119 FERC ¶ 61,318
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

PJM Interconnection, L.L.C. Docket Nos. ER05-1410-002
EL05-148-002
ER05-1410-003
EL05-148-003

ORDER ON REHEARING AND CLARIFICATION
AND
ACCEPTING COMPLIANCE FILING

(Issued June 25, 2007)

Paragraph Numbers

1. In this order, the Commission denies rehearing in part and grants rehearing in part, and grants clarification in part of an earlier order[1] in which the Commission approved, with conditions, a Settlement filed by PJM Interconnection, L.L.C. (PJM) and PJM market participants concerning PJM's Reliability Pricing Model (RPM). The Commission also accepts a related compliance filing.

2. The Commission affirms its finding that the RPM market design is a just and reasonable method of managing resource adequacy and ensuring reliable energy supplies within PJM. The RPM market design provides greater assurance of a stable and sustainable supply of capacity resources than PJM's current capacity mechanism by establishing locational pricing to reflect the actual costs of capacity resources within specific service areas and a forward procurement requirement to ensure stability for both capacity buyers and capacity sellers. RPM also provides for integration of generation, transmission, and demand response into the determination of supply needs and prices, as well as setting up a process for considering the inclusion of energy efficiency.

[1] *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 (2006) (December 22 Order).

3. RPM provides load serving entities (LSEs) with two options to meet their energy supply requirements, a fixed resource self-supply option and a requirement based on a downward sloping demand curve. The second option establishes prices based on generator bids and the use of a downward sloping demand curve that replaces the vertical demand curve used in PJM's current auction. The downward sloping demand curve is designed to reflect the increased value provided by additional energy resources and to reduce the price volatility of the current vertical demand curve. The downward sloping demand curve is based on the cost of new entry and is adjusted over time as those costs change. The fixed resource requirement permits LSEs to provide capacity through their own generation or other means (*e.g.* through contracts) sufficient to meet PJM's reserve margin. Further, RPM includes explicit rules governing market power mitigation in the capacity market to address the potential for increased market power for both generators and load within the newly established Locational Deliverability Areas.

4. Parties seeking rehearing present a range of objections to RPM, each of which we address below. These issues include legal objections, such as lack of jurisdiction, as well as issues relating to locational pricing, forward procurement, the shape and slope of the demand curve, the determination and adjustment of the cost of new entry, and mitigation procedures for protecting consumers against possible market power. We concluded in the December 22 Order, upon consideration of all protested elements of the RPM Settlement, that the Settlement represents a just and reasonable design for a new PJM capacity market. With one exception, we reaffirm our holdings.

I. <u>Background</u>

5. The background of this proceeding is set out in greater detail in the Commission's prior orders in this proceeding.[2]

6. PJM operates the largest competitive wholesale electricity market in the country, covering 14 states, from the Eastern seaboard as far south as North Carolina and as far west as Chicago. This system has eliminated barriers between regional utilities, providing for a more efficient sharing of resources and enabling parties to more easily access the cheapest sources of electricity from within the PJM footprint. To protect customers against the possibility of losing service, PJM is responsible for ensuring that its system has sufficient generating capacity to meet its reliability obligations. In particular,

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[2] *See* December 22 Order, 117 FERC ¶ 61,331 at P 8-23; *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 at P 9-17 (2006) (April 20 Order).

PJM must address specific reliability concerns that may arise in localized areas within its regional control.[3]

7. After extensive discussions within the membership of PJM, on August 31, 2005, PJM filed its original RPM proposal (the August 31 filing) to revise its markets to deal with current and projected violations of its reliability requirements.

A. PJM's August 31 Filing

8. In its August 31 filing, PJM stated that it oversees the capacity obligations of its LSEs to ensure that they have sufficient generating capacity to satisfy their reliability responsibilities.[4] For some years, PJM stated, it had experienced intermittent difficulty in meeting reliability requirements in localized areas, and it expects this problem to expand to other areas as well.[5] PJM together with its stakeholders developed a comprehensive approach to both retaining existing generation and establishing prices that, PJM believed, would encourage the entry of resources to resolve reliability problems.

9. Currently, PJM's Reliability Assurance Agreements and Operating Agreement require each LSE within PJM to procure its share of the Installed Reserve Margin which, for each LSE, is equal to a specified amount of capacity above its forecasted peak load. This additional amount is determined by the PJM Board, and currently is equal to 15 percent of the forecasted peak load.[6] This requirement is intended to ensure the availability of sufficient capacity to guarantee reliability. In its August 31 filing made under sections 205 and 206 of the Federal Power Act (FPA),[7] PJM proposed to replace its existing capacity obligation rules with its RPM construct. PJM stated that its existing

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[3] *See D.C. Pub. Serv. Comm'n*, 114 FERC ¶ 61,017 (2006) (for discussion of areas within the PJM system that are defined by physical constraints).

[4] PJM determines its Installed Reserve Margin (the amount of reserve capacity it requires to ensure reliability throughout its system), and also determines the share of Installed Reserve Margin for which each LSE within PJM is responsible. Each LSE must demonstrate that it can provide sufficient generation capacity to meet its projected peak load, and to procure its share of PJM's Installed Reserve Margin.

[5] August 31 filing, Transmittal at 5.

[6] April 20 Order, 115 FERC ¶ 61,079 at P 9 n.7.

[7] 16 U.S.C. §§ 824d and 824e (2000).

capacity market had become unjust and unreasonable, in that the current construct could no longer ensure that PJM would meet its reliability obligations.

10. According to PJM, it had experienced steady load growth for several years, at the same time that many generators had retired due to their inability to recover sufficient revenues to cover their costs.[8] PJM stated that, as a result of these supply problems, it anticipated degraded reliability in Eastern PJM, particularly in New Jersey, the Delmarva Peninsula and the Baltimore-Washington area.[9] PJM stated that multiple reliability criteria violations in PJM, particularly in New Jersey, have occurred recently, primarily due to generation retirements.[10] However, PJM also viewed the potential for reliability criteria violations as not limited to New Jersey. PJM contended that present trends, if continued, would lead to violations in other areas of PJM where similar conditions exist.[11] PJM further reported a spike in generation retirements within PJM.[12]

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[8] PJM, August 31, 2005 filing, Affidavit of Joseph Bowring, Tab G (PJM August 31 filing, Bowring Affidavit) at 15, Affidavit of Steven Herling Affidavit, Tab F (PJM August 31 filing, Herling Affidavit) at 7-8.

[9] April 20 Order, 115 FERC ¶ 61,079 at P 11.

[10] PJM contends that much of PJM's generation fleet is very old (and thus, may soon be retired). "The PJM system has thousands of megawatts of generation units tied up in aging infrastructure. . . . 75 percent of steam generators are 30 years or older, with 20 percent 50 years or older." Statement of Audrey Zibelman, PJM Executive Vice President and Chief Operating Offer, at Technical Conference on Reliability Pricing Model in Docket Nos. ER05-1410-000 and EL05-148-000, February 2, 2006.

[11] PJM estimated that in New Jersey load will increase by 1,950 megawatts (9.8 percent) between 2005 and 2010, but that generation additions are not expected to keep pace. In 2003 and 2004, only 51 megawatts of new generation were constructed in New Jersey, and only 1,340 megawatts are under construction. PJM further alleged that load growth in the Delmarva Peninsula was projected to be 2.7 percent per year, or an increase of 573 megawatts over the next five years, but planned generation additions were minimal. Only 60 megawatts were added on the Delmarva Peninsula in 2004, and 150 megawatts were at that time being studied. In the Baltimore-Washington area, only 77 megawatts were added in 2004, and PJM reported no additions being currently studied. *See generally* August 31 filing, Herling Affidavit at 7-8.

[12] Between 1999 and 2002, 274 megawatts were retired in the Mid-Atlantic region. By contrast, from January 1, 2003 through June 22, 2005, 1,709 megawatts have been

(continued)

11. As noted in the April 20 Order, PJM had previously made extensive efforts to develop a stakeholder consensus to address its capacity problems. Ultimately, PJM's August 31 filing proposed to address the ineffectiveness of its current capacity market in eliciting a sufficient capacity supply in a number of ways. First, PJM stated that, because its current construct was based on short-term capacity commitments, capacity resources were unable to anticipate a sufficient revenue stream to meet their going-forward costs, and in this way the current construct does not accurately reflect the value that capacity resources bring to the system by providing reliability.[13] PJM proposed to address this problem by requiring LSEs to make commitments to purchase capacity four years ahead, rather than one day ahead as is the case under the current requirement. LSEs would also be required to commit to purchase capacity for at least one year's duration.[14] To meet the capacity needs of LSEs that failed to procure enough capacity through self-supply or bilateral contracts, PJM proposed to hold an auction each year, in which PJM would procure the remainder of the capacity requirement. If adequate resources were not committed through the auctions for four consecutive delivery years, PJM stated that it would conduct a reliability backstop auction to ensure that sufficient capacity is procured.[15]

12. PJM also stated that its current capacity market is flawed because it allows LSEs to fulfill their capacity obligations by contracting with resources located anywhere within PJM, regardless of whether generation from those resources is actually deliverable to those LSEs' customers, or whether transmission constraints would prevent delivery. Thus, there is no price difference among resources in different locations to signal whether

retired, and an additional 1,694 megawatts are proposed for retirement between 2006 and 2008. Of the retirements effectuated since 2003, and including those currently proposing to retire, forty percent are located in New Jersey. According to PJM, owners of retired generation pointed to excess generation in the western region of PJM and their inability to compete economically. PJM's witness Mr. Herling stated that these retirements have led to identified reliability criteria violations for 2005 and each succeeding year in the most recent planning horizon, and that one hundred and one megawatts of generation were retired in the Baltimore-Washington area in 2003, resulting in likely reliability criteria violations for the Baltimore-Washington area and the Delmarva Peninsula in 2008. *Id*.

[13] April 20 Order, 115 FERC ¶ 61,079 at P 24.

[14] *Id*. P 14.

[15] *Id*. P 55.

that capacity is more or less valuable due to its location. PJM proposed to establish up to 23 capacity zones, or Locational Deliverability Areas,[16] and require LSEs to procure capacity from resources that would be deliverable to that LSE's Locational Deliverability Area.

13. PJM also proposed to integrate its capacity procurement program with its Regional Transmission Expansion Planning protocol and with demand side response, so that LSEs could satisfy their capacity obligations through purchasing capacity, merchant transmission upgrades, or development of demand side response. PJM would also conduct a Base Residual Auction four years before the start of each year (the Delivery year) to enable commitment of capacity resources needed to satisfy remaining capacity needs of LSEs after taking account of their owned and contracted resources.

14. As to the amount of capacity that PJM would require LSEs to purchase and the price for that capacity, PJM proposed to establish a Variable Resource Requirement for the LSEs in each Locational Deliverability Area. The auction clearing model would set prices based on locational constraints, the submitted supply offers, and a Variable Resource Requirement curve. Thus, depending on the amount of supply offered, the capacity requirement could be more, less, or the same as the Installed Reserve Margin under the current construct. The Variable Resource Requirement curve provided for a price equal to the Cost of New Entry of a new peaking unit when the amount of capacity to be supplied is one percent greater than the Installed Reserve Margin, with prices rising when the amount of the capacity within the Locational Deliverability Area fell, but falling when the amount of capacity within the Locational Deliverability Area rose.[17]

15. Finally, PJM's proposal endorsed allowing LSEs that are able to fully supply their own capacity needs to choose not to participate in the RPM program, and instead to use a long-term Fixed Resource Requirement option. Such LSEs would be required to procure

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[16] *See* Appendix A of the December 22 Order, 117 FERC ¶ 61,331 for the 23 Locational Deliverability Areas proposed by PJM.

[17] Under PJM's August 31 proposal, when a Locational Deliverability Area's capacity level was more than 116 percent of peak load (*i.e.*, one percent greater than the Installed Reserve Margin), the price would fall until a capacity level of 120 percent of peak load is reached, at which point the price would fall to zero; at capacity levels less than 116 percent, however, the price would increase until the capacity level falls to 112 percent of peak load, at which point the price would reach two times the Cost of New Entry. April 20 Order, 117 FERC ¶ 61,331 at P 89-90.

the full amount of their capacity needs in advance for a one-year period, so that they would not need to take advantage of PJM's four-year-ahead procurement auction.[18]

B. April 20 Order and Initiation of Settlement Proceedings

16. In the April 20 Order, the Commission found PJM's existing capacity market to be unjust and unreasonable due to a combination of factors, and accepted certain elements of PJM's RPM proposal, but required further proceedings to resolve the remaining issues.

17. The Commission stated that PJM's existing market rules fail to set prices adequate to ensure sufficient supply.[19] PJM’s current market rules establish a single market for supply, but this structure does not assure that the supply is available to all local areas. Further, PJM had stated that current market revenues are likely to be insufficient to sustain continued and future investment.[20] PJM demonstrated that in some areas, under the current system, the addition of new generating units to the system would lag dramatically behind the anticipated growth in demand. PJM's current rules also create significant price volatility for electric supply. Generating units can easily leave and re-enter the markets, for periods as short as a single day. Therefore, prices spike as soon as the supply of generation falls below the minimum needed to meet reliability criteria, and then fall to zero as soon as the supply rises above that required minimum. PJM asserts that generators are reluctant to invest in new plants, or retain existing plants, under conditions of such extreme volatility.

18. Based on this record, the Commission found in the April 20 Order that PJM’s existing market for supply was unjust and unreasonable, and established further

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[18] *Id.* P 91 and 101.

[19] *Id.* P 1-6.

[20] *See* August 31 filing, Bowring Affidavit, at 12, 15 (net generator revenue in PJM has been insufficient to cover the full costs of investment for "several years"). Mr. Bowring provided the following figures regarding the annual average revenues of generating units from 1999 to 2004: the average cost of new entry (20-year nominal levelized annual cost) for a new combustion turbine unit is $72,000/megawatt, while the average annual net revenue from such a unit is $44,000 per megawatt; the average cost of new entry for a combined cycle unit is $93,500/megawatt, while the annual net revenue from such a unit is $77,000 per megawatt; the average cost of new entry of a coal unit is $208,000/megawatt; annual net revenue from such a unit is $142,000 per installed megawatt.

proceedings to determine a just and reasonable replacement for the existing market structure. The Commission stated:

> PJM has shown that the existing construct will, in the future, fail to achieve the intended goal of ensuring reliable service. It does not enable market participants to see the reliability problems in particular locations, does not provide price signals that would elicit solutions to reliability problems in enough time before the problems occur, and does not allow transmission and demand response to compete on a level playing field with generation to solve reliability problems. These factors, in conjunction with other factors (such as load growth in particular locations, and the lack of price signals sent by the energy markets) render PJM's current construct unreasonable on a long-term basis. While one or more of the elements of PJM's current capacity construct may exist and be just and reasonable in other regional transmission organizations, the Commission finds the combination of these elements, results in an unjust and unreasonable capacity construct within PJM.[21]

19. We also found, however, that we could not approve PJM's August 31 filing:

> While the Commission has determined that the capacity construct as it currently exists is unjust and unreasonable, it cannot at this time determine that the RPM capacity construct is a just and reasonable substitute. . . . [T]he Commission finds that while the collective elements of RPM may provide a just and reasonable solution, many aspects of those elements need to be further analyzed and clarified before the Commission can rule on this matter.[22]

Therefore, the Commission required additional proceedings, namely, a technical conference and a paper hearing, to develop further facts to enable the Commission to rule conclusively on the August 31 filing.

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[21] April 20 Order, 115 FERC ¶ 61,079 at P 29.

[22] *Id*. P 37.

20. While these additional proceedings were taking place, on May 17, 2006, the Commission granted a motion by American Forest & Paper Association (AFPA) to set this case for settlement judge proceedings. From June through September 2006, the parties engaged in intensive settlement negotiations, with more than 65 parties participating in the extensive settlement discussions for over 25 days, and reached a settlement (Settlement) that was widely supported. The parties supporting or not opposing the Settlement included a broad segment of PJM stakeholders, including generators, LSEs, municipalities, as well as five state commissions and two consumer groups.[23]

21. On September 29, 2006, pursuant to Rule 602 of the Commission's Rules of Practice and Procedure,[24] PJM and the Settling Parties filed the Settlement with the Commission.[25]

C. <u>December 22 Order</u>

22. On December 22, 2006, the Commission issued an order approving the Settlement, subject to certain conditions.

23. We first found that:

> the Settlement, with a few changes, will result in continued provision of reliable energy supplies within PJM at just and reasonable rates. Based on the evidence supplied by the parties, the Settlement is expected to provide greater incentives for new generation, transmission, and demand response, while also providing sufficient revenues to retain existing resources that are needed. The evidence submitted shows that the Settlement is forecasted to enable PJM to meet its reliability obligations 95 percent of the time, as compared with a forecast of only 52.2 percent under its existing market structure. It also projects that the overall cost of the

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[23] For a list of the parties who either joined the Settling Parties or agreed not to oppose the settlement, *see* Appendix B to the December 22 Order, 117 FERC ¶ 61,331.

[24] 18 C.F.R. § 385.602 (2006).

[25] The Settlement included revisions to the PJM Tariff, Operating Agreement, and Reliability Assurance Agreement, and an Explanatory Statement.

> Settlement provisions will be less than what would be incurred under PJM's existing mechanisms.[26]

24. The Commission also discussed the major provisions of the Settlement, including: (1) the creation of 23 separate Locational Deliverability Areas within PJM, such that LSEs providing electricity to customers within each Locational Deliverability Area must purchase supply that is deliverable within that area; (2) a requirement that companies providing service to customers must contract with suppliers three years in advance; (3) an auction market that will set prices for capacity through a demand curve that reflects the reliability value of supply; (4) the option of permitting utilities that prefer not to participate in the auction market and that meet certain other requirements to avoid the auction process by procuring a pre-determined amount of supply sufficient to ensure reliability for their customers; (5) the requirement that utilities may supply their energy needs through a combination of generation, transmission, and demand response; and (6) mitigation rules and incentives for new entry that would prevent the exercise of market power by sellers.[27]

25. Under the Settlement, PJM is to use a Variable Resource Requirement curve (Settlement Curve) to clear the RPM capacity auctions, as had been proposed in the August 31 filing. In both the proposed curve in the August 31 filing and the Settlement Curve, the price for capacity would increase as the amount of capacity falls below the Installed Reserve Margin, and would decrease as the amount of capacity exceeds the Installed Reserve Margin. PJM stated, however, that the Settlement Curve was designed as a general matter to yield lower prices than the August 31 Curve would have elicited, as either capacity surpluses or capacity shortages increase. PJM also stated that it anticipated that, like the August 31 Curve, the Settlement Curve would lead to reserve levels meeting or exceeding the Installed Reserve Margin.[28] Under the Settlement, PJM is required to determine the Cost of New Entry, which would establish the Variable Resource Requirement curves of the proposed Locational Deliverability Areas, on an administrative basis for the transition period at the levels proposed in the August 31

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[26] December 22 Order, 117 FERC ¶ 61,331 at P 6, *citing* Settlement Explanatory Statement, Supplemental Affidavit of Benjamin F. Hobbs, filed September 29, 2006 (Settlement Explanatory Statement, Hobbs Supplemental Affidavit) at 4. *See also* PJM, October 30, 2006 Reply Comments, Supplemental Affidavit of Benjamin Hobbs.

[27] *Id*. P 6.

[28] Settlement Explanatory Statement at 7-9.

filing.[29] The Settlement further provided that, in subsequent delivery years, the Cost of New Entry would be adjusted to reflect empirical information on actual capacity market activity when there is a "net demand for new resources" over three consecutive delivery years (the "empirical Cost of New Entry" or "E-CONE" mechanism).[30] Entities that prefer not to participate in the auctions and that meet certain other requirements may elect instead the long-term Fixed Resource Requirement option, if they can demonstrate the capacity to satisfy their entire capacity obligation for all load, including load growth, in the applicable Fixed Resource Requirement service area for the term of their participation in the Fixed Resource Requirement alternative.[31]

26. The Commission approved the use of the Settlement Curve as just and reasonable. It first stated that a downward-sloping demand curve would reduce capacity price volatility and increase the stability of the capacity revenue stream over time and that the lower price volatility under the sloped demand curve would render capacity investments less risky, thereby encouraging greater investment and at a lower financing cost.[32] The Commission then found that, although the Settlement Curve differed from the original Variable Resource Requirement curve proposed by PJM in its August 31 filing, it would also provide for just and reasonable prices for capacity to meet PJM's reliability needs. In so finding, the Commission relied on the testimony of PJM's witness Dr. Benjamin F. Hobbs, who stated that, according to his analysis, the Settlement Curve would meet or exceed PJM's reliability requirements 95.2 percent of the time.[33]

27. The Settlement also retained a forward commitment of capacity as proposed in the August 31 filing, but reduced the period of time of commitment from four to three years. The commitment period for capacity offered into the Base Residual Auction remains one year, as originally proposed by the August 31 filing. However, the Settlement also proposed a New Entry Price Adjustment, under which certain new entrants in small Locational Deliverability Areas where new entry has significant impact on prices may opt to receive their first-year clearing price for up to two additional years if certain conditions

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[29] December 22 Order, 117 FERC ¶ 61,331 at P 25-26.

[30] *Id.* P 27.

[31] *Id.* P 36.

[32] *Id.* P 75.

[33] *Id.* P 80-81.

are met.[34] The Commission found that the New Entry Price Adjustment balanced the need to ensure that efficient entry in small Locational Deliverability Areas is not unduly discouraged, and that all suppliers receive a market clearing price that reasonably reflects value.[35]

28. The Settlement further retained the creation of Locational Deliverability Areas, as proposed in the August 31 filing,[36] and required the parties to establish additional processes within PJM to pursue and support demand response and incorporate energy efficiency applications in RPM.[37] The Commission approved the Settlement's proposed locational provisions and transitional proposal (under which there would be four Locational Deliverability Areas for each of the three transition years, and 23 by year four) finding this proposal just and reasonable as providing appropriate price signals to provide incentives to construct facilities necessary for regional reliability, and finding the transition useful as allowing market participants a period of time to understand and become accustomed to the dynamics of the new capacity market prior to its full implementation.[38]

29. Additionally, the Settlement provided two aspects of mitigation that apply to Settling Parties only. First, during the three year transition period, signatories in certain circumstances were to have higher default bids than non-signatories. Second, signatories that must make a project investment to comply with a government requirement were to have more options for adjusting their default competitive bids to reflect investment cost recovery than non-signatories.[39] The Commission conditioned its approval of the Settlement on the filing by PJM of changes to the provisions that discriminate between signatories and non-signatories, changes to the provisions giving inappropriate discretion to the PJM Market Monitor, and changes to enable a greater number of resources expeditiously to recover the costs of complying with state-mandated requirements. The Commission also required PJM to conduct a forum for discussions to identify and rectify

[34] *Id.* P 28.

[35] *Id.* P 92.

[36] *Id*. P 29-30.

[37] *Id*. P 32.

[38] *Id.* P 68.

[39] *Id.* P 35.

barriers to entry of demand response within 60 days of the date of the December 22 Order, and to file a report on the status of the additional process for pursuing demand response and incorporating energy efficiency applications within 240 days of the date of the December 22 Order.[40]

30. The Commission also dismissed the majority of the issues raised in petitions for rehearing of the April 20 Order. With regard to requests for rehearing of the Commission's April 20 Order, we noted that the Settlement replaced the RPM proposal filed by PJM on August 31 as a complete proposal for a replacement for its existing tariff provisions, and as a result, we found the requests for rehearing of that order to be moot and dismissed them.[41] Ultimately, the Commission approved the Settlement while requiring certain compliance filings. The Commission required PJM to submit, within 30 days of the December 22 Order, a compliance filing that provides equivalent treatment to all similarly-situated parties with regard to certain mitigation provisions.[42]

D. Withdrawals from the Settlement

31. After issuance of the December 22 Order, three parties who had previously been signatories to the Settlement indicated their intention to withdraw from the Settlement. Mittal Steel USA, Inc. (Mittal Steel), PJM Industrial Customer Coalition (PJMICC), and Portland Cement Association notified the Commission of their withdrawal on January 8, 2007. The D.C. Office of the People's Counsel and American Municipal Power – Ohio (AMP-Ohio) notified the Commission on January 8, 2007 and January 22, 2007, respectively, of their withdrawal from their earlier commitments not to oppose the Settlement. All withdrawing parties cited, as reasons for their withdrawal, the new conditions that the Commission imposed on the Settlement.

