed by Prairie Power, Inc. (Prairie Power) against Ameren Services Company, Ameren Illinois Company (Ameren Illinois) and Ameren Transmission Company of Illinois (Ameren Transmission) (collectively, Ameren), the FERC held that Ameren's delays in filing a Joint Agreement to implement Prairie Power's revenue requirement for transmission that had been turned over to MISO, based on Ameren's disagreement with that revenue requirement, was unjust and unreasonable.[291] The FERC also found MISO's tariff unjust and unreasonable because it did not provide for Prairie Power's recovery of its Attachment O revenue requirement through a joint pricing zone.[292] The FERC instituted an FPA section 206 proceeding to establish such tariff provisions and determine transmission facilities to be included in the Attachment O revenue requirement to be recovered through Ameren Illinois joint pricing zone rates.[293] The FERC noted that Prairie Power could commit to refunds to obtain an earlier effective date than a date after hearing and settlement procedures.[294]

VIII. PUBLIC UTILITY REGULATORY POLICIES ACT

A. Southern California Edison Co.

The FERC considered whether certain Qualifying Facility (QF) power purchase agreements (PPA) approved pursuant to a state regulatory authority's implementation of section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA)[295] are exempt from most FPA provisions.[296] In this instance, the provision in question is FPA section 205's requirement that no wholesale sale of electric energy may be made between a franchised public utility with captive customers and a market-regulated power sales affiliate without prior FERC authorization.[297] Southern California Edison Company (SoCal Edison)

290. *Id.* at P 62.

291. *Prairie Power, Inc. v. Ameren Servs. Co.*, 144 F.E.R.C. ¶ 61,193 at PP 13, 25 (2013).

292. *Id.* at P 25.

293. *Id.* at P 2.

294. *Id.* at P 32 n.27.

295. 16 U.S.C. § 824a-3 (2012).

296. *Southern Cal. Edison Co.*, 143 F.E.R.C. ¶ 61,222 at PP 1, 13-14 (2013).

297. 18 C.F.R. § 35.39(b) (2012); *see also* Order No. 697, *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, F.E.R.C. STATS. & REGS. ¶ 31,252 at P 467, 72 Fed. Reg. 39,904 (codified at 18 C.F.R. pt. 35), *clarified*, 121 F.E.R.C. ¶ 61,260 (2007), *order on reh'g*, Order No. 697-A, F.E.R.C. STATS. & REGS. ¶ 31,268, 73 Fed. Reg. 25,832 (codified at 18 C.F.R. pt. 18), *clarified*, 124 F.E.R.C. ¶ 61,055, *order on reh'g*, Order No. 697-B, F.E.R.C. STATS. & REGS. ¶ 31,285, 73 Fed. Reg. 79,610 (2008), *order on reh'g*, Order No. 697-C, F.E.R.C. STATS. & REGS. ¶ 31,291, 74 Fed. Reg. 30,924 (2009), *order on reh'g*, Order No. 697-D, F.E.R.C. STATS. & REGS. ¶ 31,305, 75 Fed. Reg. 14,342 (2010),

submitted a request for authorization of affiliate transaction for a PPA it had entered into with Watson Cogeneration Company (Watson Cogeneration), a 385 MW combined heat and power (CHP) QF.[298] SoCal Edison is a wholly-owned subsidiary of Edison International while Watson Cogeneration is owned by three general partners, one of which is a wholly-owned indirect subsidiary of Edison International.[299]

In December 2010, the California Public Utilities Commission (CPUC) approved a settlement between California investor-owned utilities (IOUs), representatives of CHP QFs, and statewide consumer and ratepayer groups (QF/CHP Settlement) that provided for a transition period for moving expiring PURPA contracts to competitively-procured contracts.[300] Under the QF/CHP Settlement, a CHP QF currently selling to an IOU under an existing contract (or an extension of an existing contract) may sign a Transition PPA with that same IOU that expires upon the election of seller but no later than the end of the Transition Period on July 1, 2015.[301] The PPA between SoCal Edison and Watson Cogeneration is, with limited exceptions, the standard Transition PPA adopted under the QF/CHP Settlement.[302] In dismissing SoCal Edison's request for authorization, the FERC held Transition PPAs, like the PPA between SoCal Edison and Watson Cogeneration, are not subject to the FERC's jurisdiction and do not require FPA section 205 approval to engage in affiliate transactions.[303] It rejected the argument that because the mandatory PURPA purchase obligation ended for QFs with more than 20 MW capacity in the service territories of SoCal Edison and the other California IOUs.[304] PPAs entered into post-*PG&E* were subject to its jurisdiction.[305] It stated that its holding in *Pacific Gas & Electric Co. (PG&E)* applied to "*new* obligations or contracts to purchase electric energy."[306] It noted the obligation under the QF/CHP Settlement to transition from a PURPA regime to a non-PURPA regime was established before *PG&E* and is "part of a continuing obligation to buy from QFs that the Commission relied on" in making its determination in *PG&E*.[307]

