REPORT OF THE POWER GENERATION AND MARKETING SUBCOMMITTEE

The following is the report of the Energy Bar Association's Power Generation and Marketing Subcommittee. In this report, the Committee summarizes key developments in state and federal regulation of power generation and marketing from July 2014 to June 2015.

I. CAITHNESS SHEPHERDS FLAT, LLC V. FERC

In 2012, the Energy Bar Association Renewable Law Committee reported on FERC proceedings concerning Bonneville Power Administration's (BPA) protocols for curtailing wind-powered generation interconnected to its transmission system during times when BPA had an oversupply of federal hydroelectric generation in the Pacific Northwest.[1] The FERC rejected an "Environmental Redispatch Policy" and, pursuant to section 211A of the Federal Power Act (FPA), directed BPA to file a tariff "for transmission service on terms and conditions that are comparable to those under which Bonneville provides . . . to itself and that are not unduly discriminatory or preferential."[2] BPA subsequently filed a proposed "Oversupply Management Protocol" (OMP) that would compensate curtailed wind generators for lost Production Tax Credits, lost sales of Renewable Energy Credits, and penalties and lost revenues under power sales contracts for failure to supply wind energy during hours BPA displaced wind generation with excess federal hydropower. BPA proposed to recover these costs in its transmission rates. The FERC conditionally approved the OMP but did not

1. *Report of the Renewable Energy Committee*, 33 ENERGY L.J. 333, 358-59 (2012).

2. *Iberdrola Renewables, Inc. v. Bonneville Power Admin.*, 137 F.E.R.C. ¶ 61,185 at P 1 (2011), *reh'g denied*, 141 F.E.R.C. ¶ 61,233 (2012).

find BPA's proposed cost allocation to be an appropriate and equitable cost burden on all firm transmission customers.[3] The FERC said that it would need to consider rate and non-rate terms and conditions to determine whether the OMP as a whole complies with the FERC's directive to provide comparable and not unduly discriminatory transmission service to all generating resources connected to BPA's transmission system.[4]

In March 2013, BPA filed a Revised OMP to be effective through September, 2015. BPA proposed a revised cost allocation methodology that would spread the costs of displacement across its transmission system.[5] BPA also submitted to the FERC a proposed transmission rate, OS-14, in accordance with the Northwest Power Act and Part 300 of the FERC's regulations, as a mechanism to recover its costs incurred pursuant to the Revised OMP.[6] Wind generators argued that the Revised OMP had not been shown to provide comparable transmission service, and was unduly discriminatory and unduly preferential in removing wind generation from the supply market and augmenting the demand for federal hydropower by confiscating the power loads of the curtailed wind generators in order to increase the revenues of its power marketing function.[7] Instead of the Revised OMP, wind generators asked the FERC to "direct [BPA] to negotiate bilateral arrangements with customers for curtailing during oversupply events or sell excess energy at market prices and allocate the associated costs to power [supply] rates" rather than its transmission customers.[8]

On October 16, 2014, the FERC issued companion orders approving the Revised OMP under FPA section 211A and approving BPA's OS-14 transmission rate pursuant to the Northwest Power Act.[9] The FERC determined that the Revised OMP, together with BPA's cost allocation methodology, complied with the FERC's earlier directives that BPA develop nondiscriminatory curtailment practices and an equitable cost allocation methodology that results in comparable transmission service.[10] The FERC determined that BPA properly categorized its costs associated with curtailment of wind generators during periods of oversupply of hydroelectric generation, directly related to "the interconnection of significant amounts of wind generation on Bonneville's transmission system."[11] The FERC accepted BPA's proposal to allocate the costs associated with oversupply management based upon scheduled, rather than actual, transmission use because it is the scheduling of transmission by the wind generators that affects BPA's entire transmission system and results in the need for BPA to displace wind power with federal hydropower and incur oversupply costs. The displaced generators

3. *Iberdrola Renewables, Inc., et al. v. Bonneville Power Admin.*, 141 F.E.R.C. ¶ 61,234 at P 1 (2012), *reh'g denied*, 143 F.E.R.C. ¶ 61,274 (2013).

4. *Id*.

5. *Iberdrola Renewables, Inc., et al. v. Bonneville Power Admin.*, 149 F.E.R.C. ¶ 61,044 at P 11 (2014), *reh'g denied*, 150 F.E.R.C. ¶ 61,113 (2015).

6. *Id*.

7. *Id.* at P 62.

8. *Id.* at P 37.

9. *Id*. at PP 1, 9, 11; *Bonneville Power Admin.*, 149 F.E.R.C. ¶ 61,043 at P 1, *reh'g denied*, 150 F.E.R.C. ¶ 61,112 (2015).

10. *Id.* at P 52.