E. Requests for Rehearing and/or Clarification and Motions Regarding the December 22 Order

32. Coral Power, LLC (Coral), and Maryland Office of People's Counsel (MPC) sought rehearing of the December 22 Order. New Jersey Board of Public Utilities (New

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[40] *Id*. P 7.

[41] *Id*. P 40-42.

[42] *Id.* Ordering Paragraph B. The Commission also required additional compliance filings (*see* Ordering Paragraphs C through F).

Jersey Commission), Indicated Buyers,[43] and the PSEG Companies (PSEG) sought rehearing or clarification. Mittal Steel filed a motion to vacate the December 22 Order, or, in the alternative, a request for rehearing. The PJMICC filed a motion for stay and request for rehearing and clarification.

33. PJM, Pepco Holdings, Inc. (PHI) and Capacity Buyers/Suppliers[44] sought to file answers to the requests for rehearing. Mittal Steel filed an answer to the answers of PJM and Capacity Buyers/Suppliers, and PSEG filed an answer to PJM's answer. PJM then filed an answer to Mittal Steel's answer.

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[43] Indicated Buyers include Allegheny Electric Cooperative, Inc.; American Forest & Paper Association; Blue Ridge Power Agency; North Carolina Electric Membership Corporation; Office of the People's Counsel for the District of Columbia; Old Dominion Electric Cooperative; Pennsylvania Department of Environmental Protection; Pennsylvania Office of Consumer Advocate; Pennsylvania Public Utility Commission; Portland Cement Association; Southern Maryland Electric Cooperative, Inc.; and Virginia Municipal Electric Association.

[44] Capacity Buyers and Suppliers include Constellation Energy Commodities Group, Inc., Baltimore Gas and Electric Company, Calvert Cliffs Nuclear Power Plant, Inc., Constellation Generation Group, LLC, Constellation NewEnergy, Inc., Constellation Power Source Generation, Inc., and Handsome Lake Energy, LLC (collectively, Constellation); Dominion Energy Marketing, Inc., Virginia Electric and Power Company, Dominion Retail, Inc., Armstrong Energy Limited Partnership, LLLP, Elwood Energy, LLC, Fairless Energy, LLC, Pleasants Energy, LLC, Dresden Energy, LLC, Kincaid Generation, LLC, and State Line Energy, LLC (collectively, Dominion); Duke Energy North America, LLC (Duke Energy); Edison Mission Energy, Edison Mission Marketing & Trading, Inc., and Midwest Generation EME, LLC (collectively, Edison Mission); Exelon Corporation, Exelon Generation, Commonwealth Edison Company, and PECO Energy Corporation (collectively, Exelon); FPL Energy Marcus Hook, L.P., North Jersey Energy Associates, L.P., Doswell Limited Partnership, Backbone Mountain Windpower LLC, Mill Run Windpower LLC, Somerset Windpower LLC, Meyersdale Windpower LLC, Waymart Wind Farm, LP, and Pennsylvania Windfarms, Inc. (collectively, FPL Energy Generators); Mirant Energy Trading, LLC, Mirant Chalk Point, LLC, Mirant Mid-Atlantic, LLC, Mirant Potomac River, LLC, and Mirant Sugar Creek, LLC (collectively, Mirant); and Reliant Energy, Inc. for Orion Power Midwest, L.P., Reliant Energy Electric Solutions, LLC, Reliant Energy Services, Inc., Reliant Energy Seward, LLC, Reliant Energy Solutions East, LLC, and Reliant Energy Wholesale Generation, LLC (collectively, Reliant).

F. January 22, 2007 Compliance Filing

34. On January 22, 2007, PJM made a compliance filing as directed by the December 22 Order. In that filing, PJM submitted revisions to its Open Access Transmission Tariff and the Reliability Assurance Agreement among LSEs in the PJM region. The revisions were made within 30 days of the December 22 Order, as ordered.

35. The filing was noticed in the Federal Register,[45] with interventions, comments or protests due by February 12, 2007. Mittal Steel filed a motion to reject the compliance filing, or, in the alternative, a protest. PJM filed an answer to Mittal Steel's motion to reject the filing.

II. Requests For Rehearing And/Or Clarification And Motions With Regard To December 22 Order

A. Procedural Issues

36. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2006), prohibits a reply to a reply, unless otherwise ordered by the decisional authority. We will accept PJM's, Capacity Buyers/Suppliers' and PHI's answers, Mittal Steel's and PSEG's answers to those answers, and PJM's answer to Mittal Steel's answer, because they have provided information that assisted us in our decision-making process.

B. Legal Issues

1. Commission's Jurisdiction over Resource Adequacy

Positions of the Parties

37. Mittal Steel and PJMICC challenge the Commission's jurisdiction over resource adequacy and, therefore, the Commission's authority to accept the RPM Settlement Agreement. Mittal Steel and PJMICC argue that RPM intrudes upon the development of resource adequacy that historically has been the province of the states. These parties also contend that this reservation of resource procurement authority to the states was reaffirmed by Congress in the Energy Policy Act of 2005 (EPAct 2005).[46] By making

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[45] 72 Fed. Reg. 4,500 (2007).

[46] Energy Policy Act of 2005, Pub. L. No. 109-58, §§ 1261 *et seq.*, 119 Stat. 594 (2005) (amending section 215(i)(2) and (3) of the FPA).

RPM part of the PJM tariff, Mittal Steel and PJMICC argue, the Commission is overstepping its Congressional mandate. Further, Mittal Steel argues that if the Commission really believes that RPM does not intrude into state jurisdiction over resource adequacy because it may not necessarily prompt the construction of new generation, then the Commission should not have approved RPM as just and reasonable.[47]

38. PJMICC also argues that RPM's reliability backstop auction is inconsistent with EPAct 2005 because it usurps state jurisdiction over resource adequacy. Similarly, argues PJMICC, RPM's forward procurement auction forces LSEs to either construct generation or confront financial consequences for not doing so. Further, PJMICC contends that the administratively determined demand curve, which will set standards for resource adequacy, intrudes upon state authority and is not merely a means of meeting the 1-day-in-10-years reliability standard.[48] Finally, although Mittal Steel and PJMICC acknowledge that RPM offers a long-term Fixed Resource Requirement, they argue that the Commission is not preserving the states' jurisdiction over resource adequacy because the Commission is determining the conditions under which states can exercise control over resource adequacy decisions.

39. PJM responds to these allegations that the Commission lacks jurisdiction over resource adequacy by arguing that any limitations imposed by EPAct 2005 would only be relevant to this proceeding if the Commission based its authority upon EPAct 2005, which PJM asserts is not the case. PJM argues that the Commission has clear authority under FPA sections 205 and 206 over such sales for resale in interstate commerce, and the rules, conditions, and practices affecting such sales. Additionally, the Commission derives its authority to reform PJM's capacity rules from the Commission's authority over multi-state electric pooling, reserve-sharing and organized market agreements. Further, PJM argues that it is well-settled that LSEs that rely on regional sharing of resources to help assure service to their loads are properly subject to regional rules on the resources they must provide. Moreover, PJM states, the EPAct 2005 provision cited by Mittal and PJMICC merely confirms that the statutory provision does not change the

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[47] Mittal Steel's request for rehearing at 9-10 ("if the Commission believes [that RPM will not cause new generation to be constructed,] it has no business approving RPM as generating just and reasonable rates. . . .").

[48] Under the 1-day-in-10-years reliability standard, the probability of disconnecting any firm load due to resource inadequacy must not exceed, on average, once in ten years.

Commission's pre-existing authority; the provision neither adds to, nor detracts from, the Commission's pre-existing authority from other sources.

Commission Determination

40. Parties seeking rehearing regarding the issue of whether the Commission has jurisdiction over resource adequacy argue that this is a state rather than a federal concern. The Commission has addressed this subject in recent orders[49] by first acknowledging that this question of jurisdiction over resource adequacy is a complex matter that stands at "the confluence of state-federal jurisdiction."[50] While we recognize the traditional role of state and local entities in regulating resource adequacy, we are also aware of our responsibilities under the FPA to ensure that adequate service is provided, and that wholesale rates are just and reasonable. We will defer to state and local entities' decisions when possible on resource adequacy matters, but in doing so we will not shirk our congressionally-mandated responsibilities. We find that resource adequacy can have a significant effect on wholesale rates and service and, therefore, is subject to Commission jurisdiction.

41. The parties cite to certain of the savings provisions of the EPAct 2005 which they assert do not "authorize the [Electric Reliability Organization][51] or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or

[49] See, *e.g.*, *ISO New England, Inc. and New England Power Pool*, 118 FERC ¶ 61,157, at P 15– 21 (2007) (*ISO New England III*); *Cal. Indep. Sys. Operator, Corp*., 116 FERC ¶ 61,274, P 1112 – 19 (2006) (*CAISO III*), *order on reh'g*, 119 FERC ¶ 61,076, P 212-22 (2007). Also, in *Connecticut Department of Public Utility Control v. Federal Energy Regulatory Commission* (*CT DPUC*), 2007 U.S. App. LEXIS 9119, *5 (April 20, 2007), the D.C. Circuit recently remanded a case involving similar jurisdictional questions to the Commission, for failure to explain the basis on which the Commission exercises jurisdiction over resource adequacy. The court's remand, however, was based solely on the agency's failure to present its explanation of its jurisdiction in its orders; the court did not address the substantive question of the Commission's jurisdiction.

[50] *CAISO III*, 116 FERC ¶ 61,274 at P 1112.

[51] On July 20, 2006, the Commission certified the North American Electric Reliability Corporation (NERC) as the single Electric Reliability Organization for the United States. *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

services."[52] These provisions expand the Commission's jurisdiction over the reliability of the nation's electric grid, while allowing states to take action to preserve facility safety and adequacy. They do not remove any authority of the Commission under the FPA to establish just and reasonable rates and terms and conditions for services subject to its jurisdiction. Section 201(b)(1) of the FPA confers jurisdiction on the Commission over the transmission of electric energy in interstate commerce, and sales of electric energy at wholesale in interstate commerce.[53] Further, section 205(a) of the FPA states:

> All rates and charges made, demanded, or received by any public utility for or in connection with the transmission or sale of electric energy subject to the jurisdiction of the Commission, and all rules and regulations affecting or pertaining to such rates or charges shall be just and reasonable, and any such rate or charge that is not just and reasonable is hereby declared to be unlawful.[54]

42. Thus, the FPA confers upon the Commission the responsibility for ensuring that wholesale rates and charges, including any rule, regulation, practice or contract affecting them are just and reasonable and not unduly discriminatory. The Commission finds that the resource adequacy in PJM and the resource requirements set forth in RPM directly affect wholesale rates and therefore are subject to Commission jurisdiction.

43. This determination of jurisdiction is consistent with court decisions regarding the Commission's jurisdiction over capacity requirements and charges. In *Mississippi Industries v. FERC*,[55] the U.S. Court of Appeals for the D.C. Circuit recognized the connection between the allocation of capacity and wholesale rates. In that proceeding, the Commission had altered the allocation of capacity and costs of a nuclear generation

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[52] Mittal Steel, Jan. 22, 2007, Motion to Vacate at 9.

[53] 16 U.S.C. § 824(b)(1)(2000).

[54] 16 U.S.C. § 824d (2000). FPA section 206 gives the Commission the ability to review "any rate, charges, or classification" charged by a public utility for any transmission or sale subject to the jurisdiction of the Commission, as well as any rule, regulation, practice or contract affecting such rate, charge, or classification . . . ." 16 U.S.C. § 824e (2000).

[55] 808 F.2d 1525, 1542, *vacated in part on other grounds*, 822 F.2d 1103 (D.C. Cir. 1987) (*Mississippi Industries*).

plant among operating companies of an integrated utility system. Petitioners asserted that, in allocating the cost and capacity of the nuclear plant, the Commission had asserted jurisdiction over generating facilities in direct violation of the FPA section 201(b) prohibition against Commission regulation of generating facilities. Petitioners asserted that "reallocating generation costs falls outside of FERC's rate making jurisdiction and instead falls solely within state authority over generation."[56] The court rejected the claim that this action was beyond the Commission's FPA jurisdiction. Instead, it found that the Commission has authority over the allocation of capacity among market participants because this allocation affects wholesale rates. The court stated, "[c]apacity costs are a large component of wholesale rates" and, therefore, the share of the capacity costs of the system carried by each affiliate will significantly affect the wholesale price it pays for energy.[57] The allocation of capacity did not set sales prices, but it directly affected costs and "consequently, wholesale rates"[58] and therefore "FERC's jurisdiction under such circumstances is unquestionable."[59] The court further noted that:

> Petitioners ignore the critical point here that, while these provisions [allocating capacity] do not fix wholesale rates, their terms do directly and significantly affect the wholesale rates at which the operating companies exchange energy, due to the highly integrated nature of the system.[60]

44. Subsequently, in *Municipalities of Groton* v. *FERC*,[61] the court upheld the Commission's authority to review section 9.4(d) of the New England Power Pool Agreement, which included a deficiency charge for each participant in the agreement whose prescribed level of generating capacity, known as "capacity responsibility," fell by more than one percent below the set level.[62] The court found that these charges are

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[56] *Id*. at 1543.

[57] *Id*. at 1541.

[58] *Id*.

[59] *Id*. (*citing Nantahala Power & Light Co*. v. *Thornburg*, 476 U.S. 953 (1986)).

[60] *Mississippi Industries* at 1542.

[61] 587 F.2d 1296 (D.C. Cir. 1978) (*Groton*).

[62] *Id*. at 1300.

within Commission jurisdiction because they are under "the Commission's inclusive jurisdictional mandate – which reaches discriminatory practices 'with respect to' jurisdictional transmissions, or 'affecting' such transmissions or services . . . ."[63] The Court further stated:

> [i]t is sufficient for jurisdictional purposes that the deficiency charge affects the fee that a participant pays for power and reserve service, irrespective of the objective underlying that charge. This is well within the Commission's authority as delineated in other court opinions.[64]

45. The Commission likewise has addressed this question as it involves resource adequacy provisions that impact jurisdictional rates in New England.[65] Specifically, in *ISO New England, Inc.*,[66] the Connecticut Department of Public Utility Control argued that, while the Commission has the authority to establish the price of capacity or how capacity requirements will be allocated among LSEs, it does not have the jurisdiction to dictate the amount of Installed Capacity Requirement that must be purchased. However, as the Commission explained, the Forward Capacity Market settlement "establish[es] a mechanism and market structure for the purchase and sale of installed capacity at wholesale in interstate commerce and to determine the prices for those sales, bringing it squarely within the Commission's jurisdiction under the FPA."[67]

46. This view of the Commission's jurisdiction over resource adequacy is also reflected in the Commission's recent order accepting a market redesign for the region operated by the California Independent System Operator. In that case, the Commission responded to charges that it lacked jurisdiction over resource adequacy by explaining:

> [W]here an interconnected transmission system is operated on a regional basis as part of an organized market for electricity,

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[63] *Id*. at 1302.

[64] *Id*. at 1302 (*citing e.g., FPC v. Conway Corp*., 426 U.S. 271 (1976)).

[65] *ISO New England, Inc*., 111 FERC ¶ 61,185 (2005), *reh'g denied*, 112 FERC ¶ 61,254 (2005).

[66] *ISO-NE III*, 118 FERC ¶ 61,157 (2007).

[67] *Id*. P 15; *accord id.* P 16-21.

> . . . all users of the system are interdependent, particularly with respect to reliability, i.e., one participant's reliability decisions can impact the reliability of service available to other participants and the related costs other participants must bear . . . . We find that, in situations where one party's resource adequacy decisions can cause adverse reliability and cost impacts on other participants in a regionally operated system, it is appropriate for us to consider resource adequacy in determining whether rates remain just and reasonable and not unduly discriminatory.[68]

47. In that case, the Commission also noted that "resource adequacy plays an important role in addressing whether Commission-jurisdictional wholesale prices reflect the exercise of market power or the scarcity of supply."[69] The Commission found similar considerations in the ISO-New England capacity construct where the Commission held that absent an affirmative mechanism to elicit the construction of new supply, bid caps would harm customers by discouraging such construction, rather than protecting customers from the exercise of market power or abuse.[70] PJM also has bid caps applicable to its energy market, and similar to the ISO-New England and California situations, resource adequacy in PJM is needed to ensure that energy market bid caps effectively restrict the ability of sellers to exercise market power, but not result in insufficient capacity being added to ensure long-term reliability.

48. As in these other cases, we find here that maintaining adequate resources within PJM has a significant and direct effect on jurisdictional rates and services, and therefore falls within the Commission's jurisdiction. This finding is fully consistent with *Mississippi Industries* and *Groton*. The PJM capacity costs are a component of the wholesale price for power and, as such, fall within the Commission's jurisdiction. If insufficient resources are made available, system reliability throughout the PJM grid may be compromised. In addition, where resource demand exceeds the supply, the price for capacity may increase. These are direct effects on Commission-jurisdictional rates.

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[68] *CAISO III*, 116 FERC ¶ 61,274 at P 1113, *citing Calif. Indep. Sys. Operator*, 115 FERC ¶ 61,172, at P 36 (2006) (CAISO II), *Gainesville Utils. Dep't v. Fla. Power Corp*., 402 U.S. 515, 529 (1971) (Commission has the "responsibility to the public to assure reliable efficient electric service").

[69] *CAISO III*, 116 FERC ¶ 61,274 at P 1114.

[70] *ISO-New England III*, 118 FERC ¶ 61,157 at P 19.

Further, RPM's Base Residual Auction will "set a sales price" that will directly affect wholesale rates[71] and, therefore, is subject to the Commission's jurisdiction over wholesale rates under section 205 of the FPA.

49. We do not agree with Mittal Steel or PJMICC that the Commission has intruded upon the jurisdiction of the states through RPM or the requirements imposed through the Fixed Resource Requirement, or the RPM reliability backstop auction. In this case, the Commission is not determining the capacity requirement; rather, PJM uses the loss of load methodology as determined by Reliability First, the regional reliability council,[72] of which PJM is a member, to determine the resource adequacy requirement. The adoption of RPM has not changed in any way the 15 percent installed reserve margin used by PJM to ensure reliability. RPM, including the Fixed Resource Requirement,[73] establishes the just and reasonable rate in order to ensure that PJM is able to meet the applicable reserve margin.

50. Mittal Steel and PJMICC argue that even though the Commission has offered LSEs the opportunity to procure capacity at the Installed Reserve Margin through the Fixed Resource Requirement, the Commission has intruded on states' rights in violation of EPAct 2005 by specifying the time limit for the LSE's contract, the level of the deficiency charge, and whether an LSE that fails to procure the required capacity may use this mechanism in the future. The Commission finds that RPM's provisions are just and reasonable mechanisms of ensuring that rates, terms and conditions for capacity remain just and reasonable. EPAct 2005 amendments to the FPA did not limit the Commission's jurisdiction to impose just and reasonable terms and conditions related to the provision of services subject to its jurisdiction. As stated above, the Commission is not determining the reliability or capacity requirement; it is setting the mechanism for procuring capacity at just and reasonable wholesale rates. Moreover, the Fixed Resource Requirement is merely an option available to an LSE. An LSE wishing to avoid these requirements can

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[71] *Groton* at 1541.

[72] Specifically, Standard RFC – RES – 001 -1 --- Resource Planning Reserve Requirements, Section B (R1) states: "The Loss of Load Expectation (LOLE) for any load in RFC due to resource inadequacy shall not exceed one occurrence in ten years. This requirement applies to all Load Serving Entities (LSEs) and Planning Reserve-Sharing Groups (PRSGs) within Reliability First (RFC)."

[73] Those eligible under the Settlement to elect the Fixed Resource Requirement option include investor owned utilities, electric cooperatives, public power entities and single-customer LSEs. *See* Settlement Agreement at 33-34.

simply participate in the auction process at the just and reasonable rates established by RPM.

51. Further, neither RPM nor the Fixed Resource Requirement require the construction of new generation, as Mittal Steel and PJMICC seem to argue. An important function in designing rates is to ensure that such rates provide sufficient incentive for the construction of infrastructure necessary to meet the needs of the system.[74] As we explained in the April 20 Order, RPM does not mandate or require the construction of new generation, or that any participant satisfy its capacity obligation through the use of any particular resource or set of resources.[75] "Rather, it seeks to render transparent the choices that LSEs make to fulfill their capacity needs, so that they may make those choices in a more informed fashion,"[76] we stated.

2. Termination of the Settlement

Positions of the Parties

52. Mittal Steel argues that the Settlement has terminated by its own terms because the modifications required by the Commission, including the expansion of the availability of the Fixed Resource Requirement option to signatories and non-signatories alike, have materially changed the balance of risks and rewards in the Settlement. Mittal Steel explains that it became a signatory to the Settlement because it believed this was the only way in which it could opt-out of the RPM auctions and satisfy its capacity obligations through the Fixed Resource Requirement option. When the Commission expanded the availability of the Fixed Resource Requirement option to both signatories and non-signatories in the December 22 Order, Mittal Steel concluded that the risks of the Settlement were no longer off-set by its benefits and expressed these concerns in a January 4, 2007 e-mail to the Settling Parties.[77] Mittal Steel argues that Article IV of the

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[74] *See Elec. Consumers Res. Council v. FERC*, 407 F.3d 1232, 1237 (D.C. Cir. 2005) (*ELCON*) ("the ICAP Demand Curve encourages investment in new generation capacity by ensuring 'increased stability in ICAP revenues'").

[75] April 20 Order, 115 FERC ¶ 61,079 at 169-72.

[76] *Id*. P 172.

[77] *See* Mittal Steel, Jan. 22, 2007 Answer at 4.

Settlement[78] establishes the conditions leading to the termination of the Settlement, and that it met these conditions when it notified the other Settling Parties on January 4, 2007 of its intent to withdraw from the Settlement. Mittal Steel also explains that it notified the Settling Parties of its willingness to discuss this matter, and on January 8, 2007, after not receiving a response from PJM, Mittal Steel formally notified the Commission of its withdrawal from the Settlement. Based upon these actions, Mittal Steel now argues that under the terms of the Article IV of the Settlement, the Settlement has been terminated. Accordingly, Mittal Steel also contends that the Commission's December 22 Order has been rendered moot and, in accordance with *New England Power Co.*,[79] the Commission should now vacate this order.

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[78] Article IV of the Settlement provides:

> APPROVAL AND EFFECTIVE DATE OF SETTLEMENT AGREEMENT
>
> The Parties shall seek and cooperate in securing Commission approval of this Settlement Agreement. This Settlement Agreement shall become effective as of the date on which the Commission approves or accepts the Settlement Agreement in its entirety. . . . If the Commission does not approve this Settlement Agreement by December 22, 2006, this Settlement Agreement shall terminate unless the Settling Parties agree to an extension. If the Commission should condition its approval of this Settlement Agreement or seek to require modification of any of the terms of this Settlement Agreement (a "Conditional Approval Order"), the Settling Parties shall confer and either accept the condition or negotiate in good faith, if necessary, to restore the balance of risks and benefits reflected in this Settlement Agreement as executed. Any such renegotiated settlement agreement shall be filed with the Commission. If no agreement can be reached within fifteen (15) days of the date of issuance of the Conditional Approval Order, and unless all of the Settling Parties agree to extend the time period for such negotiations, this Settlement Agreement shall terminate.

[79] 75 FERC ¶ 61,214 (1996) (*New England Power*) (order vacated upon the operation of the tariffs' own terms).

53. PJM and Capacity Buyers/Sellers, in their answers, insist that the actions taken by Mittal Steel have not terminated the Settlement because Mittal Steel did not comply with the Settlement's Article IV termination procedures. Pursuant to these provisions, an objecting party has 15 days of the Commission's action to renegotiate an objectionable change. PJM explains that one week after the issuance of the Commission's December 22 Order, it informed all the Settlement signatories that it considered the Commission's changes to be minor, and that it intended to comply with the Commission's directives. PJM contends that Mittal Steel's stated action to withdraw from the Settlement does not comply with the termination procedures of the Settlement that include an expressed obligation to negotiate with other parties to restore the balance of the original Settlement. Instead of affirmatively trying to negotiate with other parties, PJM argues that on January 4, 2007, 13 days after the Commission issued its order, Mittal Steel communicated by e-mail its concerns about the December 22 Order, and stated that it intended to withdraw from the Settlement. PJM and Capacity Buyers/Sellers contend that Mittal Steel's notification of its intent to withdraw does not meet the Article IV negotiation requirement, and does not indicate that Mittal is making a good-faith attempt to preserve the Settlement. PJM and Capacity Buyers/Sellers note that although other setting parties have withdrawn from the Settlement, Mittal Steel is the only party contending that the Settlement has terminated.

