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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C. Docket Nos. EL05-148-000
ER05-1410-000

INITIAL ORDER ON RELIABILITY PRICING MODEL

Issued: April 20, 2006

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FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Nora Mead Brownell, and Suedeen G. Kelly.

PJM Interconnection, L.L.C. Docket Nos. EL05-148-000
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INITIAL ORDER ON RELIABILITY PRICING MODEL

(Issued April 20, 2006)

1. On August 31, 2005, PJM Interconnection, L.L.C. (PJM) filed under sections 205 and 206 of the Federal Power Act (FPA) a proposal for a reliability pricing model (RPM) to replace its existing capacity obligation rules (August 31st Filing). In this order, the Commission finds that PJM's existing capacity construct is unjust and unreasonable, makes rulings and provides guidance as to various issues raised with respect to establishing the just and reasonable replacement for the existing construct, and establishes further procedures, including a paper hearing and staff technical conference, for resolving the remaining issues. At the same time, the Commission encourages the parties to continue to seek a negotiated resolution, and offers the Commission's settlement judge procedures or dispute resolution service (DRS) to facilitate these discussions.

2. PJM operates the largest competitive wholesale electricity market in the country, covering 14 states, ranging from the Eastern Shore (New Jersey to North Carolina) west to the Midwest heartland. This system has eliminated seams and pancaked rates between regional utilities, providing for a more efficient sharing of resources and enabling parties to more easily access the cheapest sources of supply from within the PJM footprint. PJM is responsible for ensuring the reliability of the system it operates and currently oversees capacity obligations of its LSEs to ensure it has sufficient generating capacity to satisfy its reliability responsibilities.[1] Within the breadth of

[1] *See* PJM Operating Agreement (OA), Schedule 11 ("the PJM Capacity Credit Markets shall be administered by the Office of Interconnection in accordance with the principles and procedures specified in this Schedule"); PJM Reliability Assurance Agreement (RAA), Article 7, Schedule 6, Schedule 10, and Schedule 11.

PJM's system, it must also address reliability concerns that may arise in localized areas[2] within its regional control.

3. The current PJM capacity construct assumes that generating resources located anywhere within PJM can satisfy the capacity needs in any local area within PJM. PJM states that while it has sufficient overall capacity for its system today, in recent years PJM has had difficulty from time to time in meeting reliability requirements in localized areas, and it expects this problem to expand to other areas as well.[3]

4. As a result of these reliability concerns, PJM has been working with its stakeholders for several years to develop a comprehensive approach to both retaining existing generation and establishing prices that will encourage the entry of resources to resolve reliability problems. Because the stakeholders were unable to reach the requisite consensus on a single solution to this issue, PJM made the instant filing under sections 206 and 205 of the FPA asking the Commission to find that its existing capacity construct is unjust and unreasonable and that its RPM proposal is a just and reasonable replacement.[4]

5. As discussed below, the Commission finds that as a result of a combination of factors, PJM’s existing capacity construct is unjust and unreasonable as a long-term capacity solution, because it fails to set prices adequate to ensure energy resources to meet its reliability responsibilities.

6. The Commission cannot at this time find that the RPM proposal as filed by PJM is the just and reasonable replacement for the current capacity construct, because certain elements of the proposal need further development and elaboration before the Commission can issue a final order. However, the Commission finds that certain elements of the RPM proposal, with some adjustment and clarification, may form the basis for a just and reasonable capacity market. In this order, the Commission will provide guidance on PJM’s RPM proposal, as well as other features that need to be included in a just and reasonable capacity market, and will establish procedures to resolve these issues. The following summarizes the determinations made.

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[2] *See generally District of Columbia Public Service Commission,* 114 FERC ¶ 61,017 (2006) for discussion of areas within the PJM’s system that are defined by physical constraints.

[3] August 31st Filing, Transmittal at 5.

[4] *Id.* at 3.

- Locational Capacity Markets: The Commission finds PJM's proposal to include a locational element in its capacity construct to be just and reasonable. However, the Commission cannot make a determination based on the current record that the areas proposed by PJM will best reflect the operational characteristics of the system, and therefore establishes paper hearing procedures to determine the best method to ensure that the locations in the capacity construct reflect transmission constraints within PJM.

- Forward Procurement: The Commission agrees that PJM’s current method of allowing daily and monthly procurement of capacity should be replaced with an obligation to acquire capacity sufficiently in advance of the time of delivery to support planning. The Commission is approving here PJM's proposal to implement the four-year-forward procurement requirement, and is setting for paper hearing the appropriate length of that commitment.

- Integration of Generation, Demand Response, and Transmission: The capacity construct must permit generation, demand response, and transmission a reasonable opportunity to compete in solving reliability concerns. The Commission finds that PJM’s proposed approach adequately integrates demand response resources. The Commission understands that PJM is working on revisions to its Regional Transmission Expansion Plan (RTEP) and strongly encourages PJM and the parties to make sure that such revisions are made in a way that coordinates with the capacity market, and is requiring PJM to report to the Commission on that coordination, as described below.

- Mechanism for Acquiring Capacity: In recognition of the differences between the multiple areas within PJM, the Commission finds it is appropriate to allow a dual method of satisfying capacity obligations from which states and utilities can choose. One method would be the use of the capacity auction approach proposed by PJM with the price set at the intersection of a downward sloping demand curve and supply bids made by capacity resources. This option would result in a resource requirement for load serving entities (LSEs) that varies over time. With respect to this approach, the Commission finds that such a demand curve is one just and reasonable method of establishing capacity resource prices, but will determine the parameters and slope of the demand curve in the technical conference established here.

  The second method will be to require each LSE to be responsible through self-supply or contracts for meeting its locational reliability targets for the procurement period determined. This option would result in a capacity requirement for LSEs that is fixed (as a percentage of its peak load). The

Commission finds that LSEs choosing this approach must commit to using this approach exclusively for a sufficiently lengthy time period (such as 10 years), to ensure that LSEs do not switch between the approaches whenever prices are more favorable, thereby potentially purchasing a lesser amount of capacity than would otherwise be desirable over the long-term. The Commission also finds that there must be a meaningful deficiency charge for failure to meet reliability targets under this approach. The Commission will determine certain details of this approach, such as the basis and computation of the deficiency charge, the duration of the commitment to this approach, whether an LSE that chooses RPM should be required to commit to RPM for more than one year (and, if so, how long), and the determination of the amount of capacity that the LSE must acquire through the technical conference that it is establishing here.

