

## REPORT OF THE ELECTRICITY COMMITTEE

This report covers significant electric regulatory orders issued by the Federal Energy Regulatory Commission (FERC or Commission) in 2016. This report does not, however, address transmission reliability, demand-side management, renewable energy, FERC enforcement matters, or appellate decisions.\*

I.	Rulemakings and Policy Statement.....	2
A.	Rule 207(a) of the Commission’s Rules of Practice and Procedure .....	2
B.	Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities.....	3
C.	Policies for Future Implementation of Hold Harmless Commitments in Section 203 Transactions .....	4
D.	Order Clarifying Electric Quarterly Report Reporting Requirements and Updating Data Dictionary .....	4
E.	FERC Access to NERC Databases .....	5
F.	Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators .....	6
G.	Data Collection and Reporting Requirements for Market-Based Rate (MBR) Sellers and Entities Trading Virtual Products or Holding Financial Transmission Rights in Wholesale Markets..	7
II.	RTO/ISO Developments .....	8
A.	ISO New England .....	8
B.	New York Independent System Operator, Inc. ....	9
C.	PJM Interconnection, L.L.C.....	11
D.	Midcontinent Independent System Operator, Inc. ....	19
E.	Southwest Power Pool, Inc. ....	22
F.	California Independent System Operator Corp.....	23
G.	Electric Reliability Council of Texas.....	25
III.	Transmission Rates/Formula Rates.....	25
IV.	Mergers and Acquisitions .....	26
V.	Complaints .....	26
VI.	PURPA.....	28
VII.	Generator Interconnection.....	32
VIII.	Miscellaneous.....	33

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## I. RULEMAKINGS AND POLICY STATEMENT

A. *Rule 207(a) of the Commission's Rules of Practice and Procedure*

On March 17, 2016, in docket no. EL15-86, the Commission dismissed a request for declaratory order of ITC Grid Development, L.L.C. (ITC Grid). In dismissing ITC Grid's requests, the Commission declined to make the requested findings that (1) "binding revenue requirement bids selected as the result of Commission-approved, Order No. 1000-compliant, and demonstrably competitive transmission project selection processes will be deemed just and reasonable when filed at the Commission as a stated rate" pursuant to Federal Power Act (FPA) section 205; and (2) that such binding bids would be entitled to protection under the *Mobile-Sierra* standard, and so "may not subsequently be changed by means of a complaint filed under FPA section 206 unless required by the public interest."<sup>1</sup>

In seeking the declaratory order, ITC Grid emphasized the value of cost containment proposals and the prevalence of cost data in the Midcontinent Independent System Operator, Inc. and Southwest Power Pool, Inc., competitive development processes as a selection metric.<sup>2</sup> ITC Grid argued that the proposals would help hold developers to their bids, lending integrity to the RTO/ISO competitive bidding processes.<sup>3</sup>

The Commission acknowledged that the request implicated important policy considerations regarding the benefits and treatment of cost containment proposals in competitive solicitations, but found that a declaratory order was "not the appropriate vehicle" for addressing the issues raised in the petition.<sup>4</sup> The Commission found that the broad scope of ITC Grid's request and the lack of application to specific facts and circumstances necessitated a more general finding inappropriate for the scope of a declaratory order.<sup>5</sup> However, the Commission noted that it would convene a technical conference exploring "how the Commission should consider and evaluate rates that result from a competitive development process that include binding revenue requirements."<sup>6</sup> The issue of cost containment was subsequently discussed at the June 27-28, 2016 technical conference regarding competitive development processes in docket no. AD16-18.<sup>7</sup> Post-technical comments have been submitted in the docket.

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1. *ITC Grid Dev., L.L.C.*, 154 F.E.R.C. ¶ 61,206, at P 1 (2016).

2. *Id.* at P 4 (citing *ITC Grid Dev., L.L.C.*, Petition for Declaratory Order, docket no. EL15-86 (filed July 29, 2016)).

3. *Id.* at P 7.

4. *Id.* at PP 47, 49.

5. *Id.* at P 45.

6. 154 F.E.R.C. ¶ 61,206 at PP 1, 49.

7. Notice Inviting Post-Technical Conference Comments, *Competitive Transmission Dev. Technical Conference*, docket no. AD16-18-000 (2016).

*B. Refinements to Policies and Procedures for Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*

On May 19, 2016, the Commission issued Order No. 816-A affirming its rules for market-based rates for wholesale sales of electricity services and providing additional clarification as necessary.<sup>8</sup> The Commission issued Order No. 816-A in response to several requests for rehearing and clarifications filed in response to Order No. 816 issued on October 16, 2015.<sup>9</sup>

Specifically, the Commission denied rehearing regarding (1) “the requirement to include the expiration date of the contract when a seller claims that its capacity is fully committed,” and (2) the request for “capacity in first-tier markets [to] be included for determining the 100 megawatt (MW) change in status threshold.”<sup>10</sup> The Commission clarified that: (1) applicants with generation from a qualifying facility exempt from section 205 of the FPA are exempt from the rule requiring the entity to “report all long-term firm energy and capacity purchases from generation capacity located within the RTO/ISO market if the generation is designated as a resource with capacity obligations,” (2) it did not revise the definition of long-term firm transmission reservations in Order No. 816, and that “long-term firm transmission reservations are longer than 28 days,” and

(3) a hydropower licensee that otherwise sells power only at market-based rates will not be subject to the full requirements of the Uniform System of Accounts as a consequence of filing a cost-based reactive power tariff with the Commission, and may satisfy the requirements in Part 101 of the Commission’s regulations by complying with General Instruction 16 of the Uniform System of Accounts.<sup>11</sup>

The Commission also clarified the particular markets that would be a seller’s “relevant geographic market for purposes of the 100 MW threshold reporting requirement” in Order No. 816.<sup>12</sup>

The Commission affirmed that (1) “market-based rate seller[s] must list all of [their] long-term firm power purchases in [their] asset appendi[ces],” (2) determinations regarding the Commission’s 100 MW threshold for the “requirement to report new affiliations” made in Order No. 816, and (3) its determination in Order No. 816 that “sellers are not required to include behind-the-meter generation in the 100 MW change in status threshold, the 500 MW Category 1 seller status threshold, or to include such generation in the asset appendices and indicative screens.”<sup>13</sup>

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8. Order No. 816-A, *Refinements to Policies & Procedures for Mkt.-Based Rates for Wholesale Sales of Elec. Energy, Capacity & Ancillary Serv. by Pub. Util.*, F.E.R.C. STATS. & REGS. ¶ 61,188 at PP 5, 8 (2016) (to be codified at 18 C.F.R. pt. 35).

9. *Id.* at P 1.

10. *Id.* at P 4, 7.

11. *Id.* at P 5-6, 9.

12. *Id.* at P 7.

13. Order No. 816-A, *supra* note 8, at PP 5, 7-8.

Finally, the Commission granted an extension of time for market-based rate applicants and sellers to be compliant with corporate organizational chart requirements in Order No. 816 until the Commission issues an order in the future.<sup>14</sup>

*C. Policies for Future Implementation of Hold Harmless Commitments in Section 203 Transactions*

On May 19, 2016, the Commission issued a policy statement to provide guidance and clarification on the “future implementation of hold harmless commitments [that are] often offered by applicants as ratepayer protection mechanisms” to address rate disparities that may occur under section 203 of the FPA.<sup>15</sup>

In its policy statement, the Commission outlined a list of transaction-related costs that may be the subject of hold harmless commitments, including (1) transition costs, (2) capital costs, (3) labor costs, and (4) costs of failed transactions.<sup>16</sup> The Commission emphasized, however, that it will

continue to consider hold harmless commitments on a case-by-case basis and, as such, applicants may propose that their hold harmless commitments cover specific transaction-related costs . . . if they can demonstrate that those certain cost categories may be properly included or excluded from their hold harmless commitment without an adverse effect on rates.<sup>17</sup>

In addition, the Commission also adopted a policy requiring applicants under section 203 of the FPA that offer hold harmless commitments to provide certain details about transaction-related costs from which the customer will be held harmless, as well as a “well-documented methodology” for how the applicant derived those costs.<sup>18</sup> Regarding time limits for hold harmless commitments, the Commission clarified that it will accept hold harmless agreements that are time-limited to show that no adverse effect on rates exist.<sup>19</sup> Finally, the Commission clarified that, consistent with the FERC Merger Policy Statement, applications may employ hold harmless commitments to demonstrate that the transaction has no adverse effect on rates; however, these commitments may be unnecessary “if an applicant can otherwise demonstrate that a proposed transaction will have no adverse effect on rates.”<sup>20</sup>

*D. Order Clarifying Electric Quarterly Report Reporting Requirements and Updating Data Dictionary*

On June 16, 2016, FERC issued an order “implement[ing] certain clarifications to [its] . . . Electric Quarterly Report (EQR) reporting requirements and the EQR Data Dictionary,” and established a new procedure for making minor or non-

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14. *Id.* at P. 11.

15. *Policy Statement on Hold Harmless Commitments*, 155 F.E.R.C. ¶ 61,189 at P 1 (2016).

16. *Id.* at P 48.

17. *Id.* at P 46.

18. *Id.* at PP 3, 9, 62, 70, 73.

19. *Id.* at P 82.

20. 155 F.E.R.C. ¶ 61,189, at P 3.

material changes to EQR reporting requirements or the EQR Data Dictionary.<sup>21</sup> In the order, FERC (1) clarified the requirements for the “Increment Name” and “Commencement Date of Contract Terms” fields in the EQR Data Dictionary; (2) updated the “Time Zone” field option in the EQR Data Dictionary; (3) deleted certain fields in the EQR Data Dictionary with respect to reporting NERC e-tag ID data; and (4) clarified “that future minor or non-material changes to EQR reporting requirements and the EQR Data Dictionary, such as those outlined in this order, will be posted directly to the Commission’s website and EQR users will be alerted via email of these changes.”<sup>22</sup>

Specifically, FERC clarified the definition of “Hourly” in the “Increment Name” field,<sup>23</sup> added five-minute and fifteen-minute values for that field,<sup>24</sup> and deleted the word “consecutive” in its definitions to ensure that daily off-peak transactions were correctly reported as “Daily” in that field.<sup>25</sup> FERC also added seller and customer company names to the definition of the “Commencement Date of Contract” field, mandating that an EQR filer update the commencement date of a contract if the seller or customer company listed in the contract changes.<sup>26</sup> The order also affirmed the requirement that all public utilities and non-public utilities with a filed Open Access Transmission Tariff (OATT) must file transmission-related data in their EQRs,<sup>27</sup> and updated the “Time Zone” field by eliminating universal time and “NA (Not Applicable)” as potential values in that field.<sup>28</sup> Finally, FERC eliminated all e-Tag ID reporting requirement fields from the EQR Data Dictionary, as it found that these fields were no longer necessary.<sup>29</sup> FERC concluded its order by stating that all future changes such as those described by this order would be posted on the FERC website and EQR users would be alerted via email, rather than by the issuance of an order.<sup>30</sup>

#### *E. FERC Access to NERC Databases*

On June 16, 2016, the Commission issued Order No. 824,<sup>31</sup> which amended its regulations to require NERC to provide Transmission Availability Data System (TADS) and Generator Availability Data System (GADS) databases, as well as its protection system misoperations databases,<sup>32</sup> to the Commission on a “non-public and ongoing basis.”<sup>33</sup> The Commission determined that FERC access to the three

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21. *Order Clarifying Elec. Quarterly Report Reporting Requirements & Updating Data Dictionary*, 155 F.E.R.C. ¶ 61,280 at PP 1, 4 (2016).

22. *Id.* at P 1.

23. *Id.* at P 6.

24. *Id.* at P 7.

25. *Id.* at P 8.

26. 155 F.E.R.C. ¶ 61,280 at P 11.

27. *Id.* at P 12.

28. *Id.* at P 13.

29. *Id.* at P 14.

30. *Id.* at P 15.

31. *Availability of Certain N. Am. Elec. Reliability Corp. Databases to the Comm’n*, 155 F.E.R.C. ¶ 61,275 at P 1 (2016) (to be codified at 18 C.F.R. pt. 39).

32. *Id.* at P 1.

33. *Id.* at P 71.