The FERC also found that Transition PPAs, like the one in question, possessed "a number of attributes that are characteristic of PPAs entered into

aff'd sub nom. Mont. Consumer Counsel v. FERC, 659 F.3d 910 (9th Cir. 2011), *cert. denied*, 133 S. Ct. 26 (2012).

298. *Southern Cal. Edison*, 143 F.E.R.C. ¶ 61,222 at P 1.

299. *Id.* at P 2.

300. Application of Southern Cal. Edison Co. (U338E) for Applying the Market Index Formula & As-Available Capacity Prices Adopted in D.07-09-040 to Calculate Short-Run Avoided Costs for Payments to Qualifying Facilities Beginning July 2003 & Associated Relief, Decision 10-12-035, Application No. 08-11-001, at 2 (Cal. P.U.C. Dec. 21, 2010).

301. *Southern Cal. Edison*, 143 F.E.R.C. ¶ 61,222 at P 7.

302. *Id.* at P 8.

303. *Id.* at P 17.

304. *Pacific Gas & Elec. Co.*, 135 F.E.R.C. ¶ 61,234 at P 2 (2011).

305. *Southern Cal. Edison*, 143 F.E.R.C. ¶ 61,222 at P 17.

306. *Id.*

307. *Id.*

pursuant to a state regulatory authority's implementation of PURPA."[308] Among those attributes are pricing at avoided-cost rates and approval by the CPUC.[309] Because the QF/CHP Settlement is one of the CPUC's PURPA procurement programs, the FERC held Transition PPAs are part of a continuing PURPA obligation and not "new obligations incurred after termination of the PURPA obligation."[310]

B. Swecker v. Midland Power Cooperative

The FERC denied rehearing of a previous order[311] that found that disconnecting service to a QF was inconsistent with the requirements of PURPA.[312] The instant proceeding arose from the Sweckers' petition to enforce PURPA against Midland Power Cooperative (Midland), which they claimed had refused to purchase the excess electricity produced by their QF at full avoided cost.[313] In response, the FERC issued a notice of intent not to act,[314] and Midland disconnected the QF.

The FERC earlier held the disconnection of the Sweckers' QF to be inconsistent with Midland's PURPA obligations to purchase electricity from and sell electricity to QFs.[315] On rehearing, the Iowa Utilities Board argued that in ordering the Sweckers' electric service reconnected, the FERC entered into an area that has traditionally under state regulatory authority purview.[316] The FERC disagreed, finding that termination of the buy and sell obligation to a QF can only occur pursuant to its rules for termination.[317] Because the Sweckers' retail and QF services "are so intertwined physically that disconnection of one cannot be done without disconnection of the other, as is the case here," the FERC held that "the requirements of PURPA and [the FERC's] regulations must prevail over the proposed unilateral action of the interconnected purchasing/selling utility."[318] The FERC acknowledged that there may be instances where disconnection is warranted, but the Sweckers must first be given the opportunity to fully litigate their PURPA enforcement case, both at the FERC and in the federal courts.[319]

308. *Id.* at P 18.

309. *Id.*

310. *Id.* at P 17.

311. *Swecker v. Midland Power Coop.*, 137 F.E.R.C. ¶ 61,200 (2011).

312. *Swecker v. Midland Power Coop.*, 142 F.E.R.C. ¶ 61,207 at PP 1, 31 (2013) (citing 16 U.S.C. § 824a-3 (2012)).

313. *Id.* at P 11.

314. *Id.* at PP 12-13; *see also Swecker v. Midland Power Coop.*, 136 F.E.R.C. ¶ 61,085, *reconsideration denied*, 137 F.E.R.C. ¶ 61,035 (2011).

