

## REPORT OF THE ELECTRICITY COMMITTEE

This report covers significant electric regulatory orders issued by the Federal Energy Regulatory Commission (FERC) in 2015. This report does not, however, address transmission reliability, demand-side management, renewable energy, FERC enforcement matters, or appellate decisions.\*

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### I. RULEMAKINGS AND POLICY STATEMENTS

#### A. *Third-Party Provision of Primary Frequency Response Service*

On February 19, 2015, the FERC issued a Notice of Proposed Rulemaking (NOPR) to allow the sale of primary frequency response at market-based rates (MBR) by sellers with market-based rate authority. The FERC defined “primary frequency response” as “a reserve product that involves dedicating capacity on a generator or other resource for autonomous, automatic, and rapid action to change (within seconds) its output to rapidly dampen large changes in frequency.”<sup>1</sup> The FERC explained that the proposal is “in anticipation of the potential interest in purchase of primary frequency response service from third-parties as a result of [the new BAL-003-1] reliability standard that requires a Balancing Authority to

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1. Notice of Proposed Rulemaking, *Third-Party Provision of Primary Frequency Response Service*, 150 F.E.R.C. ¶ 61,092, at P 1 (2015) (to be codified at 18 C.F.R. pt. 35).

maintain (either via self-supply or purchase) a minimum frequency response obligation.”<sup>2</sup>

Specifically, the FERC proposed to revise its MBR regulations to provide that a seller would have a rebuttable presumption that it lacks market power with respect to sales of primary frequency response if the seller passes the existing indicative screens (i.e., the wholesale market share screen and the pivotal supplier screen) used for granting energy and capacity MBR authority for the corresponding geographic market.<sup>3</sup> In support of using the existing indicative screens, the FERC found that: (1) “the set of resources technically capable of providing primary frequency response service does not differ significantly from the set of resources represented in the existing market power screens;” (2) “the geographic market for a primary frequency response product could be the entire interconnection within which the buyer resides, and in any event would be no smaller than the geographic market represented in the existing market power screens;” and (3) “there should be no barriers related to transmission scheduling or reservation preventing sellers anywhere within the same interconnection as the buyer from providing effective primary frequency response service to that buyer.”<sup>4</sup> The FERC preliminarily concluded that “expanding the rebuttable presumption adopted in Order No. 697 for energy and capacity to include primary frequency response service provides adequate protection that market-based rates charged by public utilities will be just and reasonable and not unduly discriminatory or preferential.”<sup>5</sup> The FERC also proposed “to update its Electric Quarterly Report (EQR) system to include a specific product name option for primary frequency response service.”<sup>6</sup> Finally, the FERC did not extend the proposed rule to include frequency regulation or secondary frequency response, which is “produced from either manual or automated dispatch from a centralized control system, generally using the communications and control system known as automatic generation control (AGC).”<sup>7</sup>

#### *B. Open Access and Priority Rights on Interconnection Customer’s Interconnection Facilities*

On March 19, 2015, the FERC issued a Final Rule permitting owners and operators of Interconnection Customer’s Interconnection Facilities (ICIF, or commonly, “generator tie lines”) to obtain an automatic “blanket” waiver of the Open Access Transmission Tariff (OATT) requirements, the Open Access Same-Time Information System (OASIS) requirements, and the Standards of Conduct.<sup>8</sup> The rule also encourages those seeking to interconnect and receive transmission service over ICIF that are subject to blanket waiver procedures to negotiate service under the relevant procedures for interconnection and transmission under sections

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2. *Id.* at P 2.

3. *Id.* at P 28.

4. *Id.* at PP 22-23, 26.

5. *Id.* at P 28.

6. 150 F.E.R.C. ¶ 61,092, at P 29.

7. *Id.* at P 12.

8. Final Rule, *Open Access and Priority Rights on Interconnection Customer’s Interconnection Facilities*, 150 F.E.R.C. ¶ 61,211 at P 1 (2015) (to be codified at 18 C.F.R. pt. 35).

210, 211, and 212 of the Federal Power Act (FPA),<sup>9</sup> and establishes a five-year safe harbor period wherein the FERC will apply a rebuttable presumption that the ICIF has definitive plans to use its capacity without demonstrating through specific plans and milestones.<sup>10</sup> That safe harbor period is secured through an informational filing with the FERC, and will apply to ICIF owners and generators whose ownership or operation of transmission facilities is limited to ICIF, and to ICIF owners who are affiliated with a public utility transmission provider and are within or adjacent to the public utility transmission provider's footprint (e.g., ICIF-Owning Affiliates).<sup>11</sup>

The Final Rule adds sub-paragraph (d)(2) to 18 C.F.R. § 35.28, to grant a blanket waiver of all OATT, OASIS, and Standards of Conduct requirements to “any public utility that is or becomes subject to such requirements solely because it owns, controls, or operates ICIF, in whole or in part, as that term is defined in the standard generator interconnection procedures and agreements referenced in paragraph (f) . . . .”<sup>12</sup> Comparable jurisdictional facilities, other than the standard generator interconnection procedures and agreements referenced in paragraph (f), are eligible if the owner and/or operator sells electric energy or chooses to file a statement with the FERC that it commits to comply with the obligations and procedures applicable to electric utilities under section 210 of the FPA.<sup>13</sup> Section (d)(2)(i) clarifies when the blanket waiver will be revoked, and (d)(2)(ii) provides eligible entities seeking interconnection and transmission services with facilities that have been granted a blanket waiver pursuant to paragraph (d)(2) to follow procedures in sections 210, 211, and 212 of the FPA, 18 C.F.R. § 2.20, and 18 C.F.R. part 36.<sup>14</sup> Section (d)(2)(ii)(A) states that the FERC considers that the public interest is served by granting priority rights to the owner and/or operator of interconnection facilities eligible under section (d)(2) “when such owner and/or operator can demonstrate that it has specific plans with milestones to use such capacity to interconnect its or its affiliate's future generation projects.”<sup>15</sup> Section (d)(2)(ii)(B) provides ICIF owners and/or operators with a five-year safe harbor of priority rights to the facility's capacity, subject to a rebuttable presumption that the owner and/or operator has “definitive plans to use the capacity thereon . . . .”<sup>16</sup> The five-year safe harbor period starts on the facility's commercial operation date.

### C. Revised Exhibit Submission Requirements for Commission Hearings

On June 18, 2015, the FERC issued a Final Rule<sup>17</sup> amending Rule 508<sup>18</sup> in order “to eliminate the requirement that participants in trial-type evidentiary hearings must provide paper copies of all exhibits introduced as evidence” while

9. *Id.*

10. *Id.*

11. *Id.* at P 165.

12. *Id.* (quoting 18 C.F.R. § 35.28(d)(2) (1998)).

13. 150 F.E.R.C. ¶ 61,211, at P 165 (2015).

14. 18 C.F.R. § 35.28(d)(2)(i).

15. 18 C.F.R. § 35.28(d)(2)(ii)(A).

16. 18 C.F.R. § 35.28(d)(2)(ii)(B).

17. Final Rule, *Revised Exhibit Submission Requirements for Commission Hearings*, 151 F.E.R.C. ¶ 61,221 (2015) (to be codified at 18 C.F.R. pt. 385).

18. 18 C.F.R. § 385.508 (2015).

still allowing “the option to provide exhibits in paper form . . . .”<sup>19</sup> The rule is intended to “improve the efficiency and administrative convenience of the Commission hearing process . . . .”<sup>20</sup>

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

On September 17, 2015, the FERC issued a NOPR to address certain practices by regional transmission organizations (RTO) and independent system operators (ISO) that may fail “to compensate resources at prices that reflect the value of the service resources provide to the system, thereby distorting price signals.”<sup>21</sup> To address the complications “associated with differing dispatch intervals and settlement intervals, as well as with shortage pricing triggers,”<sup>22</sup> the FERC proposed to require each RTO and ISO to align settlement and dispatch intervals by (1) settling energy transactions in its real-time markets over the same time interval that it dispatches energy; (2) settling operating reserves transactions in its real-time markets over the same time interval that it prices operating reserves; and (3) triggering shortage pricing for any dispatch interval during which a shortage of energy or operating reserves occurs.<sup>23</sup> The FERC determined that these reforms will help ensure that resources receive price signals that reflect operating needs and have incentives to conform their output to dispatch instructions.<sup>24</sup> The FERC noted that the NOPR is a first step towards developing appropriate price signals reflecting system conditions and encouraging efficient investments, thereby enabling reliable service.<sup>25</sup> The FERC stated that it “expects to undertake further action addressing various price formation topics, including offer price caps, mitigation, uplift transparency, and uplift drivers.”<sup>26</sup>

*E. Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*

On April 16, 2015, the FERC issued a Final Rule to adopt two proposals submitted by the North American Energy Standards Board (NAESB) to better coordinate the scheduling practices of the natural gas and electric utility industries.<sup>27</sup> First, the FERC approved NAESB’s proposal to move the nomination deadline for the Timely Nomination Cycle from 11:30 a.m. Central Clock Time (CCT) to 1:00 p.m. CCT, and to require pipelines to notify shippers

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19. Notice of Proposed Rulemaking, *Revised Exhibit Submission Requirements for Commission Hearings*, 150 F.E.R.C. ¶ 61,193 at P 1 (2015) (to be codified at 18 C.F.R. pt. 385).