11. 149 F.E.R.C. ¶ 61,044 at P 40.

benefit, the FERC reasoned, as the generator's customer continues to be served, by free federal hydroelectric power.[12] The FERC found that under BPA's proposal "wind generators bear the oversupply costs in a manner proportional to their scheduled use of the transmission system during an oversupply situation, similar to all scheduled users of the system."[13]

Under the Northwest Power Act, the FERC's review of Bonneville's regional power and transmission rates is limited to determining whether Bonneville's proposed rates meet the three specific requirements of section 7(a)(2) of the Northwest Power Act: (A) they must be sufficient to assure repayment of the federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting Bonneville's other costs; (B) they must be based upon Bonneville's total system costs; and (C) they must equitably allocate the costs of the federal transmission system between federal and non-federal power.[14] The rates are prepared by BPA's Administrator, and submitted to the FERC for approval or disapproval.

In its order, the FERC found that the Revised OMP would generate sufficient revenue to recover BPA's oversupply costs.[15] Noting the BPA Administrator's certification that the OS-14 rate proposed was consistent with the Northwest Power Act, the FERC was satisfied that the OS-14 rate would be an equitable allocation between federal and non-federal use of the transmission system, and that the Administrator had demonstrated that the proposed OS-14 rate was consistent with the applicable provisions of the Northwest Power Act.[16] The FERC also noted that, to the extent the cost allocation satisfies the comparability principle under section 211A of the FPA, this is sufficient to meet the equitable allocation requirements under the Northwest Power Act. The FERC denied wind generators' petitions for rehearing. On April 20, 2015, Caithness Shepherds Flat, LLC filed a petition for review of the FERC's orders in the United States Court of Appeals for the Ninth Circuit.[17]

II. CFTC EXCLUSION OF UTILITY OPERATIONS-RELATED SWAPS WITH UTILITY SPECIAL ENTITIES FROM DE MINIMIS THRESHOLD FOR SWAPS WITH SPECIAL ENTITIES

On September 17, 2014, the Commodities Futures Trading Commission (CFTC) issued a final rule amending its regulations to permit a person to exclude utility operations-related swaps entered into with "utility special entities" when calculating the aggregate gross notional amount of that person's swap positions for purposes of the de minimis exception from swap dealer registration applicable

12. *Id*. at P 41.
13. *Id*. at P 42.
14. Northwest Power Act, 16 U.S.C. § 839e(a)(2) (2011).
15. 149 F.E.R.C. ¶ 61,044 at P 40.
16. 149 F.E.R.C. ¶ 61,043 at P 24.
17. Caithness Shepherds Flat, LLC v. FERC, Nos. 15-71211, *et al*. (9th Cir. Apr. 20, 2015) (FERC.gov, New Petitions).

to swaps with special entities (Final Rule).[18] This Final Rule codifies previously granted no-action relief, with certain modifications.

Section 1a(49)(D) of the Commodity Exchange Act requires the CFTC to exclude an entity that engages in a de minimis amount of swap dealing from the statutory definition of "swap dealer," and requires that the CFTC issue regulations establishing the parameters of this exclusion.[19]

The CTFC adopted Regulation 1.3(ggg) in 2012, which contained an exclusion from the definition of "swap dealer" for a person that has entered into swap positions connected to its swap dealing activities that do not exceed either of the two aggregate gross notional amount thresholds during the proceeding twelve-month period.[20]

On July 12, 2012, the American Public Power Association, the Large Public Power Council, the American Public Gas Association, the Transmission Access Policy Study Group, and the Bonneville Power Administration petitioned the CFTC to exclude from consideration, when determining whether a person has exceeded the Special Entity De Minimis Threshold of $25 million, swaps involving electric and gas utilities owned by state and local governments, and federal power marketing administrations—defined by the Petitioners as "utility special entities."[21] These parties were particularly concerned with "utility operations-related swaps," or swaps that a utility enters into to hedge or mitigate commercial risk.[22]

Under the CFTC's final rule, such utility operations-related swaps are subject to the higher General De Minimis Threshold of $3 billion with a phase-in level of $8 billion, rather than the significantly smaller Special Entity De Minimis Threshold of $25 million.[23] The CFTC found that this higher threshold was in the public interest, given the critical role that gas and electric distribution plays in public safety and commerce, and the important role that swaps play in the day-to-day business of the utility special entities that provide these services.[24]

III. CFTC FINAL INTERPRETATION, FORWARD CONTRACTS WITH EMBEDDED VOLUMETRIC OPTIONALITY

On May 18, 2015, the CFTC and the Securities and Exchange Commission (SEC) jointly issued the CFTC's final interpretation clarifying a transaction with embedded volumetric optionality constituting a forward contract.[25] This final interpretation follows the CFTC's and the SEC's proposal published in 2014 to amend the interpretation in the 2012 Product Definitions Release concerning

18. Exclusion of Utility Operations-Related Swaps with Utility Special Entities from De Minimis Threshold for Swaps with Special Entities, 79 Fed. Reg. 57,767 (Sept. 26, 2014) (to be codified at 17 C.F.R. pt. 1).

19. *Id*.

20. *Id*. at 57,768.

21. *Id*. at 57,768 & n.5.

22. *Id*. at 57,768 & n.7.

23. Exclusion of Utility Operations-Related Swaps with Utility Special Entities from De Minimis Threshold for Swaps with Special Entities, 79 Fed. Reg. at 57,768.