315. *Swecker*, 137 F.E.R.C. ¶ 61,200 at PP 28-39.

316. *Swecker*, 142 F.E.R.C. ¶ 61,207 at P 23.

317. *Id.* at P 31.

318. *Id.* at P 33.

319. *Id.* at P 39.

C. City of Burlington, Vermont

The FERC granted the City of Burlington, Vermont's (Burlington) PURPA section 210(m)[320] application for termination of the obligation to enter into new power purchases from the 7.4 MW Chace Mill Hydroelectric Project (Chace Mill), an interconnecting run-of-the-river hydroelectric QF with a net capacity of 7.4 MW.[321]

The FERC found Burlington met its burden to rebut the Order No. 688[322] presumption that Chace Mill, as a below-20 MW QF, does not have non-discriminatory access to ISO-NE markets, among other things, by showing that that energy from Chace Mill had been sold into the those markets after the expiration of the Burlington Purchase Agreement and there were otherwise no barriers to such Chace Mill sales.[323] The FERC noted the Chace Mill owner initiated a state PURPA proceeding prior to the Burlington petition, but declined to assess whether it could result in a legally enforceable purchase obligation or whether any such obligation would be grandfathered under PURPA section 210(m).[324]

IX. GENERATOR INTERCONNECTION

On August 14, 2013 (amended September 9, 2013), MISO submitted to the FERC an unexecuted amended and restated Generator Interconnection Agreement (Hoopeston GIA) among Hoopeston Wind, LLC (Hoopeston), Ameren Services Company, and MISO.[325] The agreement was unexecuted because Hoopeston disputed Ameren's proposed cost allocations.[326]

The original interconnection agreement among Ameren, Hoopeston, and MISO identified certain network upgrades whose costs were to be recovered by Ameren under Option 1 of the MISO Tariff (Original Network Upgrades).[327] The Hoopeston GIA identified additional network upgrades (Incremental Network Upgrades) providing the same cost recovery.[328] Hoopeston contended Ameren may not elect Option 1 to recover network upgrade costs for the Hoopeston GIA, but must instead use Option 2 where self-funding option to recover non-reimbursable portion of such costs is not applicable.[329]

The FERC conditionally accepted the Hoopeston GIA, finding that Ameren may apply Option 1 for the original network upgrades but not for the incremental

320. 16 U.S.C. § 824a-3(m) (2012).

321. *City of Burlington*, 145 F.E.R.C. ¶ 61,121 at PP 1-2 (2013).

322. Order No. 688-A, F.E.R.C. STATS. & REGS. ¶ 31,250 at PP 94-104, 72 Fed. Reg. 35,872 (2007) (codified at 18 C.F.R. pt. 292).

323. *City of Burlington*, 145 F.E.R.C. ¶ 61,121 at PP 31-36.

324. *Id.* at P 37.

325. *Midcontinent Indep. Sys. Operator, Inc*., 145 F.E.R.C. ¶ 61,111 at P 1 (2013).

326. *Id.*

327. *Id.* at P 9.

328. *Id.*

329. *Id.* at PP 15, 17.

network upgrades.[330] Thus, the FERC directed MISO to revise the agreement so that the self-fund option does not include the recovery of costs other than the return of and on the capital costs of the network upgrades.[331] The FERC also found that Ameren as a transmission owner may select self-funding under Article 11.3 of the MISO's .1a GIA.[332]

X. MISCELLANEOUS

On voluntary remand from the U.S. Court of Appeals District of Columbia Circuit, the FERC affirmed Chehalis Power Generating, L.P.'s reactive power rate schedule for service to Bonneville Power Administration to be a revised, not an "initial," rate subject to FPA section 205(e) suspension and refund, and clarified that rate schedules for jurisdictional reactive power service provided at no compensation must be filed, on a prospective basis.[333] It directed a generic workshop on filing such rate schedules.[334] The FERC reasoned "initial" rate filings, not subject to suspension and refund, must cover a new customer and a new service, and failure to file in the past did not render a filing for an ongoing service "initial."[335]

330. *Id.* at P 40.
331. *Id.* at P 41.
332. *Id.* at P 42.
333. *Chehalis Power Generating, L.P.*, 145 F.E.R.C. ¶ 61,052 at P 1 (2013).
334. *Id.* at P 12.
335. *Id.* at PP 3-4, 13.

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