20. *Id.*

21. Notice of Proposed Rulemaking, *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations & Independent System Operators*, 152 F.E.R.C. ¶ 61,218 at P 1 (2015) (to be codified at 18 C.F.R. pt. 35).

22. *Id.* at P 5.

23. *Id.*

24. *Id.*

25. *Id.* at P 7.

26. 152 F.E.R.C. ¶ 61,218, at P 7.

27. Final Rule, *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines & Public Utilities*, 151 F.E.R.C. ¶ 61,049 at P 23 (2015) (to be codified at 18 C.F.R. pt. 284).

of their scheduled quantities by 5:00 p.m. CCT.<sup>28</sup> The FERC stated that the 1:00 p.m. CCT start time for the Timely Nomination Cycle would afford generators more time to acquire natural gas supply and pipeline transportation after they are informed of their obligations to produce energy.<sup>29</sup> The FERC, however, rejected requests to extend the deadline for nominations in the Timely Nomination Cycle, noting that such a change would likely require corresponding changes to the remainder of the Timely Nomination Cycle process.<sup>30</sup> Second, the FERC adopted NAESB's proposal to establish a third intraday nomination cycle during the gas operating day (Gas Day) to help shippers adjust their scheduling to reflect changes in demand.<sup>31</sup> The FERC abandoned its prior proposal to change the start of the Gas Day.<sup>32</sup> The FERC stated that the safety impacts and costs of implementing such a change would likely outweigh the associated benefits.<sup>33</sup> The FERC added that the concerns underlying the proposals to alter the Gas Day appeared to be "primarily regional in nature."<sup>34</sup>

#### F. Revisions to Public Utility Filing Requirements

On July 16, 2015, the FERC issued a Final Rule that revises Part 46 of its regulations to revise the filing requirements for FERC-566, the annual report of the utility's largest twenty customers.<sup>35</sup> The FERC eliminated the FERC-566 filing requirement for RTOs, ISOs and Exempt Wholesale Generators (EWG), and any entity that has no reportable sales in any of the three preceding years.<sup>36</sup> The FERC also revised the FERC-566 filing requirements to no longer require filers to identify individual residential customers by name and address.<sup>37</sup> On November 19, 2015, in an order on rehearing, the FERC further clarified the FERC-566 filing requirements.<sup>38</sup> The FERC explained that while section 305(c) of the FPA expressly seeks to obtain information about purchasers of electric energy "for purposes other than resale," an EWG can only sell electric energy at wholesale and, therefore, is exempt from the FERC-566 filing requirement.<sup>39</sup>

## II. RTO/ISO DEVELOPMENTS

### A. New York Independent System Operator, Inc.

On February 19, 2015, the FERC instituted a section 206 proceeding to address "recurring issues in the wholesale markets administered by" the New York Independent System Operator, Inc. (NYISO)—specifically, the "challenges [of]

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28. *Id.* at PP 82, 87.

29. *Id.*

30. *Id.* at P 88.

31. *Id.* at PP 1-2, 23.

32. 151 F.E.R.C. ¶ 61,049, at PP 3, 23.

33. *Id.*

34. *Id.* at P 25.

35. Order No. 812, *Revisions to Public Utility Filing Requirements*, 152 F.E.R.C. ¶ 61,032 at P 1 (2015).

36. *Id.*

37. *Id.*

38. Order No. 812-A, *Revisions to Public Utility Filing Requirements*, 153 F.E.R.C. ¶ 61,176 at P 6 (2015).

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

temporarily retaining certain generation resources needed to ensure reliable transmission service until more permanent reliability solutions are in place.”<sup>40</sup> The FERC cited filings with it and with the New York Public Service Commission (NYSPSC) seeking approval of Reliability Must Run (RMR) agreements between generation owners that had sought to mothball certain units and transmission providers that needed those units to continue to operate for reliability reasons.<sup>41</sup> The FERC expressed concern that the NYISO’s tariffs lacked provisions governing the rates, terms and conditions for RMR services and, therefore, the FERC ordered the NYISO to submit “fully supported” tariff revisions governing the retention of and compensation to generating units required for reliability.<sup>42</sup> The FERC provided “general guidance” for the NYISO to follow in crafting its proposed RMR tariff revisions.<sup>43</sup> The FERC stated the tariff revisions should include provisions addressing notice of a generator’s intent to retire; the need for transparency as the NYISO evaluates the reliability impact of the retiring generator and alternatives to an RMR agreement; compensation that reflects the nature of the RMR regime (either voluntary or involuntary); and specific methodologies for allocating the costs associated with RMR agreements.<sup>44</sup>

On March 19, 2015, the FERC issued an order regarding the NYISO’s market power mitigation measures for New York City. The order granted, in part, and denied, in part, requests for rehearing of a May 2010 order on the NYISO’s market mitigation tariff proposals, including a request for rehearing regarding the Demand Curve price that is the basis for calculating the Default Offer Floor pursuant to the market mitigation measures.<sup>45</sup> The order addressed how the Offer Floor for Special Case Resources (SCRs), which are demand-side resources that participate in the capacity market, should be calculated. With respect to whether state program subsidies and other benefits should be added to the SCR Offer Floor, the FERC clarified that the May 2010 order did not intend for the NYISO to rule on the legitimacy of particular state programs, and also did not intend to grant a blanket exemption for all state programs that subsidize demand response.<sup>46</sup> The FERC relieved the NYISO of the obligation to provide a list of criteria to govern the determination of the inclusion or exclusion of specific state program payments for purposes of the Offer Floor determination. Instead, the FERC determined that it would decide that issue on a case-by-case basis following a petition for exemption filed by the state. The FERC granted rehearing with respect to the prior exclusion from the SCR Offer Floor of payments under ConEd’s Distribution Load Relief Program and the New York State Energy Research and Development Authority rebate program, writing that these two programs can seek exemptions prospectively. The FERC accepted the NYISO’s October 2008 compliance filing, except for its proposal to grant a blanket exemption from the Offer Floor

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40. *New York Indep. Sys. Operator, Inc.*, 150 F.E.R.C. ¶ 61,116, at P 1 (2015).

41. *Id.* at PP 2, 5.

42. *Id.* at PP 3-4.

43. *Id.* at P 12.

44. *Id.* at PP 12-20.

45. *New York Indep. Sys. Operator, Inc.*, 150 F.E.R.C. ¶ 61,208, at P 1 (2015).

46. *Id.* at P 30.

calculation for all payments and other benefits to SCRs under state programs, and ordered the NYISO to make a further compliance filing to delete that provision.<sup>47</sup>

On March 19, 2015, the FERC issued an order addressing National Grid's efforts to recover the costs related to two Reliability Support Services Agreements (RSSAs) with NRG Energy for power from NRG's Dunkirk generating facility in New York. National Grid sought to revise its Wholesale Transmission Service Charge (TSC) to incorporate costs related to the RSSAs. National Grid asserted that including the RSSA-related costs in its Wholesale TSC was appropriate because the costs directly related to the functioning of its transmission system and should be treated the same as costs directly incurred for reinforcements or other upgrades to the transmission system.<sup>48</sup>

In its March 19 order, the FERC established hearing and settlement judge procedures to determine if National Grid's proposed rate revisions and the Dunkirk RSSA's charges are just and reasonable. The FERC stated that it would not revisit the reliability determinations underlying the RSSAs, but that it "continue[d] to have concerns regarding the costs reflected in those agreements."<sup>49</sup> The FERC's preliminary analysis indicated that National Grid's proposed rate revisions and the RSSA-related charges were not shown to be just and reasonable.<sup>50</sup>

On April 14, 2015, the FERC rejected in part, accepted in part, and suspended the RSSA between Exelon's R.E. Ginna Nuclear Power Plant (Ginna) and Rochester Gas and Electric Corporation (RG&E). The FERC found that the RSSA had not been shown to be just and reasonable and established hearing and settlement judge procedures to consider the RSSA.<sup>51</sup>

The FERC ordered Ginna to remove all provisions related to the extension of the RSSA beyond its initial term, finding that Ginna had not submitted evidence "demonstrating a reliability need beyond the initial term of the RSSA."<sup>52</sup> The FERC also stated that the future needs for Ginna's operations, beyond the RSSA's initial term, would be subject to the RMR provisions under development by the NYISO.<sup>53</sup> The FERC also ordered Ginna to remove provisions that would provide it with a 15% share of its market revenues, finding that the revenue sharing provision is not cost-based and may allow Ginna to earn more than its full cost of service.<sup>54</sup> The FERC accepted provisions that required Ginna, if it remains in service after the end of the RSSA's term, to repay RG&E the capital investments that Ginna makes during the RSSA. The FERC found that those provisions provide a sufficient disincentive for Ginna to toggle between the RSSA and the NYISO markets.<sup>55</sup>

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47. *See generally id.*

48. *New York Indep. Sys. Operator, Inc.*, 150 F.E.R.C. ¶ 61,206, at P 9 (2015).