54. Further, both PJM and PHI note that the December 22 Order was a decision on the merits of each element of the contested Settlement, following *Trailblazer Pipeline Co.*,[80] and therefore, the status of the Settlement does not provide a basis to vacate the merits order. PJM also argues that the equitable relief of vacatur of an order is not appropriate where the party seeking this relief was in control of the circumstances that created the basis for vacating an order.[81]

55. Capacity Buyers/Sellers argue that vacatur of an order is granted only in extraordinary circumstances[82] and that Mittal Steel's reliance upon *New England Power*, where all the parties agreed that the orders in question were moot, is inapposite to the

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[80] *Citing Mobil Oil Corp. v. FPC,* 417 U.S. 283 (1974); *Trailblazer Pipeline Co*., 85 FERC ¶ 61,345(1998) (*Trailblazer*)*, reh'g denied*, 87 FERC ¶ 61,110 (1999).

[81] *Citing Montaup Electric Co*., 64 FERC ¶ 61,175 (1993); *So. Cal. Edison Co*., 55 FERC ¶ 61,258 (1991).

[82] *Town of Neligh v. Kinder Morgan Interstate Gas Transmission*, L.L.C., 94 FERC ¶ 61,075 at 61,348 (2001); *State of Maine*, 91 FERC ¶ 61,213 at 61,771-72 (2000) (*Maine*).

circumstances of the instant matter. Further, they argue a decision to grant a motion to vacate must take into account the public interest,[83] which must be shown by the movant.[84] Capacity Buyers/Sellers argue that Mittal Steel's motion to vacate, similar to a motion to stay, would not serve the public interest in having a just and reasonable capacity construct within PJM. These parties also argue that the Settlement is still in effect. They argue that Mittal Steel only conveyed to the other Settling Parties its opposition to provisions of the December 22 Order and its intent to withdraw; it did not represent its view that the Settlement would terminate, as it now claims.

56. Mittal, in its response to PJM's answer, argues that it complied with the Article IV requirements of the Settlement by using e-mail to convey its concerns about the Commission's December 22 Order and its modifications. This communication, Mittal Steel argues, set in motion the process required by Article IV. Mittal Steel argues that when none of the Settling Parties sought an extension of time to renegotiate the Settlement, the Settlement, by its own terms, terminated. Mittal Steel also contests PJM's position that Mittal Steel should have more quickly conveyed to the other Settling Parties its concerns about the December 22 Order. Instead, Mittal Steel argues that it is PJM who should have begun the renegotiation process because during the Settlement negotiations, PJM was aware of Mittal Steel's concerns about the issues that the Commission subsequently modified. Mittal Steel also notes that PJMICC, of which it is a member, responded within two days of PJM's communication with requests for information about PJM's assessment of the modifications ordered by the Commission, and that this communication should be considered part of the Article IV negotiation process. Mittal Steel concludes that it only announced it was withdrawing from the Settlement after PJM did not respond to the PJMICC e-mail seeking information about the impact of the modifications contained in the December 22 Order. Mittal Steel also comments that PJM could have prevented the Settlement from terminating, as Mittal Steel contends it has, by extending the renegotiation timeframe.

57. Mittal Steel contends that *Trailblazer* applies only to contesting parties, and not to non-contesting parties who oppose modifications made by the Commission to a Settlement that alters the balancing of interests achieved by the Settling Parties. Thus, Mittal Steel argues, the Article IV provision regarding termination is not affected by the Commission's *Trailblazer* analysis, and the Commission should uphold the Article IV provision for the sake of encouraging parties in the future to settle.

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[83] *U.S. Bancorp Mortgage Co. v. Bonner Mall P'ship*, 513 U.S. 18 (1994).

[84] *Maine*, 91 FERC ¶ 61,213 at 61,772.

58. In its answer of March 6, 2007, PJM asserts that, contrary to Mittal Steel's representations, counsel for PJM responded to requests, including from PJMICC, for analysis of the impact of the Commission's modification to the Settlement. PJM contends that none of these communications included requests to negotiate or make changes to the Settlement, as modified by the Commission, nor to request a meeting or Settlement conference. PJM insists that Mittal Steel did not communicate directly with PJM following the issuance of the December 22 Order until, on January 4, 2007, it announced that it planned to withdraw from the Settlement.

Commission Determination

59. The Commission finds that the Settlement has not terminated and that therefore, we do not find a basis for granting vacatur of the December 22 Order.

60. First, PJM states that the Settlement has not terminated and, aside from Mittal Steel, no other party to the Settlement argues that it has terminated. Further, Mittal Steel has not identified any provision of the Settlement providing that the objections of one party to conditions imposed by the Commission automatically terminates the Settlement. Indeed, the Settlement states that "[i]f the Commission should condition its approval of this Settlement Agreement or seek to require modification of any of the terms of this Settlement Agreement (a "Conditional Approval Order"), the Settling Parties shall confer and either *accept the condition or* negotiate in good faith, if necessary, to restore the balance of risks and benefits reflected in this Settlement Agreement as executed" (emphasis added). The vast majority of the parties have accepted the conditions, with a few deciding that they would withdraw from the Settlement. Thus, we conclude that the Settlement has not terminated.

61. Moreover, in the December 22 Order, the Commission addressed each of the contested Settlement issues and, upon consideration of the extensive record compiled in this proceeding, concluded that the contested provisions of the Settlement, with some modification, were just and reasonable. The Commission commented:

> The Commission finds that this record is sufficient to rule on the proposed Settlement, and that with conditions, the Settlement provisions establish a just and reasonable capacity market. We, therefore, describe and evaluate below each of the contested elements of the Settlement, and make a determination whether the provisions are just and reasonable,

> taking into account the integrated nature of the capacity market design.[85]

62. When the Commission conditions a contested settlement, it must not only rule on the contested issues, but in recognition that the conditions may deprive parties (who withdrew from the Settlement on account of the conditions) of the benefit of their negotiations, it must provide an opportunity for such Settling Parties on rehearing to raise other issues on which they may have compromised in agreeing to the settlement. As the Commission stated in *Sea Robin Pipeline Co.*:

> In this context it was not appropriate to consider only the issues contested by the Indicated Shippers and then reduce the proposed settlement rates based on those objections. Rather, before finding Sea Robin's existing rates unjust and unreasonable, the Commission must consider all contested issues, including those on which Sea Robin might have prevailed on the merits in the absence of a settlement offer.[86]

63. Accordingly, later in this order, the Commission considers all the arguments raised by the Settling Parties who have withdrawn from the Settlement, and finds that the tariff provisions it is approving are just and reasonable as to all the issues raised by the rehearing requests.

64. With respect to Mittal Steel's motion for vacatur, since we have found that the Settlement is still valid as to the remaining Settling Parties and we are addressing all Mittal Steel's rehearing requests on the merits, there is no basis for vacating the December 22 Order. On previous occasions, we have explained that "we are disinclined to devote our time and limited resources (as well as the parties' time and resources) to addressing motions to vacate."[87] Further, where the Commission has granted such motions, it has been in response to situations where orders have become moot by virtue of settlement or conduct otherwise outside the control of the parties moving for vacatur.[88]

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[85] December 22 Order, 117 FERC ¶ 61,331 at P 58.

[86] 81 FERC ¶ 61,146, at 61,652 (1997).

[87] *Southern Cal. Edison Co. and San Diego Gas & Electric Co.*, 55 FERC ¶ 61,497, at 62,759 (1991).

[88] *New England Power*, 75 FERC ¶ 61,214, at 61,719 (1996).

65. Applying these considerations to the circumstances of the instant proceeding, Mittal Steel has not shown the relief of vacatur to be warranted. As discussed above, we do not find that the Settlement has been terminated. Further, the December 22 Order rendered a binding merits decision on each of the contested issues. We, therefore, have no basis upon which to conclude that the December 22 Order is now moot. We also note that the Settlement continues to have broad stakeholder support and, therefore, we cannot agree that it would be equitable to all parties to this proceeding to vacate the December 22 Order. Of the thirty-two signatories to the Settlement, only three have withdrawn from it, and only two of the seventeen parties that voted not to oppose the Settlement have indicated that they can no longer bind themselves to their former position.

C. Substantive Motions for Rehearing

1. Locational Pricing

66. To ensure that sufficient supply is obtained for local areas throughout PJM, the Settlement provides a transition from the existing capacity market to RPM so as to allow market participants to realign their contractual obligations to meet the new capacity market. The Settlement uses four Locational Deliverability Areas,[89] which will be phased in in years one through three, with the full complement of Locational Deliverability Areas in place in year four.[90] In the fourth year, RPM establishes 23 Locational Deliverability Areas (this includes the 16 transmission owner zones that

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[89] As defined in the August 31 filing at P 552 “Locational Deliverability Area” or “LDA” shall mean a geographic area within the PJM region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan.

[90] The transitional four Locational Delivery Areas consist of: (1) Southwestern Mid-Atlantic Area Council (MAAC), which includes Potomac Electric and Power Company and Baltimore Gas & Electric Company; (2) Eastern MAAC, which includes Public Service Electric And Gas Company, Jersey Central Power & Light Company, Philadelphia Electric Company, Atlantic Electric, Delmarva Power & Light, and Rockland Electric); (3) the MAAC Region plus Allegheny Power System (Southwestern MAAC and Eastern MAAC plus Pennsylvania Electric, Metropolitan Edison, PPL, and Allegheny Power); and (4) the remaining zones in the PJM region (Commonwealth Edison, American Electric Power, Dayton Power & Light, Dominion-Virginia Power, and Duquesne Light).

system planners currently test each year for deliverability, plus seven combinations or portions of those zones).[91]

67. In its prior orders, the Commission found that the creation of Locational Deliverability Areas is a central element of PJM's RPM proposal. The Locational Deliverability Areas create accurate price signals to incent new generation, transmission and demand response in the locations where they are most needed. In addition, we found that the locational phase-in provisions of the Settlement as proposed are just and reasonable.[92]

68. The Settlement includes mechanisms to identify the existence of transmission constraints for pricing purposes. The Settlement also establishes a default screen to determine whether to use a separate Variable Resource Requirement Curve for a Locational Deliverability Area, and to create a separate Variable Resource Requirement Curve for a Locational Deliverability Area whenever the ability to import energy on an emergency basis into a constrained area is limited beyond certain thresholds. Moreover, the Settlement preserves provisions of the August 31 filing that supported self-supply and bilateral contracts through various means, including capacity pricing hubs and electronic transactions.

Positions of the Parties

69. PJMICC states that the Commission has not provided sufficient justification for locational pricing. According to PJMICC, the Commission did not cite any empirical evidence for the premise that a locational element in this capacity mechanism will improve local reliability problems, but rather just presumes that reliability will improve. PJMICC states that the Commission erred by accepting the locational pricing provisions

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[91] The seven combinations or portions of transmission owner zones are: (1) MAAC region; (2) the PJM West region consisting of the zones of Allegheny Power System (APS), Commonwealth Edison Company (ComEd), American Electric Power System-East Operating Companies (AEP), Dayton Power and Light Company (Dayton), and Duquesne Light Company (Duquesne); (3) the Eastern MAAC region; (4) the Southwestern MAAC region; (5) the western MAAC region consisting of the zones of Pennsylvania Electric Company, Metropolitan Edison Company, and PPL; the PSEG North region (the portion of the PSEG zone north of the Linden substation); and (7) the Delmarva South region (the portion of the Delmarva zone south of the Chesapeake and Delaware Canal).

[92] December 22 Order, 117 FERC ¶ 61,331 at P 68-69.

as just and reasonable and must reconsider this issue.[93] PJMICC argues that locational capacity pricing adds another layer of locational pricing on top of locational marginal pricing (LMP) for energy, and must be viewed as evidence that locational marginal pricing has fallen short in achieving its intended objective.

70. PJM, in its answer, states that RPM's use of locational pricing is well-supported. PJM states that the affidavits of Mr. Ott and Mr. Herling attached to its August 31 filing and the evidence brought out in the paper hearing in this case explain and justify the locational pricing proposal and supply substantial evidence to support the Commission's conclusions. PJM argues that the principle that the price for capacity should reflect its value to the system based on the actual system constraints in delivering capacity to the area is sound, and does not require empirical evidence.

71. Coral states that PJM's choices with regard to the transition period from four to 23 Locational Deliverability Areas unduly discriminate against generators within Dominion-Virginia Power's service area. The RPM transition plan creates four Locational Deliverability Areas, three of which reflect the transmission constraints within those areas, and the fourth consists of Dominion-Virginia Power (an area which Coral argues is constrained) and the Rest-of-Market (*i.e*., the remaining unconstrained portions of PJM), which are temporarily grouped together. Coral argues that the Commission disregarded substantial evidence before it that showed Dominion-Virginia Power is electrically separate from the Rest-of-Market and that this temporary grouping ignores major transmission constraints within the Locational Deliverability Area. Coral asserts that, therefore, higher capacity prices will be necessary within Dominion-Virginia Power's service area to maintain existing generation in operation and induce investment in new capacity in Eastern PJM, and that by ignoring these transmission constraints for the transition period, RPM allows generators located in the western part of PJM to sell capacity into Dominion-Virginia Power at the same prices as Virginia generators during this period, even though those generators are not deliverable within Dominion-Virginia Power. At the same time, Coral argues, generators in other transitional Locational Deliverability Areas that reflect transmission constraints during the transition period will immediately get the benefit of higher capacity prices, whereas generators in Dominion-Virginia Power will not. Thus, Coral asserts, the Commission erred by characterizing Coral's protest as seeking preferential treatment, because it is actually asserting that it was the victim of undue discrimination.

[93] PJMICC cites to *Mo. Pub. Serv. Comm'n v. FERC*, 337 F.3d 1066 (D.C. Cir. 2003); *Chem. Mfg. Ass'n v. Dept. of Transp.*, 105 F.3d 702 (D.C. Cir. 1997); *ELCON*, 747 F.2d 1511 (D.C. Cir. 1984); PJM-ISO Order, 81 FERC ¶ 61,257.

72. PJM states in response that Coral has not shown any need for a separate Locational Deliverability Area during the transition period. PJM further states that Coral repeats assertions and arguments that it has made previously, and which have been rebutted in the record.[94] PJM argues that the Commission's December 22 Order correctly held that there is no compelling reason for granting Coral's request.

Commission Determination

73. The Commission denies rehearing as to PJMICC and Coral's challenges. The evidence on the record adequately supports the principle for locational pricing with a phase-in period.

74. With regard to the challenge raised by PJMICC, the Commission finds that it has already explained its rationale for supporting locational capacity pricing in the April 20 Order, which stated that:

> Not all capacity in PJM is deliverable to all locations in PJM, and it is unreasonable to allow an LSE in one location to satisfy its capacity requirement with resources whose energy is not deliverable to the LSE. The evidence provided by PJM shows that the lack of a locational element is a contributing factor to reliability problems within PJM. Due to a series of recent generation retirements in particular locations, there is inadequate local generation capacity to consistently meet reliability targets in those locations, and there is inadequate transmission capability to import sufficient energy to make up the deficit.[95]

75. We also stated that:

> a locational element in the capacity construct will provide better price signals to potential new entrants and allow proper reflection of the differential costs of operation by locality. The lack of coordination of market design elements, such as the current PJM LMP for energy and system wide capacity

[94] PJM, Feb. 2, 2007, Answer to Motion to Vacate Order, Motion for Stay Request for Clarification and Certain Requests for Hearing at 44.

[95] April 20 Order, 115 FERC ¶ 61,179 at P 49.

> markets, mutes the market pricing signals needed to maintain current resources and attract new entrants in areas where they are needed to maintain reliability. We do not agree with intervenors that LMP price signals in the energy markets automatically provide adequate price signals to maintain capacity resources at appropriate levels to ensure reliability in the long term, since during periods of scarcity when energy prices would otherwise rise, energy market bid caps can blunt those signals.[96]

76. Capacity market prices must be locational in order to be fully effective. Because of transmission constraints, capacity in one location is not always deliverable to loads in other locations; in those instances, separate capacity prices are necessary in separate locations in order to reflect the differences in costs and capacity needs among the locations. Further, if a single capacity price is set for the entire region, capacity prices do not reflect the need for generation in particular locations and, as a consequence, generation entry in load pockets or import-constrained areas may not occur, and the transmission constraints may worsen over time as load grows.

77. PJMICC argues that locational capacity pricing is not needed since locational energy pricing has been unsuccessful at sending price signals, due to the presence of congestion. We disagree. It is precisely these congestion problems and the subsequent failure of the generators' "universal deliverability" concept that make locational pricing for capacity necessary. With the proper design, capacity price differentials between zones will provide necessary signals to ensure that required generation, demand response and/or transmission infrastructure are developed where they are most needed, and to make sure that the locational marginal prices, in turn, send the most useful information to customers about how much and when to consume.

78. PJMICC also argues that the Commission does not have any empirical evidence for the premise that a locational element in this capacity mechanism will actually work. But the purpose of rate design is to create a construct that is designed to send the proper price signals. As we found in the April 20 Order, the existing system-wide capacity pricing mechanism is unjust and unreasonable because it mistakenly assumes that generators can deliver power anywhere within PJM. In fact, PJM has identified multiple reliability criteria violations in New Jersey, the Delmarva Peninsula and the Baltimore-

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[96] *Id.* P 51.

Washington areas due to generation retirements and other factors.[97] Thus, the lack of locational pricing for capacity is not simply a theoretical problem, as PJMICC suggests. PJM has already demonstrated the existence of this problem in some parts of Eastern PJM, and we believe it is likely to continue in the future unless generators receive signals to locate new capacity where it is most needed.

79. RPM addresses this problem through the creation of Locational Deliverability Areas. As the transmission capacity to import energy into a Locational Deliverability Area becomes constrained, price separation will occur much as it does today in the day-ahead and real-time energy markets. This will reflect the added value of capacity within a constrained area and will be an incentive for participation in the capacity market (and energy markets) of existing or planned generation capacity resources and demand resources that are located within the constrained area. This added value will also be available to planned transmission upgrades that increase the transfer limits into the constrained area through the award of the arbitrage rights between the unconstrained capacity price and the capacity price within the constrained area. As we stated in our December 22 Order:

> [N]o market system can guarantee success. However, we have found that the current capacity market is unjust and unreasonable because it does not provide sufficient capacity to ensure reliability. As discussed earlier, the Settlement establishes a just and reasonable replacement for the existing construct by creating financial incentives within the context of a market system to encourage investment in additional infrastructure in the locations where they are needed. The evidence and simulations provided by PJM projects that the capacity market as structured by the Settlement, in coordination with the energy market, should provide for sufficient capacity to solve PJM's capacity problems. As discussed above, PJM's energy market does not provide for sufficient revenue to assure reliability given the constraints imposed by price caps and mitigation, as well as the need to procure capacity above the current demand level. The Commission finds that RPM, by providing for a three-year forward market in better defined geographic markets, along

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[97] PJM, February 3, 2006 Technical Conference, comments of Andrew Ott, transcript at 47; PJM August 31 2005 filing, Tab F, Affidavit of Steven Herling.

> with a downward sloping demand curve, is superior to the current capacity market and, based on the evidence submitted, should procure sufficient capacity to solve PJM's capacity needs. [98]

80. In addition, PJM is responsible for assuring reliability and can file to revise RPM if it fails to provide for sufficient capacity to assure reliability.[99]

81. Coral claims that the four Locational Deliverability Areas used during the transition period are discriminatory because Virginia should be carved out as a separate delivery zone during the transition period. Coral has not adequately shown the evidence of transmission constraints within Dominion-Virginia Power that would render generation from the western part of the Rest-of-Market area to be undeliverable within Dominion-Virginia Power. PJM has, in fact, provided evidence rebutting this assertion, stating that:

> PJM has not found any violations of load deliverability criteria to the [Dominion-Virginia Power] zone. For this reason, PJM is comfortable that reliability is not adversely affected by the Settlement provisions that combine the [Dominion-Virginia Power] zone with other zones during the transition period. Moreover, PJM previously has advised stakeholders that the Capacity Emergency Transfer Limit for the [Dominion-Virginia Power] zone for the next three years exceeds the Capacity Emergency Transfer Objective by a large margin.[100]

82. PJM established the four transitional Locational Deliverability Areas on the basis of violations of load deliverability criteria violations. But PJM has not found such violations for the Dominion-Virginia Power zone and therefore we find it reasonable not to subdivide that zone as Coral argues. While PJM has found violations of other reliability criteria within the Dominion-Virginia Power zone, such as the Bedington-Black Oak constraint referenced by Coral, these will be addressed by transmission

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[98] December 22 Order, 117 FERC ¶ 61,331 at P 146.

[99] *Id*. P 147.

[100] PJM, Oct. 30, 2006, Reply Comments to Coral's protest of the Settlement filing at 15.

upgrades proposed for Virginia, and are not equivalent to violations of load deliverability criteria. For example, PJM has found that Capacity Emergency Transfer Limit for the Dominion-Virginia Power zone for the next three years exceeds the Capacity Emergency Transfer Objective by a large margin. For the 2009-10 delivery year, for example, the Capacity Emergency Transfer Limit is approximately 3,100 megawatts, while the Capacity Emergency Transfer Objective is only 1,155 megawatts. This means that the amount of capacity that can be imported into the Dominion zone is two and a half times as large as the amount of capacity imports that zone is expected to need in the 2009-10 delivery year.

83. For this reason, PJM has found that reliability is not adversely affected by the settlement provisions that combine the Dominion-Virginia Power zone with other zones during the transition period, and we agree that this is a reasonable basis for establishing that the Dominion zone should not be a separate Locational Deliverability Area during the transition period.

84. However, even assuming *arguendo* that, as Coral posits, prices within Dominion-Virginia Power will be higher than prices outside Dominion-Virginia Power once the transition to 23 Locational Deliverability Areas is complete, the use of a transition period is just and reasonable. Once the transition to 23 Locational Deliverability Areas is completed, Dominion-Virginia Power will, in fact, be a single Locational Deliverability Area, and at that time, generators within Dominion-Virginia Power may or may not receive capacity prices that are higher than the capacity prices received by generators outside of that area. Coral argues, in essence, that it is discriminatory that generators selling within other congested Locational Deliverability Areas during the transition period are immediately able to receive higher capacity prices, while Coral will not receive such higher capacity prices until farther into the transition period. It is the nature of transitional mechanisms, however, that their purpose is to accomplish the transition from one compensation mechanism to another in a measured rather than an immediate manner, and Coral's claim of discrimination is, therefore, really an argument against any measured transition period, as opposed to full implementation of RPM immediately.

85. As the Commission has previously stated, "generally, the use of transition periods [is] to mitigate large cost shifts and rate effects."[101] Moving from PJM's current capacity market to RPM will require all market participants to adjust to a new competitive environment, and that transition will occur more smoothly if all parties are given sufficient time to adjust.

[101] *Calif. Indep. Sys. Operator Corp.*, 91 FERC ¶ 61,205 at 61,725 (2000) (*CAISO I*), *order on reh'g*, 104 FERC ¶ 61,062 (2003).

86. On this basis, the Commission found in the December 22 Order that:

> The adoption of a transition period must strike a reasonable balance between the need to implement RPM to generate relevant prices, and the provision of some period to enable parties to understand and make adjustments to the new market. The Settlement proposal adds several features to the locational market and the transition in response to market participants' concerns.[102]

87. Thus, the Commission found a transition period to full RPM implementation to be just and reasonable. We continue to find that to the extent that there is indeed any temporary discrepancy, it is an unavoidable part of any phased mechanism, and, as the Commission found, it is a just and reasonable balancing of the many benefits the transition will provide to all market participants. Coral has not provided sufficient reason to upset the balanced transition program that PJM has developed together with its stakeholders, and we therefore deny Coral's request for rehearing.

2. Forward Procurement

88. RPM's forward procurement mechanism is designed to allow for planning and construction of new resources, including generation, transmission and demand response, to compete with existing resources in the capacity market. The Settlement reduced the period of time between the Base Residual Auction and the start of the delivery year from four years to three years. The Settlement retains the one-year commitment period for capacity offered into the Base Residual Auction, but offers the option to certain new entrants in small Locational Deliverability Areas to receive their first-year clearing price for up to two additional years under certain conditions.

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[102] December 22 Order, 117 FERC ¶ 61,331 at P 73. For example, one feature PJM added in the Settlement in response to market participant concerns with the transition mechanism is that PJM will post during the transition period the prices that would have resulted if all 23 Locational Deliverability Areas were in place. Having this additional information will allow market participants to better inform their project scope and location decisions, their hedging strategies and their business practices to be implemented after the transition.