- Integration with Revenues Derived from the Energy Market: The Commission recognizes that if the capacity market is to provide sufficient incentives for new entrants, the market must be confident that the capacity construct will continue long enough for entrants to recover their investment costs. At the same time, the capacity construct must be flexible enough so that changes in energy market rules, such as scarcity pricing or changes in offer caps, may change the revenues that generators can expect to receive for capacity sales. The Commission finds that PJM's proposal to include energy revenues in determining the slope of its demand curve is a reasonable method of ensuring that changes in energy markets will be reflected in the capacity market.

7. The Commission requires PJM to file a response to the issues set forth below for paper hearing by May 19, 2006. Parties may file comments by June 2, 2006. Reply comments may be filed by June 16, 2006. We also set for staff technical conference the additional issues below. The dates of that technical conference will also be provided in a subsequent order. A list of the specific issues set for paper hearing, and the specific issues set for staff technical conference, are at Appendix A to this order.

8. Upon completion of the paper hearing and technical conference, the Commission expects to issue a final order as soon as possible thereafter.

I. Background

A. Current Capacity Construct

9. The PJM market structure includes a generation capacity construct as a means to ensure long-term adequacy of supply and adequate availability of generation to meet demand. It was designed to ensure that generation would be available when needed to meet peak day load on a reliable basis and is described in PJM’s RAAs and Schedule 11

of the OA.[5] PJM's RAA states that each LSE must procure capacity resources equal to a fixed percentage above its peak load to ensure a sufficient amount of capacity to meet the forecasted load plus reserves adequate to provide for the unavailability of capacity resources, load forecasting uncertainty, and planned and maintenance outages.[6] This requirement is determined by the PJM Board and is currently equal to 15 percent.[7] LSEs can acquire capacity resources by entering into bilateral agreements, by participating in the PJM-operated Capacity Credit Markets or by constructing generation.[8] Capacity resources do not include transmission upgrades or demand response resources, and there is no mechanism to include planned resources. Further, there is no mechanism to consider the operational characteristics of a capacity resource. While each LSE must procure the requisite capacity for every day of the year, the LSE may wait to procure its requirement until the day before the operating day. Capacity resources under the existing construct can be committed for periods as short as one day, although there are limited incentives for longer term capacity commitments for LSEs**.** In addition, under the PJM-operated Capacity Credit Market, the same price is paid for capacity regardless of where the capacity is located.[9] Failure to meet the requirement results in a deficiency charge based upon the cost of new entry of a combustion turbine.[10] LSEs may use resources located anywhere within PJM to fulfill their capacity requirements, and as a result, since

[5] PJM uses a loss of load expectation (LOLE) to measure capacity requirements. The LOLE goal is for demand to exceed capacity no more than one day in ten years. August 31st Filing, Transmittal at 37.

[6] *See* PJM RAA, Article 7; PJM Southern Region RAA, Article 7; and PJM Western Region RAA, Article 8.

[7] *See* PJM RAA, Schedule 4.1; PJM Southern Region RAA, Schedule 4.1; and PJM Western Region RAA, Schedule 4.1.

[8] *See* PJM RAA, Article 7.4; PJM Southern Region RAA, Article 7.4; PJM Western Region RAA, Article 8.4; and OA, Schedule 11, section 1.3.

[9] *See* PJM RAA, Schedule 4.1; PJM Southern Region RAA, Schedule 4.1; and PJM Western Region RAA, Schedule 4.1.

[10] *See* PJM RAA, Schedule 11; PJM Southern Region RAA, Schedule 11; and PJM Western Region RAA, Schedule 11.

universal delivery of capacity to all loads is assumed as part of this construct, there is no price difference among resources in different locations.

10. PJM is responsible for ensuring reliability within the PJM region.[11] It alleges that several factors external to its current capacity construct have had an impact on the capacity construct.[12] For example, generators' inability to recover sufficient costs in PJM's energy markets has had significant impact on their ability to remain in service.[13] Additionally, PJM has experienced steady load growth.[14]

11. According to PJM, the limitations of PJM's capacity construct will result in multiple reliability criteria violations in Eastern PJM, particularly in New Jersey, the Delmarva Peninsula and the Baltimore-Washington area as early as 2006. PJM also anticipates that other parts of Eastern PJM are trending in this same direction. PJM asserts that these violations result from steady load growth and insufficient generation additions. PJM predicts that these underlying trends will continue in the future if the current capacity construct is left in place. Additionally, PJM identifies the lack of a requirement for a long-term forward commitment for capacity as one of the principal deficiencies in its current capacity adequacy construct. Because capacity commitments are largely short-term, capacity resources are not able to project an adequate revenue stream going forward. In this way, PJM argues, the current construct does not provide meaningful price signals to capacity resources of the true value of the level of reliability that they provide to the system.[15] In addition, PJM asserts that its daily and monthly

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[11] *See PJM Interconnection, L.L.C.*, 96 FERC ¶ 61,061 at 61,229 (2001) (in finding that PJM qualified to be a Regional Transmission Operator (RTO), the Commission stated that an RTO "must have exclusive authority for maintaining the short-term reliability of the grid that it operates"); *PJM Interconnection, L.L.C.*, 109 FERC ¶ 61,094 at P 30 (2004) ("PJM is responsible for the reliability of the entire PJM footprint").

[12] August 31st Filing, supporting affidavits.

[13] August 31st Filing, Transmittal at 7, *citing* Tab G, Affidavit of Joseph Bowring (Bowring Affidavit) at 15.

[14] August 31st Filing, Tab F, Affidavit of Steven L. Herling (Herling Affidavit) at 7.

[15] August 31st Filing, Tab E, Affidavit of Andrew Ott (Ott Affidavit) at 13.

capacity credit market has led to significant volatility in capacity prices.[16] PJM also asserts that this creates sufficient uncertainty regarding the possibility of cost recovery, so as to render generators reluctant to invest in new generation. PJM claims that, as a result, planned generation has been often cancelled.[17] Thus, PJM asserts, its current capacity regime cannot sustain long-term generation investment.