24. *Id*. at 57,772.

25. Final Interpretation, Forward Contracts with Embedded Volumetric Optionality, 80 Fed. Reg. 28,239 (May 18, 2015).

forward contracts with embedded volumetric optionality and further defining the terms "swap" and "security-based swap."[26]

The final interpretation modifies the fourth and fifth elements of the seven-element test—used to determine whether a transaction falls within the "forward contract exclusion from the 'swap' and 'future' delivery definitions"—by clarifying that it applies to embedded volumetric optionality in the form of both puts and calls, and does not preclude swing contracts from falling within this exclusion. By contrast, the CFTC's final interpretation focuses primarily on the seventh element.[27] The CFTC clarifies that a transaction falls within the forward exclusion when "the embedded volumetric optionality is primarily intended, at the time that the parties enter into the agreement, contract, or transaction, to address physical factors or regulatory requirements that reasonably influence demand for, or supply of, the nonfinancial commodity."[28]

IV. FERC ORDER NO. 809, COORDINATION OF THE SCHEDULING PROCESSES OF INTERSTATE NATURAL GAS PIPELINES AND PUBLIC UTILITIES

On April 16, 2015, the FERC issued an order revising "Part 284 of its regulations relating to the scheduling of transportation service on interstate natural gas pipelines to better coordinate the scheduling practices of the wholesale natural gas and electric industries, [and] to provide additional scheduling flexibility to all shippers on interstate natural gas pipelines."[29] Specifically, the FERC revised "the nationwide Timely Nomination Cycle nomination deadline for scheduling natural gas transportation from 11:30 a.m. Central Clock Time (CCT) to 1:00 p.m. CCT and revise[d] the intraday nomination timeline, to include [an additional] intraday scheduling opportunity during the gas operating day (Gas Day)."[30] To effectuate these revisions, the FERC incorporated by reference into its regulations revised standards of the North American Energy Standards Board (NAESB).[31] The FERC also revised its regulations to provide additional contracting flexibility to firm natural gas transportation customers through the use of multi-party transportation contracts.[32]

The FERC explained that the revision to the nomination deadline for the Timely Nomination Cycle to 1:00 p.m. CCT was generally supported by both the gas and electric industries, and that it "will provide generators more time to acquire natural gas supply and pipeline transportation after learning their electric dispatch obligations, provided changes are made to the [Independent System Operator (ISO) and Regional Transmission Organization (RTO)] scheduling processes."[33] The revised NAESB standards incorporated by the Commission also

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26. *Id.*; Proposed Interpretation, 79 Fed. Reg. 69,073 (proposed Nov. 20, 2014) (to be codified at 17 C.F.R. pts. 230, 240 & 241); Request for Comment on Final Interpretation, 77 Fed. Reg. 48,207 (2012).

27. Forward Contracts with Embedded Volumetric Optionality, 80 Fed. Reg. at 28,240.

28. *Id*.

29. Order No. 809, *Coordination of the Scheduling Processes of Interstate Natural Gas Pipeline and Public Utilities*, F.E.R.C. STATS. & REGS. ¶ 31,368 at P 1 (2015), 80 Fed. Reg. 23,197 (2015) (to be codified at 18 C.F.R. pt. 284) [hereinafter Order No. 809].

30. Order No. 809, *supra* note 29, at P 1.

31. *Id*.

32. *Id*.

33. *Id*. at P 87.

revised the deadline for notice to shippers of scheduled quantities from 4:30 p.m. CCT to 5:00 p.m. CCT, while maintaining the nomination deadline for the Evening Nomination Cycle at 6:00 p.m. CCT, and revising the deadline for notice to shippers of scheduled quantities from 10:00 p.m. CCT to 9:00 p.m. CCT.[34] The FERC noted that the revision to notice of scheduled quantities to 5:00 p.m. "enables gas industry participants to complete the Timely Nomination Cycle by the end of the business day, while still providing sufficient time for the nomination, confirmation and scheduling process."[35]

The FERC explained that increasing the intraday nomination cycles from two to three "will provide natural gas-fired generators, as well as other pipeline shippers, with increased scheduling flexibility."[36] The FERC also explained that by making the Intraday 2 Nomination Cycle "bumpable," "firm shippers will have greater opportunity to utilize the intraday schedules to reflect load and weather changes consistent with the higher priority of their service . . . ." and that "[t]he later time for the bumpable nomination will help shippers in the west, in particular, by allowing them to reflect later changes in weather forecasts into their nominations."[37] The FERC further explained that the new no-bump Intraday 3 Nomination Cycle, which will start at 7:00 p.m. CCT, "will give firm shippers a further opportunity to adjust their nominations consistent with their needs, while also providing certainty to interruptible transactions, so shippers and pipelines can plan for flows during the Gas Day."[38]

Last, the FERC explained that it would not require all interstate pipelines to modify their tariffs to offer multi-party firm transportation contracts, but rather will require pipelines to offer such an option if requested to do so by a shipper.[39] The FERC further explained that "the availability of multi-party firm transportation contracts will provide shippers, including gas-fired generators, with greater flexibility and facilitate more efficient use of pipeline capacity," and its revised regulations will ensure that "pipelines are responsive to shipper requests when, and if, a shipper is interested in pursuing a multi-party transportation agreement, while not requiring pipelines to implement tariff provisions offering that option where there is no shipper interest."[40] The revised regulations became effective on July 8, 2015.