NERC databases as proposed in the Notice of Proposed Rulemaking (NOPR) is “necessary for the Commission to carry out its obligations under FPA section 215,”<sup>34</sup> and should be available to FERC as long as the data is “regarding U.S. facilities” and includes data that is “provided to NERC on a mandatory basis” pursuant to section 215 of the FPA.<sup>35</sup> The Commission stated that by requiring that since only “mandatorily-provided data” will be available to the Commission, “there should be no impact on an entity’s willingness to share additional, voluntary information.”<sup>36</sup>

In Order No. 824, the Commission recognized that information contained in the three NERC databases may be “sensitive,” and “may qualify as [critical electric infrastructure information] (CEII) under the Commission’s regulations.”<sup>37</sup> As such, the Commission ordered that the Final Rule will not become effective until the Commission issues a Final Rule adopting regulations to implement the newly enacted FPA section 215A (commonly known as the “FAST Act”), which exempts the Commission from Freedom of Information Act (FOIA) requests for information designated as CEII by either the Commission or the Department of Energy.<sup>38</sup> Notably, the Commission issued a NOPR proposing to amend the Commission’s regulations to implement section 215A of the FPA on June 16, 2016, contemporaneously with Order No. 824.<sup>39</sup>

#### *F. Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*

On June 16, 2016, FERC issued a final rule revising its regulations relating to settlement intervals in organized energy markets.<sup>40</sup> In the order, FERC required that each regional transmission organization (RTO) and independent system operator (ISO): (1) settle energy transactions in the RTO/ISO real-time markets “at the same time interval [the RTO/ISO] dispatches energy;” (2) settle “operating reserves transactions in [the RTO/ISO’s] real-time markets at the same time interval [the RTO/ISO] prices operating reserves;” and (3) settle “intertie transactions in the same time interval that [the RTO/ISO] schedules intertie transactions.”<sup>41</sup> FERC further required that “each RTO/ISO establish a mechanism to trigger shortage pricing for any interval in which a shortage of energy or operating reserves is indicated during the pricing of resources for that interval.”<sup>42</sup>

In establishing these requirements, FERC found that some RTO/ISO settlement practices failed to reflect the actual value of services being provided, thus providing inappropriate pricing signals that did not reflect the actual needs of the

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34. *Id.* at P 26.

35. *Id.* at P 1.

36. 155 F.E.R.C. ¶ 61,275, at P 39.

37. *Id.* at P 46.

38. *Id.*

39. *Id.* at 47.

40. *Settlement Intervals & Shortage Pricing in Mkts. Operated by Reg’l Transmission Orgs. & Indep. Sys. Operators*, 155 F.E.R.C. ¶ 61,276 at P 1 (2016) (to be codified at 18 C.F.R. pt. 35).

41. *Id.* at P 1.

42. *Id.*

market.<sup>43</sup> Specifically, FERC found that discrepancies between the dispatch and settlement time intervals for services sold in RTO/ISO markets resulted in distorted pricing for real-time,<sup>44</sup> operating reserve,<sup>45</sup> and intertie transaction markets.<sup>46</sup> FERC also found that some RTO/ISO settlement practices resulted in a “mismatch between the time when a system experiences a shortage of energy and operating reserves and the time when [market] prices reflect [such a] shortage condition.”<sup>47</sup> FERC found that the Final Rule advanced two of FERC’s goals relating to price formation: (1) providing “correct incentives for market participants to follow commitment and dispatch instructions” and (2) providing correct incentives for “efficient investments in facilities and equipment, and maintain reliability.”<sup>48</sup>

The Final Rule amends 18 C.F.R. § 35.28 by modifying paragraph (g)(1)(iv)(A) by adding the following sentence at the end of the paragraph: “Each Commission-approved independent system operator and regional transmission organization must trigger shortage pricing for any interval in which a shortage of energy or operating reserves is indicated during the pricing of reserves for that interval.”<sup>49</sup> The Final Rule also adds a new paragraph at 18 C.F.R. § 35.28(g)(1)(vi):

*Settlement intervals.* Each Commission-approved independent system operator and regional transmission organization must settle energy transactions in its real-time markets at the same time interval it dispatches energy, must settle operating reserves transactions in its real-time markets at the same time interval it prices operating reserves, and must settle intertie transactions at the same time interval it schedules intertie transactions.<sup>50</sup>

*G. Data Collection and Reporting Requirements for Market-Based Rate (MBR) Sellers and Entities Trading Virtual Products or Holding Financial Transmission Rights in Wholesale Markets*

On July 21, 2016, FERC issued a NOPR to amend and simplify its data collection requirements for market-based (MBR) sellers, as well as entities that trade virtual products or hold financial transmission rights (FTR) in organized wholesale markets (Virtual/FTR Participants).<sup>51</sup> This NOPR supersedes the Collection of Connected Entity Data from RTO and ISO Operators NOPR and Ownership Information in MBR Filings NOPR, which the Commission has withdrawn.<sup>52</sup>

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43. *Id.* at P 2.

44. *Id.*

45. 155 F.E.R.C. ¶ 61,276, at P 3.

46. *Id.* at P 2.

47. *Id.* at P 3.

48. *Id.* at P 6.

49. *Id.* at P 132.

50. 155 F.E.R.C. ¶ 61,276, at 132.

51. Notice of Proposed Rulemaking, *Data Collection for Analytics & Surveillance & Mkt.-Based Rate Purposes*, 156 F.E.R.C. ¶ 61,045 at P 1 (2016) (to be codified at 18 C.F.R. pt. 35).

52. *Id.* at P 3.

First, concerning Connected Entity Information, the Commission proposes various changes, including “that the definition of Connected Entity ownership information be limited to ‘affiliates,’ as defined for purpose of MBR requirements in section 35.36(a)(9),” which “would permit, where possible, unified submission for both MBR and Connected Entity Information.”<sup>53</sup> Under the NOPR, both MBR sellers and Virtual/FTR Participants are responsible for filing Connected Entity Information directly with the Commission. Second, concerning MBR Information required of MBR sellers, the Commission, among other ownership revisions, proposes “to revise the requirements of Order No. 697-A such that MBR sellers would only be required to provide information on certain ‘affiliate owners’” as defined in section 35.36(a)(9).<sup>54</sup> Additional ownership reporting revisions allow for the elimination of the need to file corporate organizational charts.<sup>55</sup> The NOPR also contains detailed changes reducing the information required from MBR sellers in asset appendices as well as other updates to MBR filings.

## II. RTO/ISO DEVELOPMENTS

### A. ISO New England

On June 16, 2016, FERC issued its order<sup>56</sup> in Docket No. ER10-2881-014 concerning a request by NextEra Energy Power Marketing, L.L.C., for an incremental capacity increase at its Bellingham Energy Center (Bellingham)<sup>57</sup> to be effective for participation in ISO New England’s (ISO-NE) Forward Capacity Auction (FCA) for the 2019-2020 commitment period (FCA 10). ISO-NE denied the request and NextEra filed a complaint before FERC against the ISO pursuant to sections 205 and 306 of the FPA.<sup>58</sup>

On March 3, 2015, NextEra submitted an interconnect request seeking a summer Qualified Capacity rating increase of twenty-five MW; this amount was later adjusted to ten MW.<sup>59</sup> Section III.13.1 of the ISO-NE tariff (Tariff) indicates that an Existing Generating Capacity Resource may elect to have an incremental amount of capacity participate in FCA as a new Generating Capacity Resource, but that certain conditions related to size of the incremental capacity and investment must be met; otherwise that incremental capacity would be considered a Significant Capacity Increase.<sup>60</sup> NextEra’s incremental capacity did not meet the threshold conditions and therefore qualified as a Significant Increase under Section III.13.1.2.2.5 of the tariff.<sup>61</sup> This Tariff provision specifies that where an Existing Capacity Resource makes an adjustment for a Significant Capacity increase, it may elect to add the Existing Summer Capacity and the incremental capacity for

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53. *Id.* at P 17-18.

54. *Id.* at P 25.

55. *Id.* at P 29.

56. *NextEra Energy Power Mktg. v. ISO New England*, 155 F.E.R.C. ¶ 61,270 at P 27 (2016).

57. Bellingham facility is a dual fuel generation plant located in Bellingham, Mass. *See* 155 F.E.R.C. ¶ 61,270, at P 2.

58. Complaints, 18 C.F.R. § 385.206 (a) (2015).

59. 155 F.E.R.C ¶ 61,270, at P 6.

60. *Id.* at PP 2-4.

61. *Id.* at PP 26-27.

purposes of the FCA, provided, however, that the participant must meet all other provisions of being a New Capacity Resource.<sup>62</sup> Although the parties agreed that the incremental capacity should be treated as a Significant Capacity Resource for FCA 10, they disagree as to the proper treatment of the capacity bid -- that is, whether the incremental capacity may be combined with existing summer capacity, or whether the capacity must be submitted via a composite offer that links incremental Summer Capacity to Winter Capacity, in which case the ten MW would be added to both capacity measures.<sup>63</sup>

NextEra argued that since the Bellingham incremental capacity meets the definition for “Significant Increase,” it could elect to have the participating Summer Capacity be the sum of the existing capacity and incremental capacity and in turn elect not to submit a composite offer.<sup>64</sup> ISO-NE argued that NextEra did not meet all requirements of being a New Capacity Resource as outlined in Section III.13.2.2.5 of the Tariff and therefore cannot elect to add the incremental capacity to the existing Summer Capacity.<sup>65</sup> ISO-NE further argued that NextEra was provided opportunities, but did not correct the bid error including filing a waiver after review of the capacity commitment shared with NextEra on October 19, 2015; which showed a zero MW incremental bid, or protest the November 10, 2015 Informational Filing for FCA 10.<sup>66</sup>

FERC agreed with ISO-NE that NextEra’s argument “ignores the limiting clause of Section III.13.2.2.5” requiring the participant to abide by all other provisions of the section III.13 applicable to a New Generating Capacity Resource.<sup>67</sup> In its finding, the Commission noted that it recently found the Tariff to be unclear with regards to “whether new incremental generating capacity and existing generating capacity at the same resource must submit a composite offer in order to participate in an FCA.”<sup>68</sup> Yet, the Commission indicated that even if NextEra had failed to argue that the Tariff was unclear, it would not have granted the requested relief since NextEra had failed to protest the capacity commitment bid treatment at opportunities provided in the process.<sup>69</sup>

#### *B. New York Independent System Operator, Inc.*

On April 21, 2016, FERC issued the compliance and rehearing order for the New York Independent System Operator (NYISO) regarding its Reliability Must Run (RMR) practices.<sup>70</sup> This Order was the outgrowth of the investigation that the Commission undertook pursuant to its FPA section 206 powers.<sup>71</sup> The result of the investigation was that the Commission directed NYISO to make revisions

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

63. *Id.* at P 5.

64. 155 F.E.R.C. ¶ 61,270, at PP 6, 8-9.

65. *Id.* at P 16.

66. *Id.*

67. *Id.* at P 26.

68. *Id.* at P 27 (citing *Dominion Energy Mktg., Inc. v. ISO New England, Inc.*, 155 F.E.R.C. ¶ 61,121 at P 21 (2016)).

69. 155 F.E.R.C. ¶ 61,270, at P 27.

70. *N.Y. Indep. Sys. Operator, Inc.*, 155 F.E.R.C. ¶ 61,076 P 1 (2016).

71. *Id.*

to its RMR tariff.<sup>72</sup> The Commission conditionally accepted in part the compliance filing subject to additional filings and denied it in part.<sup>73</sup> Furthermore, the Commission denied the request for rehearing and clarification by the New York Public Service Commission.<sup>74</sup> The Commission found in its investigation of NYISO's Market Administration and Control Area Services Tariff (the Services Tariff) that the Services Tariff was unjust and unreasonable because "it does not contain provisions governing the retention of and compensation to generating units needed for reliability."<sup>75</sup> It also found that NYISO's proposed compliance filing failed to address the flaws in the Service Tariff because it placed the RMR analysis in the Gap Solution Analysis.<sup>76</sup> The Commission deemed this a flaw because it would allow "the New York Commission to select non-generation Gap Solutions [which] does not comply with the RMR Order, is inconsistent with Order No. 1000, and could lead to inefficient transmission development."<sup>77</sup>

In rejecting NYISO's proposed 365-day notice period, the Commission noted that because it had rejected the combination of the RMR and Gap Solution process, it could not determine if the timeframe would be just and reasonable.<sup>78</sup> While accepting NYISO's proposed use of a distinctly higher net present value, the Commission required NYISO to file within sixty days a compliance filing that would explain the criteria that NYISO would use and provide a conceptual basis on how it would be implemented.<sup>79</sup> Additionally, the Commission found that NYISO's proposal to require generators with RMR to bid higher than \$0.00 as a capacity offer price was unjust and unreasonable because it could lead to ratepayers having to pay twice, "once for the cost of the RMR agreement, and again for the generator that otherwise would not have cleared the market."<sup>80</sup> The Commission next approved NYISO's determination of compensation due to a RMR Generator as either "APR determined in accordance with Schedule 8 of the Services Tariff, or an owner-developed rate that the RMR generator proposes" and the Commission approves, as just and reasonable.<sup>81</sup> Next, the Commission found that "NYISO's proposal is inconsistent with Order No. 1000, and therefore is not 'consistent with the Commission's cost allocation principles and precedents,' as required by the RMR Order."<sup>82</sup> The Commission also accepted in part, subject to conditions, and denied in part NYISO's anti-toggling provisions because "they do not fully address the toggling concerns the Commission identified in the RMR Order."<sup>83</sup>

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72. *Id.*

73. *Id.*

74. *Id.*

75. 155 F.E.R.C. ¶ 61,076, at P 2.