Positions of the Parties

89. PJMICC states that the Commission has not provided sufficient support for the three-year forward procurement period. PJMICC contends that the Commission's finding was arbitrary and capricious, as the Commission has not given a satisfactory explanation for its action including a rational connection between the facts found and the choice made. PJMICC maintains some metric or objective standard is necessary before the Commission can move to a three-year rather than four-year standard.

90. PJM in its response states that the record contains substantial evidence in support of the three-year period. PJM explains that in setting the procurement period, it sought foremost to provide planned resources the ability to compete directly with existing resources in the Base Residual Auction. PJM believes the adopted three-year forward approach meets this objective. In addition, PJM points to unrebutted evidence submitted by its witness, Mr. Raymond L. Pasteris, showing that the development time for a typical combustion turbine plant, from initial concept through to commercial operation to be four years.[103] PJM explains that because its rules require new entry facilities to have signed an Interconnection Facilities Study Agreement as a pre-requisite to being eligible to participate in the Base Residual Auction,[104] which usually takes place after the first year of development, or within 33 months from the plant's commercial operation date,[105] it is reasonable to establish a three-year forward auction schedule. In further support, PJM states that the supplemental affidavit provided by Dr. Hobbs in support of the Settlement shows the results of dynamic modeling studies that assumed a three-year forward procurement.[106] In this affidavit, Dr. Hobbs shows that the change from a four-year ahead to a three-year ahead auction results in minor differences, which leads him to conclude that the performance of the Settlement Curve would be similar to that of the originally proposed downward-sloping demand curve, and is superior to PJM's existing capacity market.[107]

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[103] PJM, August 31 filing, Tab I, Affidavit of Raymond L. Pasteris at 23.

[104] PJM Reliability Assurance Agreement, section 1.70.

[105] Settlement Explanatory Statement, *citing* PJM August 31 filing, Tab I at 23, Figure 3.

[106] *Id.* at 39.

[107] Settlement Explanatory Statement, Attachment C, Supplemental Affidavit of Benjamin F. Hobbs at 7.

91. PJM adds that likely benefits of forward commitment include long-term contracting, incentives for investment, and a stable forward price signal that encourages long-term forward contracting, which in turn provides greater forward certainty for both capacity price and capacity adequacy. PJM's witness, Mr. Andrew Ott, testified at the Technical Conference[108] that while there is no practical way to fix a single optimal forward commitment period for this purpose, three to five years reasonably brackets the most beneficial range. Moreover, in Mr. Ott's supplemental affidavit, accompanying the Settlement Agreement, Mr. Ott concludes that a three-year forward commitment will not significantly reduce RPM's ability to provide stable, long-term price signals and will provide incentives toward infrastructure investment.[109]

Commission Determination

92. We will deny PJMICC's request for rehearing on this issue. Contrary to PJMICC's assertions, PJM has provided substantial evidence that the three-year forward procurement period, to which the Settling Parties agreed, is just and reasonable. As PJM explains in its pleadings, a forward procurement period will allow planned resources to compete directly with existing resources, unlike under the current capacity construct where capacity obligations can be fulfilled only a day in advance. We agree with PJM that holding an auction three years in advance of the delivery year provides adequate time for the development of new generation facilities, or other solutions, along with equally important incentives for bringing these solutions to market. As PJM explains, relying upon information provided by its witness, Mr. Pasteris, three years is the standard amount of time it takes to build a proposed combustion turbine plant, once it has a signed Interconnection Facilities Study Agreement with PJM. In addition, PJM's witness, Dr. Hobbs, provided quantitative analyses as part of PJM's original August 31, 2005 filing[110] and as part of the Settlement filing[111] that evaluated the likely effects of various demand curves under various conditions. These analyses support the conclusion that a three-year forward auction provides benefits compared to the current construct, where capacity obligations need not be met significantly in advance. The analysis of Dr. Hobbs filed as

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[108] Technical Conference on Reliability Pricing Model in Docket Nos. ER05-1410-000 and EL05-148-000, February 2, 2006.

[109] *Id*. at 38-39.

[110] August 31, 2005 filing, Tab H, Affidavit of Benjamin F. Hobbs.

[111] Settlement Explanatory Statement, Attachment C, Hobbs Supplemental Affidavit.

part of the Settlement also concludes that the Settlement demand curve used in a three-year forward auction produce similar results to that of the four-year forward auction in terms of providing higher average reserve margins (which would improve reliability) and lower overall costs to consumers.[112]

93. The Commission finds that RPM, by providing for a three-year forward market in better defined geographic markets, along with a downward sloping demand curve, is superior to the current capacity market and, based on the evidence submitted, is a just and reasonable method of solving PJM's capacity needs.[113]

3. <u>Sloping Demand Curve</u>

94. PJM's August 31 filing included a sloping Variable Resource Requirement curve, or demand curve. The sloping demand curve would be used in conjunction with offers from suppliers of capacity in the Base Residual Auctions to determine the capacity price as well as the amount of capacity to be purchased in each Locational Deliverability Area at the point where the supply and demand curves intersect. The Settlement proposed to continue the use of a sloping demand curve, but modified its underlying parameters from those in PJM's August 31 filing so as to lower the position of the demand curve. That is, with the changed parameters, the Settlement's demand curve would produce lower prices (for any given level of capacity up to Installed Reserve Margin plus 5 percent) than would have been produced by the original demand curve.[114] The December 22 Order accepted the Settlement's proposal to use a sloping demand curve in the Base Residual Auctions for capacity. The Commission concluded that the reasons for accepting a sloping demand curve for PJM were similar to the reasons that the Commission had previously relied on in accepting the use of a sloping demand curve in the New York Independent System Operator (NYISO) capacity market. First, a sloping demand curve would reduce capacity price volatility, thereby reducing the riskiness of capacity

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[112] As Dr. Hobbs concludes in his Supplemental Affidavit in support of the Settlement, "The qualitative conclusions [of his study conducted in support of the Settlement] are the same as in my August 31, 2005 affidavit. Thus, the change from a four year-ahead to three year-ahead auction does not change the general conclusion." *Id*. P 6.

[113] December 22 Order, 117 FERC ¶ 61,331 at P 146.

[114] At capacity levels greater than Installed Reserve Margin plus 5 percent, the price of capacity would go to zero under both the curve filed by PJM in its August 31 filing and the Settlement Curve.

investments, and thus reducing their financing costs. In addition, a sloping demand curve would provide a better indication of the incremental value of capacity at different capacity levels than the current vertical demand curve. The order also accepted the Settlement's proposal to modify the parameters underlying the demand curve proposed in PJM's August 31 filing. The Commission concluded, based on the analysis provided by PJM's witness Dr. Hobbs, that although the Settlement curve was different from the originally filed curve, it would provide for just and reasonable prices to meet PJM's reliability needs.

Positions of the Parties

95. MPC and PSEG have sought rehearing on the adoption of the sloping demand curve.

96. MPC argues that the Commission erred by accepting any sloping demand curve. According to MPC, there was insufficient factual evidence to show that a sloped demand curve will reduce price volatility. Moreover, states MPC, the Commission did not address the analysis provided by MPC's witness, Mr. Wallach,[115] in his October 19, 2005 affidavit that capacity prices have not oscillated between the capacity deficiency rates and zero, as the Commission stated in its December 22 Order. Further, MPC argues that the sloping demand curve will force the purchase of excess capacity at artificial prices that exceed marginal supply costs, because when more supply is bid into the market than is needed but the supply curve ends before intersecting the demand curve, the price is set by the intersection of the demand curve with a vertical line from the end of the supply curve.

97. By contrast, PSEG supports use of a sloping demand curve with the parameters included in PJM's August 2005 filing. PSEG argues that the Commission erred in accepting the Settlement's parameter changes from the original curve in PJM's August 2005 filing, because the Settlement curve will result in rates over time that are too low to elicit adequate investment. To support its conclusion, PSEG argues that its witness, Mr. Falk, provided a quantitative analysis (based on the simulations of Dr. Hobbs) that showed that the Settlement demand curve created greater price volatility, and thus, greater risks for developers in small Locational Deliverability Areas than in the broader market studied by Dr. Hobbs. In PSEG's view, the greater price volatility would arise because larger generation additions would represent a larger proportion of the Locational Deliverability Area's total capacity requirement, and thereby, cause significantly larger price reductions. Because of the greater risks of investing in small Locational

[115] *See* Protest of Coalition of Consumers for Reliability, October 19, 2005, Affidavit of Jonathan Wallach.

Deliverability Areas, Mr. Falk concluded, the Settlement curve would perform significantly worse than PJM's originally filed demand curve in terms of (i) the fraction of years in which the Installed Reserve Margin target was achieved, (ii) the average cost to consumers, and (iii) the percentage of capacity that would be added in the secondary auction. PSEG also states that PJM's witness, Dr. Hobbs, analyzed several alternative scenarios to evaluate the robustness of his conclusions regarding the effects of the Settlement proposal, and that Dr. Hobbs has agreed that the Settlement curve would result in unacceptable reliability and greater costs in the "high risk aversion" scenario examined as part of his analysis. While Dr. Hobbs concluded, and the Commission agreed in the December 22 Order, that the high risk aversion scenario was not a realistic scenario, in PSEG's view, this high risk aversion case is realistic, especially in small Locational Deliverability Areas, contrary to the Commission's conclusion in the December 22 Order. PSEG states that the risks to developers in small Locational Deliverability Areas include the risk of market intervention through the construction of new transmission facilities under the PJM transmission planning process, the risk that reliability backstop mechanisms will be employed if reserve levels are not readily achieved, the potential exercise of monopsony power by buyers, new performance requirements imposed on capacity resources, uncertain mitigation powers on the part of the PJM Market Monitor, a mandatory second incremental auction, an administratively determined Cost of New Entry based on unrealistic financial assumptions and a lack of a robust mechanism for adjusting Cost of New Entry. Because of these higher risks, PSEG argues, developers would need a higher rate of return (20.7 percent, according to PSEG's witness, Dr. Shanker) than the rate of return assumed in the PJM Cost of New Entry studies for a low risk mature market (*i.e*., 12 percent) or associated with the initial demand curve recommended in PJM's August 31 filing (*i.e*., 16.6 percent).

98. PSEG also argues that the December 22 Order grants an unwarranted preference in favor of the Settlement demand curve, notwithstanding the evidence that the curve proposed by PJM in its August 31 filing provided greater reliability at lower cost. In particular, PSEG criticizes the December 22 Order for asserting that even though the Commission is acting under section 206 of the FPA, the proposal of the utility (*i.e*., PJM) would be accepted over any other just and reasonable rate, as if the Settlement filing had been made under section 205 of the FPA.[116] PSEG states that "the Commission's actions improperly conflate its FPA section 205 and FPA section 206 authority" and that section 206 "does not create an evidentiary presumption in favor of the utility with respect to its

[116] *See* December 22 Order, 117 FERC ¶ 61,331 at P 85.

proposal for the replacement of a rate found to be unjust and unreasonable vis-à-vis replacement proposals made by other parties."[117]

Commission Determination

i. MPC Rehearing Request

99. We deny MPC's rehearing request and reaffirm our acceptance of a sloping demand curve. The sloping demand curve is designed to replicate a true market in which incremental amounts of capacity will have gradually declining, but positive, reliability benefits. The current vertical demand curve fails to reflect the value of incremental reliability. Moreover, the vertical demand curve results in extremely volatile pricing, because as long as supply exceeds the required amount, the price falls precipitously, while, when capacity is short, price will rise to the deficiency penalty level. Finally, the sloping demand curve reflects a reasonable trade-off between capacity and energy prices. The testimony from Dr. Hobbs shows that any so-called excess generation created by the sloped demand curve will result in lower energy prices, making the overall result just and reasonable.

100. MPC argues that the December 22 Order overstated the volatility of pricing in the current capacity market with a vertical demand curve by stating that under the current capacity market, capacity prices vary substantially between the deficiency charge and zero even though supply varies only slightly between a slight deficit below the Installed Reserve Margin and a slight surplus above the Installed Reserve Margin.

101. The data to which MPC refers, while not going to a price of $0, shows that prices do vary dramatically from year to year, ranging from a low of $4.73 in June 2005-2006 to a high of $180 in June 2001-2002. Such prices may well reflect demand conditions for the years in question, but they are not at odds with the conclusion that under a vertical demand curve prices can be volatile. Indeed, as MPC recognizes, the general slope of the supply curve would remain exceedingly low (between $0 and $20) over a range of output up to approximately 140,000 megawatts before the supply curve would turn upward at a steep rate.[118] Under this supply assumption and a vertical demand curve, price will be very low as long as the supply curve does not turn up before it reaches the Installed Reserve Margin. By the same token, price will rise sharply if the supply curve turns up

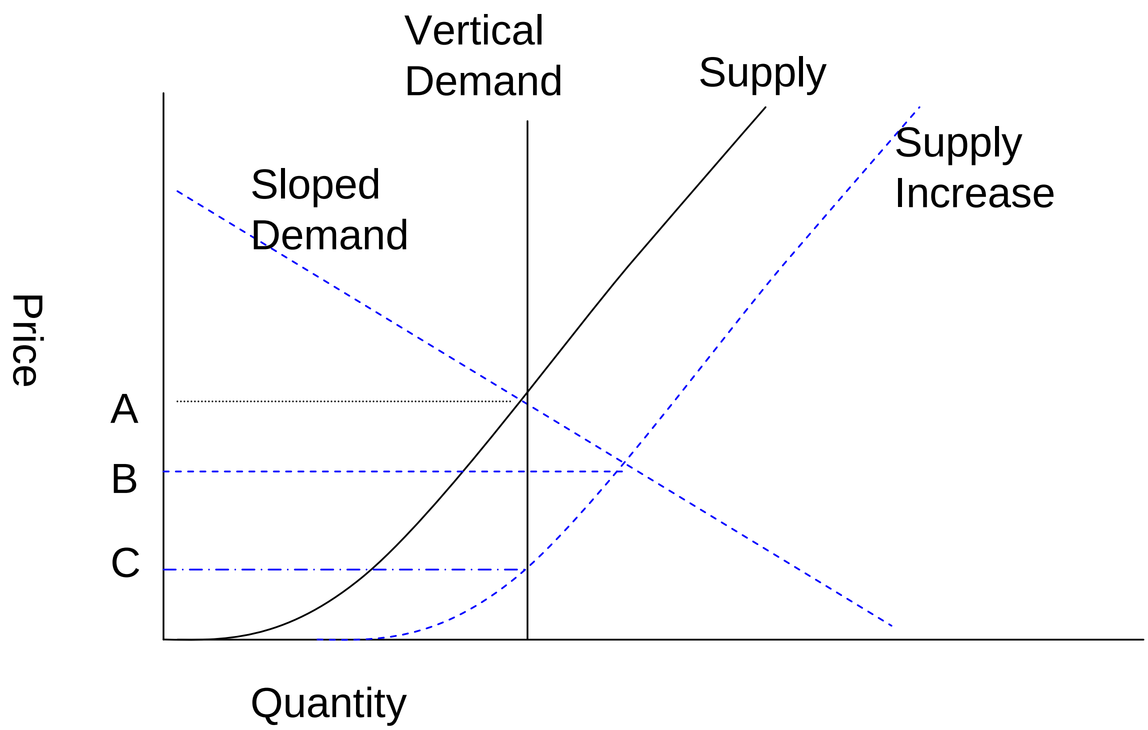
[117] PSEG, Request for Rehearing at 21.

[118] Protest of Coalition for Consumer Reliability, October 19, 2005, Affidavit of Jonathan Wallach at 19.

before the Installed Reserve Margin is met. Thus, the Commission did not overstate the volatility of capacity pricing under the current construct, as MPC argues.

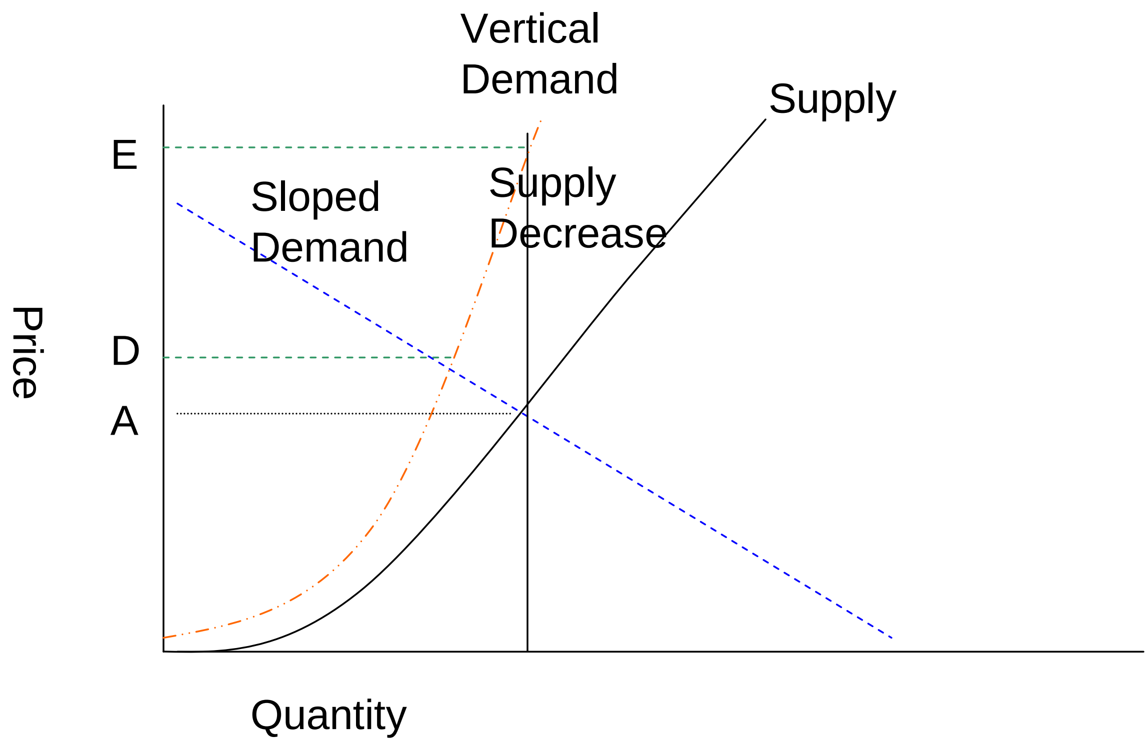
102. Moreover, even if the Commission did overstate the extent of the volatility in the December 22 Order, we continue to find that the Settlement Curve is just and reasonable because it will result in less volatility than PJM's current capacity mechanism. That is because as supply varies over time, capacity prices under a sloping demand curve would change gradually, in contrast to the drastically changing prices that buyers must pay for varying amounts of capacity under the current capacity construct. In other words, no matter what slope a supply curve has, any movement of the supply curve will create a larger change in price with a vertical as compared to a downward sloping demand curve.

103. This feature of a sloping demand curve is illustrated in the following graph.



104. Price A represents price at point A, which would be the price under either a vertical or a sloping demand curve when the applicable supply is represented by the solid upward-sloping supply curve. When the supply curve shifts downward (supply is increased) as illustrated by the dotted upward-sloping curve below the solid curve, the price under the downward sloping demand curve goes to Price B (where the new supply curve intersects the sloped demand curve). However, under a vertical demand curve, the price drops significantly farther to Price C (where the new supply curve intersects the vertical demand curve).

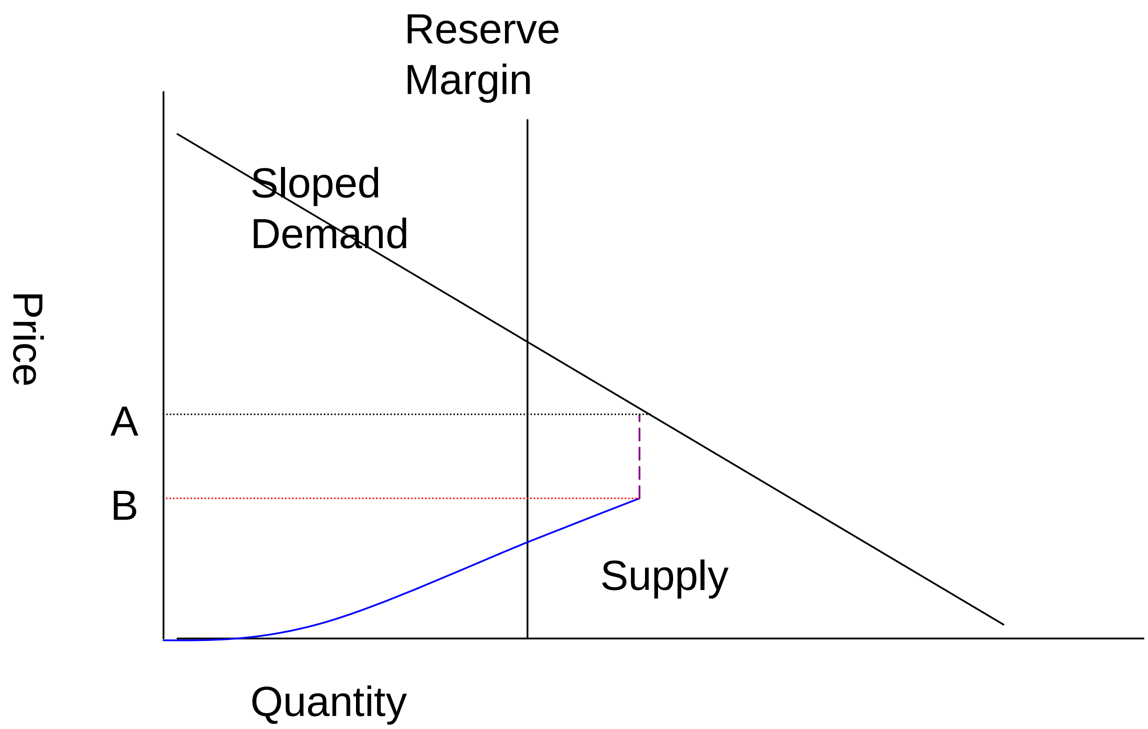
105. Similarly, as the following graph illustrates, if supply decreased (as reflected in the dotted upward-sloping supply curve above the solid curve), the price would rise higher using the vertical demand curve (to Price E), as compared to the price under the downward sloping demand curve (Price D).



106. Moreover, we disagree with MPC that it is unreasonable for additional capacity above the Installed Reserve Margin to be purchased when the capacity is offered at a sufficiently low price. As we stated in the December 22 Order, the value of capacity does not plummet to zero simply when supply equals the Installed Reserve Margin. Capacity above the Installed Reserve Margin still has value because it makes the system even more reliable, albeit at a declining level. Therefore, it is reasonable for additional capacity to be purchased if the offered price is less than the additional reliability benefits.

107. MPC also objects that the sloping demand curve will force the purchase of excess capacity at artificial prices that exceed marginal supply costs in the hypothetical circumstance in which the quantity of supply exceeds the reserve margin, but there is not sufficient supply to intersect the demand curve. In this circumstance, the price under

RPM is set by the intersection of the demand curve with a vertical line from the end of the supply curve. This is illustrated below.



108. Under RPM, the price would be set at Point A. MPC claims that in this circumstance, price should be set at Point B, the marginal supply price.

109. We find that, should this circumstance occur, it is not unreasonable to set the price at Point A, as RPM does, in order to encourage generators to submit bids at their true marginal cost bids. MPC's approach is a variant of a pay as bid approach, under which generators would have an incentive to guess at the market clearing price rather than submit marginal cost bids. Under MPC's approach, generators, in situations where they think supply might be short, would recognize that submitting a marginal cost bid could cost them revenue since a higher bid would still clear the market, and they therefore might guess at the possible price at which the market would clear rather than submitting a bid reflecting their actual marginal cost. In so doing they might inadvertently price themselves out of the market, thus leading to an inefficient result and potential added costs to customers, since these resources would be replaced by other resources with higher costs. In the hypothetical circumstances in which supply does not intersect the demand curve, we view the approach taken here as a reasonable means of ensuring that generators always have an incentive to submit marginal cost bids, thus ensuring that load is met from the generators with the lowest actual costs. This result will ensure that prices paid by customers will be as low as possible over the long term.

ii. PSEG Rehearing Request

110. We also deny PSEG's request to reject the Settlement's Curve in favor of the demand curve proposed by PJM in its August 31 filing. As we stated in the December 22 Order:

> PJM and the Settling Parties in their Settlement have provided information showing that the Settlement Curve will attract sufficient generation to meet its capacity obligations at a just and reasonable price. Therefore, PJM and the Settling Parties have met the requirement of demonstrating that the Settlement is just and reasonable.[119]

111. There may be a number of just and reasonable methods for determining the slope of the demand curve. PJM's original proposal (starting at twice the Cost of New Entry) was predicted to result in higher capacity prices with potentially lower energy prices over time. In contrast, the Settlement Curve is predicted to result in somewhat lower capacity prices with potentially higher energy prices over time. The derivation of the slope of the demand curve is at least in part subjective and cannot be reduced to simple metrics. While either of these proposals could be just and reasonable, we cannot find that the tradeoff of lower capacity prices for potentially higher energy prices is unjust and unreasonable. Dr. Hobbs' testimony[120] shows that the choice of the Settlement Curve achieves the necessary results of lowering price volatility and providing a reasonable price for generation.[121]

112. PSEG concludes that the Settlement Curve would result in rates over time that are too low to elicit adequate investment and argues that, as a result, the Settlement Curve should not be adopted, and the original demand curve should be. In support of its conclusion, PSEG points to the results of the analysis of PJM's witness, Dr. Hobbs, in his high risk aversion scenario. In that scenario, Dr. Hobbs concludes that the Settlement Curve would result in unacceptable reliability and greater costs. While Dr. Hobbs

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[119] December 22 Order, 117 FERC ¶ 61,331 at P 82.