49. *Id.* at P 16.

50. *Id.* at P 17.

51. *R.E. Ginna Nuclear Power Plant, LLC*, 151 F.E.R.C. ¶ 61,023, at P 42 (2015).

52. *Id.* at P 40.

53. *Id.*

54. *Id.* at P 44.

55. *Id.* at P 45.

On July 13, 2015, the FERC granted, in part, and denied, in part, the requests for rehearing of the April 14 order.<sup>56</sup> The FERC denied rehearing on the issues of (1) the FERC's jurisdiction over the RSSA, (2) the NYISO's reliability determination underlying the RSSA, (3) the length of the term of the RSSA, and (4) whether the RSSA's effect on market prices was outside the scope of the proceeding.<sup>57</sup> The FERC granted rehearing on the issue of whether the RSSA provided a sufficient disincentive for Ginna to toggle between the RSSA and the NYISO markets, finding that the pleadings raised disputed issues of material fact.<sup>58</sup> The FERC also granted clarification of its holding on the 15% market share provision, thereby allowing Ginna to retain a portion of its market revenues so long as the total compensation under the RSSA is capped at Ginna's full cost of service.<sup>59</sup>

*B. PJM Interconnection, L.L.C.*

On June 9, 2015, the FERC conditionally approved changes to PJM Interconnection, L.L.C.'s (PJM) capacity market to implement a Capacity Performance Resource product.<sup>60</sup> The FERC found that such reforms were necessary to address the "confluence of changes in the PJM markets, including both recent performance issues . . . impacted by inadequate incentives and penalties for resource performance under its current construct and ongoing changes in PJM's resource mix that are projected to accelerate."<sup>61</sup> The FERC approved PJM's Non-Performance Charge to provide incentives to capacity sellers to invest in and maintain their resources by tying capacity revenues more closely with real-time delivery of energy and reserves during emergency system conditions. The FERC based the Non-Performance Charge rate on the Net Cost of New Entry (Net CONE) as it "is likely to discourage non-performing resources from taking on capacity obligations, because over time the penalties are likely to fully offset the capacity revenues from the capacity market auctions."<sup>62</sup>

The Commission also accepted an annual Non-Performance stop-loss limit equal to 1.5 times annual Net CONE, and two Non-Performance Charge exemptions. The exemptions are for (1) PJM-approved generator planned or maintenance outages, and (2) instances where a resource is not scheduled by PJM due to the seller's submission of a market-based offer price greater than its cost-based offer price.<sup>63</sup> Non-Performance Charge revenues will be redistributed from under-performing resources to over-performing resources.<sup>64</sup> The FERC also approved PJM's proposal to permit aggregated offers during emergency conditions for demand resources, energy efficiency resources, capacity storage resources, intermittent resources, and environmentally-limited resources, in order

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56. *R.E. Ginna Nuclear Power Plant, LLC*, 152 F.E.R.C. ¶ 61,027, at P 1 (2015).

57. *Id.* at P 15.

58. *Id.* at P 48.

59. *Id.* at P 29.

60. Order on Proposed Tariff Revisions, *PJM Interconnection, L.L.C.*, 151 F.E.R.C. ¶ 61,208 at P 4 (2015) ("Capacity Performance Order").

61. *Id.* at P 7.

62. *Id.* at P 159.

63. *Id.* at P 167.

64. *Id.* at P 182.

to enhance their ability to provide reliability benefits to the PJM region and increase competition in the capacity market.<sup>65</sup>

FERC also accepted PJM's proposal to apply its existing must-offer requirement to Capacity Performance Resources to prevent physical withholding of resources, noting that the use of a must-offer requirement is both consistent with established capacity market practice and necessary to safeguard against manipulation in the PJM capacity market.<sup>66</sup> In addition, the FERC accepted PJM's proposal to exempt categorically from the Capacity Performance must-offer requirement intermittent resources, capacity storage resources, demand resources, and energy efficiency resources because without ownership concentration they do not raise the same physical withholding concerns as do existing generation resources.<sup>67</sup> Chairman Norman Bay dissented in a separate statement.

On July 22, 2015, the FERC issued an order addressing a request for rehearing, filed by Joint Consumers,<sup>68</sup> and a complaint, filed by the Advanced Energy Management Alliance Coalition (AEMA), concerning non-generation resources' participation in the Capacity Performance *Transition Incremental Auctions* (Transition Auctions) for PJM's Capacity Performance Product. The FERC granted, in part, Joint Consumers' request for rehearing and granted, in part, AEMA's complaint to allow non-generation resources that are technically capable of providing the capacity service to be procured through the Transition Auctions to participate in those auctions.<sup>69</sup> The FERC disagreed with Joint Consumers and AEMA's assertions that, under the Capacity Performance construct, any Capacity Performance Resource (including non-generation resources such as demand response resources) was eligible to participate in the Transition Auctions, and that Attachment DD, section 5.14D(B)(3) could not be read to bar this right.<sup>70</sup> The FERC found that section 5.14D(B)(3) specifies which resources are permitted to submit offers, and that section names only a "Generation Capacity Resource" and an "external Generation Capacity Resource." Therefore, the FERC concluded that section 5.14D(B)(3) establishes that only Generation Capacity Resources, including external Generation Capacity Resources, are eligible to submit offers into the Transition Auctions.<sup>71</sup>

The FERC then determined that PJM failed to provide an adequate explanation as to how non-generation resources were not similarly situated to Generation Capacity Resources for purposes of providing the capacity services PJM plans to procure through the Transition Auctions.<sup>72</sup> Stating that the purpose

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65. 151 F.E.R.C. ¶ 61,208, at P 101.

66. *Id.* at P 354.

67. *Id.* at P 355.

68. *PJM Interconnection, L.L.C.*, 152 F.E.R.C. ¶ 61,064 at n.1 (2015) (Joint Consumers consist of the following entities: the PJM Industrial Customer Coalition, the New Jersey Board of Public Utilities, the New Jersey Division of Rate Counsel, the Public Power Association of New Jersey, Maryland Office of People's Counsel, the Office of the People's Counsel for the District of Columbia, the Pennsylvania Office of Consumer Advocate, the Delaware Division of the Public Advocate, Duquesne Light Company, the Illinois Citizens Utility Board, and the West Virginia Consumer Advocate Division).

69. *See generally id.*

70. *Id.* at P 34.

71. *Id.* at P 35.

72. *Id.* at P 38.

of the Transition Auctions was to procure a more reliable portfolio of capacity resources, the FERC found no basis for excluding non-generation resources capable of providing that service from participating. The FERC found that the inclusion of non-generation resources in section 5.5A(a) of the Capacity Performance provisions suggests that non-generation resources may be capable of providing reliable year-round performance, and therefore may be similarly situated to generation resources for the purposes of the Transition Auctions.<sup>73</sup> Commissioner Moeller issued a concurring opinion and Commissioner Clark dissented.