V. REQUEST FOR REHEARING OF THE ISO NEW ENGLAND, INC. FCM COMPLIANCE ORDER

On April 20, 2015, the FERC issued an order denying requests for rehearing of its February 12, 2013 order (2013 Compliance Order) on an ISO New England, Inc. (ISO-NE) compliance filing regarding its Forward Capacity Market (FCM) rules.[41]

34. *Id*. at P 78.
35. Order No. 809, *supra* note 29, at P 87.
36. *Id*. at P 104.
37. *Id*.
38. *Id*.
39. *Id*. at P 142.
40. Order No. 809, *supra* note 29, at P 142.
41. Order Denying Rehearing, *ISO New England, Inc.*, 151 F.E.R.C. ¶ 61,055 at P 1 (2015).

In the 2013 Compliance Order, the FERC generally approved ISO-NE's proposal to establish a buyer-side market power mitigation minimum offer price rule mechanism (MOPR) that would reflect benchmark prices for different types of assets that offer into the FCM.[42] The FERC declined to require ISO-NE to establish a blanket exemption from the MOPR for self-supplied resources, finding that such an exemption would "allow entities with new self-supply to circumvent the MOPR, thereby allowing subsidized uneconomic entry to artificially depress prices."[43] The FERC also concluded that the lack of a blanket exemption would not unduly discriminate against self-supply, including public or consumer-owned resources, and clarified that, while its earlier decisions regarding the FCM rules allowed for stakeholders to develop a mechanism to address the concerns of consumer-owned self-supply, it had not required ISO-NE to establish any such mechanism.[44]

In its April 20th order, the FERC addressed requests for rehearing filed by the Eastern Massachusetts Consumer-Owned Systems and Danvers Electric Division (EMCOS) and by numerous public power entities within ISO-NE (Public Systems).[45] EMCOS argued that ISO-NE's benchmark prices were unduly discriminatory due to their disproportionate impact on public power projects, such that these resources would be forced to use the unit-specific review process to participate in the FCM.[46] The FERC denied rehearing, ruling that the benchmarks and resulting MOPR mechanism were not unduly discriminatory to public power, since the unit-specific exemption option remained available, and because there was no evidence that the exemption presented significant burdens to public power entities.[47] In addition, public power entities' use of the unit-specific exemption would place them in the same position with regard to process and requirements as other types of resources.[48]

The FERC also rejected Public Systems' argument that the 2013 Compliance Order unlawfully overstepped the Commission's jurisdiction by "overriding" consumer-owned entities' decisions—including decisions to rely on new self-supply—regarding how to meet long-term customer service obligations.[49] The FERC stated that, due to its well-established jurisdiction over "aspects of [ISO] services that affect wholesale rates . . ." it also has jurisdiction over FCM rates and the Installed Capacity Requirement (ICR), "even though the operation of the FCM may influence the type of generation that contributes to that capacity."[50] Similarly, the FERC concluded that it may rule on mechanisms that protect against buyer-side market power, even if those rules "might impact the type of capacity resources that are likely or able to clear in that market."[51]

42. *Id.* at P 7.
43. *ISO New England, Inc.*, 142 F.E.R.C. ¶ 61,107 at P 80 (2013).
44. *Id.* at PP 80-81.
45. 151 F.E.R.C. ¶ 61,055 at P 11 (2015).
46. *Id.* at PP 12-13.
47. *Id.* at P 7.
48. *Id.* at PP 22-24.
49. *Id.* at PP 14, 16, 21.
50. 151 F.E.R.C. ¶ 61,055 at P 25 (2015).
51. *Id.*

The FERC noted that the FCM rules do not prohibit the development or offer of new capacity, but simply "[address] the price at which that capacity can be offered . . . ."[52] The FERC also determined that the payments consumer-owned utilities receive from their members should be treated as out-of-market payments under ISO-NE's rules, and thus rejected Public Systems' argument that the Commission should have required ISO-NE, in conducting unit-specific review, to include these payments as in-market.[53] Finally, the FERC rejected Public Systems' argument that the approval of a self-supply exemption in the PJM Interconnection, L.L.C. (PJM) MOPR rules indicates that similar rules would be appropriate for ISO-NE. The FERC noted that the current PJM exemption was more limited in nature than what was originally proposed, and concluded that Public Systems had not shown the absence of such an exemption for ISO-NE to be unjust and unreasonable or unduly discriminatory.[54]

VI. MICHIGAN PUBLIC SERVICE COMMISSION V. FERC

In *Public Service Commission of Wisconsin*, the FERC addressed the appropriate cost allocation of System Support Resource (SSR) Units associated with Midcontinent Independent System Operator, Inc.'s (MISO) Open Access Transmission Energy and Operating Resource Markets Tariff (OATT).[55] As of June 30, 2015, this case is pending before the U.S. Court of Appeals for the D.C. Circuit.[56]