B. Reliability Pricing Model: Overview of the Proposal

12. PJM states that its efforts to reform its capacity rules have been ongoing for the past five years.[18] RPM was devised as a comprehensive solution to PJM's continuing capacity market issues.[19] PJM explains that it organized numerous stakeholder meetings to discuss the merits of this proposal and to refine its design. On June 16, 2005, the Commission sponsored a technical conference to explore the purpose of a capacity market and the elements of PJM's proposal. This technical conference also addressed alternatives to the RPM proposal.[20] Twice PJM and its board sought stakeholder support for its RPM proposal, but the proposal has failed to achieve supermajority support from the PJM Members Committee.[21]

13. On August 31, 2005, PJM filed its RPM proposal under sections 205 and 206 of the FPA to change its existing capacity construct under its OA and to implement changes to its tariff and RAA. PJM made its filing under both FPA sections because it failed to

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[16] *See* August 31st Filing, Tab H, Affidavit of Benjamin Hobbs (Hobbs Affidavit) at 45-56..

[17] August 31st Filing, Transmittal at 46.

[18] *Id*. at 49.

[19] *Id*. at 50.

[20] *See Capacity Markets in the PJM Region*, Docket No. PL05-7-000, Notice of Technical Conference (May 19, 2005).

[21] *See* Letter of Phil Harris to the PJM Members Committee and Stakeholders, March 22, 2005, available at http://www.pjm.com/committees/members/downloads/ltr-to-mc-stakeholders-replaces-311560.pdf.

get the requisite stakeholder approval for a section 205 filing under its OA.[22] PJM recognizes that it cannot put the section 205 filing to revise its tariff and RAA into effect until after the Commission has completed action on the section 206 filing:

> To the extent the Commission requires additional time to process the section 206 request in this filing, PJM consents to an effective date for the tariff and RAA sheets submitted under section 205 that coincides with the effective date the Commission establishes under section 206 for the operating agreement changes.[23]

14. PJM offers RPM as a comprehensive capacity adequacy construct to address the deficiencies in PJM's current structure in a comprehensive and integrated manner. The major features of the PJM RPM proposal include:

- Locational capacity requirements. Over a four-year period, PJM would establish up to 23 separate capacity zones. Each LSE would be required to procure resources that were deemed to be able to deliver energy to that LSE's zone in light of transmission constraints.

- Four-year-forward procurement auction. Each LSE would be required to meet its capacity obligation four years in advance, rather than one day in advance as at present. In addition, each LSE would commit to purchase the capacity resource for at least one year. PJM would procure resources through an auction for LSEs that have not met their obligations by the four-year-ahead deadline.

- Demand response and transmission participation. LSEs will be allowed to satisfy their capacity obligations not only with generation, but also with

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[22] Unlike most utilities, PJM was formed through an agreement of its stakeholders. This agreement provided that PJM could not make filings to revise its OA (which contains its existing capacity construct) unless it receives a 2/3 vote from its Members Committee. *See* PJM OA, section 7.7 (vi) (PJM Board can file under section 206 with respect to a provision of the OA it believes to be unjust, unreasonable, or unduly discriminatory), section 8.8 (Members Committee must vote on changes to the OA), and section 8.4 (c) (.667 vote required for Members Committee approval). Because PJM did not receive the requisite 2/3 vote of its Members Committee, PJM was required to file its proposal to change its OA under section 206.

[23] August 31st Filing, Transmittal at 2 n. 4.

existing and planned demand resources. Transmission participation will also be integrated into the RPM capacity market by allowing for planned transmission upgrades that provide incremental increases in import capacity into constrained areas to be offered into the auctions.

- Variable resource requirement (VRR). The capacity obligation (and the price per MW) would be determined using a downward sloping demand curve.

- Mitigation. A set of explicit market power mitigation rules that directly address market structure concerns of capacity markets.

- Quick-start and load-following requirements. A specified percentage of the total capacity obligation would be required to have quick-start or load-following capabilities.

- PJM included in its draft business rules an "opt-out alternative." Under these draft rules, an LSE electing this alternative would submit to PJM each year a fixed capacity resource plan covering the next five years, including the RPM Delivery Year, designating the load to be covered, the unit-specific generation resources to cover the capacity requirement, and any transmission upgrades needed to ensure deliverability of the generation to the load.

15. PJM explains that RPM is intended to provide incentives for needed generation capacity in the near future[24] PJM argues that RPM is designed to automatically de-emphasize the capacity construct as the energy market develops effective incentives for creating capacity resources. PJM also argues that the VRR curve, which is designed to reflect varying levels of generator revenues, is offset by net revenues from other sources and thus will automatically track (although with a time lag) any transition towards energy markets, including changes to the offer price cap, development of scarcity pricing or evolution of load management techniques and compensation.

16. In its August 31st Filing, PJM requested the Commission to issue a final order on this matter by January 31, 2006 to allow PJM to replace its current capacity construct with RPM on June 1, 2006. PJM subsequently changed the requested date for

[24] *Id.* at 15-16.

Commission action to October 1, 2006. Under this revised time frame, PJM is seeking to implement its RPM proposal by June 1, 2007.[25]

17. The RPM filing was noticed in the Federal Register, with protests, comments and notices of intervention due to be filed on September 21, 2005.[26] The parties seeking intervention are listed in Appendix B. Parties filing comments or protests are listed in Appendix C. Subsequently, PJM, Cinergy, Edison Mission and PSEG filed answers to the protests and comments, and AMP-Ohio, Mirant and PPANJ filed answers to those answers. On February 3, 2006, the Commission conducted a technical conference to explore the current state of the PJM capacity construct, to address the specifics of the RPM proposal and to evaluate alternative approaches to RPM.[27] Conference participants were subsequently given the opportunity to submit comments to issues raised at this conference.

II. <u>Procedural Issues</u>

18. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2005), timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. The Commission finds that granting all late-filed motions to intervene filed up to the date of issuance of this order will not delay, disrupt, or otherwise prejudice this proceeding, or place an additional burden on existing parties. Therefore, for good cause shown, pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2005), we will grant the late-filed motions to intervene.