76. *Id.* at P 31.

77. *Id.*

78. *Id.* at P 63.

79. *Id.* at P 73.

80. 155 F.E.R.C. ¶ 61,076, at P 82.

81. *Id.* at P 85.

82. *Id.* at P 108.

83. *Id.* at P 122.

Lastly, the Commission had two concerns about toggling that it wanted NYISO to address: (1) “when a generator is needed for reliability and has an incentive to seek to deactivate prematurely,”<sup>84</sup> and (2) “when a generator that is operating under an approved RMR agreement must make capital expenditures to continue to meet the reliability need during the term of the RMR agreement.”<sup>85</sup> The Commission found that NYISO successfully addressed the second form of toggling, but it failed to address the first form and thus needed to submit a compliance filing.<sup>86</sup> That compliance filing would require that if a RMR generator wishes to continue to operate beyond its RMR agreement, “it must repay NYISO the higher of: (1) the capital expenditures less depreciation, that NYISO reimbursed the RMR generator to enable it to remain in service during the term of the RMR agreement; or (2) the above-market payments the RMR generator received during the term of the RMR agreement.”<sup>87</sup>

### C. *PJM Interconnection, L.L.C.*

On April 19, 2016, the United States Supreme Court, in an 8-0 opinion, affirmed a decision by the Fourth Circuit Court of Appeals, which had held that a Maryland program incentivizing in-state generation is preempted for impermissibly intruding upon FERC’s domain to regulate the wholesale electricity market.<sup>88</sup> Under the Maryland program, Maryland would guarantee its selected in-state generator a certain contract rate for capacity, even if the in-state generator’s capacity did not clear in PJM Interconnection, L.L.C.’s (PJM) capacity auction, thereby encouraging the generator to bid its capacity into the auction at the lowest possible price.<sup>89</sup> Incumbent generators in Maryland had filed suit in the United States District Court for the District of Maryland, contending that Maryland’s program, which was approved by the Maryland Public Service Commission, violated the Supremacy Clause by setting wholesale electricity rates and by interfering with FERC’s and PJM’s capacity-auction rules and policies.<sup>90</sup> The District Court held that Maryland’s power is limited by FERC’s exclusive authority to set wholesale energy and capacity prices.<sup>91</sup> The Fourth Circuit affirmed.

The United States Supreme Court observed that a state law will be preempted under the Supremacy Clause if Congress has comprehensively legislated the entire field of regulation and if the challenged state law impedes the full purposes and objectives of Congress.<sup>92</sup> In explaining the division of authority between state and federal regulators, the Court explained that the FPA allocated to FERC exclusive jurisdiction over “rates and charges . . . received . . . for or in connection with”

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84. *Id.* at P 123.

85. 155 F.E.R.C. ¶ 61,076, at P 124.

86. *Id.* at P. 125-26.

87. *Id.* at P. 126.

88. *Hughes v. Talen Energy Mktg.* 136 S.Ct. 1288, 1290-91 (2016).

89. *Id.* at 1294-95.

90. *Id.* at 1296-97.

91. *Id.* at 1296.

92. *Id.* at 1297 (citing *Nw. Cent. Pipeline Corp. v. State Corp. Comm’n of Kan.*, 489 U.S. 493, 509 (1989); *Crosby v. Nat’l Foreign Trade Council*, 530 U.S. 363, 373 (2000)).

interstate wholesale sales.<sup>93</sup> The Court emphasized that Maryland's program, by establishing a "contract for differences," required the in-state generator to participate in PJM's capacity auction, but would still guarantee the in-state generator a rate distinct from the auction clearing price for its interstate sales of capacity to PJM.<sup>94</sup> Accordingly, in agreeing with the Fourth Circuit's judgment, the Court concluded that Maryland's program invaded on FERC's regulatory turf by adjusting an interstate wholesale rate.<sup>95</sup>

The Court analogized this case to previous cases where the Supreme Court invalidated attempts by states to second-guess the reasonableness of interstate wholesale rates under the federal regulatory scheme.<sup>96</sup> Under that precedent, the Court explained that even if a state is exercising its traditional authority over retail rates or in-state generation, a state intrudes upon the federal regulatory scheme if it interferes with an interstate wholesale rate that FERC has determined to be just and reasonable.<sup>97</sup> The Court narrowly tailored its holding, specifically rejecting Maryland's program because it disregards the FERC-required interstate wholesale rate.<sup>98</sup> The Court did not address the permissibility of state incentives to encourage the development of new or clean generation.<sup>99</sup> Justice Sotomayor filed a separate concurring opinion<sup>100</sup> and Justice Thomas concurred in the judgment of the Court's 8-0 opinion and wrote a separate concurring opinion.<sup>101</sup>

On March 17, 2016, the Commission issued an order denying rehearing of its 2011 orders accepting certain revisions to PJM and Midcontinent Independent System Operator, Inc.'s (MISO) OATTs, granting clarification in part to those orders, and conditionally accepting certain compliance filings.<sup>102</sup> The revisions, initial order, and the order denying rehearing addressed American Transmission System, Inc.'s (ATSI) responsibility for RTO exit fees and legacy transmission expansion plan project costs resulting from ATSI's decision to leave MISO and realign with PJM, as well as associated tariff revisions and compliance filings.<sup>103</sup>

On rehearing, ATSI contended that FERC erred in characterizing legacy MISO Transmission Expansion Plan (MTEP) project costs as MISO exit fees.<sup>104</sup> ATSI contended that legacy project costs are not costs incurred by MISO, but rather are costs incurred by MISO transmission owners to construct certain transmission upgrades.<sup>105</sup> ATSI argued that "Legacy MTEP Project costs are existing

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93. *Hughes* at 1292 (citing 18 U.S.C. § 824d (a)).

94. *Id.* at 1294-95.

95. *Id.* at 1297 (citing *FERC v. Elec. Power Supply Ass'n.*, 577 U.S. \_\_\_, 136 S. Ct. 760, 780 (2016)).

96. *Id.* at 1298-99 (citing *Miss. Power & Light v. Miss. ex rel. Moore*, 487 U.S. 354, 360-64 (1988); *Nantahala Power & Light Co. v. Thornburg*, 476 U.S. 953, 956-62 (1986)).

97. *Hughes* at 1299.

98. *Id.*

99. *Id.*

100. *Id.* at 1299-1300.

101. *Id.* at 1300-01.

102. *PJM Interconnection & Midwest Indep. Transmission Sys. Operator*, 154 F.E.R.C. ¶ 61,217 at P 3 (2016).

103. *Id.* at P 1.

104. *Id.* at P 13.

105. *Id.*

costs that ATSI zone transmission customers were paying under the MISO Tariff prior to ATSI's departure, and that ATSI customers would have continued to pay the Legacy MTEP Project cost if ATSI had not departed from MISO."<sup>106</sup> In connection with this argument, ATSI contended that FERC did not explain why a comparison of costs and benefits is required to justify a continued recovery of costs that were recovered from ATSI Zone Transmission customers under the MISO tariff, under rates that FERC previously accepted as just and reasonable.<sup>107</sup> ATSI also argued that FERC should reverse its finding concerning the calculation of ATSI Zone Transmission customers' share of legacy project costs and the distribution of resulting payments.<sup>108</sup> ATSI contended that FERC's finding was based on its erroneous decision that legacy project costs cannot be recovered from ATSI's wholesale transmission customers without a further showing of benefits to wholesale transmission customers that outweigh those costs.<sup>109</sup>

FERC disagreed with ATSI's contention that legacy MTEP project costs are not costs associated with the RTO realignment decision.<sup>110</sup> FERC concluded that while not included in MISO exit fees, the legacy MTEP project costs are appropriately costs associated with the RTO realignment decision.<sup>111</sup> FERC noted that the legacy projects were approved by the MISO board of directors prior to ATSI's integration into PJM, and under the MISO tariff, all transmission owners in MISO are responsible for their proportionate share of all transmission costs incurred while they were members of MISO.<sup>112</sup> FERC held that once ATSI changed RTOs, those costs did not necessarily benefit ATSI transmission customers since they currently receive service using the PJM Transmission System.<sup>113</sup> In sum, ATSI's obligation to pay the legacy MTEP project costs is a corporate obligation based on its agreement with the other MISO transmission owners, but ATSI cannot recover legacy MTEP project costs from its customers without a further showing that the benefits to wholesale transmission customer exceed the costs of the realignment.<sup>114</sup>

FERC next addressed ATSI's argument that its decision that ATSI, and not its customers, is responsible for paying legacy MTEP project costs does not reconcile with the fact that the MISO transmission owners' customers will continue to pay for those projects.<sup>115</sup> FERC distinguished the ATSI situation on the basis that unlike ATSI, the MISO transmission owners have not withdrawn from MISO.<sup>116</sup>

In response to the MISO parties' request for clarification, FERC confirmed that MISO is entitled to recover the legacy MTEP project costs allocated to the

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106. *Id.*

107. 154 F.E.R.C. ¶ 61,217, at P 14.

108. *Id.* at P 17.

109. *Id.*

110. *Id.* at P 25.

111. *Id.*

112. 154 F.E.R.C. ¶ 61,217, at P 25.

113. *Id.*

114. *Id.*

115. *Id.* at P 26.

116. *Id.*

ATSI Zone from ATSI.<sup>117</sup> In doing so, FERC disagreed with ATSI's argument that the request for clarification was asking that the Commission make a ruling inconsistent with precedent.<sup>118</sup> FERC reiterated that the project costs are a part of ATSI's corporate withdrawal obligation and do not rest with ATSI's transmission customers, in the absence of a showing by ATSI that the benefits to wholesale transmission customers exceed the costs of the realignment.<sup>119</sup>

FERC also disagreed with ATSI's claim that it did not incur legacy MTEP project costs prior to the dates of its withdrawal from MISO membership, because MISO billed those costs directly to the customer, making the customers responsible.<sup>120</sup> The Commission stated that MISO's billing mechanics when ATSI was a member of MISO does not affect the underlying realities that ATSI's business decision, including its decision to leave MISO, established responsibility for those exit costs with no ability for ATSI's customers to influence that obligation.<sup>121</sup> The Commission cited precedent establishing that under the MISO transmission owners agreement, ATSI, as the transmission owner, bore responsibility for costs resulting from its own business decisions.<sup>122</sup> FERC reiterated that the imposition of MISO exit fees on ATSI is a function of its obligation under the MISO transmission owners agreement, not a finding that these costs necessarily benefit ATSI's wholesale customers.<sup>123</sup> FERC also noted that ATSI had cited no MISO tariff position holding customers responsible for paying legacy MTEP project costs as an exit obligation.<sup>124</sup>

Finally, FERC found that the ATSI-MISO exit fee agreement does not absolve ATSI of legacy MTEP project cost responsibility.<sup>125</sup> FERC concluded that the operative sections of the exit fee agreement indicate the intent to satisfy limited financial obligations, and this intent is not outweighed by any general language in the preamble.<sup>126</sup>

On April 21, 2016, FERC denied a 2014 complaint filed by the Independent Market Monitor for PJM (PJM IMM) against PJM asserting that PJM's tariff fails to treat demand response and generation resources in a comparable manner, because: (1) demand resources are not subject to a must offer requirement in PJM's day-ahead energy market nor (2) subject to an offer cap on energy offers.<sup>127</sup> Specifically, the PJM IMM argued that although PJM's capacity market auctions clear demand response resources as full substitutes for a generation capacity resource, for dispatch purposes in PJM's energy market demand response is treated as an emergency only resource having no obligation to submit a day-ahead offer.<sup>128</sup> The

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117. 154 F.E.R.C. ¶ 61,217, at P 34.

118. *Id.*

119. *Id.*

120. *Id.* at P 36.

121. 154 F.E.R.C. ¶ 61,217, at P 36.

122. *Id.*

123. *Id.*

124. *Id.* at P 40.

125. *Id.* at P 41.

126. 154 F.E.R.C. ¶ 61,217, at P 44.

127. *Indep. Mkt. Monitor for PJM v. PJM Interconnection, L.L.C.*, 155 F.E.R.C. ¶ 61,059 at PP 1, 4 (2016).

128. *Id.* at P 2.