Prior to July 2012, the MISO OATT required its market participants to give MISO twenty-six weeks' notice prior to retiring or suspending its power plants for electricity generation, at which time it would conduct a study "to determine whether all or a portion of the resource's capacity is necessary to maintain system reliability, such that SSR status is justified."[57] If MISO was unable to obtain a substitute generation source before the retirement or suspension date, MISO and the involved market participant would enter into an agreement, subject to FERC approval, to continue generation until an alternative generation was found (SSR Agreement).[58] The rate schedule would set forth the costs associated with continued electricity generation to be apportioned to individual Load-Serving Entities (LSEs) benefiting from such generation.[59]

On July 25, 2012, MISO submitted a filing to the Commission related to the treatment of plants providing notice of suspension or retirement. The FERC conditionally accepted the filing subject to further compliance.[60] In January 2014, MISO filed, with the FERC, an SSR Agreement and Rate Schedule 43G entered into with Wisconsin Electric's Presque Isle Units 5-9, which identified the costs

52. *Id*. at P 27.

53. *Id*. at P 29.

54. *Id*. at P 30.

55. Order on Complaint, *Public Service Commission of Wisconsin*, 148 F.E.R.C. ¶ 61,071 (2014); Order Dismissing Complaints, *Michigan Public Service Commission*, 150 F.E.R.C ¶ 61,105 at PP 8-9 & n.13 (2015).

56. Michigan Public Service Commission, et al. v. FERC, No. 15-1049, et al. (D.C. Cir. March 9, 2015) (FERC.gov, Pending Cases).

57. 150 F.E.R.C. ¶ 61,105 at P 5.

58. *Id*.

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

60. *Id*. at P 6.

due for the continued operation of Presque Isle Units 5-9.[61] In the rate schedule, MISO also allocated the costs of the generation of Presque Isle Units 5-9 as SSR Units to each LSE within the American Transmission Company footprint on a pro rata basis.[62] On April 1, 2014, the FERC accepted the Original Presque Isle Rate Schedule 43G effective February 1, 2014, subject to refund and further order.[63] As a result of the filing, the Public Service Commission of Wisconsin (Wisconsin Commission) filed a complaint with the FERC, alleging Schedule 43G was "unjust, unreasonable, and unduly discriminatory."[64] The FERC agreed and ordered MISO to eliminate the ATC SSR pro rata cost allocation from the MISO OATT and allocate "SSR costs to the LSE(s) which require[d] the operation of the SSR Unit for reliability purposes."[65] The FERC also ordered MISO to perform a load-shed study and submit a compliance filing to align cost allocations to the rate schedule. The FERC then ordered MISO to refund any costs in excess of the costs to allocate to those LSEs under MISO's final load-shed study from April 3, 2014, until the date of the Wisconsin Commission complaint. Several parties filed requests for rehearing concerning that outcome.[66]

On August 11, 2014, MISO made a filing which included an addition to the Original Presque Isle SSR Agreement that addressed compensation when SSR units operate for economic purposes versus reliability purposes, as well as revisions concerning the Presque Isle SSR Unit, which eliminated the ATC SSR pro rata cost allocation section.[67] After submitting its load-shed study, MISO filed a revised rate schedule with the FERC reflecting the change in cost allocations.[68] On November 10, 2014, the FERC accepted the replacement SSR Agreement, subject to refund, and set the cost-related issues for hearing and settlement judge proceedings. Several parties filed request for rehearing due to the FERC overturning the original rate schedule.[69] On June 13, 2014, MISO filed with the FERC an SSR Agreement between MISO and the City of Escanaba, known as Escanaba Unit 1 and 2. Consistent with Section 38.2.7K of the MISO OATT, MISO assigned "SSR costs on a *pro rata* basis to all LSEs within the ATC footprint."[70]

The FERC conditionally accepted the new Escanaba SSR Agreement and Rate Schedule, but ordered MISO to revise the SSR Agreement to (1) "include language relating to compensation when the SSR Unit operates for economic rather than reliability purposes"; (2) perform a load-shed study to identify LSEs that used the Escanaba SSR Units for reliability reasons; and (3) adjust the costs

61. *Id*. at P 7.

62. 150 F.E.R.C. ¶ 61,105 at P 7.

63. *Id*.

64. 148 F.E.R.C. ¶ 61,071 at P 3.

65. *Id*. at P 66.

66. *Id*. at PP 66-67.

67. 150 F.E.R.C. ¶ 61,105 at P 10 & n.17.

68. *Id*. at PP 9-10.

69. Order on Rehearing, *Pub. Serv. Comm'n of Wis. v. Midcontinent Indep. Sys. Operator, Inc.*, 150 F.E.R.C. ¶ 61,104 at P 10 (2015).