19. Rule 213(a) (2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a) (2) (2005), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept the answers because they have provided information that assisted us in our decision-making process.

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[25] PJM answer at 1.

[26] 70 Fed. Reg. 54,041 (2005).

[27] *See* Notice of Commission Technical Conference, PJM Interconnection, L.L.C., Docket Nos. ER05-1410-000 and EL05-148-000, issued December 8, 2005.

III. Discussion

20. Under section 206 of the FPA, before imposing a rate change, the Commission must both find that the "existing rate, charges, or classification, demanded, observed, charged, or collected by any public utility … is unjust, unreasonable, unduly discriminatory or preferential," and must also "determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order."[28] The Commission finds that under section 206, PJM has demonstrated that its current capacity construct is unjust and unreasonable, on a long-term basis. We are, therefore, providing rulings and guidance to determine a just and reasonable alternative.[29]

A. PJM has demonstrated that its current capacity adequacy construct is not just and reasonable.

21. The Commission finds that under section 206 PJM has demonstrated that its current capacity regime is not just and reasonable as a long-term capacity construct because it fails to address inadequacies in reliability, as discussed at length herein.

a. PJM's Position

22. PJM argues that its current capacity construct is unjust and unreasonable because it fails to assure that reliability will be maintained at a reasonable cost. PJM identifies three major factors that, in its view, create this failing. First, PJM argues that the current capacity construct lacks an important locational element.[30] PJM states that the system's ability to deliver capacity can vary by location, but the current tariff rules do not differentiate capacity prices by location. The result, according to PJM, is that PJM has seen few generation additions, but high rates of generation retirements, in some of the areas where load is growing the fastest. As a result, PJM concludes, New Jersey faces

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[28] 18 U.S.C. § 824e (2000).

[29] PJM recognizes that it cannot put its section 205 filing into effect until the Commission has completed action under its section 206 proposal, which includes finding that PJM's existing tariff is unjust and unreasonable, and concludes that PJM has established a just and reasonable replacement. Consistent with PJM's statement, PJM cannot make its section 205 filing effective until the Commission completes its action on PJM's section 206 proposal.

[30] August 31st Filing, Transmittal at 5-6.

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 argues, it has an aging generation fleet which will cause the problem to expand both geographically and temporally.[31]

23. The second factor, according to PJM, is that the current capacity construct fails to provide sufficient financial incentives for supply additions.[32] PJM states that capacity prices have been very volatile. PJM reports that daily prices in the PJM capacity credit market have been at or near zero for most of the 2000 – 2004 period, with occasional spikes (some lasting multiple months) of well over $100 per megawatt-day. Moreover, PJM's Market Monitor testifies that net revenues to generators from all sources have been insufficient to cover the cost of investment in the most efficient marginal capacity unit, i.e., a gas turbine peaking unit.[33] PJM states that the current construct assesses a capacity deficiency charge based on the costs of a new peaker if the LSE commits less capacity than its Installed Reserve Margin (IRM) requirement. PJM argues that this construct promotes price volatility because prices become very high if there is a shortage of even a few megawatts below the IRM, but drop to zero if there is a surplus of even a few megawatts above the IRM.

24. The third factor identified by PJM is that the current rules do not look far enough into the future to secure capacity in time to meet reliability needs.[34] The current rules allow capacity resources to be committed for as short as one day, and PJM administers Capacity Credit Markets only for the succeeding twelve months. Capacity resources can opt out of their capacity resource status (or "de-list") with as little as 36 hours' notice. PJM argues that the short-term nature of the current construct is fundamentally inconsistent with the need to preserve system reliability in the longer term. PJM contends that the current rules fail to create a long-term forward commitment or forward price signal.

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

[32] August 31st Filing, Transmittal at 6-8.

[33] Bowring Affidavit at 10-16.

[34] August 31st Filing, Transmittal at 8-9.

25. PJM argues that, in addition to these major failings, the current construct provides no meaningful opportunity for demand resources to compete to satisfy reliability requirements, does not allow merchant transmission to compete directly with locational generation to resolve load deliverability problems, fails to recognize the added value provided by generation having load-following and 30-minute-start capabilities, and contains no explicit provisions to address market power concerns in capacity markets.[35]

b. Comments

26. At the February 3, 2006 technical conference and in the comments submitted after the technical conference, there was a broad consensus that the existing capacity construct cannot be relied on to assure reliability and to assure just and reasonable rates. Parties disagree about the magnitude of the existing problems and about the appropriate solution, but no party at the technical conference argued that the existing capacity construct should remain unchanged. For example, FirstEnergy agreed that there are "serious deficiencies" with the current capacity construct, while expressing concerns with some of the features of the proposed RPM, such as the role that states would play, as well as the concern that only four years of price signals would not provide a sufficient incentive for new construction.[36] The Pennsylvania Commission also noted that there are inadequacies in the current capacity construct.[37] Morgan Stanley stated that efficiently attracting and sustaining needed capacity is not achieved under existing capacity structures, and recommended a change to an energy-only market without bid caps combined with requirements for LSEs to enter into long-term contracts.[38]

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[35] *Id*. at 9.

[36] Comments of John Judge, FirstEnergy Service Co., at February 3, 2006 technical conference, transcript at 63-67.

[37] Comments of Andrew Tubbs, Counsel for Commissioner Kim Pizzingalli, Pennsylvania Commission, at February 3, 2006 technical conference, transcript at 72.

[38] Comments of James Sheffield, Morgan Stanley, at February 3, 2006 technical conference, transcript at 200-02.