PJM IMM contrasted the treatment of demand resource treatment with that of generation capacity resources which maintain a requirement to submit daily offers subject to the default offer cap.<sup>129</sup>

The FERC majority denied the complaint, finding that the PJM IMM had not met the burden of establishing that any unequal treatment was inappropriate. FERC reiterated its prior finding “that comparability does not require that generation resources and demand response resources be subject to the same operational parameters in every circumstance”<sup>130</sup> in finding that demand response need not be subject to the same operational rules as generation resources.<sup>131</sup> FERC noted that generation resources bids are permitted to reflect short-run marginal cost up to \$2,000/MWh while demand response resource bids reflect the opportunity cost of foregoing production based on the entity’s operations and economic circumstances so that both sets of resources are “currently able to submit offers that reflect either the short-run marginal cost of providing energy or the cost of providing demand response, even though the mechanics of having these offers validated differ.”<sup>132</sup> As to the request that demand response be subject to a must-offer obligation, FERC found that the Market Monitor has not provided sufficient justification to warrant imposition of that requirement given that demand response resources have different business objectives in participation as a demand resource in the capacity market than generation resources and “the Commission has long allowed a distinction between demand response resource participation in a day-ahead or real-time energy market . . . and demand response under programs that RTOs or ISOs administer for reliability or emergency conditions.”<sup>133</sup>

Commissioner Clark dissented from the majority finding that the PJM IMM had not met its burden under FPA section 206 to establish that not requiring demand response to meet a must-offer obligation was unjust, unreasonable, or unduly discriminatory or preferential. Clark reasoned that the Commission majority’s reliance on the difference in primary business function between generation resources and demand response resources was misplaced since both made “the voluntary decision to compete and receives a stream of funding from the wholesale market for capacity services.”<sup>134</sup> As such, Clark believed “the IMM provides adequate justification showing this policy [of distinct treatment] to be unjust, unreasonable, and a threat to grid reliability.”<sup>135</sup>

On April 21, 2016, FERC denied a 2012 complaint filed by Viridity Energy, Inc. (Viridity) against PJM challenging provisions of the PJM Operating Agreement regarding the classifications and treatment of end-use customers participating in PJM’s Emergency Load Response Program.<sup>136</sup> Viridity argued that the PJM

129. *Id.*

130. *Id.* at P 30 (quoting Order No. 890, *Preventing Undue Discrimination & Preference in Transmission Serv.*, F.E.R.C. STATS. & REGS. ¶ 31,241 (2007), *order on reh’g & clarification*; Order No. 890-A, F.E.R.C. STATS. & REGS. ¶ 31,261 at P 216 (2007) (to be codified at 18 C.F.R. pts. 35, 37)).

131. *Id.* at P 31.

132. 155 F.E.R.C. ¶ 61,059, at P 32.

133. *Id.* at P 33.

134. *Id.*, partial dissent of Comm’r Clark at 2.

135. *Id.*

136. *Viridity v. PJM Interconnection, L.L.C.*, 155 F.E.R.C. ¶ 61,060 at P 1 (2016).

compensation provisions available to a Capacity Only resource, one that uses one Curtailment Service Providers (CSP) for Capacity and a separate one for energy, are unduly discriminatory because an end-use customer that registers with a single CSP for both capacity and energy market purposes, the Full Option Program, receives a different payment.<sup>137</sup>

FERC denied the complaint, finding that Viridity had not shown that PJM's OATT was unduly discriminatory in its classification and treatment of Full Program Option resources and Capacity Only resources.<sup>138</sup> FERC accepted PJM's assertions that the distinctions in compensation between Full Program Option participants and Capacity Only participants served legitimate purposes, justified by the need to avoid errors in measurement and verification that could arise when two different CSPs are utilized.<sup>139</sup> FERC noted that "there is not necessarily undue discrimination simply because a customer is permitted to choose" and that choice has financial consequences.<sup>140</sup>

On May 31, 2016, FERC rejected PJM's proposed amendments to Attachment DD, section 10A(d) of PJM's OATT, which would have excused Capacity Performance Resources from Non-Performance Charges during emergency conditions.<sup>141</sup> In its application, PJM proposed to excuse such resources from Non-Performance Charges when the resource followed PJM's dispatch instructions and operated at a ramp rate PJM had previously approved.<sup>142</sup> PJM proposed that it would consult the PJM IMM and review and verify each unit's average historic ramp rate performance over a three month reference period.<sup>143</sup> PJM averred that it was concerned that without the proposed exemption, units may opt to self-schedule their capacity before the Performance Hour to avoid the Non-Performance Charge.<sup>144</sup>

The Market Monitor and LS Power argued that FERC should reject the proposal because PJM did not support its assertion that that system control issues would result from excessive self-scheduling during high load periods.<sup>145</sup> The Market Monitor also commented that PJM's proposal disincentivizes units with faster ramp rates to a higher standard during a Performance Assessment Hour.<sup>146</sup> In response, PJM asserted that the proposed amendment was designed to balance performance incentives of the Capacity Performance construct against reliability of the system.<sup>147</sup> PJM also noted that the proposed amendment was an interim solution.<sup>148</sup>

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137. *Id.* at PP 2, 4-5.

138. *Id.* at P 21.

139. *Id.* at P 22.

140. *Id.* at P 25 (citing *Transcon. Gas Pipeline Corp.*, 46 F.E.R.C. ¶ 61,364 at 62,141 (1989)).

141. *PJM Interconnection, L.L.C.*, 155 F.E.R.C. ¶ 61,213 at P 1 (2016).

142. *Id.* at P 3.

143. *Id.*

144. *Id.* at P 4.

145. *Id.* at P 10.

146. 155 F.E.R.C. ¶ 61,213, at P 11.

147. *Id.* at P 15.

148. *Id.*

In rejecting PJM's proposal, FERC noted the importance of the penalty structure to PJM's Capacity Performance design.<sup>149</sup> FERC noted that the proposed exemption would dampen the long-term incentive for retention and entry of flexible capacity resources.<sup>150</sup> FERC agreed with the Market Monitor that Performance Assessment Hours occur during periods when the system is under stress; FERC noted that during these periods, the risk of losses due to self-scheduling combined with a Non-Performance Charge provides a proper incentive to owners to maintain their units and to follow dispatch instructions.<sup>151</sup> Similarly, FERC was not persuaded by PJM's argument that deviations charges are insufficient to prevent units from ignoring real-time dispatch instructions.<sup>152</sup>

On remand from the U.S. Court of Appeals for the Seventh Circuit,<sup>153</sup> FERC approved a proposal by MISO to impose a charge for Multi-Value Projects (MVP) on export and wheel-through transactions that sink in the PJM region.<sup>154</sup> FERC had previously rejected MISO's proposal to apply the MVP charge to such PJM transactions as inconsistent with earlier Commission orders requiring elimination of pancaked rates between MISO and PJM.<sup>155</sup>

Responding to the court's instruction that FERC determine whether the prohibition on MVP charges for transactions sinking in PJM was justified "in light of current conditions,"<sup>156</sup> the Commission found that the export pricing restriction was not warranted.<sup>157</sup> As grounds for allowing the charge, FERC cited changes in MISO and PJM membership that "significantly reduced the geographic complexity of the seam between the RTOs,"<sup>158</sup> improvements in market-to-market coordination between MISO and PJM,<sup>159</sup> and the fact that MVPs would not be local MISO projects providing only local benefits.<sup>160</sup> FERC rejected the claim that imposing the MVP usage charge on exports into PJM would be inconsistent with Order No. 1000 cost allocation principles,<sup>161</sup> and the Commission declined to consider arguments that MISO had improperly filed its proposal under section 205 of

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149. *Id.* at P 23.

150. *Id.* at P 24.

151. 155 F.E.R.C. ¶ 61,213, at P 25.

152. *Id.* at P 27.

153. *Ill. Commerce Comm'n v. FERC*, 721 F.3d 764 (7th Cir. 2013), *cert. denied sub nom*; *Schuette v. FERC*, 134 S. Ct. 1277 (2014), *cert. denied sub nom*; *Hoosier Rural Energy Coop., Inc. v. FERC*, 134 S. Ct. 1278 (2014).

154. *Midwest Indep. Transmission Sys. Operator, Inc.*, 156 F.E.R.C. ¶ 61,034 (2016).

155. *Midwest Indep. Transmission Sys. Operator, Inc.*, 133 F.E.R.C. ¶ 61,221 (2010), *order on reh'g and compliance filing*, 137 F.E.R.C. ¶ 61,074 (2011).

156. 156 F.E.R.C. ¶ 61,034 at P 52 (citing *Ill. Commerce Comm'n*, 721 F.3d at 780).

157. *Id.* at PP 50-57.

158. *Id.* at P 53.

159. *Id.* at P 54.

160. *Id.* at P 55.

161. 156 F.E.R.C. ¶ 61,034, at P 56 (discussing Order No. 1000, *Transmission Planning & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, F.E.R.C. STATS. & REGS. ¶ 31,323 (2011), *order on reh'g*; 139 F.E.R.C. ¶ 61,132 (2012), *order on reh'g and clarification*, 141 F.E.R.C. ¶ 61,044 (2012), *aff'd sub nom*; *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014)).

the FPA as beyond the scope of the court's remand.<sup>162</sup> FERC made its ruling effective prospectively from the date of the order.<sup>163</sup>

In three related orders issued on April 22, 2016, FERC rejected challenges to proposed cost allocations for new transmission projects in the PJM region.<sup>164</sup> At issue in each proceeding was whether the solution-based distribution factor (DFAX) method used by PJM to allocate costs of certain new regionally-planned transmission projects produced just and reasonable results. FERC rejected arguments that application of the solution-based DFAX method—which allocates costs based on use of a new facility—is inappropriate for projects that do not address electricity flow-based reliability concerns.<sup>165</sup> Further, FERC was not persuaded by arguments that certain components of PJM's DFAX method contributed to unjust and unreasonable results when applied to small zones and/or merchant transmission facilities.<sup>166</sup> The PJM OATT, FERC also concluded, did not give PJM discretion to modify allegedly unreasonable DFAX results, except in limited circumstances not applicable to the challenged project cost allocations.<sup>167</sup> Commissioner LaFleur partially dissented from all three orders, asserting in each case that the record “clearly establishes that there is a discrete and identifiable set of transmission projects as to which [solution-based DFAX] produces an anomalous result and does not allocate costs in a manner roughly commensurate with benefits.”<sup>168</sup>

In *PJM Interconnection, L.L.C.*,<sup>169</sup> FERC granted rehearing of a May 2015 order<sup>170</sup> and accepted proposed revisions to the PJM OATT pursuant to which 100% of the costs of transmission projects included in the PJM Regional Transmission Expansion Plan (RTEP) solely to address local transmission owner planning criteria would be allocated to the PJM zone in which such local planning criteria applies.<sup>171</sup> FERC agreed that, although the relevant projects would be included in the PJM RTEP, they were not projects selected in the RTEP for purposes of cost allocation within the meaning of Order No. 1000.<sup>172</sup> Accordingly, the cost allocation methods used for RTEP projects designed to address other PJM planning criteria need not apply to projects required solely to address an individual transmission owner's local planning criteria.<sup>173</sup> Commissioner LaFleur dissented in part, arguing that high-voltage projects in PJM (double-circuit 345 kilovolts

162. *Id.* at P 58.

163. *Id.* at P 59.

164. *Del. Pub. Serv. Comm'n & Md. Pub. Serv. Comm'n v. PJM Interconnection, L.L.C. & Certain Transmission Owners Designated Under CTOA RS FERC No. 42*, 155 F.E.R.C. ¶ 61,090 (2016); *Linden VFT, L.L.C. v. PJM Interconnection, L.L.C.*, 155 F.E.R.C. ¶ 61,089 (2016); *Consol. Edison Co. of N.Y. v. PJM Interconnection, L.L.C.*, 155 F.E.R.C. ¶ 61,088 (2016).

165. 155 F.E.R.C. ¶ 61,090, at PP 67-69; 155 F.E.R.C. ¶ 61,089, at PP 55-57; 155 F.E.R.C. ¶ 61,088, at PP 40-42.

166. 155 F.E.R.C. ¶ 61,089, at PP 60-64; 155 F.E.R.C. ¶ 61,088, at PP 45-46.

167. 155 F.E.R.C. ¶ 61,089, at PP 65-66; 155 F.E.R.C. ¶ 61,088, at P 47.

168. 155 F.E.R.C. ¶ 61,090, dissent of Comm'r LaFleur at 2; 155 F.E.R.C. ¶ 61,089, at 61,560; 155 F.E.R.C. ¶ 61,088, at 61,545.

169. *PJM Interconnection, L.L.C.*, 154 F.E.R.C. ¶ 61,096 (2016).

170. *PJM Interconnection, L.L.C.*, 151 F.E.R.C. ¶ 61,172 (2015).

171. 154 F.E.R.C. ¶ 61,096, at P 1.

172. *Id.* at P 13 n.16 (citing Order No. 1000, F.E.R.C. STATS. AND REGS. ¶ 31,323 at P 63).

173. *Id.* at P 13.