[120] Settlement Explanatory Statement, Attachment C, Hobbs Supplemental Affidavit.

[121] *See ELCON*, 407 F.3d 1232 (D.C. Cir. 2005) (affirming the use of sloped demand curve finding that balancing of short-term costs against long-term benefits is within the Commission's discretion).

concludes that the conditions underlying the higher risk aversion scenario are not realistic, PSEG argues that the conditions are realistic, especially in small Locational Deliverability Areas, because of the large risks associated with investing in small Locational Deliverability Areas.

113. However, we conclude that PSEG's reliance on Dr. Hobbs' scenario analysis is misplaced, for the reasons articulated by PJM and Dr. Hobbs in PJM's October 30, 2006 reply comments responding to PSEG's arguments.[122] PSEG confuses the relative aversion of investors to risk with the relative riskiness of investments. The extreme risk aversion case included in Dr. Hobbs' sensitivity analysis involves an assumption that investors are extremely risk averse; it does not examine a change in the riskiness of investments (compared with the other scenarios examined in his analysis). By contrast, PSEG's argument addresses the relative riskiness of investments in small Locational Deliverability Areas. That is, Dr. Hobbs' extreme risk aversion case studies what the effect would be if *investors* were different (*i.e.*, were more averse to risk) than in the base case, while PSEG makes the argument that the *investments* are likely to be different (*i.e*., riskier) than in Dr. Hobbs' base case. Therefore, the effects of the higher level of riskiness of investments that PSEG argues is likely in small Locational Deliverability Areas under the Settlement cannot be inferred from the results of the extreme risk aversion scenario included in Dr. Hobbs' analysis. In summary, PSEG has not persuaded us that Dr. Hobbs' high risk aversion scenario for investors is a likely scenario.

114. We are not persuaded by the analysis of PSEG's witness, Mr. Falk, that investments in small Locational Deliverability Areas are likely to be so risky that the Settlement Curve is unjust and unreasonable. We agree with the analysis presented by Dr. Hobbs in his October 19, 2006 affidavit that responded to Mr. Falk's quantitative analysis. In assessing the risks of investing in small Locational Deliverability Areas, Mr. Falk appears to assume that small Locational Deliverability Areas have no ability to import or export capacity, when, as Dr. Hobbs notes, all Locational Deliverability Areas will be able to import and export capacity up to the limits of their transmission capability. Mr. Falk's assumption would result in overstating the riskiness of investing in small Locational Deliverability Areas, because the analysis would conclude that building a large generator in a small Locational Deliverability Areas would create an enormous capacity surplus that would substantially depress the capacity price, perhaps to zero. However, as Dr. Hobbs points out, the local capacity price cannot fall below the PJM unconstrained area capacity price, because the Locational Deliverability Area could stop

[122] PJM, October 30, 2006, Reply Comments at 18-19, and Supplemental Affidavit of Benjamin F. Hobbs, at 14-18.

importing capacity and begin to export its capacity surplus. Based on the entirety of Dr. Hobbs' analysis, we continue to agree with PJM that the Settlement Curve is likely to produce just and reasonable capacity prices. However, even if PSEG is correct that the riskiness of investments in small Locational Deliverability Areas is significantly greater than that assumed by PJM and Dr. Hobbs and would justify a higher Cost of New Entry, the Settlement provides for a mechanism to increase the Cost of New Entry based on actual market experience, as discussed below.

115. PSEG argues that the Commission erred in applying its section 206 authority by giving preference to PJM's proposed Settlement Curve over other possible curves, simply because PJM is the proposing utility. In the December 22 Order, the Commission cited to our prior statement in *ANR Pipeline Co.* to the effect that, in recognition of the fact that a gas pipeline was given primary authority under section 4 of the Natural Gas Act (NGA) to propose new rates, we would also accept the pipeline's just and reasonable proposal under NGA section 5 even if there were competing just and reasonable proposals.[123] As the Commission explained in *ANR*:

> While the Commission is acting here under section 5, in considering the protests to ANR's compliance filing, the Commission also takes into account the fact that the NGA delegates to the pipeline the primary initiative to propose the rates, terms, and conditions for its services under NGA section 4. If the rates, terms, and conditions proposed by the pipeline are just and reasonable, the Commission must accept them, regardless of whether other rates, terms, and conditions may be just and reasonable. Therefore, to the extent ANR's proposed remedy is just and reasonable, the Commission will accept ANR's proposal even if other remedial provisions might also be just and reasonable.[124]

116. As the U.S. Court of Appeals for the District of Columbia Circuit has recognized, when there is a continuum of potential just and reasonable rates "at each of these places

[123] 110 FERC ¶ 61,069 at P 49 (2005).

[124] *Id.* A simple example will show why such preference makes sense. Suppose there are three just and reasonable provisions put forward in a section 206 proceeding and the Commission does not adopt the utility provision. The utility can then make a section 205 filing, and since its proposal is just and reasonable the Commission would have to adopt the utility's proposal.

along the continuum, the pricing mechanism will essentially lie in the hands of the initiating pipeline."[125]

117. Moreover, in this case, "a significant majority of negotiating parties, representing a broad array of interests, were able to agree to [the Settlement Curve]."[126] Since the Settlement Curve is supported by PJM as well as a wide variety of interests, and has been shown to be just and reasonable, the Commission has a sufficient basis for accepting it.

4. **Empirical Cost of New Entry**

118. The demand curve would initially be established, in part, based on an administratively determined estimate of the Cost of New Entry. Specifically, the price on the demand curve would equal the Cost of New Entry at the point where capacity is equal to the Installed Reserve Margin plus 1 percent. The December 22 Order accepted the Settlement's proposal for calculating the value of the Cost of New Entry to be used in the initial auctions. The order also accepted the Settlement's proposal that after a transition period, an area's Cost of New Entry would be adjusted to reflect empirical information on actual capacity market activity when there is a net demand for new resources over three consecutive delivery years and certain other conditions are met. The Settlement defines a "net demand for new resources" to occur whenever the sum of load growth and generation retirements over the 3-year period exceeds the sum of the first year surplus and the net increase in "Capacity Emergency Transfer Limit" (*i.e.*, transmission transfer capability between the area and the neighboring areas). Increases in the Cost of New Entry would raise the demand curve, while decreases in the Cost of New Entry would lower the curve. The Cost of New Entry adjustments would seek to move toward "E-CONE" (or Empirical Cost of New Entry), which is defined as the average of the clearing prices in the area for the previous three years, plus the average of the area's net energy and ancillary services revenue offsets for the previous three years. Specifically, the Cost of New Entry adjustment would be half the difference between the current Cost of New Entry and Empirical Cost of New Entry, but not to exceed 10 percent of the current Cost of New Entry. In accepting the Settlement's proposed Cost of New Entry adjustments, the Commission's December 22 Order rejected PSEG's proposal to adjust the Cost of New Entry based on all actual new entry bids (screened to exclude outliers) whether the bids clear or not. The Commission reasoned that the PSEG proposal could encourage some participants to submit inflated offers merely to increase the Cost of New Entry value.

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[125] *"Complex" Consol. Edison Co. v. FERC*, 165 F.3d 992, 1004 (D.C. Cir. 1999).

[126] December 22 Order, 117 FERC ¶ 61,331 at P 84, *citing ELCON* at 1239.

Position of the Parties

119. PSEG acknowledges that the Commission should take steps to ensure that new entry bids do not reflect offers by inefficient generators or generators attempting to bias the process. But PSEG argues that using the Settlement adjustment mechanism will not promptly or accurately adjust the Cost of New Entry. In PSEG's view, a better solution would be to use screens or statistical analysis to select actual bids.

120. PSEG argues that delays in necessary Cost of New Entry adjustments would be quite significant because, first, there must be at least three study years, and second, any adjustments are limited to a fraction of the difference between the current Cost of New Entry and Empirical Cost of New Entry. For example, according to PSEG, if Empirical Cost of New Entry is 40 percent higher than the current Cost of New Entry, it would take 6 years to raise Cost of New Entry to within 92 percent of Empirical Cost of New Entry.

121. Moreover, PSEG argues, the Settlement's adjustment mechanism may often understate the actual Cost of New Entry, for reasons illustrated in several scenarios. First, the adjustment mechanism would not adjust Cost of New Entry when capacity falls within the "equilibrium zone" (*i.e.*, between Installed Reserve Margin and Installed Reserve Margin plus 2 percent), despite the fact that several new entrant bids were accepted and all of them were above the current Cost of New Entry value. Second, the calculated Empirical Cost of New Entry could be below the current Cost of New Entry value because no new capacity is needed in the first two years of the 3-year examination period, and therefore, prices are below Cost of New Entry, despite the fact that all accepted new entrants' bids in the third year of the examination period are above the current Cost of New Entry value. Third, no adjustment to Cost of New Entry would be made even though new entrant bids above Cost of New Entry are accepted when a transmission project is built that increases the transmission capacity between areas, so that there is no net demand for new resources. Fourth, no adjustment to Cost of New Entry would be made even though new entrant bids above Cost of New Entry are accepted in each of the 3-year examination period, when the amount of the capacity deficit does not change over the 3 years.

Commission Determination

122. We will not modify the Cost of New Entry adjustment process specified in the Settlement at this time. PSEG does not raise any new arguments on this issue in its rehearing request. We determined in the December 22 Order that the administratively-determined value of Cost of New Entry to be used in the initial Base Residual Auctions is just and reasonable, and we would not expect significant changes to the Cost of New Entry value to be necessary immediately. Of course, in the future, changes to the initial Cost of New Entry value may be necessary as market conditions change. We continue to

conclude that relying on cleared prices in instances when new entry is actually needed is a better way to adjust the Cost of New Entry value than PSEG's proposal to rely on all offers by new entrants (including those that do not clear), since cleared bids provide a market test. PSEG acknowledges that the Commission should be concerned about whether new entry bids reflect offers by inefficient generators or generators attempting to bias the process. To address this concern, PSEG's solution is to use screens or statistical analysis to select bids. However, PSEG's screening solution would appear to reinstitute a large element of administrative judgment in determining which bids to consider in adjusting the Cost of New Entry, which would defeat the purpose of relying on empirical market information to adjust the Cost of New Entry.

123. We further find that the three-year delay built into the Cost of New Entry calculation is a reasonable method of ensuring that sudden changes in new entry costs do not result in sudden price shifts. While PSEG described potential anomalies with the Cost of New Entry calculations, it is not clear that these hypothetical events will even occur or how significant they may be. If experience shows that the scenarios described by PSEG become significant, the Settlement provides that PJM has the right to file to change the Cost of New Entry calculation, and PSEG can file under section 206 based on actual evidence supporting its proposed changes.

5. New Entry Price Adjustment

124. The December 22 Order accepted the Settlement's proposed New Entry Price Adjustment, under which certain new entrants in small Locational Deliverability Areas where new entry has a significant impact on prices may opt to receive their first-year clearing price for up to two additional years if certain conditions are met. If the seller chooses the New Entry Price Adjustment option, its offer sets the clearing price in its first year, and its offer clears in a subsequent year, it receives the higher of its first-year offer price or the clearing price for that subsequent year. In delivery years after the first year, any payment to the seller above the clearing price will not increase the clearing price received by other sellers.

Position of the Parties

125. MPC objects to the New Entry Price Adjustment provision of the Settlement on the grounds that it artificially maintains high prices in the years following the entry of a new unit into the capacity market. MPC concludes that due to the combination of the sloping demand curve and New Entry Price Adjustment, prices will either be high because supply is tight compared to demand or because of the New Entry Price Adjustment price subsidies. Moreover, MPC objects to the ability of the new entrant to submit inflated bids in the second and third years, and thereby inflate the market clearing price.

126. By contrast, PSEG concludes that the New Entry Price Adjustment contains rigid eligibility requirements that undermine the value of its potential application. PSEG states that the December 22 Order failed to address the testimony of its witness, Mr. Sorenson, who concluded that the New Entry Price Adjustment would fail to provide average revenues over time equal to the average Cost of New Entry, and thus, it would not support entry in small Locational Deliverability Areas. Mr. Sorenson's conclusion is based on an analysis of an example provided in Dr. Stoddard's testimony of a 4,000 megawatt Locational Deliverability Area where adding an efficient-sized plant of 500 megawatts would bring the Locational Deliverability Area from a point of deficiency to a point of substantial surplus (*i.e.*, more than 11 percent in excess of Installed Reserve Margin). Assuming 1.7 percent annual load growth, Mr. Sorenson stated that it would take 8 years for the capacity surplus to be absorbed by load growth, but after the three-year New Entry Price Adjustment price guarantee, the new generator would face capacity prices below (and often significantly below) Cost of New Entry for the remaining five years of the capacity surplus period. Mr. Sorenson continued that if the generator's initial bid was the Cost of New Entry, three years of Cost of New Entry payments combined with five years of prices below Cost of New Entry would yield an average price below Cost of New Entry.

127. Mr. Sorenson stated that in principle, a new generator could achieve an average price over time that was equal to the Cost of New Entry by submitting an initial bid that was sufficiently higher than the Cost of New Entry. But he was concerned, however, that the initial price might need to be higher than 1.5 times the Cost of New Entry (the highest price possible under the demand curve), that the PJM Market Monitor might not permit the required price, or that PJM might utilize the backstop generation procurement mechanism or order the construction of new transmission projects to increase the Locational Deliverability Area's import capability and thereby depress the Locational Deliverability Area's capacity price. PSEG concludes that the Commission should reject the Settlement's three-year bid guarantee under the New Entry Price Adjustment and adopt instead the five-year price persistence rule included in PJM's August 31, 2005 filing.

Commission Determination

128. We reaffirm our determination that the Settlement's New Entry Price Adjustment is just and reasonable.[127] The purpose of this provision is to provide a new entrant in a small Locational Deliverability Areas with some assurance that it can recover its costs in the event that its new entry creates a capacity surplus which will depress prices in

[127] December 22 Order, 117 FERC ¶ 61,331 at P 92.

subsequent years. An adjustment of this type cannot be determined with exactitude, and we find that the three year period in the Settlement is reasonable especially since there has been no experience under the RPM construct. If experience shows that this provision needs to be adjusted, PJM or other parties can make filings based on actual evidence supporting an adjustment.

129. MPC raises no new arguments regarding the New Entry Price Adjustment. To encourage needed new entry, investors must expect that the average price over time approximates the actual average annual Cost of New Entry. The New Entry Price Adjustment is intended to address a situation where new entry into a Locational Deliverability Area is needed but the minimum efficiently sized generation facility results in excess capacity. In this situation, if the new entrant were not guaranteed that the first-year clearing price would continue for some period of time, it might not choose to enter.

130. To encourage needed new entry, investors must expect that the average price over time approximates the actual average annual Cost of New Entry. To achieve this expectation in the absence of the New Entry Price Adjustment provision, the capacity price in years when new entry is needed would need to be significantly higher than the average annual Cost of New Entry, in order to offset the very low prices that would arise in the years of capacity surplus. But the features of the settlement might prevent the first year price from rising high enough. For example, in some instances (when entry in one year creates a large number of succeeding years of surplus) the price needed in a new entrant's first year may need to exceed 1.5 times the Cost of New Entry. But the maximum price that can result under the Settlement demand curve is 1.5 times the Cost of New Entry. So in these instances in the absence of the New Entry Price Adjustment, the first year price of a new entrant could not rise high enough to offset the subsequent years of low prices resulting from surplus capacity. The New Entry Price Adjustment provision reduces this problem by providing the opportunity to receive the first year price for two additional years, thereby increasing the revenues that can be received in a resource's first years, and increasing the likelihood that these revenues can offset any revenues below the average Cost of New Entry that may result from capacity surpluses that extend beyond the third year. The New Entry Price Adjustment also provides for greater revenue stability in small Locational Deliverability Areas. Also, contrary to MPC's argument that the new entrants' bids affect the market clearing prices in the second and third year, the Settlement provides that the "payment to the [new] seller above the clearing price will not increase the clearing price received by other sellers."[128]

[128] Settlement Explanatory Statement at 26.

131. We also deny PSEG's request to find that the Settlement's three-year New Entry Price Adjustment is too short. We do not agree with all of Mr. Sorenson's assumptions used in his conclusion that the three-year New Entry Price Adjustment price provision will necessarily fail to provide sufficient revenues over time to cover the average Cost of New Entry.

132. First, Mr. Sorenson's example seems to presume that the small Locational Deliverability Area would always be an importer of capacity. Mr. Sorenson argues that a capacity surplus in the Locational Deliverability Area would depress the price in the Locational Deliverability Area for many years (eight years in his example) and implicitly assumes that the Locational Deliverability Area would continue to import as much capacity after a new resource enters the market as it imported before the new entry.

133. However, his example does not take into account that, once the Locational Deliverability Area experiences a capacity surplus, it is likely to stop importing and begin exporting capacity. During years of capacity surplus, the limited transmission capacity into the Locational Deliverability Area will not be needed for imports and could be used to export at least part of the Locational Deliverability Area's capacity surplus to neighboring Locational Deliverability Areas. The ability to export capacity would reduce the number of years when a capacity surplus would otherwise depress capacity prices in the small Locational Deliverability Area. And where neighboring Locational Deliverability Areas with significant amounts of transmission capacity interconnecting them are simultaneously experiencing large capacity surpluses for several years, the resulting low prices would appropriately send an accurate signal that new capacity is not needed in any of the neighboring Locational Deliverability Areas.

134. Second, in any instances where transmission capacity is so limited that exports cannot absorb a significant portion of a Locational Deliverability Area's capacity surplus (and thus, where a single efficient new entrant would create a surplus that would exist for more than three years), a new entrant may legitimately need to submit a bid that exceeds the average annual Cost of New Entry, in order to offset periods of lower prices in later years. Mr. Sorenson is concerned that an initial bid price above the average annual Cost of New Entry might not be accepted by the PJM Market Monitor. However, as stated in our December 22 Order, any rejection of new entrant bids by the PJM Market Monitor would be reviewed by the Commission, and we would consider all relevant factors related to such bids, including the legitimate needs of a new entrant to obtain a price above the average annual Cost of New Entry in its initial years of operation to offset extended periods of low prices in future years.

6. Mitigation Issues and Market Monitoring

135. RPM includes specific measures to mitigate the exercise of market power as measured by the "three-pivotal supplier" test.[129] For sellers owning existing resources that fail this test, mitigation entails capping their capacity bids at a predetermined avoidable or opportunity cost level. Unit specific avoidable cost estimates may serve as a bid cap in this instance and, as specified in section 6.8 of the PJM tariff,[130] are the sum of specified cost elements adjusted for uncertainty, investment cost incurred to assure the unit's availability, and hard-to-measure avoidable costs, such as seller risk created by the Settlement's peak availability charge. Offers for new or planned resources are generally not subject to mitigation except in two specific cases. In the case where the seller may have the incentive and ability to increase prices above the competitive level, its bid for a planned resource may be rejected by the Market Monitor. In the case where the seller may have the incentive and ability to depress prices below the competitive level, its bid for a planned resource may be increased to more appropriately reflect the Cost of New Entry (Minimum Offer Price Rule).

136. Five parties seek rehearing of market monitoring and mitigation issues. No party challenges the use of the three-pivotal supplier test to determine when bids are to be mitigated. They challenge various aspects of the determination of the default replacement bid.

137. Indicated Buyers, Mittal Steel, and MPC seek rehearing on various aspects of how avoidable cost default bids that may be used to lower bids from existing resources that have market power are determined. In particular, they raise objections to the way these default bids reflect investment cost and hard-to-measure avoidable costs. Mittal Steel raises concerns about the legitimacy of default bids to account for such avoidable costs generally. MPC seeks rehearing of the Minimum Offer Price Rule provisions in the Settlement arguing that they inappropriately restrict legitimate LSE behavior while

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[129] For purposes of imposing an offer cap if a load pocket is not competitive, PJM defines a "pivotal supplier" as one whose output is required to meet relevant load. The generation resources' offers are not capped when its offers combined with the two largest other generation suppliers are not pivotal. PJM tariff, Attachment K-Appendix, section 6.4.1(e). Further, more than one supplier can be pivotal at any given time, if the output of any supplier or combination of suppliers is required to meet load affected by that transmission limit. Four or more jointly pivotal suppliers are considered competitive, as are zero pivotal suppliers.

[130] PJM Tariff, Attachment DD, section 6.8.

Indicated Buyers object to the description of these provisions as a reasonable method to forestall monopsony power. PJMICC requests clarification or rehearing to assure that all suppliers in a Locational Deliverability Area that fail the three-pivotal supplier test will be subject to mitigation. Indicated Buyers seek rehearing of Commission-ordered changes that diminish the authority of the Market Monitor to exercise discretion. In contrast, PSEG seeks clarification or rehearing that restricts Market Monitor discretion to reject bids of new entrants. We address these various concerns, requests for clarification and rehearing in greater detail below.

a. <u>Determination of Avoidable Cost Default Bids</u>

138. Just as marginal cost is used as a measure of a competitive bid in mitigating in the energy markets, avoidable cost is a good measure of a competitive bid for bid mitigation in the RPM forward capacity markets. A competitive seller of capacity is expected to bid its avoidable costs or the costs it would not incur if it does not commit to supplying capacity in the delivery year. Consequently, mitigation of market power under RPM relies on the concept of avoidable cost as the basis for mitigating non-competitive offers from existing resources.

139. Mittal Steel's argument seems to suggest that through the use of mitigated bids, bidders will receive a guaranteed cost recovery or that capacity prices will rise. It is important to recognize at the outset that default bids do not provide sellers owning existing resources any guarantee for cost recovery or assurance that their offer will be accepted and included in the calculation of market clearing prices. The default bid simply sets a cap on the amount a generator with market power is permitted to bid. Whether that default bid (if submitted by the generator) is accepted will be determined by the other bids in the market, and there is no guarantee that the generator will be paid its default bid. Indeed, in some cases, a generator may not submit a bid as high as the default bid (it would be permitted to submit) because of a concern that it would not be taken at the default bid level. Moreover, by definition, for a bid to be mitigated, the generator's original bids must be higher than the default bid. Therefore, mitigation of existing suppliers always results in lower market clearing prices than would have occurred had the bid not been mitigated.

b. <u>Capital Recovery Factors</u>

140. Section 6.8 of the PJM tariff describes the calculation of unit-specific default avoidable costs, using data provided by the seller. The avoidable cost rate defined in section 6.8 is the sum of various avoidable cost elements. One element of the formula reflects avoidable investment costs that a capacity seller actually incurs to enable the resource to be available during peak-hour periods of the delivery year.

141. The avoidable project investment recovery rate equals the Capital Recovery Factor times the project investment. Capital Recovery Factors deal only with how quickly a generator can depreciate its investment cost for the purpose of setting its default bid. Capital Recovery Factors are generally based on the age of the plant, so that the older the plant (with a potentially shorter useful life), the larger the Capital Recovery Factor, and, accordingly, the higher the default bid. Generators, however, can choose to lengthen their Capital Recovery Factors by choosing a Capital Recovery Factor of the next shortest interval (*e.g.*, a 15-year old plant could choose the Capital Recovery Factor of a 10 year old plant). Capital Recovery Factors may be included in default bids only for the time period equal to the expected useful life of the plant. For example, a 15-year old plant may include a Capital Recovery Factor in its default bid for five years, its expected remaining useful life.

142. Section 6.8 of the PJM tariff allows for six Capital Recovery Factors that vary inversely with the expected remaining life of the plant. Two of the six factors, referred to as Mandatory Capital Expenditures (Mandatory Cap X) and 40 Plus, do not take effect until after the three year transition period.