70. Order Conditionally Accepting Tariff Filings, *Midcontinent Indep. Sys. Operator, Inc.*, 148 F.E.R.C. ¶ 61,116 at P 1 (2014); 150 F.E.R.C. ¶ 61,104 at P 11 (2015).

under the new rate schedule.[71] The FERC "directed MISO to refund, with interest, any costs allocated to LSEs under [the new rate schedule] from June 15, 2014 to August 12, 2014 . . . ."[72]

On April 15, 2015, MISO filed with the FERC a proposed SSR Agreement between it and White Pine, and a proposed Rate Schedule 43H.[73] On June 13, 2014, the FERC accepted the new rate schedule subject to refund and further order. The FERC ordered MISO to include language relating to compensation when the SSR Unit operates for economic rather than reliability purposes, to conduct a load-shed study that identified the LSEs requiring the use of the White Pine Unit 1 for reliability reasons, and to adjust the SSR cost allocations according to the load-shed study. Additionally, the FERC ordered MISO to refund, with interest, any costs allocated to LSEs under the prior rate schedule from April 16, 2014 until August 21, 2014, if the costs were higher than the costs to be allocated to those LSEs according to the load-shed study analysis.[74] On September 26, 2014, MISO accordingly filed, with the FERC, revised rate schedules for the Escanaba, Presque Isle, and White Pine SSR Agreements to reflect new cost allocations based upon the formation of a new Local Balancing Authority (LBA). MISO created it by splitting the Wisconsin Electric Company LBA into the Wisconsin Electric Company LBA and the Michigan Upper Peninsula LBA.[75] MISO informed the FERC that the rate schedules pending for Escanaba and White Pine would use the same Wisconsin Electric Company LBA designation. MISO noted that all three rate schedules would be changed to indicate the LBA boundaries. MISO also noted that it revised the payment schedules for those three SSR Units according to the ratios calculated from a new load-shed study.[76]

On September 19, 2014, parties filed complaints against MISO splitting the original Wisconsin Electric Company LBA. The Michigan Public Service Commission also filed a complaint, with the FERC, charging the SSR costs based upon the reduced boundaries of the new Michigan Upper Peninsula LBA.[77] Other parties filed late motions to intervene, requests for rehearing, answers to or comments on rehearing, and requests to supplement requests of hearings.[78] The primary issue raised was whether the ATC SSR pro rata cost allocation under the Original Presque Isle Rate Schedule 43G followed cost causation principles.

The FERC found that MISO's original ATC SSR pro rata cost allocation for Presque Isle failed to follow causation principles and as a result was "unjust, unreasonable, unduly discriminatory, or preferential . . . ."[79] The FERC noted that, contrary to the contention of certain parties, the preliminary load-shed study proposed by MISO, which indicated the Wisconsin LSE would receive only 42% of the reliability benefit of the Presque Isle SSR Unit, but be allocated 92% of the

71. 150 F.E.R.C. ¶ 61,104 at P 15; 148 F.E.R.C. ¶ 61,116 at P 37.

72. 150 F.E.R.C. ¶ 61,104 at P 12.

73. Order on Tariff Revisions, *Midcontinent Indep. Sys. Operator, Inc.*, 148 F.E.R.C. ¶ 61,136 at P 1 (2014).

74. *Id*. at P 8.

75. 150 F.E.R.C. ¶ 61,104 at P 17.

76. *Id*. at PP 18-20.

77. 150 F.E.R.C. ¶ 61,105 at P 2.

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

79. *Id*. at P 9.

cost, was properly identified new evidence that showed cost allocations were unjust and unreasonable.[80] The FERC found that the parties' assertions were incorrect because the argument that the FERC ignored the history of the ATC SSR pro unit cost allocation provision had no validity. In addition, the FERC held that "although ATC may have been originally formed as a single price zone within MISO in order to promote the sharing of costs for regional transmission planning, that original intent [of ATC formation does] not require all costs be shared equally in perpetuity."[81]

The FERC found that MISO's use of LBAs and LBA splits in its SSR cost allocation method was improper. The FERC noted that the LBA approach failed to adequately show the LSEs use of the Presque Isle, White Pine, and Escanaba SSR Units, and that using LBAs to apportion costs for SSR Units may result in costs being assigned to LSEs that may not benefit from the SSR Units apportioned.[82] The FERC noted that the revised cost allocation conformed the allocation of SSR costs in the ATC footprint to the existing methodology, applied through the rest of the MISO region. Also, the FERC held that the costs at issue "were limited to those associated with a single SSR Unit, to be allocated among a defined set of customers within a limited geographic area, for a period of less than four months."[83] Finally, the FERC found that "refunds would not cause broad adjustments to MISO's markets."[84]

VII. MICHIGAN V. EPA

On June 29, 2015, in an opinion delivered by Justice Scalia, the Supreme Court held that the Environmental Protection Agency (EPA) interpreted section 7412(n)(1)(A) of the Clean Air Act (CAA) unreasonably when it refused to consider costs, including compliance costs, before deciding whether to regulate power plants in relation to the EPA's Mercury and Air Toxics Standards (MATS).[85]