(kV) and above), “even if developed solely to address local planning criteria, provide regional benefits that warrant some regional cost allocation.”<sup>174</sup>

*D. Midcontinent Independent System Operator, Inc.*

On April 21, 2016, FERC denied Occidental Chemical Corporation’s (Occidental) request for rehearing of FERC’s January 21, 2016, Order (January Order) on Entergy Services, Inc.’s (Entergy) application to terminate its operating companies’ requirement to purchase electric energy and capacity from qualifying co-generation or small power production facilities (QFs) with a net capacity in excess of 20 MW.<sup>175</sup> Entergy filed its application pursuant to section 292.309(e) of FERC’s regulations, which provides a rebuttable presumption that Regional Transmission Organizations, such as the MISO, provide QFs access to markets to qualify for an exemption under section 292.309(a)(1) from purchasing electric energy and capacity from QFs.<sup>176</sup> Based on Entergy’s un rebutted statements in its Application, FERC’s June 21, 2016, Order found that MISO provided nondiscriminatory access for QFs in Entergy’s operating companies’ service territories to MISO’s Markets, with the exception of Dow Chemical Company’s Plaquemine QF.<sup>177</sup> In the January Order, FERC rejected Occidental’s claim that its QF in Hahnville, Louisiana did not have nondiscriminatory access to MISO’s markets due to being located in a load pocket.<sup>178</sup>

In its February 22, 2016, request for rehearing, Occidental made three arguments. First, Occidental argued that FERC ignored record evidence that the MISO QF Integration Plan denied Occidental’s QF access to MISO’s markets.<sup>179</sup> In rejecting Occidental’s argument, FERC noted that it analyzed all pertinent evidence in the record, including the evidence submitted by Occidental in its separate complaint in Docket No. EL13-41-000.<sup>180</sup> In its complaint case, Occidental alleged that MISO’s QF Integration Plan: (1) improperly conditions QFs’ registration and participation in the MISO markets upon QFs’ waiving rights under Public Utilities Regulatory Policies Act (PURPA); (2) improperly restricts QFs from exercising their PURPA rights participating simultaneously in the MISO markets; and (3) is not contained in the FERC-approved MISO Tariff.<sup>181</sup> FERC rejected Occidental’s first argument, while finding that Occidental’s complaint case was the appropriate forum to address broad issues related to MISO’s QF Integration Plan.<sup>182</sup> FERC then noted that its Order issued in Occidental’s complaint case denies Occidental’s complaint.<sup>183</sup>

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174. *Id.*, partial dissent of Comm’r LaFleur at 2.

175. *Entergy Servs., Inc.*, 155 F.E.R.C. ¶ 61,069 at P 1 (2016) (citing *Entergy Servs., Inc.*, 154 F.E.R.C. 61,035 (2016)).

176. *Id.*

177. *Id.*

178. *Id.* at P 2.

179. *Id.* at P 5.

180. 155 F.E.R.C. ¶ 61,069, at P 5.

181. *Id.* at P 6.

182. *Id.* at P 8.

183. *Id.* at P 9.

FERC also rejected Occidental's second argument that FERC ignored the plain meaning of section 292.309(e) of FERC's own regulations, which provides, *inter alia*, that a QF with over 20 MWs may seek to rebut the presumption that it has nondiscriminatory access to markets.<sup>184</sup> Occidental asserted that its QF is located in a load pocket.<sup>185</sup> In rejecting Occidental's second argument, FERC cited to Order No. 688, which provides that "the Commission will consider, on a case-by-case basis, among other things, the opportunity for QFs, on a nondiscriminatory basis, to obtain transmission upgrades to relieve constraints and whether the structure of the relevant market provides for the opportunity for the QF to sell notwithstanding the constraint."<sup>186</sup> Based on its review of the record, FERC determined that Occidental's QF had nondiscriminatory access to sell capacity either in MISO's Planning Resource Auction or through bilateral sales.<sup>187</sup>

Finally, FERC rejected Occidental's third argument that FERC relied upon speculation instead of record evidence, stating that Entergy's evidence that Occidental's QF had access to MISO markets was more persuasive.<sup>188</sup>

On April 29, 2016, FERC conditionally accepted proposed revisions to section 39.1.1 of the MISO OATT that authorize MISO to extend or reopen the Day-Ahead and Operating Reserve Market (Day-Ahead Market) when necessitated by "unanticipated events."<sup>189</sup>

MISO proposed allowing to extend or reopen the Day-Ahead Market when unanticipated events would otherwise adversely affect the Day-Ahead Market results in "a manner that would significantly impair the reliability of MISO's markets or systems."<sup>190</sup> Unanticipated events would be limited to those that (1) interfere with MISO's ability to receive or process bid, offer, or interchange schedule data; (2) render bid, offer, or interchange schedule data plainly inaccurate in a manner likely to significantly impede MISO's ability to deliver a feasible market solution; or (3) are otherwise likely to have a widespread negative impact on the results of the Day-Ahead Market, adversely threatening or affecting the reliability of market operations or of the transmission system.<sup>191</sup>

MISO explained that certain unanticipated events can have significant adverse impacts on the closing of the Day-Ahead Market, posing undue risks to the reliability of MISO's markets and systems.<sup>192</sup> Examples included technical issues preventing submission of bids, offers, or interchange schedules for an extended

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184. *Id.* at P 10.

185. 155 F.E.R.C. ¶ 61,069, at P 10.

186. *Id.* (citing Order No. 688, *New PURPA Section 210(m) Regulation Applicable to Small Power Prod. & Cogeneration Facilities*, F.E.R.C. STATS. & REGS. ¶ 31,233 at P 84 (2006), *order on reh'g*; Order No. 688-A, F.E.R.C. STATS. & REGS., ¶ 31,250 (2007), *aff'd sub nom.*; *Am. Forest & Paper Ass'n v. FERC*, 550 F.3d 1179 (D.C. Cir. 2008)) (emphasis removed).

187. *Id.* at P 11.

188. *Id.* at P 17.

189. *Midcontinent Indep. Sys. Operator, Inc.*, 155 F.E.R.C. ¶ 61,110 at P 1 (2016).

190. *Id.* at P 2.

191. *Id.*

192. *Id.* at P 4.

period of time; incomplete demand and supply data; and unreliable data (for example, data compromised by software bugs).<sup>193</sup> To avoid harmful market or system impacts, MISO proposed to extend the Day-Ahead market, or reopen it promptly after closing, so that MISO could have a reasonable opportunity to address events that threaten to, or actually, result in such impacts.<sup>194</sup> MISO stated that in the event of extending or reopening the Day-Ahead Market, public notice would be provided to all market participants, as well as prompt follow-up communications.<sup>195</sup>

Wisconsin Electric Power Company (Wisconsin Electric) and Wisconsin Public Service Corporation (WPSC) stated that although they generally supported MISO's proposal, that the extension or reopening of the Day-Ahead Market should only be used for, and limited to, de-commitment of a cleared resource, or correction of gross data entry errors that would impact multiple market participants and lead to improper price signals.<sup>196</sup> MISO disagreed with these limitations, arguing that the Day-Ahead Market is not the appropriate mechanism for de-committing a resource, and that events warranting the extension or reopening of the Day-Ahead Market may not necessarily be resolved by de-committing resources (such as excessive system generation causing minimum generation emergencies, deficient system generation causing maximum generation emergencies, and invalid congestion management planning that can put transmission elements at physical risk).<sup>197</sup> MISO further stated that its proposed OATT changes were intended to be applied in limited circumstances, and only to mitigate large scale issues.<sup>198</sup>

FERC accepted the proposed OATT revisions, subject to condition, effective on the requested April 29, 2016, date.<sup>199</sup> FERC found that MISO's proposal enables MISO to ensure its ability to procure and process bid, offer, and interchange schedule data that are reflective of the market participant's intentions and the expected system conditions for the Operating Day, and also found that MISO's proposal reasonably limits unanticipated events.<sup>200</sup> FERC disagreed with Wisconsin Electric and WPSC's proposed limitations to only de-commit resources or correct gross data errors.<sup>201</sup> FERC noted that adopting the limitations would prevent MISO from extending or reopening the Day-Ahead Market to address technical issues; that MISO's proposal already addressed gross data errors; that the Day-Ahead Market is not the appropriate mechanism for de-committing resources; and that adverse impacts on an individual load serving entity can adversely affect sizeable loads (so there should not be a limitation to data entry errors impacting multiple market participants).<sup>202</sup>

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193. *Id.*

194. 155 F.E.R.C. ¶ 61,110, at P 5.

195. *Id.* at P 6.

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

197. *Id.* at P 11.

198. *Id.* at P 12.

199. 155 F.E.R.C. ¶ 61,110, at P 15.

200. *Id.*

201. *Id.* at P 16.

202. *Id.*

However, FERC did find that MISO's proposed OATT revisions lacked detail on the type of information that would be posted publicly in MISO's follow-up communications.<sup>203</sup> FERC said that "MISO's follow-up communications . . . should include the circumstances in which MISO's authority was exercised, rationale for exercising such authority, length of time the Day-Ahead Market was extended or reopened, and whether MISO's action was successful in addressing the issue that prompted the action."<sup>204</sup> FERC directed MISO to submit a compliance filing regarding the follow-up communications.<sup>205</sup>

On June 16, 2016, FERC issued an order to show cause pursuant to section 206 of the FPA on its own motion directing MISO to either: (1) revise its Tariff to ensure that a generation or non-generation resource owner will no longer receive compensation for Reactive Supply and Voltage Control Service ("Reactive Service"—Schedule 2 under the *pro forma* OATT) after it has deactivated or transferred its unit(s), and to clarify the treatment of Reactive Service revenue requirements for such unit(s); or (2) show cause why it should not be required to do so.<sup>206</sup> FERC also directed MISO to post and maintain a chart listing all resource owners receiving compensation for Reactive Service, along with their current Reactive Service revenue requirements.<sup>207</sup>

FERC noted that in prior proceedings involving PJM, it had expressed concern that PJM may have continued to pay generation and non-generation resources for Reactive Service after units had deactivated and were no longer capable of providing that service, and that such practice may be unjust and unreasonable.<sup>208</sup> FERC took action with respect to MISO in light of filings by two MISO member companies that updated their Reactive Service revenue requirements to reflect changes to their generating fleets.<sup>209</sup>

#### *E. Southwest Power Pool, Inc.*

On June 16, 2016, FERC issued an order<sup>210</sup> granting clarification and denying rehearing of its December 15, 2015 order<sup>211</sup> that accepted proposed revisions to the Southwest Power Pool, Inc. (SPP) Tariff to add a formula rate template and implementation protocols to accommodate the recovery of an annual transmission revenue requirement for new SPP member Central Power Electric Cooperative, Inc. (Central Power), an otherwise non-jurisdictional transmission owner.<sup>212</sup>

FERC clarified for Otter Tail Power Company (Otter Tail), which operates an integrated transmission system with Central Power, that the initial order was intended to include in the hearing and settlement judge procedures the issue of

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203. *Id.* at P 17.

204. 155 F.E.R.C. ¶ 61,110, at P 17.

205. *Id.*

206. *Midcontinent Indep. Sys. Operator, Inc.*, 155 F.E.R.C. ¶ 61,254 at P 1 (2016).

207. *Id.*

208. *Id.* at P 3.

209. *Id.* at P 7.

210. *Sw. Power Pool, Inc.*, 155 F.E.R.C. ¶ 61,259 (2016).

211. *Sw. Power Pool, Inc.*, 153 F.E.R.C. ¶ 61,367 (2015).

212. 155 F.E.R.C. ¶ 61,259, at P 1.

whether any service agreement provisions would be needed to mitigate the impact of duplicative or pancaked rates on the integrated transmission system, regardless of whether the individual facilities within the integrated transmission system are jointly or individually owned by Otter Tail and/or Central Power.<sup>213</sup> FERC also granted the requested clarification of the Minnesota Public Utilities Commission, North Dakota Public Service Commission, and South Dakota Public Utilities Commission (collectively, Joint Commissions) that the initial order did not prohibit parties other than Otter Tail from addressing whether any service agreement provisions would be necessary to mitigate the impacts of duplicative or pancaked rates on the integrated transmission system that did not exist before Central Power's integration into SPP.<sup>214</sup>

In the order FERC also denied requests for rehearing.<sup>215</sup> Specifically, FERC denied a request for rehearing by Otter Tail and the Joint Commissions that Otter Tail be held harmless from the operational and financial impacts of Central Power joining SPP.<sup>216</sup> FERC also denied Otter Tail's request for rehearing of FERC's decision not to address rate pancaking that results from Central Power's membership in SPP.<sup>217</sup>

#### *F. California Independent System Operator Corp.*

On February 18, 2016, FERC instituted a section 206 proceeding under the FPA on its own motion to examine whether “the must-offer obligation imposed in the Western Electricity Coordinating Council (WECC) during the California energy crisis of 2000-2001 is no longer necessary and therefore has become unjust and unreasonable.”<sup>218</sup> The proceeding was initiated after receipt of a letter on March 16, 2015, by then-Chairperson Cheryl LaFleur from the Western Systems Power Pool (WSPP), requesting that FERC clarify whether the must-offer requirement imposed on utilities as part of the Western energy crisis mitigation needed to continue, as there was no longer the market dysfunction that initially compelled the obligation.<sup>219</sup>

On April 26, 2001, FERC “established a prospective mitigation and monitoring plan for the California wholesale electric markets.”<sup>220</sup> This plan included a must-offer obligation which “required most resources serving California markets to offer all of their capacity in real time, during all hours, if they were available and were not already scheduled to run through bilateral agreements.”<sup>221</sup> This West-wide obligation also required posting of available energy on both the utilities' and WSPP's websites.<sup>222</sup>

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213. *Id.* at P 15.