*C. California Independent System Operator Corp.*

On May 14, 2015, the FERC conditionally accepted Nevada Power Company and Sierra Pacific Power Company's (together, NV Energy) proposed revisions to their combined OATT to allow NV Energy to participate in the Energy Imbalance Market (EIM) created by the California Independent System Operator Corporation (CAISO).<sup>74</sup> The FERC accepted most of NV Energy's proposed OATT revisions, finding that "there is record evidence regarding NV Energy's participation in the EIM and expected net benefits to the EIM as a whole and to NV Energy's customers."<sup>75</sup>

The FERC accepted (1) NV Energy's proposal to use available transfer capability, as calculated consistent with the NV Energy OATT, to support EIM transfers between balancing authority areas (BAAs);<sup>76</sup> (2) NV Energy's proposed scheduling timelines;<sup>77</sup> and (3) NV Energy's proposal to require that external resources utilize a pseudo-tie arrangement to electrically move from the external BAA to NV Energy's BAA.<sup>78</sup> The FERC also conditionally accepted NV Energy's proposal to settle energy imbalances using the EIM LMPs for all customers under its OATT Schedules 4 (Energy Imbalance Service), 9 (Generator Imbalance Service), and 10 (Loss Compensation Service).<sup>79</sup> The FERC found no evidence that NV Energy will not fulfill its responsibility to "maintain sufficient resources to meet NERC [(North American Electric Reliability Corporation)] and WECC [(Western Electricity Coordinating Council)] reliability criteria for its BAA."<sup>80</sup>

The FERC directed NV Energy to submit a compliance filing within thirty days after issuance of an order in the ongoing FERC proceeding under section 206

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73. *Id.* at P 39. Specifically, Attachment DD, section 5.5A(a) of the Capacity Performance provisions provide that "internal or external Generation Capacity Resources, Annual Demand Resources, Capacity Storage Resources, Annual Energy Efficiency Resources, and Qualifying Transmission Upgrades" that can "demonstrate to the satisfaction of [PJM] that the resource meets the necessary requirements" of the higher quality Capacity Performance Resource product may submit sell offers as Capacity Performance. *Id.* (internal citations omitted).

74. *Nevada Power Co.*, 151 F.E.R.C. ¶ 61,131 (2015). "The EIM enables entities with [BAAs] outside of the CAISO to voluntarily take part in the imbalance energy portion of the CAISO locational marginal price (LMP)-based real-time electricity market alongside participants from within the CAISO BAA." *Id.* at P 2.

75. *Id.* at PP 85-86.

76. *Id.* at P 116.

77. *Id.* at P 161.

78. 151 F.E.R.C. ¶ 61,131, at P 185.

79. *Id.* at P 174.

80. *Id.* at P 195.

of the FPA, to investigate issues underlying imbalance energy price spikes in the PacifiCorp BAAs<sup>81</sup> The FERC wrote that the compliance filing should include any revisions to NV Energy's OATT that are appropriately based on the outcome of that proceeding.<sup>82</sup> The FERC also wrote that the actual implementation of NV Energy's participation in the EIM is subject to NV Energy's compliance with readiness requirements being developed by the CAISO in conjunction with its stakeholders.<sup>83</sup> In addition, the FERC directed NV Energy to "submit a market power analysis to demonstrate that it does not have market power in the EIM market . . . no later than 60 days prior to . . . the date on which NV Energy plans to commence making sales at market-based rates in the EIM."<sup>84</sup>

The FERC also directed NV Energy to submit a compliance filing to explain how its participation in the EIM will work in conjunction with dynamic transfers from the Apex Generating Station under the City of Los Angeles Department of Light and Power's Dynamic Scheduling Agreement.<sup>85</sup> Further, the FERC directed NV Energy to submit an informational report regarding flexible ramping constraint costs within fifteen months after NV Energy's entry into the EIM.<sup>86</sup>

#### D. ISO-NE Developments

On December 28, 2015, the FERC issued an order finding that ISO-NE's Transmission Markets and Services Tariff (Tariff) is unjust, unreasonable, and unduly discriminatory or preferential because it applies vertical demand curves within constrained zones, which does not sufficiently address concerns such as price volatility and a susceptibility to the exercise of market power as part of its Forward Capacity Market (FCM) rules.<sup>87</sup> The FERC ordered ISO-NE to submit Tariff revisions by March 31, 2016, that provide for inclusion of zonal sloped demand curves in its FCM rules, to be implemented with the eleventh Forward Capacity Auction (FCA).

The FERC originally had ordered ISO-NE to submit a sloped demand curve for use in the FCM by April 1, 2014, in time for the ninth FCA.<sup>88</sup> However, ISO-NE failed to meet that deadline and was unable to submit zonal sloped demand curves in time for the tenth FAC.<sup>89</sup> In October 2015, ISO-NE informed the FERC that "it expects stakeholders to consider a final proposal in April 2016 and anticipates making a Commission filing shortly thereafter" but the schedule was tentative.<sup>90</sup> The FERC stated that "[w]hen vertical demand curves are used, even small increases or decreases in supply can result in large changes in price, because a fixed amount of capacity must be procured."<sup>91</sup> "[G]iven the shift in New

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81. Notice of Technical Conference, *California Indep. Sys. Operator Corp.*, F.E.R.C. Docket Nos. EL15-861-000, EL15-53-000 (March 24, 2015).

82. 151 F.E.R.C. ¶ 61,131, at P 74.

83. *Id.* at PP 74, 100.

84. *Id.* at P 201.

85. *Id.* at P 132.

86. *Id.* at P 213.

87. *ISO New England Inc.*, 153 F.E.R.C. ¶ 61,338, at P 1 (2015).

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

89. 153 F.E.R.C. ¶ 61,338, at PP 4, 8.

90. *Id.* at P 10.

91. *Id.* at P 12.

England's capacity supply in recent years, . . . it is even more important to ensure that the market produces accurate price signals."<sup>92</sup> As the "continued delay creates uncertainty for market participants and the continued use of vertical demand curves in constrained zones results in less efficient markets and affects confidence in market outcomes[,] further delay by ISO-NE is not justified."<sup>93</sup>

In this December 28, 2015, order the FERC found that ISO-NE's tariff is unjust, unreasonable, and unduly discriminatory or preferential because it lacks adequate transparency and sufficient detail needed to determine how certain costs are derived and recovered with regard to the formula rates for ISO-NE Participating Transmission Owners' (PTOs) for current Regional Network Service (RNS) and Local Network Service (LNS).<sup>94</sup>

The FERC noted that "the reason for including formula rate protocols . . . is to provide the parties paying such rates specific procedures for notice and review of, and challenges to, the transmission owners' annual updates."<sup>95</sup> The FERC found that: (1) several of the ISO-NE PTOs that provide LNS are not required to submit annual updates; (2) "interested parties are not provided with all the information necessary to understand and evaluate the implementation of the formula rate for either the correctness of inputs and calculations or the reasonableness and prudence of the costs to be recovered;" (3) there are no challenge provisions to allow interested parties to resolve rate implementation disputes informally; (4) "the rates themselves lack sufficient detail to determine how certain costs are derived and recovered;" (5) and concerns "existed regarding the timing and synchronization between the RNS and LNS formula rates."<sup>96</sup> The FERC also noted that "because the ISO-NE PTOs' formula rates are written out in words and not in mathematical formula," the PTOs may have different interpretations of the single RNS formula applicable to all the PTOs.<sup>97</sup> Accordingly, the FERC is instituting an FPA section 206 investigation into the justness and reasonableness of the ISO-NE PTOs' RNS and LNS formula rates.<sup>98</sup>

In this case, petitioner TransCanada Power Marketing Ltd. (TransCanada) appeals from two FERC orders—144 F.E.R.C. ¶ 61,204 (2013) and 145 F.E.R.C. ¶ 61,023 (2013). Both orders relate to ISO-NE's Winter Reliability Program (Program) during the 2013-14 winter. In the first order, the FERC tentatively approved the Program, but rejected the tariff proposal to allocate costs to Regional Network Load as inconsistent with cost-causation principles and directed ISO-NE to submit a compliance filing that would allocate the costs of the Program to Real-Time Load Obligation; and in the second order, the FERC approved the Program and the results of ISO-NE's bid-selection process.<sup>99</sup>

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92. *Id.*

93. *Id.* at P 14.

94. *ISO New England Inc. Participating Comm'n*, 153 F.E.R.C. ¶ 61,343, at P 1 (2015).

95. *Id.* at P 5.

96. *Id.* at P 6.

97. *Id.* at P 9.

98. *Id.*

99. *TransCanada Power Mktg. Ltd. v. FERC*, No. 14-1103, 2015 WL 9287782, at \*1 (D.C. Cir. Dec. 22, 2015).