143. The Mandatory Cap X option is targeted to existing generators that may require significant environmental upgrades. In this case, default bids may include an avoidable project investment recovery rate equal to .45 times investment cost for up to four years provided that the overall default avoidable cost does not exceed 90 percent of the Net Cost of New Entry. One of two sets of conditions determines a resource's eligibility for the Mandatory Cap X option, and the Commission required changes to the second set of conditions only.[131]

144. Under the second set of conditions, the Mandatory Cap X option originally applied to a coal-fired unit that was in a Locational Deliverability Area with a separate Variable Resource Requirement curve and that had been in operation at least 50 years at the time of the Settlement, if the seller was a signatory or an affiliate of a signatory. The Commission found these conditions unduly discriminatory and required that a coal-fired unit in operation for at least 50 years, regardless of its age at the time of Settlement, would be eligible for the Mandatory Cap X Capital Recovery Factor even if it were not a signatory. This does not mean that the bid of such a coal-fired unit will be increased or that it is guaranteed any specific investment cost recovery. It means that if the unit is found to possess market power, its bid will not be allowed to exceed the lesser of its avoidable cost which includes an investment cost element or 90 percent of the Net Cost of New Entry.

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[131] December 22 Order, 117 FERC ¶ 61,331 at P 108.

145. Under the 40 Plus option, avoidable cost for units over 40 years old may include 1.1 times the investment cost in one bid only as long as that bid does not exceed the Net Cost of New Entry. Thus, a unit that is at least 40 years old and that possesses market power will not be allowed to bid above the lesser of its avoidable cost or the Net Cost of New Entry. The default avoidable cost does not increase its bid or guarantee any specific cost recovery. If mitigation is triggered, the bid of the unit may be reduced, never increased.

Position of the Parties

146. Mittal Steel criticizes the use of Capital Recovery Factors in the formula for avoidable costs generally and especially the Mandatory Cap X and 40 Plus options. It argues that there is no record evidence to indicate what effect these adjustments may have on costs or how many additional generating units and megawatts might be eligible to take advantage of the new categories. It is especially concerned because recent environmental legislation may lead to massive capital investments in older generators.

147. Mittal Steel and Indicated Buyers object to extending eligibility of the Mandatory Cap X alternative as the Commission required. In particular, Indicated Buyers argue that whether to have a fixed cut-off date for eligibility depends on the purpose of the provision, and the observation that other provisions have a rolling eligibility is not a reasoned basis for the Commission’s change. Indicated Buyers emphasize that the fixed cut-off was intended as a transition and limited to a narrow, finite, and bounded set of resources that may be needed to maintain adequate capacity levels. Thus, according to Indicated Buyers, eliminating the fixed cut-off would only serve to continue support for otherwise uneconomical coal units. According to Indicated Buyers, PSEG was not opposed in principle to a fixed cut-off date, only to the date agreed to in the Settlement. Although PSEG may favor a different cut-off date, the key point is that eligibility for Mandatory Cap X should not be based on a rolling time period, and the 50-year fixed cut-off date proposed in the Settlement is reasonable.

Commission Determination

148. The Commission denies the rehearing requests. The Capital Recovery Factor is the means by which generators are permitted to include in their default bids the actual costs they incur in order to be available. Mittal Steel argues that there is no record evidence to indicate what effect these adjustments may have on costs or how many additional generating units and megawatts might be eligible to take advantage of the new categories. Mittal Steel is concerned that capacity costs might sharply increase under RPM because complying with environmental rules may be costly in its region.

149. However, the inclusion of capacity costs is not an adjustment. As discussed above, the investment costs are the actual costs incurred by a generator in order to participate in the capacity market. The Capital Recovery Factors simply determine the depreciation rate for such costs based on the age of the unit. The use of different depreciation rates is reasonable because older units are more likely to retire earlier, and their default bids should reflect their actual, prudently incurred investment costs over the reasonable remaining life of the asset.

150. If during the auction a generator that qualifies for Mandatory Cap X Capital Recovery Factor is selected to meet capacity needs, and mitigation is required, then its default bid should be included in the calculation of the market clearing price for capacity. However, the higher the bid from these generators, the less likely they will be selected in the auction because new entrants, demand response, or transmission projects may submit lower bids. The concern of mitigation is that capacity costs not reflect the exercise of market power. Mitigation does not, and should not, protect customers from actual capacity cost increases that may be attributable to environmental requirements or other necessary investments in order to allow that generator to participate in the capacity market.

151. Mittal Steel and Indicated Buyers are mistaken to the extent they believe that default bids increase bids, prices, or costs to consumers. If the use of a default bid is triggered because a seller is found to have market power, the outcome is lower bids, prices, and costs to consumers. The default bid should reflect what a competitive seller would offer, a seller that does not have the ability or incentive to increase prices above a competitive level. The avoidable cost default bids do not set the value a seller must offer; they set a value the seller may not exceed when it is found to possess market power. A seller in a competitive market that was required to incur new investment costs in order to participate in that market would ordinarily submit a bid sufficient to recover those investment costs; if price was not high enough to justify such an expenditure, the seller would not incur the costs or participate in the market. Finally, we note that default bids from sellers using the Mandatory Cap X or 40 Plus options are further limited by either 90 or 100 percent of the Net Cost of New Entry even if their calculated avoidable cost would otherwise be higher.

152. Mittal Steel also objects to the Settlement provision giving a generator that qualifies for a given Capital Recovery Factor the option to elect a smaller Capital Recovery Factor to determine its default avoidable cost bid. Under this provision, a generator can opt for a lower Capital Recovery Factor which means that it will have a longer period to recover its costs, and hence that its default bid cap will be lower. Mittal Steel does not explain how it would be harmed by such an option, since the default bid submitted by the generator would be lower. However, we find that such an option is just

and reasonable because the Capital Recovery Factors are based on projected ages and useful lives of plants. It may be that a particular generator believes its plant will last longer than envisioned by the Capital Recovery Factor, and this option provides it with the ability to select a more appropriate depreciation rate.

153. Mittal Steel and Indicated Buyers also seek rehearing of the Commission's determination that the Mandatory Cap X Alternative should be extended to non-signatories and to all generators that are 50 years old, rather than a fixed cut-off date. Indicated Buyers argue that eliminating the fixed cut-off would only serve to continue support for otherwise uneconomical coal units.

154. We deny the rehearing request with respect to the condition that this provision be extended to all generators when they reach the 50-year threshold. As we found in the December 22 Order, it is unduly discriminatory to find that a unit that is 50 years on a fixed date is entitled to a different recovery factor as compared to a unit that becomes 50 years old on the day after the cut-off. Since this provision finds that when units reach the age of 50 years, faster recovery is appropriate, such recovery should be applicable to all units as they reach the applicable age.

155. The application of the Mandatory Cap X alternative does not provide special support for otherwise uneconomic coal units or interfere with the transition to more efficient units or with the price signals sent by RPM, as Indicated Buyers suggest. As discussed above, units eligible for this recovery cannot submit a bid that will recover any more than their actual investment costs. The Mandatory Cap X alternative only allows their default bid to reflect faster depreciation of their investment for significant environmental expenditures in light of the age of these units. In addition, as we also note above, generators eligible for the Mandatory Cap X recovery and possessing market power, cannot submit a bid that exceeds the lesser of either 90 percent of the Cost of New Entry, or the default bid. We reiterate that all generators with market power are subject to bid mitigation. Importantly, mitigation does not guarantee any particular cost recovery, or that a generator will be selected in the auction.

156. Mittal Steel and Indicated Buyers do not provide any evidence, other than the compromise reached by the Settling Parties, for limiting this default bid calculation to a particular set of generators that were 50 years old as of a set date, as opposed to all generators that meet the 50-year applicable criteria. Regardless of such compromise, we reaffirm our determination that this provision in the Settlement was unduly

discriminatory and that Mandatory Cap X should be available to all generators meeting applicable criteria.[132]

c. Bid Adders

157. The Settlement allows during the transition period avoidable cost default bids to reflect a specified dollar adder for up to 3,000 megawatts of capacity for sellers in unconstrained Locational Deliverability Areas with no more than 10,000 megawatts of capacity. The adder is intended to reflect hard-to-measure avoidable costs. For example, PJM noted that the Settlement's peak availability charge arguably adversely affects sellers' risk and costs in a way that is difficult to quantify, and the adder resolved a dispute about how to define these avoidable costs given such changes in the Settlement. PJM supported this adjustment as a limited transition measure unlikely to affect market clearing prices and that encouraged broader support of the Settlement among sellers. The Commission accepted this adjustment as a reasonable measure under the specified circumstances, and extended its applicability to non-signatories.

Position of the Parties

158. Indicated Buyers and Mittal Steel seek rehearing of bid adders and object to this adjustment and to the Commission's condition in the December 22 Order that it be made available to non-signatories, arguing that it is baseless and has no empirical support.

Commission Determination

159. The Commission denies rehearing. During the transition period, PJM will be conducting Base Residual Auctions for four Locational Deliverability Areas, and bid adders only apply to the default bids of certain sellers with market power in unconstrained Locational Deliverability Areas that are subject to mitigation. At the outset, the rehearing requests appear to interpret the term "bid adder" as permitting suppliers to raise bids. This is incorrect. The bid adders are part of default bids that are part of the overall RPM mitigation mechanism that is intended to ensure that sellers with market power will not charge prices to customers that are unjust and unreasonable. These default bids will only come into play in circumstances where sellers have market power, and are being mitigated. Thus, in that circumstance, default bids will lower prices rather than raise them.

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[132] We address the request for rehearing of the extension of certain provisions to non-signatories later in this order.

160. However, in the event that a mitigated generator is relying on a default bid, we find it appropriate for such bid to account for hard-to-measure avoidable costs and we find that the bid adder, as negotiated in the Settlement, is a just and reasonable way to resolve disputes about how to measure these costs during the transition period. Allowing a bid adder for mitigated bids in these circumstances does not reflect the exercise of market power; it merely ensures that certain small suppliers that are mitigated during the transition period are permitted to submit bids that include legitimate, but hard-to-measure avoidable costs.

161. It is also is not clear that these bid adders will have much if any practical effect on the market. First, they apply only to sellers with total capacity of no more than 10,000 megawatts. Because the delivery areas are unconstrained, these sellers have strong incentives to bid the lowest possible price, regardless of their default bid either with or without the bid adder; otherwise, in an unconstrained area, they would run a significant risk of not being selected in the auction. PJM notes that in these unconstrained areas, prices are expected to be low since there are a large number of suppliers and a lack of any need for new entry. To bid above a competitive level would only increase the likelihood of their offer not clearing in the Base Residual Auction.

162. Mittal Steel and Indicated Buyer also object to the Commission's determination to permit these bid adders for non-signatory parties. We address this issue later in this order.

d. Minimum Offer Price Rule

163. One aspect of the settlement calls for a Minimum Offer Price Rule, which addresses the risk that a capacity seller that is also a net buyer could depress market clearing prices unreasonably. The Commission accepted this feature of the Settlement. Basically, a net buyer of sufficient size might build or purchase new capacity under contract and offer it in the auction at less than cost, thus depressing market clearing prices. The Minimum Offer Price Rule would prevent or limit this result in certain circumstances.

Position of the Parties

164. MPC seeks rehearing arguing that this provision would increase price as a result of rational economic behavior on behalf of load. Specifically, MPC argues that an LSE might reasonably decide to serve part of its load through self-supply with a new unit, and bid the supply as a price taker, but the Minimum Price Offer Rule might wrongly increase this bid and market clearing prices. Indicated Buyers do not object to Minimum Price Offer Rule, but do object to the Commission's stated rationale for accepting the Minimum Offer Price Rule. It emphasizes that the Settlement characterized it as a price

support for generators during a transitional period, not a limit on the exercise of monopsony power.

Commission Determination

165. The Commission denies the MPC's rehearing and approves the Minimum Offer Price Rule for the same reason we gave in accepting a comparable Alternative Price Rule in ISO-New England's Forward Capacity Market—"because it helps to ensure that capacity prices will reflect the price needed to elicit new entry when new capacity is needed."[133] As we stated in the ISO-NE order:

> In the absence of the alternative price rule, the price in the FCA could be depressed below the price needed to elicit entry if enough new capacity is self-supplied (through contract or ownership) by load. That is because self-supplied new capacity may not have an incentive to submit bids that reflect their true cost of new entry. New resources that are under contract to load may have no interest in compensatory auction prices because their revenues have already been determined by contract. And when loads own new resources, they may have an interest in depressing the auction price, since doing so could reduce the prices they must pay for existing capacity procured in the auction. If the owners of these two categories of resources control more new capacity than the amount of new capacity needed in a capacity zone, their low bids could artificially depress the price in the FCA.[134]

166. The Settlement Explanatory Statement summarizes the mechanism as follows:

> The PJM Market Monitoring Unit will evaluate any offer based on a new entry unit submitted in a Base Residual Auction for the first Delivery Year in which the unit qualifies as new entry, in any Constrained LDA, and determine whether (i) the offer affects the Clearing Price; (ii) the offer is less than 80% of the applicable Net Asset Class Cost of New entry; and (iii) the seller and any affiliates have a "net short

[133] *ISO-New England*, 115 FERC ¶ 61,340, at P 113 (2006).

[134] *Id.*

> position" (as defined in section 5.14(h)(ii)(3)) in the Base Residual Auction for the LDA that equates to 5 or 10 percent (depending on LDA size) of the LDA Reliability Requirement.
>
> If the PJM Market Monitoring Unit determines that these conditions are met, it will notify the seller and give it an opportunity to provide information to support its offer. If the seller doesn't provide the information, or the information doesn't support its offer, then an alternative Sell Offer, equal to 90% of the applicable Net Asset Class Cost of New Entry, will be employed in place of the actual Sell Offer.[135]

167. In certain circumstances, small additions of capacity by a net buyer may reduce auction prices significantly, and yield a net profit for the buyer, depending on the extent of its net shortage. For example, when capacity exceeds a constrained Locational Deliverability Area's reliability requirements by 2 percent, the demand curve sets prices at 80 percent of the Cost Of New Entry. Adding capacity equal to just 2 percent more of the Locational Deliverability Area's reliability requirements pushes auction prices down to 40 percent of the Cost Of New Entry. An LSE with a significant net shortage in this Locational Deliverability Area might be able to profit substantially by adding this small amount of capacity, even though capacity in the Locational Deliverability Area already exceeds the Locational Deliverability Area's reliability requirements. In the circumstances defined by the Minimum Price Offer Rule, the costs to the buyer of adding the capacity in this situation would be less than the benefits it would receive from reducing the price.[136]

168. If a net buyer's bidding or its self-supply would depress prices as specified in the Minimum Price Offer Rule, the new buyer could cause the market to send incorrect price signals about the value of capacity, potentially encouraging the exit of existing competitive generation, and ultimately discouraging new private investment from anyone other than the dominant LSE given its ability to control price. The Minimum Price Offer Rule is a reasonable tool for avoiding this result.

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[135] Settlement Explanatory Statement at 27. The Commission modified this provision to require that, rather than relying on the Market Monitor's discretion, PJM develop objective criteria for determining when the conditions are met.

[136] *See* Affidavit of Robert B. Stoddard, Representing Mirant parties, in Support of Settlement Agreement. September 29, 2006, at 6-11.

169. Indicated Buyers maintain that the provisions of the PJM tariff do not establish the requisite elements of monopsony power as required by the antitrust laws, in part, because the antitrust laws favor lower prices for consumers. We agree with Indicated Buyers that we are not seeking to enforce the antitrust laws definition of monopsony power, but rather to assure that prices remain just and reasonable for both generators and load, as required by the FPA.[137]

170. The Minimum Offer Price Rule establishes relevant conditions for determining when sellers can depress prices below the competitive level. The Minimum Offer Price Rule identifies sellers of planned resources that satisfy three conditions: (1) their offer must affect the clearing price; (2) their offer is less than 70 or 80 percent of a specified cost of new entry; and (3) they are required to purchase a specified amount or more of the area's reliability requirement. When these conditions are met, and the seller is unable to justify its offer, a sensitivity analysis will be performed to determine if the offer should be increased to a specified alternative default level. The Minimum Offer Price Rule takes effect only if the sensitivity analysis shows specified effects on market clearing prices.

171. These conditions reasonably define when an LSE can cause market clearing prices to be unreasonably low. Condition 1 (requires that the LSE's offer must affect price) shows that the LSE has control over price and output in the market. Condition 2 (a bid lower than 70-80 percent of the cost of new entry) establishes that the LSE's bid price is significantly lower than the cost of new entry, that one would expect a new entrant to bid. Condition 3 limits the Minimum Price Offer Rule to LSEs with a "Net Short" position at or above 5 or 10 percent of the Locational Deliverability Area's reliability requirement. Importantly, the test permits the LSE to justify its bid and, if it cannot, PJM applies a sensitivity analysis to determine whether to adjust the bid. Given all of these indicators, we find that the Minimum Offer Price Rule properly ensures reasonable prices.

172. The issue here is not whether the LSEs are acting rationally to try to reduce market prices, as argued by MPC. The issue here is to ensure that the capacity market works

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[137] *Fed. Power Comm'n* v. *Hope Natural Gas Co*., 320 U.S. 591, 603 (1944) ("The rate-making process under the [Natural Gas] Act, i. e., the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interests"); *see also Bluefield Water Works & Improvement Co*. v. *Pub. Serv. Comm'n of W.Va*., 262 U.S. 679, 692 (1923) ("A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties").

efficiently and produces just and reasonable prices that will reliably guide private investment in electric infrastructure—generating capacity, transmission, and demand response. The Minimum Offer Price rule achieves that objective by ensuring that the prices are just and reasonable.

e. Three-Pivotal Supplier Test

173. A critical element determining whether a particular seller will be subject to mitigation is whether the seller fails the three-pivotal supplier test. The test examines whether capacity controlled jointly by any three suppliers in a Locational Deliverability Area is essential to satisfy the area's capacity requirement. If their combined capacity is required, then the three suppliers are pivotal and subject to mitigation. Because the analysis is conducted for each supplier in combination with the two largest suppliers, more than three entities may be subject to mitigation. That is, capacity jointly held by different combinations of three suppliers may be determined to be pivotal under the test and all such suppliers would be subject to mitigation.

Positions of the Parties

174. PJMICC seeks clarification that all pivotal suppliers in a Locational Deliverability Area that fail the three-pivotal supplier test will be mitigated. It wants this matter specifically spelled out in Attachment DD to PJM's tariff. PJM states in response to the "three-pivotal supplier" issue that application of the test does not mean that no more than three suppliers can be mitigated (i.e. all suppliers that fail the test in a given Locational Deliverability Area will be mitigated).

Commission Determination

175. Section 6.3 of Attachment DD of the PJM RPM tariff provides as one of the market structure tests that "there are not more than three-pivotal suppliers." The three-pivotal supplier test is set out in section 6.4.1 (f) (iii) of Attachment K of the PJM tariff. That provision states that "offer price caps will apply on a generation supplier basis … and only the generation suppliers that fail the three-pivotal supplier test will have their units that are dispatched with respect to the constraint offer capped. A generation supplier's units are offer capped if, when combined with the two largest other generation suppliers, the generation supplier is pivotal."

176. The PJM tariff, therefore, makes clear that if mitigation is triggered in a particular Locational Deliverability Area, all sellers in that Locational Deliverability Area that fail the three-pivotal supplier test will be subject to mitigation. That is, each seller will be limited to a bid that does not exceed its specified default bid value. Regardless, PJM has indicated that it is willing to make clear in the tariff that all generators that fail the three-

pivotal supplier test will be mitigated, and we will require PJM to include such a provision in the tariff.

f. **Role of the Market Monitoring Unit**

177. Under the Settlement, three sections of the tariff[138] would have given the Market Monitor authority to exercise discretion in ways that could potentially affect market clearing prices. These sections specified conditions and parameters that allowed for negotiation between the Market Monitor and sellers that could result in reduced bids, rejection of bids judged by the Market Monitor to be non-competitive, and use of Market Monitor-developed default bids. The Commission found such Market Monitor authority inappropriate. However, in the interest of not delaying the start of the RPM markets, the Commission accepted these three tariff sections on condition that if they are used in the initial Base Residual auctions, they will be subject to a review process by the Commission. PJM was directed to file within nine months appropriate changes to these sections that would eliminate the Market Monitor's discretion and would substitute objective criteria.

[138] Under section 5.14 (h), the Minimum Offer Price Rule that applies to capacity sellers who are also net buyers, the Settlement would give the Market Monitor the discretion to reject certain bids, after negotiation with the seller, if the Market Monitor determined that the justification for the bid was not satisfactory, and replace the bid with an alternate value derived from objective criteria.

Under section 6.5 (a) (ii), which applies to new entrants that meet specified conditions for market power, the Settlement would require the Market Monitor to use discretion to evaluate new entrant bids based on specified criteria. If the Market Monitor determines that a bid is not competitively justified, the entrant is provided an opportunity to submit an alternate bid. However, the Market Monitor could reject the alternate bid if, in its view, the alternate bid was not competitively justified according to the specified criteria.

Under section 6.7 (c), which applies to existing generators that choose not to submit unit-specific data necessary to develop either an avoidable cost or opportunity cost default bid, the Settlement gave the Market Monitor the authority to develop alternative generic, safe-harbor default bids in consultation with stakeholders.

Positions of the Parties

178. Indicated Buyers assert that under RPM, contrary to the Commission's finding in the December 22 Order, the Market Monitor does not have excessive discretion with regard to the Minimum Offer Price Rule, mitigation rules, and data submission. According to Indicated Buyers, the Market Monitor discretion allowed by the Settlement in each example was carefully circumscribed and overseen by a stakeholder process. Indicated Buyers break down each mitigation process about which discretion was an issue and argue that limitations placed on the Market Monitor allow no discretion at all. They insist that the Commission's ordered changes will weaken the Market Monitor's ability to identify and respond to exercises of market power. Indicated Buyers also request that, if the Commission does not grant rehearing of the Market Monitor discretion issue, it should direct PJM to engage in a stakeholder process to develop objective supplemental criteria, not require that PJM alone develop these criteria and make a filing in nine months.

179. PSEG notes that although the Commission has required PJM to eliminate Market Monitor discretion, it is unclear whether the Market Monitor could reject new entrant bids that include various risk premiums. It requests that the Commission clarify that the Market Monitor not reject bids that provide a reasonable basis for included risk premiums or modify the terms of the Settlement to allow for bids to reflect such premiums. PJM responds that to the extent PSEG is asking that default bids be allowed to reflect any measure of risk offered by a seller, its request should be denied. PJM states that although sellers may bid as they choose to reflect their perception of risk, their default avoidable cost bids will be set with objective standards.

Commission Determination

180. We disagree with the arguments of Indicated Buyers and deny rehearing on the issues of Market Monitor discretion they raised. It is true that the range and extent of discretion are limited to some degree in the Settlement, but as we found in the December 22 Order, those provisions still leave the Market Monitor with discretion. Because this discretion would allow the Market Monitor to use its sole judgment to determine inputs that can ultimately set the market clearing price, we reaffirm our determination that such discretion is not appropriate. Instead of relying on the Market Monitor's discretion, objective criteria should be developed for use in such instances so that predictable results will emerge. Absent such objective criteria, the rehearing request of Indicated Buyers does not convince us that the Settlement's mitigation plan produces clearly just and reasonable results to serve as Commission-approved rates.

181. As to Indicated Buyers' point that the objective criteria required by the Commission should be developed in a stakeholder process, we agree and clarify our

December 22 Order accordingly. As with most tariff filings by PJM, we expect the modifications required by our Order to use the stakeholder process to arrive at consensus results on these issues, if possible. If, however, no consensus is possible, PJM, as a public utility, needs to satisfy the conditions of the December 22 Order by filing to amend its tariff by removing the discretion granted to the Market Monitor.

182. PSEG is concerned that the Market Monitor may reject bids with a reasonable risk factor and that the December 22 Order did not specifically rule out that possibility. It is not clear exactly what PSEG is requesting here. We will not grant clarification that any proposed risk factor is acceptable. But to the extent that a new entrant believes it has proposed a reasonable risk factor, it is protected by the short-term and long-term requirements we placed on PJM concerning Market Monitor discretion.

183. In the initial administration of the Base Residual Auctions, PJM is required to file with the Commission all instances in which Market Monitor discretion was relied upon for mitigation. The Commission will review these actions on an expedited basis and all parties will have an opportunity to object to the actions taken. Any bid that was rejected due to a risk factor that the Market Monitor found to be excessive would fall under this procedure.