214. *Id.* at P 17.

215. *Id.* at P 18.

216. *Id.* at P 19.

217. 155 F.E.R.C. ¶ 61,259, at P 21.

218. *Cal. Indep. Sys. Operator Corp.*, 154 F.E.R.C. ¶ 61,110 at P 1 (2016).

219. *Id.* at P 3.

220. *Id.*

221. *Id.*

222. *Id.*

In adopting this West-wide must-offer requirement, FERC found there was a “critical interdependence among the prices in the California Independent System Operator Corp.’s (CAISO) spot markets with the bilateral prices in California and WECC.”<sup>223</sup> FERC noted that a key to resolving the dysfunction in the Western energy markets was to “eliminate California’s excessive reliance on the spot markets to meet its load,” and that there was a “need for uniform pricing” throughout the West.<sup>224</sup> FERC required public and non-public utilities in the WECC to meet this West-wide obligation, and extended the requirement past its initial expiration date of September 30, 2002, until longer-term market-based solutions were fully implemented.<sup>225</sup>

In the current proceeding, FERC noted that “due to the passage of time and significant changes to California’s wholesale markets, the must-offer obligation established for the WECC in 2001 appears to have outlived its usefulness,” and the requirement that all public utility sellers in the WECC must post on their utility and the WSPP website the amount of capacity for sale may have become burdensome.<sup>226</sup> FERC proposed terminating the West-wide must-offer requirement as no longer just and reasonable, noting that it previously stated it would consider removing the requirement after adequate infrastructure and market design improvements had been made.<sup>227</sup> California no longer relies on CAISO’s spot markets to meet the load of the public utilities it serves, and has employed both a renewable portfolio standard and a resource adequacy program by which it requires load-serving entities in its balancing authority to meet resource adequacy requirements.<sup>228</sup> This includes planning reserve margins to ensure there is sufficient capacity to reliably operate the system.<sup>229</sup> Also, FERC noted that since the requirement for the West-wide must-offer obligation was established, FERC has “approved significant changes to CAISO’s generation interconnection process . . . [which] have resulted in robust generation reserve margins in CAISO.”<sup>230</sup> With significant improvements to market design and infrastructure in CAISO, FERC proposed eliminating the West-wide must-offer requirement and the requirement to post available capacity on utilities’ and the WSPP websites.<sup>231</sup> FERC established a refund effective date pursuant to the FPA’s section 206 provisions.

On March 17, 2016, FERC issued an order denying rehearing of its October 1, 2015 order conditionally accepting tariff revisions filed by the CAISO to implement Phase 1A of the CAISO’s two-phase reliability services initiative to enhance its resource adequacy rules and processes.<sup>232</sup> Specifically, FERC denied a request for rehearing in which NRG Power Marketing, L.L.C., and GenOn Energy Management, L.L.C., argued that FERC had acted arbitrarily and capriciously in

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223. 154 F.E.R.C. ¶ 61,110, at P 1.

224. *Id.*

225. *Id.* at P 2.

226. *Id.*

227. *Id.* at P 3.

228. 154 F.E.R.C. ¶ 61,110, at P 4.

229. *Id.*

230. *Id.* at P 11.

231. *Id.* at P 6.

232. *Cal. Indep. Sys. Operator Corp.*, 154 F.E.R.C. ¶ 61,200 (2016).

accepting the CAISO's proposal to replace an existing CAISO tariff provision, which stated that resource adequacy substitutions are allowed prior to the close of the day-ahead market for the next trading day, with a tariff provision stating that such substitutions are allowed in accordance with the timeline specified in the CAISO business practice manual.<sup>233</sup> FERC found on rehearing that the directive in the 2015 order had correctly applied FERC's "rule of reason" policy and correctly stated that the existing CAISO tariff provision was ambiguous, and that specifying the timeline in the business practice manual would not have a significant effect on rates, terms, and conditions of service.<sup>234</sup>

### G. *Electric Reliability Council of Texas*

On May 19, 2016, FERC issued an order granting a petition for declaratory order made by LS Power Development, L.L.C., (LS Power) and Cross Texas Transmission, L.L.C., (Cross Texas), and disclaiming jurisdiction over the Electric Reliability Council of Texas (ERCOT).<sup>235</sup> LS Power and Cross Texas sought a declaratory order from FERC stating that their planned use of control centers within Texas for transmission projects outside of Texas would not affect ERCOT's non-jurisdictional status before FERC.<sup>236</sup> FERC granted the request for declaratory order, and concluded that the planned actions by the petitioners did not "result in the transmission or sale for resale of electric energy between ERCOT and the rest of the continental United States" and thus did not affect the jurisdictional status of ERCOT under the FPA.<sup>237</sup>

## III. TRANSMISSION RATES/FORMULA RATES

On May 19, 2016, FERC denied a request for rehearing of FERC's September 17, 2015 order<sup>238</sup> which had conditionally accepted Kanstar's Formula Rate, subject to a further compliance filing, to be effective once Kanstar's formula rate template and protocols were filed with the Commission to become part of SPP's OATT, consistent with the effective date to be established in that future proceeding.<sup>239</sup> The September 17 Order also granted: (1) Kanstar's proposed fifty basis point adder for participation in a RTO, subject to the resulting return on equity (ROE) being within the zone of reasonableness established for Kanstar;<sup>240</sup> (2) Kanstar's request for authorization to defer as a regulatory asset all of its prudently incurred pre-commercial and formation costs for later recovery, effective September 21, 2015, as requested;<sup>241</sup> and (3) Kanstar's request to use a hypothetical capital structure of up to 60% equity and 40% debt, to remain in effect until the first transmission project it is awarded through the SPP transmission owner

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233. *Id.* at PP 4-7.

234. *Id.*

235. *LS Power Dev., L.L.C. & Cross Tex. Transmission, L.L.C.*, 155 F.E.R.C. ¶ 61,176 (2016).

236. *Id.* at P 8.

237. *Id.* at P 14.

238. *Kanstar Transmission, L.L.C.*, 152 F.E.R.C. ¶ 61,209 (2015).

239. *Kanstar Transmission, L.L.C.*, 155 F.E.R.C. ¶ 61,167 (2016).

240. 152 F.E.R.C. ¶ 61,209, at P 51.

241. *Id.* at P 22.

selection process is placed in service.<sup>242</sup> “Finally, the Commission granted Kanstar’s request that its existing three affiliates and other yet-to-be-formed affiliates within SPP (collectively, Midwest Power SPP Entities) be authorized to utilize the same Formula Rate and requested incentives.”<sup>243</sup>

On May 19, 2016, FERC denied a request for rehearing filed by the Kansas Corporation Commission (Kansas Commission). The Kansas Commission challenged FERC’s determination that “the Midwest Power SPP Entities will each be subject to the ROE that is determined through the hearing and settlement judge procedures that have been ordered herein for Kanstar.”<sup>244</sup> Kansas Commission argued that each yet-to-be-formed Midwest Power SPP Entity should be required to support its own formula rate template, as well as the ROE to be included in its formula rate, as part of an individual section 205 filing.<sup>245</sup> Kansas Commission argued that the ROE that would be applied to yet-to-be-formed Midwest Power SPP Entities would not reflect the capital market conditions at some future date.<sup>246</sup> Kansas Commission made a similar argument with respect to other elements of the Kanstar Formula Rate being applied to the Midwest Power SPP Entities.<sup>247</sup>

FERC rejected the Kansas Commission’s arguments. FERC found that determining a base ROE for yet-to-be-formed Midwest Power SPP Entities using current market conditions was no different than determining a base ROE for any other Kanstar entity at the then-current time, and that the Midwest Power SPP Entities would be state-specific transmission companies with the same parent companies utilizing the same formula rate and participating in the same SPP competitive solicitation process, and would therefore be similarly situated with respect to risk and capital requirements.<sup>248</sup>

#### IV. MERGERS AND ACQUISITIONS

On March 28, 2016, Exelon Corporation (Exelon) filed notice at FERC stating that the merger of Exelon and Pepco Holdings, Inc. (Pepco), had been consummated on March 23, 2016.<sup>249</sup> Exelon filed this notice pursuant to the November 2014 FERC order authorizing the merger.<sup>250</sup>

#### V. COMPLAINTS

On February 18, 2016, FERC denied a complaint filed by the City of Osceola, Arkansas against Entergy Arkansas, Inc. and Entergy Services, Inc. (collectively, Entergy) pursuant to sections 206 and 306 of the FPA.<sup>251</sup> Osceola asked FERC to order Entergy to refund money paid under a formula rate for “rough production

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242. *Id.* at P 28.

243. 155 F.E.R.C. ¶ 61,167, at P 3.

244. 152 F.E.R.C. ¶ 61,209, at P 84.

245. 155 F.E.R.C. ¶ 61,167, at P 6.

246. *Id.* at P 7.

247. *Id.* at P 8.

248. *Id.* at P 9.

249. Notice of Consummation of Exelon-PHI Merger, docket no. EC14-96-000 (Mar. 28, 2016).

250. *Exelon Corp.*, 149 F.E.R.C. ¶ 61,148 (2014).

251. *City of Osceola v. Entergy Ark., Inc.*, 154 F.E.R.C. ¶ 61,099 (2016).

costs equalization bandwidth payments” that were passed through the Purchased Power portion of the formula rate because the Commission previously found such charges inappropriate and ordered a refund on a “substantially identical” formula rate between Entergy and Union Electric Company.<sup>252</sup> The Commission denied Osceola’s claim because it had “actual notice” of the bandwidth equalization payments when it “previously settled the claim on which [Osceola’s] Complaint rests.”<sup>253</sup>

On April 21, 2016, FERC granted in part a complaint filed by Northern Indiana Public Service Company (NIPSCO) against MISO and PJM.<sup>254</sup> NIPSCO’s complaint sought revisions to the interregional transmission planning process set forth in joint operating agreement (Joint Operating Agreement) between PJM and MISO.<sup>255</sup>

FERC first ordered several changes to the Joint Operating Agreement’s interregional transmission planning cycles. FERC found that the transmission planning cycles embodied in the Joint Operating Agreement were unjust and unreasonable, as it provided no specific deadlines for each step of the coordinated system plan study process.<sup>256</sup> FERC, therefore, ordered PJM and MISO to establish such deadlines, explaining that their absence could lead to significant delays in the identification, analysis, and potential approval of interregional economic transmission projects.<sup>257</sup> However, FERC emphasized that MISO and PJM were merely required to establish deadlines for the coordinated system plan study process, rather than revising the process itself.<sup>258</sup> FERC additionally required PJM and MISO to describe in the Joint Operating Agreement how the specific steps in the coordinated system plan study process interact with their respective regional transmission planning processes.<sup>259</sup>

FERC, however, rejected NIPSCO’s contention that MISO and PJM should be ordered to utilize a single combined MISO-PJM transmission planning model for interregional reliability and economic planning projects.<sup>260</sup> FERC explained that the Joint Operating Agreement already requires MISO and PJM to use a joint model with the same assumptions for reliability and economic planning for interregional planning purposes.<sup>261</sup> FERC also relied on the fact that the Joint Operating Agreement requires an annual exchange of data between PJM and MISO, and a coordinated planning study that compromises on assumptions and a joint model for transmission planning.<sup>262</sup>

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252. *Id.* at P 1 (citing *Entergy Servs., Inc.*, 130 F.E.R.C. ¶ 61,023, at PP 100-104 (2010), *order on reh’g*; Opinion No. 505-A, 139 F.E.R.C. ¶ 61,103, at PP 18-39 (2012)).

253. *Id.* at PP 3, 9.

254. *N. Ind. Pub. Serv. Co. v. Midcontinent Indep. Sys. Operator, Inc.*, 155 F.E.R.C. ¶ 61,058, at P 1 (2016).

255. *Id.*

256. *Id.* at P 54.

257. *Id.* at P 55.

258. *Id.*

259. 155 F.E.R.C. ¶ 61,058, at P 57.

260. *Id.* at PP 65, 88.

261. *Id.* at P 88

262. *Id.* at P 89.