As to the petitioner's appeal of the first order, TransCanada advanced two claims: (1) the FERC "failed to adequately consider the costs of the Program before tentatively accepting it; and (2) the FERC erred in ordering ISO-NE to allocate Program costs to Real-Time Load Obligation."<sup>100</sup> The D.C. Circuit held that the first claim was unripe for judicial review because the FERC made it clear that its decision was tentative.<sup>101</sup> The court held that the second claim was without merit because the FERC's analysis supported its decision that the allocation of costs to Real-Time Load Obligation was just and reasonable and that ISO-NE's proposal to allocate costs to Regional Network Load "violated principles of cost causation."<sup>102</sup> In particular, the D.C. Circuit noted that "because the Program was designed to allow Load-Serving Entities to meet their Real-Time Load obligations, the Commission's decision on cost allocation properly followed cost causation principles."<sup>103</sup>

As to the petitioner's appeal of the second order, TransCanada argued that in approving the Program, the "FERC relied on a record that is devoid of any evidence regarding how much of the Program cost was attributable to profit and risk mark-up . . . [And] without this information, [the] FERC could not properly assess whether the Program rates were just and reasonable."<sup>104</sup> The D.C. Circuit agreed, concluding that the FERC's reasoning in response to that point is inadequate.<sup>105</sup> The court found that the FERC should have inquired into the profit and risk mark-up or explained its decision not to do so, rather than simply not addressing the matter.<sup>106</sup> The FERC also did not explain how it balanced the Program's costs with non-cost factors or "how it applied the non-cost factors."<sup>107</sup> Rather, the FERC "concluded that the profit margins were not unreasonably high, without ever discussing the margins or their connections to particular suppliers" and "made no effort to define the relevant market or determine the participants' market power."<sup>108</sup> Therefore, the D.C. Circuit remanded the second order.<sup>109</sup>

### III. TRANSMISSION RATES

On March 3, 2015, the FERC denied requests for rehearing of the FERC's June 19, 2014 order on initial decision<sup>110</sup> concerning a complaint challenging the New England Transmission Owners' (NETOs) base return on equity (ROE).<sup>111</sup> The FERC disagreed with the NETOs' argument that the FERC failed to meet its burden of proof in finding that the NETOs' base ROE of 11.14% is unjust and

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100. *Id.* at \*7.

101. *Id.* at \*8.

102. *Id.*

103. *Id.* at \*9.

104. *TransCanada*, 2015 WL 9287782, at \*10.

105. *Id.* at \*11.

106. *Id.*

107. *Id.*

108. *Id.* at \*11-12.

109. *TransCanada*, 2015 WL 9287782, at \*12.

110. Opinion No. 531, *Coakley, Mass. Attorney Gen. v. Bangor Hydro-Elec. Co.*, 147 F.E.R.C. ¶ 61,234 (2014).

111. Opinion No. 531-B, *Coakley, Mass. Attorney Gen. v. Bangor Hydro-Elec. Co.*, 150 F.E.R.C. ¶ 61,165 at PP 1, 3-4 (2015).

unreasonable and that the just and reasonable base ROE is 10.57%.<sup>112</sup> The FERC also denied the NETOs' requested clarification that adjustments to the NETOs' ROE incentive adders are outside the scope of this base ROE proceeding.<sup>113</sup> The FERC rejected that request, explaining that ROE incentive adders may "not exceed the high end of the zone of reasonableness" and that the NETOs had notice of this policy and the opportunity to present evidence to the contrary.<sup>114</sup>

A group of complainants and intervenors (collectively, Petitioners) and the Eastern Massachusetts Consumer-Owned Systems (EMCOS) challenged the Commission's "placement of the NETOs' base ROE three-quarters of the way up the zone of reasonableness."<sup>115</sup> The FERC supported its determination by describing how the presence of "anomalous capital market conditions" warranted the placement of the NETOs' base ROE above the midpoint of the zone of reasonableness.<sup>116</sup> The Petitioners further argued that the FERC's reliance on UIL Holding's discounted cash flow (DCF) result was flawed because that result "was based on an IBES short-term growth projection that reflected only one analyst's growth rate projection."<sup>117</sup> The FERC rejected the Petitioners' argument, explaining that "it is contrary to years of established Commission precedent approving the use of IBES short-term growth projections in the two-step DCF methodology."<sup>118</sup>

The Petitioners also argued that the Commission should not have relied upon evidence concerning state commission-authorized ROEs because those ROEs are "not relevant to this proceeding."<sup>119</sup> The FERC dismissed that argument, stating that the FERC did not set the NETOs' base ROE based on the state commission-authorized ROEs, but rather relied on that evidence only to corroborate the FERC's determination.<sup>120</sup> Petitioners further asserted that the Commission erred in relying on the NETOs' capital asset pricing model (CAPM) analysis because that analysis is "overly optimistic."<sup>121</sup> The FERC rejected that argument, explaining that the CAPM analysis was "a generally accepted methodology routinely relied upon by investors" and was "appropriately used to corroborate" its decision.<sup>122</sup> The EMCOS similarly challenged the FERC's reliance on certain record evidence. Specifically, the EMCOS argued that the FERC should not have adopted the NETOs' risk premium analysis because "the Commission has repeatedly rejected the use of [a] risk premium analysis" in setting "a just and reasonable ROE."<sup>123</sup> The FERC rejected this argument and found "the NETOs' risk premium analysis sufficiently reliable" to corroborate the FERC's decision

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112. *Id.* at PP 8, 20.

113. *Id.* at P 139.

114. *Id.* at P 142.

115. *Id.* at P 39.

116. 150 F.E.R.C. ¶ 61,165, at P 49.

117. *Id.* at P 71.

118. *Id.*

119. *Id.* at P 81.

120. *Id.* at P 84.

121. 150 F.E.R.C. ¶ 61,165, at P 104.

122. *Id.* at P 109.

123. *Id.* at P 92.

“to place the NETOs’ base ROE above the midpoint of the zone of reasonableness produced by the DCF analysis.”<sup>124</sup>

The FERC also dismissed Petitioners’ claims that the NETOs’ expected earnings analysis was flawed. The FERC stated that it considered the analysis “to be sound, as it is forward-looking, based on a reliable source of earnings data, and appropriately converts the proxy companies’ earnings to reflect average returns.”<sup>125</sup> Lastly, the EMCOS and Petitioners requested “that the [FERC] clarify that it intended for Opinion No. 531 to establish 10.57 percent as the prospective base ROE” effective “from the date of issuance of Opinion No. 531[,]” June 19, 2014.<sup>126</sup> The FERC found that such a clarification would be inaccurate because the NETOs are “subject to the submission of the record evidence at the paper hearing” that the Commission instituted in Opinion No. 531, and that “[o]nly with the issuance of Opinion No. 531-A,<sup>127</sup> on October 16, 2014, did the Commission establish the prospective” base ROE.<sup>128</sup>

On March 31, 2015, the FERC issued an order conditionally accepting ITC Midwest LLC’s (ITC Midwest) request for a 100-basis point incentive ROE adder (Transco Adder) for independent transmission ownership, subject to the Transco Adder being reduced to 50-basis points, and subject to the resulting ROE being within the zone of reasonableness to be determined in the ongoing complaint proceeding in Docket No. EL14-12-000 (Complaint Proceeding).<sup>129</sup> The FERC suspended the tariff revisions for a nominal period and “accept[ed] ITC Midwest’s request to defer collection of the Transco Adder pending the outcome of the Complaint Proceeding.”<sup>130</sup>

ITC Midwest requested a 100-basis point Transco Adder as an incentive for independent transmission ownership, consistent with section 219 of the FPA and Order No. 679.<sup>131</sup> The FERC conditionally granted the Transco Adder, “finding that ITC Midwest is a fully independent, stand-alone transmission company” and that transmission incentives are appropriate, pursuant to Order No. 679, in order to encourage the formation of independent transmission companies and recognize the benefits of their business model to customers.<sup>132</sup> However, the FERC noted Order No. 679 does not specify the size of the Transco Adder, and concluded that a 50-basis point adder, rather than the requested 100-basis point adder, struck the right balance by encouraging independent transmission while accounting for concerns that a higher adder would have too high of a rate impact.<sup>133</sup> The FERC rejected arguments that (1) the award of a Transco Adder requires additional

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124. *Id.* at P 98.

125. *Id.* at P 126.

126. 150 F.E.R.C. ¶ 61,165, at P 148.

127. Opinion No. 531-A, *Coakley, Mass. Attorney Gen. v. Bangor Hydro-Elec. Co.*, 149 F.E.R.C. ¶ 61,032 (2014).

128. 150 F.E.R.C. ¶ 61,165, at P 151 & n.331 (2015).