184. As for the longer term when PJM is required to file objective criteria to replace the discretionary elements, any party, through the stakeholder process and in comments to the Commission, would have the opportunity to propose objective criteria for determining a reasonable risk factor or to contest the criteria that are chosen with respect to this issue. Both of these processes provide a more appropriate opportunity for PSEG, or any other party, to question the level of a risk factor in a bid than for the Commission to offer nebulous guidance on this issue here.

g. Rate Impacts and Cost Based Rates

Positions of the Parties

185. The New Jersey Commission argues that in accepting the Settlement, the Commission failed to discuss the price impact on states like New Jersey on whom the largest price increases will be imposed. The New Jersey Commission acknowledges that severe local reliability problems exist in New Jersey, but states that the RPM Settlement will not address those problems. In the New Jersey Commission's view, the Commission failed to recognize that the settlement is not just and reasonable because it will raise prices and provide only speculative benefits. It states:

> [N]owhere in the December 22 Order is there a discussion by the Commission of the actual price impact on states like New

> Jersey on whom the largest price increases in this experimental construct will be imposed. Without a discussion of those actual rate impacts, the Commission cannot rationally conclude that the resulting rates will be just and reasonable or that the new capacity construct will result in more good than harm.[139]

186. In particular, the New Jersey Commission argues that the Commission's reliance on the RPM Settlement to elicit sufficient capacity is purely speculative, and fails to examine the specific price impact on states like New Jersey. The New Jersey Commission asserts that, absent such a specific evaluation, the Commission's finding that the downward-sloping demand curve is just and reasonable is insufficient: "[r]eliance on economic theory cannot substitute for substantial record evidence and the articulation of a rational basis for the Commission’s decision."[140]

187. PJMICC complains that the Settlement deploys an approach to resource adequacy that is largely administrative and that is a hybrid market/cost-of-service approach, but does not include the necessary safeguards required by cost-of-service rates. PJMICC states that the high cost of natural gas has increased locational marginal prices, resulting in increased inframarginal revenues for all generation except marginal units. PJMICC argues that the Settlement is flawed because it fails to recognize the substantial revenues to baseload and mid-merit units; PJMICC concludes that a full reconciliation of all revenue streams is necessary to ensure that rates are just and reasonable.

188. PJMICC also argues that the Settlement mistakenly presumes that a competitive market will exist. PJMICC states that the Commission has not made the necessary findings to justify market-based rate authority for sales of capacity into the RPM clearing mechanism. PJMICC claims that numerous administrative intrusions that are built into the RPM construct – such as rules for adjusting mitigated bids and the Minimum Offer Price Rule – undermine a finding that the market is competitive. Absent such findings, in PJMICC’s view, the single-clearing price mechanism has no justification and the Commission must align sellers’ revenue opportunities with actual net costs. PJMICC additionally argues that, since the Commission did not find that RPM would produce a competitive market for capacity, the Commission should therefore terminate the market-based rate authority under which sellers now sell capacity in PJM until the capacity market is fully competitive.

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[139] New Jersey Commission request for rehearing at 2.

[140] *Id.* at 9.

189. In its Answer, PJM responds that PJM's current capacity construct already assesses an administratively determined deficiency charge based on the cost of a peaking unit. In PJM's view, moving from a single-value deficiency charge based on an estimate of peaking unit costs to a downward-sloping demand curve that uses an estimate of peaking unit costs is not an unexplained Commission policy shift, contrary to the claims of PJMICC. Moreover, PJM states that the Commission has repeatedly approved single-clearing-price markets, all of which have included Commission-approved mitigation measures that are deployed when market power concerns are triggered. Thus, PJM concludes, the single clearing price auctions in RPM are not precluded since RPM includes market power mitigation provisions.

Commission Determination

190. The New Jersey Commission argues that the Settlement cannot be just and reasonable because it may raise prices and it does not guarantee that new entry will be built or that the benefits of the Settlement will outweigh the costs. However, as the New Jersey Commission has recognized, the current PJM capacity mechanism fails to provide sufficient capacity to keep wholesale electricity in areas like New Jersey reliable. For example, when PJM's capacity market operated under the construct of universal deliverability, LSEs were able to meet their capacity obligation to serve New Jersey customers by purchasing capacity that, in reality, was not deliverable to New Jersey. As a result, under the current PJM capacity mechanism, as PJM noted in its August 31 filing, existing generation in New Jersey is retiring, and there is an insufficient number of new generators offering to replace that capacity to meet New Jersey's needs.[141] Without locational pricing, PJM is likely to continue to experience reliability violations, as it states is already the case in New Jersey and will soon be the case in other regions; or, alternatively, PJM will be forced to resort to out-of-market Reliability Must Run contracts simply to keep necessary capacity in operation.[142] The Commission found in

[141] As noted above, PJM forecasts that load growth in New Jersey will increase by 1,950 MW between 2005 and 2010, but there is insufficient new generation planned to meet this increase: in 2003 and 2004, only 51 MWs of new generation were constructed in New Jersey, and only 1,340 MWs were under construction as of the August 31 filing. Additionally, roughly forty percent of the generation capacity retirements in PJM between 2003 and 2005 were in New Jersey. Herling Affidavit at 7-8.

[142] Under a Reliability Must Run contract, a generator is paid according to its costs of service, rather than taking the market price. The Commission has already accepted two Reliability Must Run contracts in PJM (*see Orion Power Midwest, L.P.*, 117 FERC ¶ 61,049 (2006) and *PSEG Energy Resources & Trading*, 111 FERC ¶ 61,121 (2005)),

(continued)

the December 22 Order that locational pricing is a just and reasonable means of providing the capacity prices that will create incentives for the construction of necessary resources in the appropriate locations to achieve reliability, as well as retaining existing capacity that might otherwise be retired.

191. We recognize that we cannot be certain that RPM will procure the needed capacity for New Jersey and other areas until we and the parties have time to review and analyze how the program is performing. It is always possible that participation in the forward auctions will not be robust enough to meet all demand. However, this would be true of any voluntary auction process and we see no compelling evidence that this particular auction process will not have adequate participation. Furthermore, at the conclusion of each auction all winning bidders take on a binding contractual commitment to provide capacity, three years in advance for one year at a time. The binding one-year commitment coupled with three-year advanced notice provides greater assurance of performance, enforceable through standard contract enforcement measures, and greater opportunity for new entrants to compete with existing capacity providers, than anything in the current capacity construct. Accordingly, RPM provides greater certainty that needed capacity will be procured than the status quo. In approving new rate design initiatives, the Commission must rely on economic theory and evidence as to how rate designs will perform. In this case, RPM is based on the premise that competition in properly designed geographic markets will produce just and reasonable prices.[143] Since RPM combines locational pricing with the three-year forward procurement and the Variable Resource Requirement, it will improve reliability and lower overall costs to consumers. The evaluation done by Dr. Hobbs showed that over the long run overall consumer costs (energy and capacity) would be lower under RPM than under the current vertical demand curve and that reliability would be greater.[144] To ensure that prices remain competitive RPM includes procedures to mitigate the exercise of market power.[145]

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under which capacity providers are compensated under cost of service rates rather than market rates.

[143] *Associated Gas Distributors v. FERC*, 824 F.2d 981, 1009 (D.C. Cir. 1987) (empirical data may not exist for every proposition and agencies may rely on predictions that competition will result in lower prices).

[144] As stated in the December 22 Order, the evidence submitted shows that the Settlement is forecasted to enable PJM to meet its reliability obligations 95 percent of the time, as compared with a forecast of only 52.2 percent under its existing market structure. It also projects that the overall cost of the Settlement provisions will be less than what would be incurred under PJM's existing mechanisms. December 22 Order, 117 FERC

(continued)

192. The actual price effects will depend on market conditions, which are likely to vary over time and in different locations. It may be that for some period of time capacity prices in areas with reliability problems and less cost effective generation, such as New Jersey, will be higher than in areas with a surfeit of capacity. But such higher prices reflect the scarcity of capacity in those areas and will provide an incentive for the entry of more cost effective generation, transmission, or demand response resources that will serve to lower price. Indeed, in such capacity constrained areas, energy prices under the current vertical demand curve are likely to be higher, and customers could be subject to paying deficiency charges for failing to procure sufficient capacity or making Reliability Must Run payments to cover the capital costs of retaining inefficient generation that would otherwise retire. Thus, even if capacity prices may increase in capacity constrained areas, those areas will benefit in the long run from increased entry, transmission construction, and demand response.

193. Indeed, in the event that RPM fails to procure sufficient new entry, the plan contains a backstop mechanism that PJM can use to acquire sufficient capacity to maintain reliability in New Jersey and other areas. Specifically, if PJM determines that the RPM auctions are short for the next three consecutive delivery years, PJM's Office of Interconnection will declare a capacity shortage and then make a filing with the Commission for approval to conduct a reliability backstop auction.[146]

194. The Commission along with PJM and the parties will be monitoring the performance of RPM to determine whether adjustments need to be made to ensure that prices remain just and reasonable. Towards this end, we are granting the New Jersey Commission's rehearing request and are requiring PJM to prepare and post analyses of the performance of RPM so that the states, the stakeholders and the Commission can analyze its performance over time.

195. We disagree with PJMICC that the Settlement does not include necessary safeguards against market power. As PJM notes, the Settlement includes mitigation measures to protect against the exercise of market power, and it is thus unnecessary to engage in the wholesale revocation of market-based rate authority to PJM sellers that PJMICC seems to suggest. With such mitigation in place, the Commission finds that

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¶ 61,331 at P 6, *citing* Settlement Explanatory Statement, Hobbs Supplemental Affidavit at 4 and PJM, October 30, 2006 Reply Comments, Hobbs Supplemental Affidavit.

[145] December 22 Order, 117 FERC ¶ 61,331 at P 141.

[146] PJM tariff, Attachment DD, section 16.

market-based prices derived from the auctions using a single-clearing price mechanism under the Settlement will be just and reasonable. We also disagree with PJMICC who argues that the Settlement is flawed because it fails to recognize the substantial revenues to baseload and mid-merit units. To the contrary, the Settlement provides that the Cost of New Entry, which is used to establish the Variable Resource Requirement curves, will be offset by the net energy and ancillary services revenues.

h. <u>Participation of Transmission in RPM</u>

196. PJMICC asks the Commission to clarify how transmission projects would compete with generation and demand response resources in the RPM auctions.[147] For instance, PJMICC asks whether a transmission project must be approved in PJM's Regional Transmission Expansion Plan before being offered into the RPM auction, and whether, if a transmission project is approved through the Regional Transmission Expansion Plan process, it would become eligible to receive revenues through RPM.

197. We deny PJMICC's request for clarification as its questions have already been addressed. RPM's revenue source for participant-funded transmission "is not intended to be the same as the cost recovery method for regulated rate-base projects approved in the [Regional Transmission Expansion Plan]," as it offers "an alternative, market-oriented approach for project sponsors that are prepared to accept the risks of their projects."[148] Similarly, the definition of the Qualifying Transmission Upgrade in Attachment DD of the PJM Tariff does not require that transmission projects in RPM need to be approved through the Regional Transmission Expansion Plan before being offered into the RPM auctions.[149]

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[147] PJMICC, Jan. 22, 2007, Motion for Stay and Request for Rehearing and Clarification, at 30-31.

[148] PJM, May 19, 2006, Supplemental Affidavit of Steven R. Herling on Paper Hearing Issues at 10.

[149] Attachment DD of the PJM Tariff, section 2.57, states:

> "Qualifying Transmission Upgrade" shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an Local Deliverability Area by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before

(continued)

7. Energy Efficiency

Position of the Parties

198. The New Jersey Commission raises two issues for rehearing with respect to energy efficiency. First, it states that the Commission erred in approving a Settlement Agreement that does not accommodate energy efficiency as a capacity resource eligible to participate in the capacity market. The New Jersey Commission asserts:

> An industrial facility can obtain the incentives RPM offers by being available to curtail its demand for electricity during a time of peak demand. The same facility, however, is ineligible to obtain those incentives by installing energy efficiency measures which permanently reduce its demand, resulting in a barrier to entry for the investment in energy efficiency.[150]
>
> The New Jersey Commission argues that, rather than addressing this question, the Commission simply concluded generally, without reference to any evidence in the record, that the Settlement would promote energy efficiency, "in that greater price awareness is likely to incent users to (a) use energy more efficiently, and (b) become aware that they might benefit from participation in a demand response program,"[151] and did not cite record evidence to support this position.

> the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year; and (d) a Generation Interconnection Customer or Transmission Interconnection Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

[150] New Jersey Commission Request for Rehearing and Clarification at 12-13.

[151] December 22 Order at P 131.

199. Second, the New Jersey Commission also seeks clarification with regard to paragraph 133 of the December 22 Order, where we stated:

> PJM [has] committed to (a) establish an additional process within the PJM region for pursuing and supporting demand response and incorporating energy efficiency applications, and (b) establishing a forum for discussions dedicated to increasing coordination among PJM, state siting authorities, regulatory commissions, and PJM stakeholders to identify, evaluate and rectify barriers to entry of demand response. Within nine months of the issuance of this order, we direct PJM to report to the Commission on the status of the additional process on demand response and energy efficiency, and the results and conclusions from the forum for rectifying barriers to entry of demand response.[152]

The New Jersey Commission asserts that, when the Commission ordered PJM to report back, within nine months, on the results and conclusions for rectifying barriers to entry of demand response, it inadvertently failed to require PJM to report back on the results and conclusions for rectifying barriers to entry of energy efficiency as well, and asks the Commission to provide clarification on this question.[153]

200. In its response, PJM states that there is no need for the Commission to compel the parties to analyze “barriers to entry” to energy efficiency measures, as the New Jersey Commission requests. PJM argues that under section 1252(e)(3) of EPAct 2005, the Commission itself already is charged with addressing barriers to “demand response, peak reduction, and critical period pricing programs” and to that end, the Commission already has instituted collaborative discussions with the states.[154]

<u>Commission Determination</u>

201. RPM represents a significant step forward from PJM’s existing capacity construct in incorporating alternatives to generation because RPM permits demand response as well as transmission to compete with generators in satisfying capacity obligations. As we

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[152] *Id*. P 133.

[153] New Jersey Commission request for rehearing at 5-6, 12.

[154] PJM answer at 37.

stated in the December 22 Order, RPM promotes energy efficiency,[155] in broad terms, because it will facilitate the development of more efficient generating plants, as well as providing an impetus for demand response and transmission solutions. Also, by establishing prices that reflect the economic conditions in individual areas, customers that face those higher prices will have an incentive to use energy more efficiently either through investment in energy efficient appliances or through reduction in demand.[156]

202. But we agree with the New Jersey Commission that RPM does not treat investment in energy efficiency as a type of capacity resource eligible to participate in the capacity market and, that to the extent possible, energy efficiency solutions should be able to compete on an equal footing with demand response, generation, and transmission solutions.[157] The New Jersey Commission however, has not put forward a sufficiently detailed description of how energy efficiency can be included in RPM immediately.

203. We find that the better solution is to require PJM and its stakeholders to examine energy efficient applications, as discussed below, as part of its ongoing forum to determine how such applications can best be incorporated into RPM. PJM and its stakeholders should consider, as part of the forum discussed below, whether a similar

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[155] December 22 Order at P 131; *see also* Settlement, section II. P. 4 at 43.

[156] *Id*. P 141. The New Jersey Commission asserts that the Commission failed to provide evidence from the record to support the Commission's statement that the settlement will promote energy efficiency by incenting users to use energy more efficiently and by making consumers more aware of the benefits of demand response programs. It is not clear what specific evidence New Jersey believes is necessary. Customers exposed to energy and capacity prices in properly defined wholesale markets should have the proper economic incentive to adopt more energy efficient solutions to reduce their need to pay those prices. The extent to which customers have the proper incentives also may depend on the way in which states, like New Jersey, design their retail rates for customer classes.

[157] While energy efficiency solutions may be able to participate as demand response resources, it is not clear that they can do so on equal terms with other forms of demand response.

means of incorporating energy efficient applications into the capacity market to that recently proposed by ISO New England (ISO-NE)[158] could be applicable to PJM.

204. We, therefore, grant the New Jersey Commission's request for clarification with regard to the forum for discussions on demand response to include energy efficiency. The Settlement committed the Settling Parties to establish an additional process within the PJM region for pursuing and supporting demand response and incorporating energy efficiency applications.[159] In accordance with this, the December 22 Order required PJM to establish

> a forum for discussions dedicated to increasing coordination among PJM, state siting authorities, regulatory commissions, and PJM stakeholders to identify, evaluate and rectify barriers to entry of demand response. Within nine months of the issuance of this order, we direct PJM to report to the Commission on the status of the additional process on demand response and energy efficiency, and the results and conclusions from the forum for rectifying barriers to entry of demand response.[160]

We clarify that, as the New Jersey Commission requests, we did not intend to omit energy efficiency from the examination of barriers to entry, and will require PJM's

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[158] In the settlement that led to the creation of ISO-NE's Forward Capacity Market, the New England parties provided that "a distinct method shall be developed to allow energy efficiency . . . to be fully integrated as Qualified Capacity in the Forward Capacity Market." Forward Capacity Market Settlement, section 11.II.E.2.b. In the market rules for the Forward Capacity Market recently approved by the Commission (*ISO New England*, 119 FERC ¶ 61,045 (2007)), energy efficient resources (defined as "installed measures and/or systems on end-use customer facilities that reduce the total amount of electrical energy and capacity that would otherwise have been needed to deliver an equivalent or improved level of end-use service [that] include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, and industrial process equipment", *see* Market Rule 1, section III.1) are able to submit bids to provide capacity, similarly to generation resources.

[159] December 22 Order at P 32.

[160] *Id*. P 133.

report to include results and conclusions regarding barriers to entry of demand response and energy efficiency.

8. Monitoring and Business Rules

Position of the Parties

205. New Jersey Commission argues that the Settlement as approved by the Commission does not provide for sufficient monitoring, and asks the Commission to require PJM to make reports to interested parties of RPM. New Jersey Commission stated that:

> The Commission should require that PJM report to each interested party, including the [New Jersey Commission] and other state commissions, at least annually. Such reports should include the detailed calculation of the Cost of New Entry, the bid levels for winning bids in the auction, the amount of new capacity added as a result of the auction and the amount of capacity that postponed retirement as a result of the auction. PJM should also be required to provide a simulation model, by [Locational Deliverability Area], showing its estimate of the net cost or savings for each [Locational Deliverability Area] compared to what would have likely occurred absent the RPM mechanism. PJM also should be required to compare the results of the auction with the estimates used in the presentation of its witnesses.[161]

206. PJM states in response that New Jersey Commission has not demonstrated the necessity for more than the detailed data which PJM already provides. It notes that the RPM rules already require it to post significant amounts of information before and after capacity auctions.[162] It additionally states that some of the data requested by the New

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[161] *See* New Jersey Commission, Jan. 22, 2007, Request for Rehearing and Clarification at 10.

[162] PJM cites to its tariff, Attachment DD, section 5.11(a), which requires it to post, prior to conducting the Base Residual Auction for each Delivery Year, information including (i) the Preliminary PJM region Peak Load Forecast (for the PJM region, and allocated to each Zone) and the ILR Forecast by Locational Deliverability Area; (ii) the PJM region Installed Reserve Margin, the Pool-wide average EFORd, and the Forecast Pool Requirement; (iii) the Demand Resource Factor; (iv) the PJM region reliability

(continued)

Jersey Commission, such as the offer price in every offer that clears the market, is confidential and would harm competition if publicized, and that some of the data, such as the new units cleared in the auction, may be apparent from public sources. PJM further notes that its Operating Agreement already includes detailed provisions on the process for releasing such confidential data to authorized state commission representatives, while otherwise protecting the confidentiality of such data.[163] PJM finally states that, since its witnesses have not predicted actual market results, comparisons of auction results with projections by PJM would not produce useful information.

207. PJMICC asks that the Commission specify that the new business rules for RPM implementation should not include any revenue-sharing opportunities for generators that are not included in Attachment DD to PJM's tariff. It states that it has become aware of proposed provisions in draft business rules that would allow mitigated bids to be increased relative to levels contemplated under Attachment DD that would include a provision stating that a unit's net avoidable costs relative to the unit's retirement costs, which would cause higher net avoidable cost calculations than if this provision were not included in the business rule.[164]

208. PJMICC asks the Commission to clarify that PJM's business rules must adhere strictly to any finally approved tariff language. PJM asks the Commission to deny this request for clarification, stating that it follows a practice of placing into its tariff practices that significantly affect rates and services, and uses manuals for detailed implementing requirements.

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requirement, and the Variable Resource Requirement Curve for the PJM region; (v) the Locational Deliverability Area Reliability Requirement and the Variable Resource Requirement Curve for each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction, and the CETO and CETL values for all Locational Deliverability Areas; (vi) any Transmission Upgrades that are expected to be in service for such Delivery Year; and (vii) the bidding window time schedule for each auction to be conducted for such Delivery Year.

[163] PJM answer at 36, *citing* PJM Operating Agreement, section 18.17.4.

[164] PJMICC, Jan. 22, 2007, Motion for Stay and Request for Rehearing and Clarification at 31.

Commission Determination

209. The Commission will grant the New Jersey Commission's request for additional monitoring. We agree that, given the impact that the RPM settlement will have on PJM customers and on PJM infrastructure investment, additional reporting will offer PJM members and customers more timely information and analysis of the results of the RPM auctions than PJM currently proposes to provide. In addition to posting pre-auction data on its website per Attachment DD, section 5.11(a), we will require PJM to post on its website the results of each Base Residual Auction for each Delivery Year, and any updates arising from the following incremental auctions. In particular, PJM should provide details regarding (1) supply curves for each Locational Deliverability Area (without revealing the identify of any individual bidder), (2) the amount of new generation that cleared the auctions, (3) estimate of the amount of capacity that postponed retirement as a result of the auction, to the extent this information is available, (4) demand response and transmission participation, (5) information about PJM entities that chose the Fixed Resource Requirement, and (6) the amount of capacity procured. We will not, however, require PJM to estimate the net cost or savings compared to what would have likely occurred absent the RPM mechanism, because such estimates would be highly speculative. In addition, we note that the Cost of New Entry calculations are already publicly available.

210. We agree with PJMICC that PJM must follow its accepted tariff in implementing RPM. PJM's business rules cannot deviate from the provisions of its tariff.

9. Additional Issues

a. Expansion of Settlement Terms to Non-Signatories

Position of the Parties

211. In the December 22 Order, the Commission conditioned its acceptance of the Settlement on PJM removing certain provisions (Mandatory Cap X and bid adders), which provided special preference to signatory over non-signatory parties. The Commission found that such preferences were not shown to be just and reasonable and were unduly discriminatory.[165]

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[165] Specific rehearing requests related to the condition placed on the Mandatory Cap X provision are discussed earlier in the order.

212. Indicated Buyers argue on rehearing that the Commission erred because it arbitrarily expanded certain eligibility provisions of the Settlement to non-signatories. Indicated Buyers insist that the Commission failed to follow ample precedent for permitting different treatment for signatories to a settlement than for non-signatories. Further, they argue that the Commission failed to explain and support its conclusions as to why this distinction, as applied to eligibility for mitigation provisions, was unduly preferential and discriminatory, *citing Williams Gas Processing-Gulf Coast., L.P. v. FERC*, 475 F.3d 319, 326 (D.C. Cir. 2006). Indicated Buyers also argue that the result of the Commission's expansion of these provisions is to allow non-signatories to "cherry pick" the benefits of the Settlement, while preserving their ability to appeal selective issues. *Cities of Bethany. v. FERC*, 727 F.2d 1131, 1139 (D.C. Cir.), *cert. denied*, 469 U.S. 917 (1984) (*Cities of Bethany*); *Cove Point LNG, L.P.*, 98 FERC ¶ 61,270 (2002).

213. Further, Indicated Buyers argue on rehearing that Commission precedent supports their position that there is no reason for the Commission to modify a settlement as long as the rights of the parties opposing the settlement are protected. *Pub. Util. Comm'n of the State of Cal. v. El Paso Natural Gas Co.*, 106 FERC ¶ 61,315, at P 16 (2004), *citing Transcontinental Gas Pipe Line Corp*, 78 FERC ¶ 61,102, 61,362 (1997). Indicated Buyers further argue that under the second approach of *Trailblazer*, approval of a contested settlement is just and reasonable if the Commission finds "that the contesting party would be in no worse position under the terms of the settlement than if the case were litigated."[166] Moreover, Indicated Buyers contend that under *Cities of Bethany*, the Commission may accept settlements that create distinctions among customers. They further argue that because the FPA exists to protect customers, concerns regarding undue discrimination are less applicable when the distinction is among sellers. Indicated Buyers argue that the Commission did not make the findings that are relevant under *Cities of Bethany*, including that the Settlement is the product of bad faith or that it is unduly burdensome to a customer group.