FERC also concluded that the existing thresholds for interregional efficiency projects were unjust and unreasonable, though it did not deem unlawful, as NIPSCO requested, the requirement that an interregional efficiency project must satisfy the criteria set forth under both the MISO tariff and the PJM tariff.<sup>263</sup> Nevertheless, FERC agreed with NIPSCO and intervenors that interregional projects that are less than 345 kV or cost less than \$5 million may benefit both regions and, therefore, should not be automatically excluded from consideration.<sup>264</sup> FERC, thus, required MISO to amend its tariff to lower the 345 kV requirement to 100 kV, and to eliminate the minimum-cost requirement.<sup>265</sup>

Lastly, FERC disagreed with NIPSCO's contention that avoidance of market-to-market payments should be included as a separate and discrete category of benefits for assessing potential interregional economic projects.<sup>266</sup> FERC stated that the interregional planning process already accounts for the benefit of reducing congestion.<sup>267</sup>

## VI. PURPA

The Commission granted in part and denied in part an application from Entergy Services, Inc. to terminate its obligation to purchase energy and capacity from certain generators that are qualifying facilities under PURPA.<sup>268</sup> Under PURPA, electric utilities are required to purchase energy and capacity made available by a qualifying facility.<sup>269</sup> The Energy Policy Act of 2005, however, amended PURPA to give electric utilities the opportunity to apply to terminate the purchase obligation where the qualifying facility has nondiscriminatory access to wholesale markets.<sup>270</sup> Nonetheless, the termination provision does have certain limitations.<sup>271</sup> The Commission's regulations provide that a qualifying facility may not have nondiscriminatory access if it has a net capacity of twenty MW or less, if it has certain operational characteristics, or if it is affected by transmission constraints.<sup>272</sup> A number of qualifying facilities filed protests to Entergy's application arguing that they either had a net capacity under twenty MW, had existing agreements with Entergy to sell energy, or had operational characteristics or transmission constraints that would exempt them from the termination of the purchase obligation.<sup>273</sup>

With respect to the first two issues, the Commission noted that Entergy's application was limited to qualifying facilities above twenty MW, and that the ter-

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263. *Id.* at PP 129-130.

264. 155 F.E.R.C. ¶ 61,058, at P 131.

265. *Id.*

266. *Id.* at P 151.

267. *Id.*

268. *Entergy Servs., Inc.*, 154 F.E.R.C. ¶ 61,035 at P 2 (2016), *reh'g denied*, 155 F.E.R.C. ¶ 61,069 (2016).

269. *Id.* at P 1.

270. *Id.* at P 3.

271. *Id.*

272. *Id.* at PP 3, 78, 83.

273. 154 F.E.R.C. ¶ 61,035, at PP 14-31.

mination of Entergy's purchase obligation would not relieve Entergy from its obligations under existing agreements.<sup>274</sup> Next, the Commission found protesters' arguments claiming operational characteristics to be unsupported by the evidence.<sup>275</sup> In regard to transmission constraints, the Commission found all but one protest to be unsupported.<sup>276</sup> The Commission explained that the protest of Dow Chemical Company demonstrated that Dow's qualifying facility "is located in a generation pocket where the transmission capacity out of the pocket is constrained," and thus was sufficient to rebut the assumption that Dow has nondiscriminatory access to wholesale markets.<sup>277</sup> Accordingly, the Commission granted Entergy's application to terminate the purchase obligation in part noting the continuing obligation with respect to Dow.<sup>278</sup>

On January 21, 2016, FERC issued a letter order granting the request of Arkansas Electric Cooperative Corporation (AECC), which was filed on behalf of itself and its seventeen electric distribution cooperative members, to terminate various mandatory purchase obligations under PURPA.<sup>279</sup> AECC and its seventeen electric distribution cooperative members are located in the MISO footprint.<sup>280</sup>

AECC filed its application on April 15, 2015, pursuant to section 210(m) of PURPA and section 292.310 of the Commission's regulations.<sup>281</sup> In its application, AECC requested that the Commission terminate both its mandatory purchase obligation to enter into new contracts and its obligations to purchase energy and capacity from qualifying facilities with a net capacity greater than twenty MW in its members' service territories that are located in the MISO footprint.<sup>282</sup> Pursuant to applicable regulations, AECC argued that QFs in MISO have "nondiscriminatory access to independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and wholesale markets for long-term sales of capacity and energy."<sup>283</sup>

On March 17, 2016, FERC issued an order granting in part, and denying in part, a petition filed by Heartland Consumers Power District (Heartland) on October 5, 2015, requesting a waiver under § 292.402 of the Commission's regulations.<sup>284</sup> Heartland is a consumer-owned, non-regulated electric utility serving utility customers in Minnesota, Iowa, South Dakota, North Dakota, and Kansas.<sup>285</sup> Specifically, Heartland sought waiver of its customers' purchase obligations under Commission regulations to purchase energy and capacity from QFs under

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274. *Id.* at PP 74, 76.

275. *Id.* at P 80.

276. *Id.* at P 83.

277. *Id.* at P 95.

278. 154 F.E.R.C. ¶ 61,035, at PP 2, 95.

279. *Ark. Elec. Coop. Corp.*, docket no. QM15-3-000 (Jan. 21, 2016) (unpublished letter order).

280. *Id.* at P 1.

281. *Id.*

282. *Id.*

283. *Id.* at P 2.

284. *Heartland Consumers Power Dist.*, 154 F.E.R.C. ¶ 61,203 (2016).

285. *Id.* at P 2.

§ 292.303(a), and of Heartland's own obligation to sell energy and capacity requested by QFs under § 292.303(b).<sup>286</sup> Heartland's Board of Directors had adopted a policy (Policy) explaining that Heartland will purchase electric energy and capacity made available from QFs interconnected to Heartland's utility customers, and that Heartland's utility customers will sell energy and capacity to QFs.<sup>287</sup>

In its petition, Heartland stated that if such waiver were granted, Heartland would commit to purchase and pay for capacity from QFs interconnecting with its customers and will not subject a QF to any duplicate interconnection charge or charges for wheeling power to Heartland.<sup>288</sup> Heartland stated that waiver would thus not frustrate Congress's intent to encourage QFs under PURPA, as no QF would be deprived of a market for its power and Heartland will pay its full avoided cost to QFs.<sup>289</sup> Heartland further stated that since it acquires the bulk power resources required to meet its customers' loads, Heartland is in a better position than its customers to purchase energy offered from QFs.<sup>290</sup> Heartland committed to making all appropriate purchases from QFs on behalf of its customers and planned to purchase energy and capacity from QFs at negotiated rates, or if non-negotiated, at Heartland's full avoided cost.<sup>291</sup>

Protests were filed by two customers: Truman Public Utilities Commission (Truman) and South Dakota Soybean Processors, L.L.C. (Soybean Processors).<sup>292</sup> Heartland answered those protests to which Soybean Processors filed a response.<sup>293</sup> On December 11, 2015, the Commission issued a deficiency letter requiring additional information, to which Heartland responded on December 29, 2015.<sup>294</sup> Truman did not oppose Heartland's petition insofar as it applied only to Heartland customers that want to adopt, or have adopted, the Policy.<sup>295</sup> Soybean Processors argued that Heartland is violating section 210 of PURPA, by not providing the standby power rates required under 303(b) and 305(b) of the regulations.<sup>296</sup> Soybean Processors states it discussed a desire to explore cogeneration options with Heartland and the City of Volga requesting standby power provisions, but the City of Volga indicated it could not provide standby power without Heartland's involvement.<sup>297</sup> Soybean Processors argues that Heartland's Policy needs to clarify how Heartland can fulfill its PURPA obligation to purchase energy and capacity from QFs twenty MW and smaller through a purchase rate limited to payments for energy and capacity which Heartland can use to meet its total system load, given that Heartland indicates it is purchasing more energy or capacity from

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286. *Id.* at P 1.

287. *Id.* at P 3.

288. *Id.* at PP 4-6.

289. 154 F.E.R.C. ¶ 61,203, at P 4.

290. *Id.* at P 5-6.

291. *Id.* at P 5.

292. *Id.* at P 8.

293. *Id.*

294. 154 F.E.R.C. ¶ 61,203, at PP 9.

295. *Id.* at P 10.

296. *Id.* at P 11.

297. *Id.*

QFs than required to meet system load.<sup>298</sup> Soybean Processors claims Heartland's Policy is also contrary to Heartland's assertion that no QF will be deprived of a market for its power, and recommends that the Commission require Heartland's Policy be made consistent with PURPA.<sup>299</sup>

FERC granted Heartland's request in part and denied it in part.<sup>300</sup> FERC granted waivers of §§ 292.303(a) and (b) if compliance is not necessary to encourage cogeneration and small power production and is not otherwise required by section 210 of PURPA.<sup>301</sup> FERC noted Heartland's uncontradicted representation that twenty-two of its twenty-eight customers have adopted or agreed to adopt the same or a similar policy as Heartland's policy.<sup>302</sup> FERC agreed to grant Heartland's petition for those twenty-two customers who agreed to transfer their PURPA purchase obligation, and accepted Heartland's sales obligation.<sup>303</sup> It denied Heartland's petition with respect to those six customers that currently do not agree to adopt Heartland's Policy.<sup>304</sup> QFs will continue to receive both Heartland's avoided cost for the QF energy and capacity sold, and backup power from their interconnected utility that reflects Heartland's rates for sales of such power.<sup>305</sup> For those six utilities that do not currently support Heartland's waiver, FERC denied the request because 303(a) and (b) remain necessary to encourage QFs and cogeneration facilities interconnected to those six customers.<sup>306</sup>

Finally, FERC stated that the City of Volga must provide supplementary power, back-up power, maintenance power, and interruptible power for Soybean Processors' cogeneration facility if and when it should ever become operational.<sup>307</sup> As stated by Heartland in its response to the Commission's deficiency letter, the City of Volga has adopted, or agreed to adopt, the pertinent section of Heartland's Policy in which utility customers like the City of Volga assume Heartland's PURPA sales obligation in section 292.303(b) of the Commission's regulations.<sup>308</sup> Therefore, FERC waived Heartland's sales obligation with respect to Soybean Processor's proposed cogeneration facility, and the City of Volga instead must sell energy and capacity requested by Soybean Processors' QF.<sup>309</sup> If the City of Volga does not fulfill its obligations under section 292.305(b) of the Commission's regulations, Soybean Processors may file a complaint under section 210(h) of PURPA.<sup>310</sup>

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298. *Id.* at PP 11-14.

299. 154 F.E.R.C. ¶ 61,203, at P 13.

300. *Id.* at P 24.

301. *Id.* at P 25.

302. *Id.* at P 28.

303. *Id.*

304. 154 F.E.R.C. ¶ 61,203, at P 29.

305. *Id.*

306. *Id.*

307. *Id.* at 30

308. 154 F.E.R.C. ¶ 61,203, at P 30.

309. *Id.*

310. *Id.*

## VII. GENERATOR INTERCONNECTION

On June 16, 2016, FERC issued a final rule, Order No. 827, eliminating exemptions for wind generators from the requirement to provide reactive power by revising the *pro forma* Large Generator Interconnection Agreement (LGIA), Appendix G to the *pro forma* LGIA, and the *pro forma* Small Generator Interconnection Agreement (SGIA).<sup>311</sup> As a result, all newly interconnecting non-synchronous generators will be required to provide reactive power at the high-side of the generator substation as a condition of interconnection as set forth in their LGIA or SGIA as of the final rule's effective date of September 21, 2016.<sup>312</sup>

FERC stated that the reactive power requirements in the LGIA and SGIA were no longer just and reasonable, and need to be revised because of changes to the cost of providing reactive power by non-synchronous generators and the growth of non-synchronous generators.<sup>313</sup> Therefore, FERC decided to apply comparable reactive power requirements to non-synchronous generators and synchronous generators.<sup>314</sup> However, FERC cited technological differences and advancements that do not permit some non-synchronous generators to provide dynamic reactive power at reasonable cost at the point of interconnection; therefore, FERC determined that non-synchronous generators must provide dynamic reactive power at the high side of the generator substation.<sup>315</sup> FERC stated it would require non-synchronous generators to maintain a composite power delivery at continuous rated power output at the high-side of the generator substation and that it must be dynamic reactive power with the power factor range of 0.95 leading to 0.95 lagging, unless the transmission provider has established a different power factor range that applies to all non-synchronous generators in the transmission provider's control area on a comparable basis.<sup>316</sup> The provider's ability to establish different requirements is limited to establishing a different power factor range, and not to other reactive power requirements.<sup>317</sup>

FERC declined to adopt the exemption proposed in the NOPR that would have required the power factor range only when the generator's real power output is above 10% of its nameplate capacity; instead, it required all newly interconnecting non-synchronous generators to design their facilities to meet the reactive power requirements at all levels of real power output.<sup>318</sup> Regarding compensation, FERC stated that it would not change its existing policies on compensation for reactive power; any non-synchronous generator seeking reactive compensation would need to propose a method for calculating that compensation as part of its filing.<sup>319</sup>

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311. Order No. 827, *Reactive Power Requirements for Non-Synchronous Generation*, 155 F.E.R.C. ¶ 61,277 (2016) (to be codified at 18 C.F.R. pt. 35).