129. *Midcontinent Indep. Sys. Operator, Inc.*, 150 F.E.R.C. ¶ 61,252, at PP 1-2 (2015).

130. *Id.* at P 2.

131. *Id.* at P 8 (citing Order No. 679, *Promoting Transmission Investment through Pricing Reform*, F.E.R.C. STATS. & REGS. ¶ 31,222, at PP 221-223, 231 (2006), *order on reh’g*, Order No. 679-A, F.E.R.C. STATS. & REGS. ¶ 31,236, at P 77, *order on reh’g*, 119 F.E.R.C. ¶ 61,062 (2007)).

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

133. *Id.* at P 45.

justifications as to the necessity or benefits of the incentive;<sup>134</sup> (2) that requests for Transco Adders should be held to different standards than requests for RTO Adders; and (3) that approving the Transco Adder prior to resolution of the Complaint Proceeding was inappropriate.<sup>135</sup> Further, the FERC declined to reevaluate its overall transmission ROE incentive policies, noting that this proceeding relates solely to the determination of the appropriateness of the Transco Adder for ITC Midwest.<sup>136</sup>

In 2012, the FERC identified three areas of concern regarding the formula rate protocols of the Midcontinent Independent System Operator (MISO)<sup>137</sup>: (1) scope of participation in the information exchange; (2) the transparency of the information exchange; and (3) the ability of customers to challenge transmission owners' implementation of the formula rate as a result of the information exchange.<sup>138</sup> During 2013 and 2014, the FERC directed MISO and its transmission owners to revise their formula rate protocols to address the FERC's concerns.<sup>139</sup> MISO and its transmission owners subsequently submitted compliance proposals, which FERC conditionally accepted subject to further compliance filings. In July 2014, FERC staff identified certain common deficiencies in the annual formula rate updates that were impeding FERC staff's ability to verify compliance with the formula rate requirements and offered guidance to the utilities regarding the format and the level of support for inputs and calculations of their formula rate annual updates. The FERC staff guidance gave several examples of typical formula rate inputs that require such support, for example, unfunded accumulated deferred income tax balances; transaction-related costs; asset retirement obligations; and acquisition premiums.<sup>140</sup> Contemporaneously, the FERC also issued show cause orders directing individual utilities to file proposed formula rate protocols addressing certain formula rate issues.

On March 19, 2015, the FERC accepted, in part, the utilities' formula rate compliance proposals. The FERC found that, *inter alia*, (1) definitions of "interested parties" include tariff customers, "state utility regulatory commissions, consumer advocacy agencies, and state attorneys general;"<sup>141</sup> (2) utilities should post their annual revenue requirement calculations and supporting information on OASIS;<sup>142</sup> (3) utilities should disclose as part of their annual update filings any accounting changes or adjustments that affect inputs to the formula rate, and should not filter the accounting changes disclosed through materiality limits;<sup>143</sup> (4) utilities should hold annual meetings (including remote access) for interested

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134. *Midcontinent Indep. Sys. Operator, Inc.*, 150 F.E.R.C. ¶ 61,252, at P 46 (2015).

135. *Id.* at P 49.

136. *Id.* at P 52.

137. Previously known as Midwest Independent Transmission System Operator when the action commenced, it changed its name effective April 26, 2013.

138. *Midwest Indep. Transmission Sys. Operator, Inc.*, 139 F.E.R.C. ¶ 61,127 at PP 14, 18 (2012).

139. *Midwest Indep. Transmission Sys. Operator, Inc.*, 143 F.E.R.C. ¶ 61,149 (2013), *reh'g denied*, 146 F.E.R.C. ¶ 61,209 (2014).

140. Staff's Guidance on Formula Rate Updates (FERC issued July 17, 2014).

141. *Empire Dist. Elec. Co.*, 150 F.E.R.C. ¶ 61,200, at P 14 (2015).

142. *Kansas City Power & Light Co.*, 150 F.E.R.C. ¶ 61,201, at P 12 (2015).

143. *Louisville Gas and Elec. Co.*, 150 F.E.R.C. ¶ 61,202, at P 36 (2015).

parties to permit the utilities to explain, clarify and provide information regarding their annual updates;<sup>144</sup> (5) if applicable, the utilities should include in their protocols a requirement that they coordinate with other transmission owners using formula rates (and interested parties) to establish revenue requirements for recovery of the cost of transmission projects that utilize the same regional cost sharing mechanism;<sup>145</sup> (6) timelines and deadlines for challenges, discovery, etc., must be reasonable and clearly stated;<sup>146</sup> (7) reminder that nothing in the protocols will “limit an interested party’s rights to file a complaint pursuant to section 206 of the FPA;”<sup>147</sup> (8) utilities’ annual filings should include information that is reasonably necessary to determine the reasonableness of all projected costs, not just capital expenditures, and protocols to allow interested parties to obtain information on procurement methods and cost control methodologies;<sup>148</sup> and (9) the Kansas utilities should “take all necessary steps to have SPP make a parallel compliance filing to incorporate the same revisions” to SPP’s tariff protocols.<sup>149</sup>

#### IV. COMPLAINTS

On March 19, 2015, the FERC denied a complaint filed by Independent Power Producers of New York, Inc. (IPPNY) against NYISO challenging certain aspects of buyer-side market power mitigation in the NYISO Installed Capacity (ICAP) market under the NYISO’s Market Administration and Control Area Services tariff.<sup>150</sup> IPPNY argued that the NYISO tariff was unjust and unreasonable insofar as it allowed de minimis offers in the New York Control Area ICAP spot market auctions from capacity resources that would have left the market but for out-of-market revenues paid to the resources to ensure their continued operation to address local reliability issues.<sup>151</sup> IPPNY also raised concerns about suppression of ICAP market prices as a result of repowering agreements for existing resources.<sup>152</sup>

The FERC concluded that IPPNY failed to show the NYISO’s tariff was unjust and unreasonable without a minimum bid requirement for existing resources that are needed for short-term reliability.<sup>153</sup> The FERC reasoned the NYISO’s market practices “recognize that market operation rules should reflect practical realities in order to provide proper incentives to market participants,”<sup>154</sup> and IPPNY had not demonstrated harm to the market that justified relief.<sup>155</sup> Referring to specific generating units addressed in IPPNY’s complaint, the FERC agreed with the NYISO’s Market Monitor that “the units are economic from the

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

145. *Black Hills Power, Inc.*, 150 F.E.R.C. ¶ 61, 198, at P 29 (2015).

146. 150 F.E.R.C. ¶ 61,200, at P 53.

147. *Id.* at P 54.

148. *Westar Energy, Inc.*, 150 F.E.R.C. ¶ 61,203, at P 44 (2015).

149. 150 F.E.R.C. ¶ 61,201, at P 11.

150. *Indep. Power Producers of New York, Inc. v. New York Indep. Sys. Operator, Inc.*, 150 F.E.R.C. ¶ 61,214 (2015).

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

152. *Id.* at PP 18-21.

153. *Id.* at P 65.

154. *Id.*

155. 150 F.E.R.C. ¶ 61,214, at P 65.

perspective of satisfying the NYISO's reliability requirements . . . . If the reliability needs satisfied by these units were reflected in the capacity market, the units would both clear."<sup>156</sup> The FERC rejected the notion that its general policy disfavoring out-of-market agreements was a basis to grant IPPNY's complaint.<sup>157</sup> Finally, the FERC found that the record did not support IPPNY's assertion that out-of-market contracts had resulted in significant capacity price decreases in spot market capacity auctions.<sup>158</sup> Although denying IPPNY's complaint, the FERC found the complaint raised concerns about artificial price suppression associated with repowering agreements throughout the NYISO footprint.<sup>159</sup> The FERC, therefore, directed the NYISO to convene a stakeholder process regarding these issues and to submit a report to the Commission within ninety days regarding the NYISO's analysis of the issues and the outcome of the stakeholder process.<sup>160</sup>

On April 16, 2015, the FERC denied rehearing and granted, in part, requests for clarification of its June 22, 2012 order<sup>161</sup> concerning a complaint challenging the NYISO's implementation of buyer-side market power mitigation in the New York City (NYC) ICAP market.<sup>162</sup> The FERC addressed numerous technical aspects of calculating and implementing Offer Floors for new capacity resources in the NYISO's NYC ICAP market, and also accepted, subject to a further compliance filing, a NYISO compliance filing required by the June 22, 2012 order.<sup>163</sup> The FERC found that the NYISO had partially complied with the June 22, 2012 order's requirements for greater transparency in the NYISO's implementation of buyer-side mitigation rules.<sup>164</sup> Thus, the FERC directed a further compliance filing to allow broader review of the NYISO's market power mitigation and exemption determinations by the NYISO's Market Monitoring Unit.<sup>165</sup> The FERC also directed further compliance filings concerning (1) the use of an inflation component in calculating the Unit Net Cost of New Entry,<sup>166</sup> and (2) the appropriate comparison capacity prices to use in making a determination of exemption from buyer-side mitigation.<sup>167</sup>

On April 16, 2015, the FERC granted, in part, and denied, in part, requests for clarification and rehearing of a September 10, 2012, order (September 2012 Order)<sup>168</sup> concerning a complaint challenging the NYISO's implementation of buyer-side market power mitigation in the NYISO's NYC ICAP market (April 2015 Order).<sup>169</sup> In the September 2012 Order, the FERC granted the complaint,

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156. *Id.* at P 66 (quoting an affidavit filed by the NYISO Market Monitor, Dr. David Patton) (ellipsis in original).