The Court began by explaining that the EPA was tasked by Congress to determine whether it was "appropriate and necessary" to regulate power plants under the CAA.[86] The EPA determined that it was "appropriate" to regulate power plants because plant emissions pose risks to public health and the environment, and because controls are available to reduce these emissions.[87] The EPA concluded that it was "necessary" to regulate power plant emissions because these emissions were not otherwise regulated under the CAA.[88] The EPA conceded that it did not consider cost in its "appropriate and necessary" analysis when determining whether to regulate power plants in relation to MATS; however, the EPA issued a Regulatory Impact Analysis that estimated the cost would be equal

80. 150 F.E.R.C. ¶ 61,104 at P 22.
81. *Id*. at P 23.
82. *Id*. at PP 50, 137.
83. *Id*. at P 25.
84. *Id*.
85. Clean Air Act, 42 U.S.C. § 7412(n)(1)(A) (1990); Michigan v. EPA, 135 S. Ct. 2699, 2712 (2015).
86. *Id*. at 2704.
87. *Id*. at 2705.
88. *Id*.

to roughly $9.6 billion per year.[89] The EPA could not fully quantify the benefit, though it estimated a benefit at roughly $4 to $6 million per year.[90]

Though section 7412(n)(1)(A) of the CAA does not expressly require the EPA to review costs in its determination of whether regulation of power plants is "appropriate and necessary," the Court found that the term requires at least some attention be given to cost.[91] The Court also stated that "'cost' includes more than [just] the expense of complying with [the] regulations."[92] If "appropriate" is deemed to not include cost, then the EPA would not be required to consider any type of cost, including harm to human health or the environment resulting from the technologies required to eliminate the emissions.[93]

The EPA argued that Congress could have specifically listed cost as a consideration in the MATS rule with respect to power plants, as it had in other areas of the CAA, if that was Congress' intent.[94] However, the Court reasoned that it is unreasonable to assume that, if cost is expressly included as relevant in other areas of the CAA, its absence elsewhere implies that it is irrelevant in those areas.[95] The Court found that the statutory context, as well as the historical treatment of cost by agencies in their consideration of regulation, both suggest that cost should be included in the EPA's determination of whether regulation of power plants under the MATS rule is appropriate.[96]

The EPA also argued that under the CAA, even though the EPA should not be required to consider cost when deciding whether to regulate power plants, it is required to eventually consider cost in determining how much to regulate power plants.[97] The Court likened this to not considering cost when purchasing a Ferrari, but considering cost when deciding whether to upgrade the sound system, and thus found such reasoning to be unpersuasive.[98] The Court also found that ancillary benefits cannot be considered in the EPA's analysis.[99] For these reasons, the Court reversed and remanded to the D.C. Circuit Court of Appeals.

Justice Thomas concurred, citing concerns about transferring legislative power to agencies who, instead of interpreting statutes, may be enacting policies and legislation.[100] Justice Kagan delivered the dissent, along with Justice Ginsberg, Justice Breyer, and Justice Sotomayor. Justice Kagan stated that the EPA did in fact consider cost and benefits, though it did so after making the determination to regulate power plants under the MATS rule, and such consideration after the determination should have been "appropriate."[101]

89. *Id*. at 2705-06.
90. *Michigan*, 135 S. Ct. at 2706.
91. *Id*. at 2709, 2711.
92. *Id*. at 2707.
93. *Id*.
94. *Id*. at 2710.
95. *Michigan*, 135 S. Ct. at 2709.
96. *Id*. at 2707-08.
97. *Id*. at 2709.
98. *Id*.
99. *Id*. at 2711.
100. *Michigan*, 135 S. Ct. at 2712-14 (Thomas, J., concurring).
101. *Id*. at 2724 (Kagan, J., dissenting).

VIII. NEXTERA ENERGY RESOURCES, LLC V. FERC

On March 30, 2015, NextEra Energy Resources, LLC, The NRG Companies, and The PSEG Companies filed a Petition of Review with the United States Court of Appeals for the District of Columbia Circuit requesting the Court review three previous orders of the FERC regarding revisions to ISO-NE's tariff to establish a system-wide sloped demand curve and related parameters for use in its FCM.[102]

By order issued January 24, 2014, the FERC accepted ISO-NE's proposal, subject to condition that ISO-NE submit a sloped demand curve by April 1, 2014, to raise tariff-set administrative prices; the proposal having been triggered by ISO-NE's earlier determination that there was a potential for a capacity shortage in the upcoming Forward Capacity Auction.[103] On May 30, 2014, the FERC conditionally accepted ISO-NE's proposal to establish a system-wide sloped demand curve construct in the FCM subject to a compliance filing "clarifying how new resources would qualify for the [renewable Technology Resource] [E]xemption in future [capacity] auctions."[104] Several market participants petitioned the FERC for rehearing of the May 30, 2014 order, but those petitions were subsequently denied.[105]