27. Supporters of RPM, including many generators and some investor-owned utilities, agree with PJM's general assessment of the nature and magnitude of the problems with the status quo, described in the previous section.[39]

28. Opponents of RPM also agree that there are problems with the existing construct, although they argue that the problems are more modest and require more modest changes.[40] In general, opponents agree that there are capacity problems in certain portions of Eastern PJM that have arisen under the current capacity construct, but argue that these problems do not extend to other areas in PJM. This opposition is reflected in CCR's comments, which raise concerns about the severity of the risk related to generation retirements, particularly those in New Jersey, and recognizes that changes must be made to ensure that locational requirements are satisfied. However, CCR contends that this problem should be addressed through changes to the current 90-day generator retirement notice requirement and an improved PJM transmission planning process. CCR concludes that PJM is not experiencing a region-wide generation shortage, and points to a PJM-wide reserve margin of 23 percent above peak load.[41] CCR is concerned about the impacts of implementing RPM as filed, but it is also concerned about doing nothing, since doing nothing would put consumers at risk with respect to reliability. APPA argues that baseload units in PJM are earning excessive profits in the spot markets due to the single-price rule for establishing prices in PJM's spot markets, but it does not dispute PJM's conclusion about the revenue inadequacy of peaking units.[42]

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[39] *See, e.g.*, comments of Reem Fahey, Edison Mission, at February 3, 2006 technical conference, transcript at 55-58; comments of John Young, Exelon , February 3, 2006 technical conference, transcript at 58-62; and comments of Marjorie R. Philips, Constellation, February 3, 2006 technical conference, transcript at 142-146.

[40] *See, e.g.*, CCR protest at 3 ("targeted, incremental solutions are much more likely to produce successful, predictable results for the local reliability issues"), attachment to PJMICC protest (direct testimony of Darren MacDonald) at 16 (RPM is "an expensive non-solution to localized problems"), Virginia Commission protest at 4 ("a more logical approach would be to focus on those areas that are experiencing or approaching reliability criteria violations").

[41] CCR post-technical conference comments.

[42] APPA post-technical conference comments at 12-13.

c. **Commission Determination**

29. We describe above in Section I.A PJM's existing capacity construct as well as other factors that have an impact on resource adequacy and reliability in PJM. The Commission finds PJM's existing capacity construct to be unjust and unreasonable. 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.

30. As noted above, there is general agreement that PJM's existing capacity construct is ineffective. Many parties agree, and no party disputes, that at least some areas within PJM – especially New Jersey, the Baltimore-Washington area, and the Delmarva Peninsula – are failing to attract adequate infrastructure to assure local reliability, that this situation is projected to worsen, and that the existing capacity construct has contributed to this problem. While there is disagreement among the parties as to whether there are impending capacity problems outside of the "classic" PJM footprint, no party disputes the conclusion that there is a growing problem with the status quo and that at least some changes must be made to the existing capacity construct.

31. According to the affidavit of Steven Herling on behalf of PJM,[43] which no party has disputed, multiple reliability criteria violations in PJM, particularly in New Jersey, have occurred recently due to generation retirements. PJM estimates that in New Jersey load will increase by 1,950 megawatts (9.8 percent) between 2005 and 2010, but 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. Load growth in the Delmarva Peninsula is projected to be 2.7 percent per year, or an increase of 573 megawatts over the next five years, but planned generation additions are minimal. Only 60 megawatts were added on the Delmarva

[43] Herling Affidavit at 7-8.

Peninsula in 2004, and 150 megawatts are being studied. In the Baltimore-Washington area, only 77 megawatts were added in 2004, and no further additions are currently being studied.

32. Between 1999 and 2002, 274 megawatts were retired in the Mid-Atlantic region. From January 1, 2003 through June 22, 2005, 1,709 megawatts have been retired, and an additional 1,694 megawatts are proposed for retirement before 2008. Forty percent of the retirements (including those currently proposing to retire) since 2003 are located in New Jersey. Owners of retired generation point to excess generation in the Western region of PJM and their inability to compete economically. These retirements have led to identified reliability criteria violations for 2005 and each succeeding year in the most recent planning horizon (through 2009). Retirements in the Baltimore-Washington area in 2003 are projected to result in reliability criteria violations for the Baltimore-Washington and Delmarva Peninsula by 2008. Some identified violations may be resolved by planned transmission upgrades, but such upgrades are only a temporary solution.[44] PJM states that unless additional generation is sited in those areas, further load growth would require more extensive and costly transmission upgrades. There is a risk that such transmission upgrades would not be built in time. Further, delaying retirements can be only a temporary solution as many of the units are near the end of their useful lives.

33. Moreover, while the PJM footprint outside of these areas currently has a reserve margin in excess of the 15 percent requirement, much of this capacity may need to be replaced in the near future in light of the advanced age of PJM's generation fleet. Audrey Zibelman, Executive Vice President and Chief Operating Officer for PJM, testified at the February 3, 2006 technical conference that the vast majority of generators in the PJM footprint are over 20 years of age and a significant amount are over 30 years of age.[45]

34. No party disputed the information described above. The Commission finds that lack of a locational element in the existing capacity construct contributes to the current and projected shortfalls. There is widespread agreement among the parties that the lack of a locational element in the existing capacity construct is creating reliability problems. Not all capacity in PJM is deliverable to all locations within PJM due to transmission constraints. Thus, it is unreasonable to allow an LSE in one location to satisfy its

[44] *Id.*

[45] Comments of Audrey Zibelman, PJM, at February 3, 2006 technical conference, transcript at 14.

capacity requirement with resources from a different location without considering whether the energy associated with that capacity is actually deliverable to the LSE's location.

35. Moreover, the PJM Market Monitor concluded that net revenues from PJM's spot and capacity markets, in combination with the current $1,000 cap on energy bids, are currently insufficient to cover the costs of a new peaking unit. Further, the Market Monitor concludes that while net revenue in PJM has been sufficient to cover the costs of a new peaking unit in some years, net revenue has been below the level required to cover the full costs of new peaking units for the entire period PJM has operated an energy market.[46] This is a serious problem, since some areas of PJM already have insufficient generation and other infrastructure to assure reliability, and investors will not finance generation additions needed in those areas if market revenues are inadequate to recover costs. We also agree with PJM that the current capacity construct – with its deficiency charge for failure to procure IRM – creates conditions that lead to significant capacity price volatility and financial risk as aggregate supply moves between slight deficits below IRM and slight surpluses above IRM. That is because the current capacity construct effectively creates a vertical demand curve for capacity. When aggregate supply is less than the IRM, LSEs will be willing to pay a price equal to the deficiency charge for capacity in order to avoid the deficiency charge penalty; but when aggregate supply is even slightly greater than IRM, so that all LSEs can find capacity to meet their requirement, the price of capacity will fall to zero. Such volatility and risk increases the cost of financing needed generation investments.