312. *Id.* at PP 13, 75. The final rule was published in the Federal Register on June 23, 2016, making the effective date September 21, 2016.

313. *Id.* at P 13.

314. *Id.* at P 17.

315. *Id.*

316. 155 F.E.R.C. ¶ 61,277, at P 11.

317. *Id.* at P 34.

318. *Id.* at PP 41-47.

319. *Id.* at PP 50-52.

Order No. 827 will apply to all newly interconnecting non-synchronous generators that have not yet executed a Facilities Study Agreement as of the effective date of September 21, 2016.<sup>320</sup> FERC also encouraged utilities to make a section 205 filing to remove Appendix G from their LGIA.<sup>321</sup> Finally, FERC also stated it would not apply Order No. 827 to existing non-synchronous generators making upgrades that require new interconnection requests.<sup>322</sup>

### VIII. MISCELLANEOUS

On January 25, 2016, the U.S. Supreme Court reversed and remanded a decision of the United States Court of Appeals for the District of Columbia<sup>323</sup> that had vacated a FERC rule<sup>324</sup> for compensation of demand response in wholesale markets.<sup>325</sup>

The Supreme Court noted that in 2008, FERC issued Order No. 719,<sup>326</sup> which, in part, required wholesale market operators to receive demand response bids from aggregators of electricity consumers, except when the state regulatory authority overseeing those users' retail purchases bars such demand response participation.<sup>327</sup> The Supreme Court noted that the original order allowed operators to compensate demand response providers differently from generators if they so choose and that no party sought judicial review of that rule.<sup>328</sup> The Supreme Court stated that the Rule at issue in Order No. 745 attempts to ensure "just and reasonable" wholesale rates by requiring market operators to appropriately compensate demand response providers and thus bring about "meaningful demand-side participation" in the wholesale markets.<sup>329</sup> The Rule's "most significant provision" directs operators, under two specified conditions, to pay the locational marginal price (LMP) for any accepted demand response bid, just as they do for successful supply bids.<sup>330</sup>

The Supreme Court first examined whether the FPA<sup>331</sup> permitted FERC to regulate demand response at all or whether FERC's rule impermissibly impinged on the States' authority. The Supreme Court noted that the FPA authorizes FERC to regulate "the sale of electric energy at wholesale in interstate commerce," including both wholesale electricity rates and any rule or practice "affecting" such rates.<sup>332</sup> But the law places beyond FERC's power, and leaves to the States alone,

320. *Id.* at P 59.

321. 155 F.E.R.C. ¶ 61,277, at P 63.

322. *Id.* at P 65.

323. *Elec. Power Supply Ass'n v. FERC*, 753 F.3d 216 (2014).

324. *Demand Response Comp. in Organized Wholesale Energy Mkts.*, Order No. 745, 76 Fed. Reg. 16,658 (2011) (to be codified at 18 C.F.R. pt. 35).

325. *FERC v. Elec. Power Supply Ass'n*, 136 S.Ct. 760 (2016).

326. *Wholesales Competition in Regions with Elec. Mkts.*, 125 F.E.R.C. ¶ 61,071 (2008) (to be codified at 18 C.F.R. pt. 35).

327. *Elec. Power Supply Ass'n*, 753 F.3d at 230.

328. *Elec. Power Supply Ass'n*, 136 S.Ct. at 771.

329. *Id.* (citing 76 Fed. Reg. 16658 ¶ 1, 16660 ¶ 10; 16 U.S.C. § 824d (a)).

330. *Id.* (citing 76 Fed. Reg. 16666–16669, ¶¶ 45–67).

331. 16 U.S.C. § 791 (2016).

332. *Elec. Power Supply Ass'n*, 136 S.Ct. at 766 (citing 16 U.S.C. §§ 824(b), 824e(a)).

the regulation of “any other sale”—most notably, any retail sale—of electricity.<sup>333</sup> The Supreme Court noted that that statutory division generates a steady flow of jurisdictional disputes “because—in point of fact if not of law—the wholesale and retail markets in electricity are inextricably linked.”<sup>334</sup>

The Supreme Court held that the practices at issue in the Rule—market operators’ payments for demand response commitments—directly affect wholesale rates.<sup>335</sup> The Supreme Court noted that FERC has the authority, and, indeed, the duty, to ensure that rules or practices “affecting” wholesale rates are just and reasonable.<sup>336</sup> While noting that FERC’s statutory grant is broad, the Court held that its breadth is limited to a common-sense construction of the FPA’s language, limiting FERC’s “affecting” jurisdiction to rules or practices that “directly affect the [wholesale] rate.”<sup>337</sup> It held that FERC had already incorporated this standard in addressing its authority to issue the Rule and that FERC’s rules governing wholesale demand response programs met this standard “with room to spare.”<sup>338</sup> It noted that in general, wholesale market operators employ demand response bids in competitive auctions that balance wholesale supply and demand and thereby set wholesale prices.<sup>339</sup> It noted that if rewarded with prices at LMP, rather than at some lesser amount, more demand response providers will enter more bids capable of displacing generation, thus “necessarily” lowering wholesale electricity prices.<sup>340</sup>

The Supreme Court next held that in addressing the practices at issue in the Rule, FERC had not regulated retail sales.<sup>341</sup> It noted that FERC cannot take an action transgressing FPA section 824(b)’s statutory limits upon FERC’s jurisdiction, no matter how direct, or dramatic, its impact on wholesale rates.<sup>342</sup> But it noted that a FERC regulation did not run afoul of § 824(b)’s proscription just because it substantially affects the quantity or terms of retail sales, noting that “[it] is a fact of economic life that the wholesale and retail markets in electricity, as in every other known product, are not hermetically sealed from each other.”<sup>343</sup> The Supreme Court noted that when FERC regulates what takes place on the wholesale market, as part of carrying out its charge to improve how that market runs, then no matter the effect on retail rates, § 824(b) imposes no bar in setting rules for demand response, and that was all that the Rule had done.<sup>344</sup> The Supreme Court noted that the Rule only addresses transactions occurring on the wholesale market,<sup>345</sup>

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333. *Id.* (citing 16 U.S.C. § 824 (b)).

334. *Id.* at 774.

335. *Id.* at 772.

336. *Id.* at 774.

337. *Elec. Power Supply Ass’n*, 136 S.Ct. at 774 (citing *Cal. Indep. Sys. Operator Corp. v. FERC*, 372 F.3d 395, 403 (D.C. Cir. 2004)).

338. *Id.* (citing 76 Fed. Reg. 16676 ¶ 112 (stating that FERC has jurisdiction because wholesale demand response “directly affects wholesale rates”)).

339. *Id.*

340. *Id.* at 775.

341. *Id.* at 763.

342. *Elec. Power Supply Ass’n*, 136 S.Ct. at 763.

343. *Id.* at 776.

344. *Id.*

345. *Id.*

elaborating that wholesale market operators administer the demand response program, accept demand response bids when they result in a lower cost to wholesale purchasers, and pay compensation at the marginal price of wholesale electricity, with bids paid for by wholesale purchasers who benefit from lower wholesale prices because of their demand response participation.<sup>346</sup> The Supreme Court noted that FERC's "justifications for regulating demand response are all about, and only about, improving the wholesale market."<sup>347</sup> The Supreme Court rejected EPSA's argument that FERC had usurped state power by effectively regulating retail prices, by effectively raising them and by changing consumers' calculations through the opportunity to make demand response bids in wholesale markets.<sup>348</sup> The Supreme Court said that EPSA's assertion was refuted by statutory and Supreme Court case law that establish that the relevant rate is the price paid, not, as EPSA asserted, the price paid plus the cost of a foregone economic opportunity.<sup>349</sup> The Supreme Court also rejected EPSA's assertion that the Rule improperly intruded into the States' sphere by luring retail customers into the wholesale markets, finding that wholesale market operators, not FERC, had pushed for the development of wholesale demand response and that this development was "a market-generated innovation for more optimally balancing wholesale electricity supply and demand."<sup>350</sup> The Supreme Court found that in its subsequent actions promoting demand response, FERC did no more than follow the dictates of its regulatory mission to improve the competitiveness, efficiency, and reliability of the wholesale market.<sup>351</sup> The Court also noted allegations of intrusion into the States' sphere by FERC were refuted by "FERC's notable solicitude toward the States," given that the Rule allows any State regulator to prohibit its consumers from making demand response bids in the wholesale market.<sup>352</sup>

Third, the Court held that a contrary view as to FERC's regulatory authority would conflict with the FPA's core purposes by preventing all use of a tool that no parties dispute curbs prices and enhances reliability in the wholesale electricity market.<sup>353</sup> Rejecting EPSA's assertion that FERC should not regulate demand response at all, the Supreme Court noted that this would effectively leave demand response bids without regulations, as state commissions could not regulate them either, which would violate a FPA precept that "no electricity transaction can proceed unless it is regulable by someone" and thereby extinguish wholesale demand response.<sup>354</sup> The Supreme Court said that such an outcome would contravene the FPA's core objectives of protecting against excessive prices and ensuring effective transmission of electric power, given FERC's demonstration regarding how demand response helps to achieve those ends.<sup>355</sup>

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346. *Id.*

347. *Elec. Power Supply Ass'n*, 136 S.Ct. at 776.

348. *Id.* at 777.

349. *Id.* at 777-778.

350. *Id.* at 779.

351. *Id.*

352. *Elec. Power Supply Ass'n*, 136 S.Ct. at 779.

353. *Id.* at 763.

354. *Id.* at 780.

355. *Id.*

The Supreme Court also rejected EPSA's argument that FERC's decision to compensate demand response providers at LMP—the same price paid to generators—was arbitrary and capricious.<sup>356</sup> The Supreme Court noted that the Rule orders operators to pay the identical price for a successful bid to conserve electricity so long as that bid can satisfy a “net benefits test,” meaning that it is sure to bring down costs for wholesale purchasers, and in mandating that payment, rejected an alternative proposal under which demand response providers would receive LMP minus G (LMP–G), where G is the retail rate for electricity.<sup>357</sup> The Supreme Court noted that EPSA and others favoring the latter approach, contend that LMP alone provides demand response providers with a windfall—a kind of “double-payment”—unless market operators subtract the savings associated with conserving electricity from the ordinary compensation level and claimed that FERC failed to adequately justify its choice of LMP rather than LMP–G.<sup>358</sup> Noting its narrow scope of review and deference to the Commission's judgment under the arbitrary and capricious standard, particularly with respect to rate decisions, the Supreme Court found that the Commission had given a detailed explanation of its choice of LMP.<sup>359</sup> The Supreme Court noted that “[r]elying on an eminent regulatory economist's views, FERC chiefly reasoned that demand response bids should get the same compensation as generators' bids because both provide the same value to a wholesale market.”<sup>360</sup> The Supreme Court noted that FERC had explained that with both supply and demand response available on equal terms, the operator will select whichever bids, of whichever kind, provide the needed electricity at the lowest possible cost.<sup>361</sup> The Supreme Court noted that rationale received added support from FERC's adoption of the net benefits test that ensures that a demand response provider will receive the same compensation as a generator only when it is, in fact, providing the same service to the wholesale market.<sup>362</sup> The Supreme Court accepted FERC's rejection of EPSA's view that paying LMP would result in overcompensation of demand response providers because compensation ordinarily reflects only the value of the service an entity provides, not the costs it incurs, or benefits it obtains, in the process.<sup>363</sup> The Supreme Court also noted that FERC found that paying LMP will help demand response providers overcome certain barriers to participation in the wholesale market and that determining the “G” in the formula LMP–G is easier proposed than accomplished.<sup>364</sup>

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356. *Id.* at 782.

357. *Elec. Power Supply Ass'n*, 136 S.Ct. at 782.

358. *Id.*

359. *Id.* (citing 76 Fed. Reg. 16661–16669 ¶¶ 18–67).

360. *Id.* (citing 76 Fed. Reg. 16662–16664, 16667–16668 ¶¶ 20, 31, 57, 61; App. 829–851, Reply Affidavit of Dr. Alfred E. Kahn (2010) (Kahn Affidavit)).

361. *Id.* at 783 (citing *Demand Response Compensation in Organized Wholesale Mkts.*, 137 F.E.R.C. ¶ 61,215 at P 68 (2011) (“By ensuring that both . . . receive the same compensation for the same service, we expect the Final Rule to enhance the competitiveness” of wholesale markets and “result in just and reasonable rates”)).

362. *Elec. Power Supply Ass'n*, 136 S.Ct. at 783.

363. *Id.* at 784.

364. *Id.* (citing 76 Fed. Reg. 16667–16668, ¶¶ 57–59).

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