IX. PUBLIC SERVICE COMPANY OF COLORADO JOINT DISPATCH AGREEMENT

The FERC rejected the Joint Dispatch Agreement proposed by the Public Service Company of Colorado to also include Black Hills/Colorado Electric Utility Company and the Platte River Power Authority.[106] The Joint Dispatch Agreement would have "implement[ed] centralized energy dispatch to use pooled generation to serve the combined participating native load requirements" in the Public Service Company balancing authority area.[107] Transmission service would have been provided at no charge and used only non-firm, Available Transfer Capability that was available after the scheduling deadlines for all other transmission had passed.[108] Tri-State Generation and Transmission Association, Inc. protested, among other things, that without any charge for transmission under the agreement, public utilities not participating in the Joint Dispatch Agreement would subsidize the participants.[109]

102. The "NRG Companies" include NRG Power marketing, LLC, GenOn Energy management, LLC, Connecticut Jet power LLC, Devon Power LLC, Middleton Power LLC, Montville Power LLC, Norwalk Power LLC, NRG Canal LLC and Energy Curtailment Specialists, Inc. The "PSEG Companies" include PSEG Power LLC, PSEG Energy Resources & Trade LLC and PSEG Power Connecticut LLC. NextEra Energy Res., LLC. v. FERC, No. 15-1070 (D.C. Cir. Mar. 30, 2015) (FERC.gov, Pending Cases). The prior orders for review include: Order Accepting Tariff Revisions, *ISO New England Inc.*, 147 F.E.R.C. ¶ 61,173 (2014); *ISO New England Inc.*, No. ER14-1639-002, Compliance Filing Concerning the Limited Exemption from Offer Review Trigger Price Review for Renewable Technology Resources (Nov. 13, 2014) (unpublished delegated letter order); Order Denying Rehearing, *ISO New England Inc.*, 150 F.E.R.C. ¶ 61,065 (2015).

103. *ISO New England Inc.*, 146 F.E.R.C. ¶ 61,038 at PP 30, 52 (2014).

104. *ISO New England Inc.*, 147 F.E.R.C. ¶ 61,173 at P 88 (2014).

105. *ISO New England Inc.*, 150 F.E.R.C. ¶ 61,065 at P 1 (2015).

106. *Pub. Serv. Co. of Colorado*, 151 F.E.R.C. ¶ 61,248 at P 1 (2015).

107. *Id*. at P 2.

108. *Id*. at PP 8-9.

109. *Id*. at P 28.

The FERC rejected the Joint Dispatch Agreement and related tariff filings on two grounds.[110] First, Public Service Company's proposed rate, in which resources would "be compensated at a ceiling rate derived from the cost of the most expensive [megawatt] required to serve aggregate loads of the parties under the Joint Dispatch Agreement," could be affected by Public Service Company's ability to exercise market power through the costs of the units it committed to serve load.[111] Second, Public Service Company proposed to allow its merchant generation function to access non-public generation information to administer the dispatch agreement, which could have resulted in violations of the FERC Standards of Conduct.[112] The FERC stated that its concerns regarding market power and violations of the Standards of Conduct would be mitigated if Public Service Company's transmission function were instead responsible for dispatch.[113]

X. PUGET SOUND ENERGY, INC. V. ALL JURISDICTIONAL SELLERS OF ENERGY AND/OR CAPACITY AT WHOLESALE INTO ELECTRIC ENERGY AND/OR CAPACITY MARKETS IN THE PACIFIC NORTHWEST

The FERC issued an Order on Initial Decision regarding "bilateral wholesale energy contracts . . . in the Pacific Northwest spot market during 2000 and 2001."[114] In this Phase I of the proceeding, the administrative law judge was to consider whether the California Parties made the necessary showing to avoid or overcome the Mobile-Sierra presumption that the bilateral spot market contracts at issue were not just and reasonable under section 206 of the FPA or to obtain relief under section 309 of the FPA.[115]

The FERC largely affirmed the Initial Decision, but reversed and remanded as to findings that Coral Power (Coral), a subsidiary of Shell Energy North America, was liable.[116] Specifically, the FERC directed the administrative law judge to make findings as to what constituted a "contract," which contracts were affected by False Export activities, and what evidence demonstrated the causal link between any unlawful activity and the effect it had on a specific contract rate, as well as any rebuttal evidence presented by Coral.[117] The FERC further remanded questions related to allegations by the California Parties regarding contracts with Coral that were affected by bad faith negotiations: the contracts should be identified and rebuttal evidence by Coral should be considered.[118] If the administrative law judge finds that any contracts were affected by False Export

110. *Id*. at PP 98-100.

111. 151 F.E.R.C. ¶ 61,248 at P 99.

112. *Id*. at P 100.

113. *Id*. at P 101.

114. Opinion No. 537, *Puget Sound Energy v. All Jurisdictional Sellers*, 151 F.E.R.C. ¶ 62,071 at P 1 (2014).

115. California Parties include the People of the State of California, ex rel. Kamala D. Harris, Attorney General of the State of California; the Public Utilities Commission of the State of California; and Southern California Edison Company. *Id*. at P 2 & n.4.

116. *Id*. at P 3.

117. *Id*. at PP 100, 101, 105, 116, 118.

118. *Id*. at P 152.

activities or bad faith negotiations, remedies will be considered in Phase II of the proceedings.[119]

119. *Id*. at P 92.

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