157. *Id.* at P 68.

158. *Id.* at P 67.

159. *Id.* at PP 69-71.

160. 150 F.E.R.C. ¶ 61,214, at P 71.

161. *Astoria Generating Co. v. New York Indep. Sys. Operator, Inc.*, 139 F.E.R.C. ¶ 61,244 (2012).

162. *Astoria Generating Co. v. New York Indep. Sys. Operator, Inc.*, 151 F.E.R.C. ¶ 61,043 (2015).

163. *Id.* at P 2.

164. *Id.* at PP 73-76.

165. *Id.* at P 75.

166. *Id.* at P 90.

167. 151 F.E.R.C. ¶ 61,043, at P 91.

168. *Astoria Generating Co. v. New York Indep. Sys. Operator, Inc.*, 140 F.E.R.C. ¶ 61,189 (2012).

169. *Astoria Generating Co. v. New York Indep. Sys. Operator, Inc.*, 151 F.E.R.C. ¶ 61,044 (2015).

in part, directing the NYISO to reassess a previous conclusion that two generating facilities—the Astoria II project and the Bayonne project—were exempt from the NYISO tariff’s Offer Floor requirement.<sup>170</sup> The FERC explained that, if the Astoria II and Bayonne projects, upon reassessment, were found not to be exempt from the Offer Floor requirements, customers of the plants could face additional capacity costs.<sup>171</sup>

In the April 2015 Order, the FERC rejected a variety of objections raised on rehearing, finding that (1) the September 2012 Order had not inappropriately expanded the NYISO’s buyer-side mitigation rules for the NYC ICAP market;<sup>172</sup> (2) the FERC did not order retroactive relief in response to the complaint, and, in any case, the NYISO violated its tariff, which could have supported retroactive relief;<sup>173</sup> (3) the FERC took into account the potential customer impact of subjecting the Astoria II project to buyer-side mitigation inasmuch as the Commission concluded that customers would benefit from proper application of buyer-side mitigation by preventing a new entrant found to be uneconomic from suppressing the capacity price in the NYC ICAP market;<sup>174</sup> (4) the FERC properly interpreted the tariff concerning the timing of the NYISO’s buyer-side market power mitigation exemption determination;<sup>175</sup> (5) the FERC correctly concluded the NYISO’s exemption determination must be based on the most current information as of the time period the NYISO makes the determination;<sup>176</sup> (6) calculation of the Astoria II project’s costs correctly excluded certain sunk costs for facilities that the Astoria II project shared with another generating unit;<sup>177</sup> (7) the September 2012 Order did not err in failing to modify the NYISO’s methodology for calculating seasonal Offer Floors;<sup>178</sup> and (8) the FERC correctly accepted the NYISO’s use of natural gas futures prices in applying one aspect of the market power mitigation exemption test.<sup>179</sup>

However, the FERC granted rehearing on the issue of whether the September 2012 Order incorrectly found that the NYISO should not use the Astoria II project’s actual cost of capital in calculating the project’s costs for purposes of determining whether it was exempt from mitigation.<sup>180</sup> Lastly, the FERC granted the NYISO’s request for clarification that certain of the FERC’s rulings in the April 2015 Order should be applied in future application of buyer-side mitigation rules.<sup>181</sup>

On June 16, 2015, the FERC denied a complaint filed by Public Service Electric and Gas Company (PSEG) against PJM Interconnection, L.L.C. (PJM)

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170. *Id.* at PP 6-11 (summarizing Sept. 2012 Order).

171. *Id.* at P 18.

172. *Id.* at PP 19-21.

173. *Id.* at PP 28-29.

174. *Id.* at P 31.

175. 151 F.E.R.C. ¶ 61,044, at PP 45-57.

176. *Id.* at PP 65-70.

177. *Id.* at PP 74-77.

178. *Id.* at P 90.

179. *Id.* at PP 94-95.

180. 151 F.E.R.C. ¶ 61,044, at P 88.

181. *Id.* at PP 98-99.

asserting that PJM had violated its Order No. 1000<sup>182</sup>-compliant developer selection process in conducting a competitive solicitation for transmission solutions related to Artificial Island.<sup>183</sup> The FERC found that PJM was not required to apply its Order No. 1000-compliant tariff and had applied its pre-Order No. 1000 tariff to the Artificial Island competitive process. The FERC determined that “it is undisputed that PJM opened the Artificial Island proposal window on April 29, 2013[,]”<sup>184</sup> but “was not bound to its Order No. 1000 tariff provisions prior to the January 1, 2014 effective date of those provisions.”<sup>185</sup> The FERC determined that PJM was therefore only required to “implement the new solicitation process ‘to the extent feasible and practicable’ before January 1, 2014 . . . .”<sup>186</sup>

Although in July 2014 the PJM Board ordered reevaluation of the Artificial Island proposals,<sup>187</sup> the FERC determined the Board’s action was not the type of “reevaluation” that triggers a requirement to use the Order No. 1000-compliant process.<sup>188</sup> The FERC held the “reevaluation” for purposes of Order No. 1000 “occurs when PJM restudies a facility already included in the RTEP to determine if it is still needed,”<sup>189</sup> whereas PJM’s “continuing evaluation of the Artificial Island project proposals . . . was part of PJM’s original or initial evaluation.”<sup>190</sup>

The FERC also rejected the assertion that “PJM had no pre-existing rules to follow to conduct a competitive solicitation.”<sup>191</sup> According to the FERC, its prior “orders approving PJM’s pre-Order No. 1000 transmission planning process as compliant with Order No. 890 demonstrate that PJM’s long-standing process provided for consideration and selection of competing proposals.”<sup>192</sup> Moreover, the FERC noted that prior to Order No. 1000, in its decision in *Primary Power*,<sup>193</sup> the Commission held that “PJM’s tariff provisions do not preclude PJM from designating non-incumbent transmission owners to build projects included in the [Regional Transmission Expansion Plan].”<sup>194</sup> The FERC concluded that PJM’s pre-Order No. 1000 tariff required PJM to “designate projects under the relevant

182. Order No. 1000, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, F.E.R.C. STATS. & REGS. ¶ 31,323 (2011), *order on reh’g*, 139 F.E.R.C. ¶ 61,132, *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).

183. *Pub. Serv. Elec. & Gas Co. v. PJM Interconnection, L.L.C.*, 151 F.E.R.C. ¶ 61,229 (2015). The FERC noted that “‘Artificial Island’ refers to the transmission and generation infrastructure associated with the nuclear complex that includes the Salem 1, Salem 2, and Hope Creek nuclear generating units. Due to the stability-constrained nature of the complex, special operating procedures historically have been used to maintain stability in the area.” *Id.* at P 1 & n.4.

184. *Id.* at P 50.

185. *Id.* at P 49.

186. *Id.* at P 50.

187. *Id.* at P 57 & n.200.

188. 151 F.E.R.C. ¶ 61,229, at P 49; Order No. 1000, *supra* note 187, at P 65.

189. 151 F.E.R.C. ¶ 61,229, at P 51.

190. *Id.*

191. *Id.* at P 53.

192. *Id.*

193. *Primary Power, LLC*, 131 F.E.R.C. ¶ 61,015 (2010), *order on reh’g*, 140 F.E.R.C. ¶ 61,052 (2012), *appeal dismissed*, *Pub. Serv. Elec. & Gas Co. v. FERC*, 783 F.3d 1270 (D.C. Cir. Apr. 14, 2015).