214. Moreover, Indicated Buyers contend that the Settlement resulted from protracted negotiation, involving major concessions from all involved, and represents a careful balancing of interests that the Commission disturbed with the "adjustments" made by the December 22 Order. Indicated Buyers argue that the result is detrimental to consumers.

[166] 87 FERC ¶ 61,110 at 61,439 (1999), *clarifying* 85 FERC ¶ 61,345 (1998).

Commission Discussion

215. The Commission denies rehearing. We continue to find that disparate treatment of signatory and non-signatory parties who are similarly situated is not justified and is unduly preferential.

216. The Commission may accept a rate settlement where signatories and non-signatories ultimately have different rates, as Indicated Buyers argue, but, as the cases cited by Indicated Buyers indicate, such situations occur only when the Commission accepts a rate settlement applicable to the signatories, and then severs the non-signatories to litigate the proper just and reasonable rate.[167] In these cases, the Settling Parties receive the rate to which they agree, but, in contrast to the PJM Settlement, the Settling Parties do not seek to impose a higher rate on the contesting parties. Instead, the contesting parties have the choice of accepting the settlement rate or being severed to litigate the just and reasonable rate applicable to them.

217. In contrast to those cases, severance in this case is not a viable option. Because RPM will create an integrated market that will result in setting a clearing price for all market participants, the rates applicable to non-signatories cannot be separated from the rates applicable to signatories. More specifically, if the non-signatories obtained a different rate after litigation, such a rate would not only result in refunds to the non-signatories, but could require a recalculation of the market clearing prices, affecting all buyers and sellers. Moreover, Indicated Buyers have not presented any evidence that the rate they seek to impose on the non-signatory parties is just and reasonable. In effect, they are arguing that signatory parties to a settlement can seek to induce parties to join a settlement by imposing a less favorable rate on the non-signatory parties without providing an opportunity for the non-signatory parties to litigate the rate applicable to them. As the cases cited above indicate, that has not been sanctioned by the Commission.[168]

218. Indeed, when severance is not an option, the Commission has been unwilling to allow settling parties to impose a higher rate on non-signatories. In *High Island Offshore*

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[167] *See Trailblazer*, 87 FERC ¶ 61,110, at 61,477 (1999); *Cove Point LNG. L.P.*, 98 FERC ¶ 61,270, at 62,046 (2002); *Transcontinental Gas Pipe Line Corp*., 78 FERC ¶ 61,102, at 61,362 (1997).

[168] Whether a party signs a settlement is not a relevant consideration in determining whether they are similarly situated.

System, L.L.C. (*HIOS*),[169] the Commission refused to approve a settlement that imposed higher rates on inactive, non-settling parties. In *HIOS*, Indicated Shippers, a settling party, had received special consideration to sign the settlement in the form of a $3 million payment, but the Commission found the settlement unfair and unduly discriminatory with respect to the other inactive parties who would be required to pay rates twice the just and reasonable level for a significant period of time. In *HIOS*, severance was not an option because the pipeline was unwilling to agree to the settlement if the case were severed. As discussed above, the integrated nature of the RPM capacity construct renders severance not a viable option.

219. Indicated Buyers argue that, following *Cities of Bethany*,[170] the Commission may accept settlement-based distinctions among customers. But this case is similar to the ones discussed above. Even though one party (the cooperatives) was able to obtain a different rate through settlement, the parties challenging that rate (the cities) had an opportunity to litigate the just and reasonable rate applicable to them, and it was found just and reasonable.[171] In contrast, in this case, severance is not a viable option, and the non-signatory parties do not have available to them similar opportunity to litigate the just and reasonable rate applicable to them.

220. Indicated Buyers maintain that under *Trailblazer*, the Commission can approve a settlement if it finds that "that the contesting party would be in no worse position under the terms of the settlement than if the case were litigated."[172] But we cannot find that the non-signatory parties are in the same position they would have been in after severance and litigation. Aside from arguing that signatory and non-signatory parties should be treated differently, Indicated Buyers provide no evidence that the non-signatory rates are just and reasonable or that the non-signatories should not be considered similarly situated to signatories so that the same rate should apply to both.

[169] 110 FERC ¶ 61,043 at P 31-33 (2005).

[170] 727 F.2d at 1139.

[171] *Id.* at 1140 (finding that in agreeing to the settlement, the utility bore the risk that in "determining just and reasonable rates for service to the cities, [the Commission] would allocate costs to the cooperative service that were not reflected in the W-1 settlement rates").

[172] 87 FERC ¶ 61,110 at 61,439 (1999), *clarifying* 85 FERC ¶ 61,345 (1998).

221. *Pub. Util. Comm'n of the State of Cal. v. El Paso Natural Gas Co.,*[173] cited by Indicated Parties, is similarly inapposite. In *El Paso*, the Commission made a substantive finding that the settlement terms were just and reasonable as applied to the contesting parties. As the Commission found, it considered every contested issue raised as to the justness and reasonableness of the settlement. Here, Indicated Buyers provided no evidence that the bid caps applicable to the non-settling parties are just and reasonable.

b. Trial-Type Hearing

222. MPC argues that the Commission should have held a trial-type hearing before ruling on the Settlement. It states that "genuine disputes of material fact have been raised that require a full evidentiary trial to be resolved."[174] MPC does not specify which issues it believes must be resolved through trial-type proceedings; it does state, however, that "[e]vidence was presented to the Commission that indicates that RPM will result in significantly higher prices for consumers in PJM, which could amount to between $5 billion and $12 billion annually for the region."[175]

223. We find that it was not error not to hold a trial-type hearing. The record in this case contained numerous affidavits and data submitted by the parties, as well as technical conferences held on February 2, 2006 and June 7 – 8, and a paper hearing, all of which addressed the issues raised by RPM. On the basis of all these submissions, we conclude that there is a sufficient record upon which the Commission may resolve these issues. MPC has not shown that a hearing is required in this case. As the D.C. Circuit has stated, "mere allegations of disputed fact are insufficient to mandate a hearing; a petitioner must make an adequate proffer of evidence to support them,"[176] and even if such disputed material facts are clearly shown, the Commission "need not conduct such a hearing if [the disputed issues] may be adequately resolved on the written record."[177] Further, a trial-type hearing is only necessary if "motive, intent, or credibility are at issue or there is a dispute over a past event."[178] MPC has not met these standards; it has neither made clear

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[173] 106 FERC ¶ 61,315 at P 12, 16 (2004) (*El Paso*).

[174] MPC request for rehearing at 4.

[175] *Id*.

[176] *Woolen Mill Ass'n v. FERC,* 917 F.2d 589, 592 (D.C. Cir. 1990).

[177] *Moreau v. FERC,* 982 F.2d 556, 568 (D.C. Cir. 1993).

[178] *Union Pacific Fuels, Inc. v. FERC*, 129 F.3d 157, 164 (D.C. Cir. 1997).

what facts it considers "material" and "disputed," nor made its own proffer of evidence as to those disputed facts. Nor has MPC shown why a trial-type hearing including cross-examination would be required to resolve any such disputed matters of fact.

c. April 20 Order Substantive Findings

224. PJMICC seeks clarification, or in the alternative rehearing, that the substantive findings of the April 20 Order are now moot, other than the Commission's finding that PJM's current capacity mechanism is not just and reasonable. PJMICC states:

> In light of the Commission's finding that the Settlement construct replaces the RPM Proposal, and the Commission's outright dismissal of requests for rehearing of the RPM Order, the Commission should likewise clarify that all substantive findings in the RPM Order (other than the finding that PJM's current capacity market is unjust and unreasonable) are also rendered moot.[179]

225. The Commission grants the clarification sought by PJMICC. In the initial April 20 Order, the Commission found the existing PJM capacity provisions unjust and unreasonable and established procedures to determine the just and reasonable provisions to replace that construct. In the December 22 Order, we ruled only on the requests for rehearing of our determination that the existing PJM capacity construct is unjust and unreasonable. Because the Settlement that had been filed constituted an entirely new proposal,[180] we found that rehearing requests of the April 20 Order had become moot,[181] except for our finding that the existing construct is not just and reasonable.[182] Thus, we

[179] PJMICC, Jan. 22, 2007 Motion for Stay and Request for Rehearing and Clarification at 28.

[180] When PJM filed the Settlement on September 29, 2006, it made clear that that settlement proposal consisted of (a) the new tariff sheets filed with it, and (b) all remaining provisions in the original August 31 filing that were not altered by the new material in the Settlement Agreement.

[181] December 22 Order, 117 FERC ¶ 61,331 at P 42.

[182] April 20 Order, 115 FERC ¶ 61,079 at 1.

agree with PJMICC that the substantive basis for our acceptance of the Settlement is found in the December 22 Order.[183]

d. Motion to Stay

Positions of the Parties

226. PJMICC argues that the Commission should stay the effective date of the December 22 Order and delay implementation of RPM for a year or more. PJMICC contends that in accordance with the Administrative Procedure Act,[184] which permits the Commission to stay an order if "justice so requires," the Commission should consider the costs of RPM upon consumers, the complexity of proper refunds at the wholesale level and the pass-through of RPM costs to retail consumers, and the public interest in ensuring that customers' dollars are expended prudently, and grant a stay of the December 22 order. Further, PJMICC asserts that the first RPM auctionsshould be stayed pending resolution of the rehearing and appeal processes that will extend beyond this RPM start-up date.[185]

227. PJMICC notes that in *ISO New England, Inc.*,[186] the Commission granted a motion by the Maine Public Utilities Commission to stay the implementation of the Installed Capacity (ICAP) deficiency charge pending consideration of rehearing requests. PJMICC argues that, similarly to the circumstances in *ISO New England* where the Commission granted a stay of implementation of capacity charges, the start of the RPM capacity market will result in elevated locational pricing and artificially inflated prices. These capacity bids will be reflected in bilateral contracts that will be difficult, if not impossible, to reverse. Further, PJMICC argues that once retail sales are made, LSEs and their customers will suffer irreparable harm because it will be impossible to make refunds to ratepayers should the Commission or the courts subsequently reverse RPM. Moreover, PJMICC argues that its motion to stay should be granted because implementation of

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[183] To the extent, however, that the December 22 Order cites to or relies upon arguments in the April 20 Order, we have adopted those arguments as part of our ruling on the provisions of the settlement.

[184] 5 U.S.C. § 705 (2000).

[185] The first RPM auction occurred between April 2 and April 13, 2007.

[186] 94 FERC ¶ 61,015 (2001) (*ISO New England I*), *order on reh'g*, 95 FERC ¶ 61,174 (2001).

RPM will interfere with state initiatives, particularly in New Jersey and Delaware, to develop new generation and related infrastructure to address resource adequacy issues. For all these reasons, consumers will be harmed, argues PJMICC, if a stay of the Commission's December 22 Order is not granted.

228. PJMICC contends that issuance of a stay will not cause substantial or legally recognizable harm to other parties because, regardless of the faults with the current capacity market, lack of payments to generators under RPM has not yet become a legally recognizable right. Further, generators that are required for reliability are presently allowed to seek a rate based on their costs of service by applying for a Reliability Must Run contract and therefore would not be financially harmed by the issuance of a stay. Finally, PJMICC argues that the granting of a stay is in the public interest because the Commission's December 22 Order will result in unjust and unreasonable rates throughout the PJM region, and the granting of a stay will give time for some states within the PJM footprint to promote new-build generation facilities.

229. PJM, Capacity Buyers/Sellers and PHI in their answers state that PJMICC has failed to meet the burden of showing the existence of all the elements required for granting a stay. PJM and PHI argue that PJMICC cannot show that the issuance of a stay is not likely to cause substantial harm to the other parties because the Commission has already determined that the current PJM capacity construct is unjust and unreasonable. The issuance of a stay, argue PJM and PHI, would result in this unjust and unreasonable capacity market remaining in place, causing potential harm to all electric consumers. Further, PJM and PHI argue that because the Commission determined that the current capacity construct is not just and reasonable, PJMICC cannot show that the issuance of a stay of the implementation of RPM would be in the public interest.

230. PJM also contends that PJMICC cannot show that the Settlement PJMICC accepted last year, with several modifications required by the Commission, would now create irreparable harm to consumers because of possible billing and settlement issues. PJM comments that PJMICC is only speculating that the RPM demand curve will produce elevated locational prices and lead to artificially inflated prices. PJM notes that the Commission denied a similar request to stay implementation of locational marginal pricing for ISO New England made by the Connecticut Attorney General, holding that alleged difficulty in determining refunds did not constitute irreparable injury.[187] Moreover, PJM argues that PJMICC's contention that implementation of RPM will

[187] *New England Power Pool*, 102 FERC ¶ 61,248 at P 11 (2003); *see also City of Holland*, 112 FERC ¶ 61,105 at P 21 (2005); *N.Y. Power Auth. Co.*, 108 FERC ¶ 61,270, at P 13 (2004).

interfere with states' initiatives to incent new generation is speculative and does not show irreparable harm.

231. PJM requests that the Commission find that granting a stay would harm PJM loads, and that PJMICC's request, which assumes the use of Reliability Must Run contracts, is in actuality, a request for the adoption of bilateral contracts to meet the region's reliability needs.

232. Finally, PJM argues that the granting of a stay is contrary to the public interest because the Commission has already determined that RPM, as accepted and modified by the December 22 Order, is a just and reasonable mechanism for assuring the PJM region has sufficient capacity to meet its needs.

233. Capacity Buyers/Sellers argue that Mittal Steel and PJMICC are not seeking to restore the original Settlement Agreement, to which they were Settling Parties, but instead are seeking to block implementation of RPM. Further, Capacity Buyers/Sellers argue that they have not shown that they meet the legal standards to justify a stay of the December 22 Order. Capacity Buyers/Sellers argue that the injury PJMICC alleges will occur in the absence of the Commission issuing a stay is unsupported and speculative. Capacity Buyers/Sellers contends that PJMICC does not allege injury to itself, but only to ratepayers and other parties. Capacity Buyer/Sellers also argue that PJMICC cannot show injury arising from the RPM auction because the Settlement allows parties to opt-out of it through the use of the Fixed Resource Requirement option. Moreover, Capacity Buyers/Sellers argue that alleged economic loss does not constitute irreparable harm.[188] To the contrary, Capacity Buyers/Sellers also note that the record in this proceeding demonstrates that RPM will result in savings for consumers, and not economic injury, as PJMICC alleges. Capacity Buyers/Sellers contend that PJMICC cannot show that a stay would be in the public interest because the Commission in its April 20 Order determined that PJM's current capacity construct was not just and reasonable.

<u>Commission Determination</u>

234. In accordance with the Administrative Procedure Act, the standard for granting a stay by an administrative agency is whether "justice so requires."[189] In our April 22 Order we found that PJM's existing capacity market is unjust and unreasonable, because

[188] Capacity Buyers/Sellers, Answer at P 7, *citing CMS Midland, Inc.*, 56 FERC ¶ 61,177 at 61,631 (1991).

[189] 5 U.S.C. § 705 (2000)

its capacity market fails to set prices adequate to ensure energy resources in local areas sufficient to meet its reliability responsibilities due to a combination of steady load growth and insufficient generation additions. In order to rectify the deficiencies with PJM's existing capacity construct, we approved a replacement to help ensure that PJM's market structure is designed to send appropriate price signals for the needed investment.

235. RPM, by providing for a three-year forward market in better defined geographic markets, along with a downward sloping demand curve, is superior to the current capacity market and, based on the evidence submitted, should procure sufficient capacity to solve PJM's capacity needs.[190]

236. Granting a stay would prolong the time during which PJM and its customers would be subject to a capacity construct that the Commission has already determined to be unjust and unreasonable. Significant price volatility, which PJM has explained discourages investment in new plants or in retaining existing plants, would continue to exist.[191] Delaying the start of RPM could also exacerbate reliability violations that PJM forecasted would occur without new market rules.[192] New Jersey, for instance, faces reliability criteria violations in each of the next four years, and other parts of Eastern PJM, including the Baltimore-Washington area and the Delmarva Peninsula, are trending toward similar violations. Moreover, PJM has an aging generation fleet, which will cause the problem to expand both geographically and temporally.[193] Therefore, we find that a stay is not justified.

237. PJMICC maintains that precedent from ISO New England[194] supports its motion for a stay. The stay in ISO New England was granted to enable the Commission to consider rehearing requests. In this order, we have, for the most part, denied the requests for rehearing, and therefore find no basis for issuing a stay of implementation of RPM.

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[190] December 22 Order, 117 FERC ¶ 61,331 at P 146.

[191] *Id*. P 4.

[192] April 20 Order, 115 FERC ¶ 61,079 at P 11.

[193] Comments of Andrew Ott, PJM at February 3, 2006 technical conference, transcript at 47.

[194] *ISO New England I*, 94 FERC at 61,024.

238. PJMICC argues that the RPM demand curve will produce elevated locational pricing, forcing states and utilities to secure capacity through the auction processes at artificially inflated prices. As we have found in this order, the RPM market design is just and reasonable, and we see no reason to stay the effectiveness of this order. Moreover, in a retail choice state, any PJMICC member can create an individual LSE, whose sole purpose is to serve an industrial customer. This individual LSE could choose either to participate in the RPM auction or meet its capacity obligation through the Fixed Resource Requirement. Further, in a non-retail choice state, any state commission could direct an investor owned utility within its jurisdiction to choose either the RPM auction or the Fixed Resource Requirement. Thus, PJMICC members, through their LSE, have an option for participation that would enable them to avoid participating in the RPM auction.

10. Refunds

239. PJMICC asks the Commission to specify a refund effective date for RPM, and provide refunds based on the just and reasonable rates accepted in this proceeding for 2005 - 2006 and 2006 - 2007.

240. The Commission finds that under the circumstances in this case, there is no basis for establishing a refund mechanism and that ordering refunds would not be equitable or appropriate. There is no reasonable method to determine whether refunds are owed. PJM's existing tariff determined capacity prices based on the bids of buyers and sellers, and there is no means by which the prices resulting from those bids can be redetermined. RPM is the just and reasonable replacement for the pre-existing market structure that the Commission found unjust and unreasonable. RPM, however, cannot be applied retroactively to establish past price or refunds. RPM is designed for prospective application only based on auctions in which generators submit bids, and buyers have the option to either buy at those prices or self-procure capacity. This type of structure cannot be meaningfully applied retroactively.[195] PJMICC has not offered any practical method of implementing a retroactive change in the capacity market determinations made pursuant to PJM's tariff.

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[195] The facts here are very different from *Louisiana Public Service Commission v. FERC*, 482 F.3d 510 (D.C. Cir. 2007), in which the court remanded the Commission's decision not to require refunds of costs that the Commission had found unjust and unreasonable. In that case, the just and reasonable rates resulting from the Commission's determination to exclude interruptible load from the calculation of peak demand could be determined mathematically as of the refund effective date. In contrast, here, RPM, the just and reasonable replacement for the prior unjust and unreasonable methodology, by its very nature, cannot be applied retroactively.

241. Further, refunds would not be appropriate in this case because PJM fully complied with the terms of its tariff in operating its capacity market for the 2005-2006 and 2006-2007 year. Undoing that determination would thus upset the settled expectations of the parties based on past auctions as well as contractual commitments made on the basis of those allocations.

242. The Commission has significant authority to determine whether to order refunds.[196] In cases involving market outcomes on which parties have relied, and in which utilities follow their prescribed tariffs, the Commission has determined that refunds are not appropriate. In *New York Independent System Operator, Inc.*,[197] the Commission explained that:

> the Commission has generally disfavored re-determining market outcomes after the fact, holding that "retroactivity is not authorized when a new rule is substituted for an old rule that was reasonably clear so that the settled expectations of those who had relied on the old rule are protected."[198]

243. Similarly, in *Bangor Hydro-Electric Company v. ISO New England Inc.*,[199] the Commission determined not to retroactively recalculate energy prices when the ISO had complied with the filed rate in its tariff even though (unlike this case), the ISO had committed an error implementing its existing tariff. As the Commission stated: "to go

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[196] *See Niagara Mohawk Power Corp*. v. *FPC*, 379 F.2d 153, 159 (D.C. Cir. 1967) (agency discretion is often at its zenith when the challenged action relates to the fashioning of remedies); *Towns of Concord* v. *FERC*, 955 F.2d 67, 75 (D.C. Cir. 1992), *citing Moss* v. *Civil Aeronautics Board*, 521 F.2d 298, 308-09 (D.C. Cir. 1975) ("Because the 'equitable aspects of refunding past rates are . . . inextricably entwined with the [agency's] normal regulatory responsibility,' . . . absent some conflict with the explicit requirements or core purposes of a statute, we have refused to constrain agency discretion by imposing a presumption in favor of refunds"); *Connecticut Valley Electric Co. v. FERC*, 208 F.3d 1037, 1043 (D.C. Cir. 2000); *Louisiana Public Service Commission v. FERC*, 174 F.3d 218, 225 (D.C. Cir. 1999).

[197] 113 FERC ¶ 61,340 (2005).

[198] *NYISO* at P 17 (*citing Wisvest-Connecticut, LLC v. ISO New England, Inc.*, 104 FERC 61,262, at 61,849 (2003)).

[199] 97 FERC ¶ 61,339 (2001), *reh'g denied*, 98 FERC ¶ 61,298 (2002).

back at this point and change those prices, when no notice was given by ISO-NE that such a disruption might occur, would do far more harm to wholesale electricity markets than is justifiable or appropriate in light of the circumstances raised by Bangor Hydro and would be fundamentally unfair to market participants"[200]

244. In this case, PJM followed its existing tariff in determining capacity prices for the 2005-2006 and 2006-2007 years, parties had every reason to rely upon those prices in making contractual commitments, undoing the allocation would upset these contractual relationships, and no reasonable method exists for retroactively determining just and reasonable prices. In these circumstances, the Commission finds that trying to establish refunds would not be reasonable or equitable.

III. Compliance Filing

245. On January 22, PJM made a compliance filing providing revisions to its Tariff and Reliability Assurance Agreement. PJM replaced the requirement concerning the project investment offer-cap component for certain older coal-fired units with a requirement that such a unit must have begun commercial operation 50 years before the conduct of the relevant Base Residual Auction. PJM eliminated the condition that a market participant must be a Settlement signatory (or an affiliate of a signatory) to qualify for the following provisions: (1) 50-year-old coal units that qualify to include an expedited cost recovery component in their mitigated Sell Offers; (2) a transition period adder to mitigated sell offers available to certain sellers with units located in unconstrained portions of the PJM region; and (3) single-customer LSEs that are eligible to elect the Fixed Resource Requirement alternative. Finally, PJM added a new subsection to add the procedures specified in the December 22 Order to address certain discretionary determinations. PJM seeks an effective date of June 1, 2007. Also, PJM requests waiver of the requirements to permit electronic service rather than paper service.

246. Mittal Steel protests the compliance filing, restating that the Settlement agreement has terminated by its own terms, thereby making the Commission's December 22 Order moot, which makes the compliance filing process ineffective. Mittal Steel further states that the Commission cannot accept PJM's January 22 filing as a section 206 compliance filing. PJM, in its response to Mittal Steel's protest of the compliance filing, states that the filing is a collateral attack on the December 22 Order and the Commission should deny Mittal Steel's motion. PJM emphasizes that Mittal Steel is the only party to state that the Settlement has terminated.

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[200] *Id*. at 62,590.

247. First, as noted above, Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. 385.213(a)(2) (2006), prohibits an answer to a protest, unless otherwise ordered by the decisional authority. We are not persuaded to accept PJM's response to Mittal Steel's protest, and will, therefore, reject it.

248. The Commission accepts PJM's filing as being in compliance with the December 22 Order. Mittal Steel's mootness argument was addressed above in our discussion of its rehearing request, where we found that the Settlement has not terminated. PJM filed the compliance tariff sheets in accordance with the requirements of the December 22 Order, and we find that PJM complied with those requirements and the Commission will accept the filing to become effective on the same date as the RPM tariff sheets. The Commission also will waive the service requirement to permit electronic service.

The Commission orders:

(A) The Commission denies and grants requests for rehearing and grants clarification, as stated above.

(B) The Commission will require PJM to post on its website the information from each Base Residual Auction discussed above.

(C) The Commission accepts PJM's compliance filing.

By the Commission

(S E A L)

Kimberly D. Bose,
Secretary.