36. We also agree with PJM that the inability of the current capacity construct to look far enough into the future and to secure a long enough commitment from resources to remain in the market contribute to the failings of the existing capacity construct. Currently, resources may retire from PJM with only 90 days' notice.[47] Such a short notice period does not provide enough time to add new resources to replace the retiring units, and thus, reliability is put at risk. CCR suggests that the solution is to change the 90-day notice period for retirement.[48] It is questionable whether PJM could impose, or the Commission could enforce, a requirement that generators continue to operate at a

[46] Bowring Affidavit at 10-16.

[47] *PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,053 at P 136-137 (2005).

[48] CCR protest at 72.

loss.[49] Additionally, the Commission has previously stated, in denying PJM the ability to require generators to continue to operate for an indeterminate period, that while "PJM states that it has this authority under provisions of its tariff that require cooperation of its members to assure reliability . . . ., [w]e do not find that these provisions justify . . . PJM's proposal."[50] While such an approach might alleviate the situation in the very near term, this stop-gap approach would fail to address the longer-term need to provide sufficient price signals to support development of new resources and the retention of existing resources over the long term, and the capacity adequacy construct should ensure the presence of financial incentives for resources to voluntarily agree to commit to longer service terms.

B. Elements of RPM

37. 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. The Commission appreciates that this is a difficult issue, and recognizes the significant progress that has been made. However, as described in greater detail below, the 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. Accordingly, we order further proceedings, as elaborated below.

1. Locational Requirement

a. PJM Proposal

38. The current capacity construct does not take into account the location of a resource in determining its value. PJM uses a deliverability test for generation to reach load, at the time of interconnection to the system. This test is used to identify whether, at the time of a generator's interconnection, transmission upgrades are needed, and to ensure that each newly interconnecting generator is able to deliver output to loads on the bulk transmission system during peak conditions. Any needed upgrades must be completed in order for the generator to qualify as a capacity resource. The deliverability

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[49] *See In re Central R. Co.*, 485 F.2d 208, 213 (3d Cir. 1973) (even within the context of providing a public service, "[a]n owner of property retains the right ultimately to withdraw that property from a losing venture").

[50] *PJM Interconnection, L.L.C.*, 110 FERC ¶ 61,053 at P 137 (2005).

test is a snapshot in time and deliverability over time is impacted by changes in the system such as the addition of generation and transmission, retirements of generation, and load growth. This test does not affect the price of capacity, however.

39. As discussed *supra*, PJM has identified multiple reliability criteria violations due to generation retirements and other factors. Currently, these are primarily in New Jersey, the Delmarva Peninsula and the Baltimore-Washington areas. PJM states that load and retirements will increase, but generation additions are not expected to keep pace. Moreover, PJM reports that generation in Eastern PJM cannot compete economically with excess generation in the Western region of PJM.

40. In response to the current and anticipated reliability criteria violations, PJM's RPM proposal would introduce a locational element into the capacity construct. PJM explains that, as the transmission capacity to import energy into a Locational Deliverability Area (LDA) becomes constrained, price separation will occur in capacity prices 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 LDA. This added value will also be available to planned transmission upgrades that increase the transfer limits into the constrained LDA through the award of the arbitrage rights between the unconstrained capacity price and the capacity price with the constrained LDA.

41. The LDAs are capacity regions that will be identified by PJM in its planning process as those that have limited ability to import capacity. In order to transition into RPM, PJM proposes the following LDAs:

Year 1 – (1) Mid-Atlantic Area Council (MAAC) plus Allegheny Power System (APS) zone; and (2) rest of PJM

Year 2 – (1) MAAC plus APS zone; (2) Commonwealth Edison (ComEd), American Electric Power (AEP), Dayton Power & Light (DP&L), Virginia Electric Power Company (VEPCO), Duquesne Light Company (Duquesne); (3) Eastern MAAC (New Jersey, PECO, Delmarva); and (4) Southwestern MAAC (PEPCO, Baltimore Gas & Electric (BG&E)).

42. After this transition period, the LDAs will be determined through the transmission planning process. PJM expects that ultimately there will be 23 LDAs.[51] PJM notes that there may not be price differentials between many of the LDAs.

43. Under the RPM proposal, capacity resources will be offered into the auction by LDA. RPM auctions will result in clearing prices for capacity that may vary by LDA to reflect scarcity in constrained areas. The import capacity into the LDA will be awarded proportionally to each LSE in the form of capacity transfer rights to mitigate the higher prices for capacity if the region is constrained. Transmission upgrades will be awarded Capacity Transfer Rights for incremental increases in transfer capability provided into the LDA. This applies to upgrades related to generator interconnections as well. Capacity transfer rights and incremental Capacity Transfer Rights will be fully transferable.

b. Comments and Protests

44. Intervenors generally support the locational element of the RPM proposal. Several parties[52] have filed specific comments in support of the locational element. Exelon, for example, finds that the local reliability violations are occurring while PJM, as a whole, has more than sufficient capacity resources to meet the IRM for the region. Intervenors generally agree that region-wide capacity pricing is not sufficient to ensure local reliability and that capacity prices should reflect that reality.

[51] The LDAs will include: (1) the MAAC region; (2) the PJM West region (ComEd, AEP, Dayton, APS, and Duquesne); (3) the PJM South region (Virginia Power); (4) the eastern MAAC region; (5) the southwestern MAAC region; (6) the western MAAC region (Pennsylvania Electric Company, Metropolitan Edison, and PPL); (7) the ComEd zone; (8) the AEP zone; (9) the DP&L zone; (10) the Duquesne zone; (11) the APS zone; (12) the Atlantic City Electric Company (AE) zone; (13) the BGE zone; (14) the Delmarva zone; (15) the PECO zone; (16) the PEPCO zone; (17) the PSEG zone; (18) the JCPL zone; (19) the Metropolitan Edison zone; (20) the PPL zone; (21) the Pennsylvania Electric Company zone; (22) the PSEG North region; and (23) the Delmarva South region.

[52] *See, e.g.*, Dominion Resources comments at P 4, FP&L at 8, Exelon at 9 and Dayton P&L at 10 in support of the locational element.