194. 151 F.E.R.C. ¶ 61,229 at P 54.

tariff provisions in a not unduly discriminatory manner, whether sponsored by transmission owners or others.”<sup>195</sup>

The FERC found that “PJM’s application of its pre-Order No. 1000 transmission planning process was just and reasonable, and not unduly discriminatory or preferential . . . .”<sup>196</sup> Since the FERC found that “PJM considered the project proposals in a not unduly discriminatory manner . . . [t]here is no evidence in the record that PJM’s conducting of the Artificial Island solicitation process was inconsistent with its pre-Order No. 1000 procedures.”<sup>197</sup>

On August 25, 2015, the FERC denied Indicated Market Participants’<sup>198</sup> complaint arguing that PJM’s Transition Auction Methodology violates PJM’s OATT and is inconsistent with the Capacity Performance Order.<sup>199</sup> Specifically, the FERC found “that section 5.14D of Attachment DD of PJM’s OATT remains just and reasonable.”<sup>200</sup> The FERC stated that section 5.14D:

[R]equires that the Transition Auction clearing methodology will: 1) acquire resources up to the target quantities of Capacity Performance Resources specified; 2) select resources based on Sell Offers submitted in such auction; and 3) calculate a clearing price to be paid for each megawatt-day of capacity that clears in such auction.<sup>201</sup>

The FERC concluded that “PJM’s methodology properly considers all the offers made to provide Capacity Performance and clears the market at a price that meets the quantity requirement or a quantity determined by clearing at the offer cap.”<sup>202</sup> Moreover, the FERC noted that “[s]ection 5.14D does not require PJM to consider Sell Offers minus the relevant B[ase] R[esidual] A[uction] clearing price” as Indicated Market Participants argued.<sup>203</sup> The FERC found “that PJM’s single-clearing price method provides sellers the incentive to invest and develop this new product.”<sup>204</sup> In addition, the FERC disagreed with the complainants’ assertion that “in order to minimize costs, PJM’s clearing methodology must consider revenues from existing capacity commitments.”<sup>205</sup>

## V. PURPA

On May 14, 2015, the FERC denied Northern States Power Company’s (NSPM) request to terminate its mandatory purchase obligation for the Twin

195. *Id.*

196. *Id.* at P 56.

197. *Id.* at P 57.

198. *Indicated Mkt. Participants v. PJM Interconnection, L.L.C.*, 151 F.E.R.C. ¶ 61,152, at P 1 (2015) (stating Indicated Market Participants are Direct Energy Business Marketing, LLC and NextEra Energy Resources).

199. *Id.* at PP 1-2; *PJM Interconnection, L.L.C.*, 151 F.E.R.C. ¶ 61,208, at P 4 (2015) (the “Capacity Performance Order”).

200. 151 F.E.R.C. ¶ 61,152, at P 33.

201. *Id.*

202. *Id.*

203. *Id.*

204. *Id.*

205. 151 F.E.R.C. ¶ 61,208, at P 34. Because Indicated Market Participants failed to show that PJM’s OATT is unjust and unreasonable, or that PJM’s clearing methodology was inconsistent with its OATT, the Commission stated that it need not address Indicated Market Participants’ proposed alternative clearing methodologies. *Id.* at P 35.

Cities Hydro LLC (Twin Cities) Qualifying Facility (QF) under section 210(m) of the Public Utility Regulatory Policies Act of 1978 (PURPA)<sup>206</sup> and section 292.309(a) of the Commission's regulations, asserting that it had rebutted the Commission's presumption regarding small QFs and Twin Cities had nondiscriminatory access to the MISO markets.<sup>207</sup> NSPM argued that Twin Cities (1) was engaged with NSPM to provide certain wheeling services so that Twin Cities may sell energy into the MISO wholesale energy markets; (2) had access to the markets through a larger, more experienced hydroelectric plant operator; and (3) did not have other barriers to access the MISO electricity market. Twin Cities protested, arguing that (1) it was unable to reasonably or feasibly serve as a capacity/planning resource because of prohibitive costs and time constraints to complete the necessary interconnection; (2) there was a legally enforceable obligation between NSPM and Twin Cities that required NSPM to purchase service from Twin Cities; and (3) parties were still entitled to a legally enforceable obligation in situations where the other party refuses to negotiate a contract.<sup>208</sup>

Upon review, the FERC found that NSPM failed to demonstrate that Twin Cities has nondiscriminatory access to both the energy and capacity markets and, therefore, it cannot be relieved of its PURPA mandatory purchase obligation with respect to the Twin Cities QF.<sup>209</sup> The FERC stated that entities owning a small QF (at or below 20 MW) have a rebuttable presumption that they do not have nondiscriminatory access to markets<sup>210</sup> and the electric utility has the burden of proof to demonstrate that a small QF does have such access.<sup>211</sup> The FERC stated that Twin Cities does not currently have unrestricted access to the MISO capacity market and to do so would have to go through a costly and time consuming MISO interconnection process. The FERC stated that these "jurisdictional differences, pancaked deliver rates, and perhaps additional administrative procedures, to obtain access to distant buyers," are exactly the circumstances that the FERC explained, in Order No. 688, give rise to the lack of access rebuttable presumption.<sup>212</sup> The FERC found that NSPM could not meet its burden of proof by claiming the QF simply could pay for the transmission upgrades necessary to access the market and that NSPM's argument is inconsistent with section 292.309(c) of FERC regulations.<sup>213</sup> The FERC declined to address whether there

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206. 16 U.S.C. § 824a-3(m) (2012).

207. *Northern States Power Co.*, 151 F.E.R.C. ¶ 61,110 at PP 1, 4 (2015); 18 C.F.R. § 292.309(a) (2014) (stating that, according to Commission regulations, MISO markets qualify as markets that warrant termination of a mandatory purchase obligation and on the rebuttable presumption that QFs larger than 20 MW have nondiscriminatory access to the MISO markets).

208. 151 F.E.R.C. ¶ 61,110, at PP 14, 17 (2015) (citing *JD Wind I, LLC*, 129 F.E.R.C. ¶ 61,148, at P 25 (2009), *reh'g denied*, 130 F.E.R.C. ¶ 61,127 (2010); *Cedar Creek Wind, LLC*, 137 F.E.R.C. ¶ 61,006 (2011)).

209. 151 F.E.R.C. ¶ 61,110 at PP 29-32 (citing 18 C.F.R. § 292.309(d)(1) (2014)); *see also* Order No. 688, *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, F.E.R.C. STATS. & REGS. ¶ 31,233, at P 72 (2006), *order on reh'g*, F.E.R.C. STATS. & REGS. ¶ 31,250, at P 94 (2007), *appeal denied sub nom.* Am. Forest and Paper Assoc. v. FERC, 550 F.3d 1179 (D.C. Cir. 2008).

210. 151 F.E.R.C. ¶ 61,110, at P 29.

211. *Id.* at P 30; Order No. 688, *supra* note 214, at P 72.

212. *Id.* at P 34.

213. *Id.* at P 35; 18 C.F.R. § 292.309(c) (2014) ("A qualifying facility may seek to rebut the presumption of access to the market by demonstrating, inter alia, that it does not have access to the market because of operational characteristics or transmission constraints.").

was a legally enforceable obligation between Twin Cities and NSPM prior to NSPM's application for termination of its PURPA mandatory purchase obligation.

#### VI. MISCELLANEOUS

On April 27, 2015, the FERC issued an order instituting an investigation into the justness and reasonableness of Southern Companies' (Southern) market-based rates.<sup>214</sup> In its order, the FERC found that Southern displayed the potential to exert horizontal market power and that the mitigation proposal filed by Southern in the proceeding may not be effective to mitigate the market power potential. As a result, the FERC issued an order directing Southern to: (1) show cause as to why the FERC should not revoke Southern's MBR authority; (2) file a mitigation proposal specifically tailored for the circumstances; and (3) adopt other mitigation measures.<sup>215</sup> Upon review of Southern's updated market power analysis, the FERC found that the companies passed the pivotal supplier screen in all of the relevant BAAs but failed to pass the wholesale market share screens for the Southern, PowerSouth, Santee Cooper, SCEG, and Tallahassee BAAs.<sup>216</sup> The FERC found that the auction procedures that Southern established to mitigate market power concerns potentially were not effective given the limited number of transactions and participants in the auction and Southern's high prices for sales in relation to the prices of other sellers in the balancing areas.<sup>217</sup> The FERC's reviews of EQR data also revealed Southern's volume weighted prices were consistently higher than those of other competitors.<sup>218</sup>

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214. *Alabama Power Co.*, 151 F.E.R.C. ¶ 61,071 (2015).

215. *Id.* at P 2.

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

217. *Id.* at P 18.

218. *Id.* at P 20.

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