45. Several intervenors[53] find that the proposed LDAs are appropriate for the first two years, but question the ultimate number, scope and boundaries of all twenty-three proposed LDAs. They aver that too many LDAs will result in overly small LDAs, thereby reducing liquidity and increasing the probability of market power issues with attendant potential for over-mitigation. These intervenors caution that, should this situation occur, it will impair new entry into the market and prevent existing resources from recovering sufficient revenues.[54] The Maryland Commission notes that phasing in LDAs may risk increasing capacity prices in areas with sufficient resources and not encourage new resources where needed. The Maryland Commission supports using appropriately constructed LDAs from the start, based on transmission constraints. Other intervenors[55] propose implementing a locational capacity market immediately in response to the currently identified reliability violations and transmission constraints, and state they find no reason for delaying implementation of a locational capacity construct.

46. On the other hand, some intervenors[56] consider locational pricing in the capacity market to be unnecessary. They suggest that the current locational marginal pricing (LMP) of the energy market already provides sufficient price signals to create an incentive for new entry. Further, they state that if all LDAs are required to meet their own requirements for capacity, an independent transmission organization is unnecessary and that the end result will be further reductions in transmission construction.

47. Other intervenors claim that some elements of the locational plan are not locational or at best, are not clearly stated as locational. Allegheny further states that the fact that several localities remain constrained despite the location-based compensation mechanisms currently in force in PJM (such as LMP and Reliability Must Run (RMR) contracts) strongly suggests factors other than a lack of local price signals are contributing to capacity shortages in constrained areas. PJMICC states that PJM has not proven that the locational component will result in efficient investment.[57]

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[53] *See, e.g.*, Cinergy comments at 8, Duke at 8, Maryland Commission comments at 4 and FirstEnergy comments at 17.

[54] Duke protest at 3.

[55] FirstEnergy comments at 17 and Mirant comments at 17.

[56] *See, e,g*. Allegheny comments at 7, Reliant protest at 17 and DEMEC comments at 10.

[57] Allegheny comments at 8 and PJMICC comments at 26.

48. Additionally, PPL notes the revenue offsets used in the cost of new entry, such as scarcity revenues, are based on a rolling six year average of earned revenue by zone, but notes that the scarcity zones do not align with the capacity zones, thus resulting in revenue offsets to the cost of new entry not tracking appropriately over time. [58]

c. Commission Determination

49. We agree with PJM that a locational element should be included in the capacity construct as a means of attracting new resource investment in the locations where it is needed most. 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.

50. In an order setting forth the Commission's policy regarding compensation for reliability, we expressed our support for locational requirements for capacity, stating:

> Reliability Compensation Issues can easily occur when the market design elements are not well coordinated and the value of services that provide local reliability is not reflected in the market. The value of such service should be apparent to both buyers and sellers. Market design features that can work as solutions to these problems include: locational changes such as locational installed capacity, locational operating reserves, locational pricing for energy in times of local operating reserves scarcity. . . .
>
> We believe that the use of market design improved features is the preferred choice for solving material Reliability Compensation Issues.

[58] PPL protest at 39.

> Ideally, the market should encourage LSEs to engage in long-term bilateral contracting to support needed investment, however, some market structures do not appear compatible with such an approach.[59]

The Commission further noted that:

> *We believe that market design features such as locational requirements for installed capacity may prove an effective approach to create stable revenue streams.* [60]

51. Further, the Commission has approved the use of a locational element in the capacity construct for the New York Independent System Operator, Inc. (NYISO)[61] and additionally, in ISO New England, Inc.'s (ISO-NE) proposed capacity construct.[62] Thus, we agree with PJM 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 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.

52. While we agree that the capacity construct must have a locational feature, we also find that additional information is needed to evaluate PJM's specific proposal regarding the boundaries of the LDAs, as well as regarding the time frame for phasing in the LDAs. We agree with PJM's proposal to establish LDAs where there is a limited ability to import capacity. However, PJM has not spelled out in sufficient detail the criteria that it proposes to use to identify individual LDAs. Therefore, we will set this issue to be

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[59] *PJM Interconnection, L.L.C.,*107 FERC ¶ 61,112 at P19-20, footnotes omitted (2004) (Reliability Compensation Policy Order), *order on reh'g*, 110 FERC ¶ 61,053 (2005).

[60] *Id.* at P 20, emphasis added.

[61] *Central Hudson Gas & Electric Corp., et al.*, 88 FERC ¶ 61,138 (1999).

[62] *Devon Power L.L.C., et al.*, 107 FERC ¶ 61,240 (2004).

addressed in the paper hearing ordered above. Specifically, the parties should address in their filing the appropriate rules for determining the LDAs, clarify the relationship between the LDAs delineated under RPM and the constrained areas set forth in the parties' settlement in Docket No. EL03-236-006,[63] establish an LDA implementation schedule, and determine whether or not to phase in LDAs.

2. Forward Procurement

a. PJM's proposal

53. Currently, an LSE is required under PJM's RAA[64] to maintain an IRM of 15 percent above its load. It does so by self-supplying generating capacity or entering into bilateral contracts with capacity suppliers, and meets the rest of its capacity obligation through the daily and monthly capacity credits markets operated by PJM. PJM enforces LSEs' obligation to meet capacity requirements by assessing a deficiency charge against LSEs that fail to meet those requirements.[65]

54. PJM states that currently, its capacity adequacy construct requires resources that are committed to the capacity credits markets to maintain that commitment for periods as short as one day, and only provides limited incentives to suppliers to commit resources for several months. Further, a capacity resource can opt out of its capacity resource status on 36 hours' notice. PJM currently administers Capacity Credit Markets only for 12 months, so that an LSE can only meet its capacity needs through the Capacity Credit Markets for a 12-month or shorter period.

55. Under its RPM proposal,[66] PJM will require LSEs to commit four years ahead of time for capacity, and to purchase that capacity for one year. For each Delivery Year, PJM will administer a series of auctions to match the region's reliability requirements with offers to sell capacity resources, as follows:

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[63] *PJM Interconnection, L.L.C.*, 114 FERC ¶ 61,076 (2006).

[64] There are currently separate RAAs in place for PJM's three regions (classic PJM, PJM West and PJM South), which have essentially identical provisions for each region. As part of this filing, PJM proposes to put into place a single RAA that will cover all of PJM, to which all PJM LSEs will be signatories.

[65] *See generally* OA, Schedule 11.

[66] *See generally* August 31st Filing, Transmittal at 52-55.

- Four years before each Delivery Year, PJM will conduct a Base Residual Auction to enable commitment of capacity resources needed to satisfy remaining capacity needs of LSEs after taking account of their owned and contracted resources. Based on the VRR Curve (discussed *infra*) and other inputs, the auction will set the price paid to capacity resources committed to the region in the auction, and the corresponding amounts to be paid by LSEs as a Locational Reliability Charge. Within each auction, PJM will clear prices separately for each of the four seasons.

- At three specified intervals prior to each Delivery Year, PJM will hold incremental auctions to enable market participants to adjust their capacity market positions or to replace resources previously committed in the Base Residual Auction that become unavailable. To ensure that committed resources fulfill their commitments during the Delivery Year, RPM also includes compliance and deficiency charges.

- Finally, if adequate resources are not committed through the auctions above, PJM will conduct a reliability backstop auction to ensure that sufficient capacity is procured. A backstop auction will be held only if there have been four consecutive Base Residual Auctions that do not clear sufficient capacity. PJM will only initiate this backstop process with prior Commission approval, a month before the beginning of the next Delivery Year for which capacity is deficient. The backstop auction will seek commitments of additional generation resources for a term of up to fifteen years, and PJM will enter into long-term purchase agreements with sellers whose offers are accepted in the backstop auction. Each accepted seller will be paid its offer price, less any payments the seller is entitled to receive for commitment of the same resource through the regular RPM auctions, and less any contributions to the fixed cost of its resource from the energy or ancillary service markets. Each accepted seller in a backstop auction must offer all of its capacity into the Base Residual Auctions held after the backstop for all Delivery Years in the term of its offer.[67]

56. PJM states that the four-year-forward capacity commitment provision of RPM will allow more types of resources to qualify as capacity resources than is possible today, including planned generation resources, demand response programs, and planned merchant transmission upgrades that provide incremental increases in import capability into constrained LDAs. PJM asserts that its four-year-forward capacity commitment will enable planned new generation, transmission and demand response to compete with existing resources. PJM witness Ray Pasteris testified that four years is the expected

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[67] *Id*. at 90-91.

development schedule for a new combustion turbine;[68] thus, PJM has selected the four-year forward approach to create transparent long-term forward investment signals.

57. PJM also points out that RPM is a return to the long-term forward capacity commitments used in the PJM region from 1974 to 1999, and is consistent with a recent analysis on capacity market reform commissioned by PJM, ISO-NE and NYISO, which concluded that "a minimum three-year planning horizon was required to enable [a capacity] market to be a deciding factor in . . . suppliers' decisions to construct new capacity,"[69] and that a market incorporating long-term forward commitments and pricing will reflect the market's expectations about future conditions, which information will in turn assist investors by providing relatively stable long-term price signals. PJM states that long-term price signals should also create an incentive for longer-term bilateral contracts, thus enabling more effective hedging for customers. PJM further states that its four-year-forward approach should eliminate short-notice announcements of generation retirements, since under RPM, a party committing a resource will be required to replace it if that resource becomes unavailable before the Delivery Year.

58. Additionally, PJM states that, although RPM establishes commitments four years in advance, it retains flexibility, in that the auctions after the Base Residual Auction allow participants to revise their needs and commitments. PJM argues that its four-year-forward approach creates a synergy among transmission planning, competitive generation investment, demand response infrastructure investment, and generation retirement planning, and provides a consistent forward planning model that supports infrastructure investment and sustains long-term system reliability.

b. <u>Comments, Protests and Answer</u>

59. Several parties support the four-year-forward commitment provision, asserting among other things that PJM's forward commitment plan will smooth out the boom-bust cycle that has afflicted PJM, under which higher prices stimulate construction of new

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[68] *Id*. at 75-76, *citing* Tab I, Affidavit of Ray Pasteris, (Pasteris Affidavit) at 23.

[69] August 31st Filing, Transmittal at 76. PJM cites here to *New York Independent System Operator*, 109 FERC ¶ 61,023 at P 3 n. 2 (2004), *citing* National Economic Research Associates (NERA), Central Resource Adequacy Markets for PJM, NYISO, and ISO-NE, February 9, 2004.

generation, subsequently leading to prices too low to keep generation in place and ultimately to capacity shortages.[70]

60. Other parties, however, take issue with the length of the four-year procurement window. Allegheny, CCR and AMP-Ohio state that four years is not long enough to allow planning, financing and construction of transmission and most generation solutions, so that it will bias the planning process toward the construction of gas-fired combustion turbine units. Direct Energy similarly argues that the four-year period does not take account of the operational distinction between generators and electric retailers. Allegheny argues that ten years would be a more appropriate forward commitment period, since it would match up with the ten-year period PJM is likely to propose for its RTEP process.

61. Others argue that the four-year-forward commitment for a single year of capacity can serve as a high entry barrier for participation by load.[71] In the same vein, the New Jersey Commission argues that demand response cannot compete with generation and transmission until it becomes fully functional in the electricity market.[72] PJMICC considers the four-year procurement window too long to enable demand resources to participate in the RPM Base Residual Auction, since an industrial customer will not be able to commit four years in advance to reduce load when called by PJM.

62. PJM, in its answer, states that the four-year forward time only appears excessive to parties who are accustomed to committing for no more than a year or two, and that four years is not excessive from the perspective of making an investment in a reliable system. PJM further states that, although it has extended the planning horizon in its RTEP process from the current five years to a longer period, development of generation additions should not be held hostage to transmission development, in that if transmission is to fulfill its role in promoting wholesale competition by enabling excess generating capacity in one area to serve loads in another, that generating capacity must be available as well.

63. CCR raises a concern regarding PJM's proposal for a backstop reliability auction for capacity resources that may receive revenue through the PJM tariff for a period of up to fifteen years. CCR argues that this is insufficient time to address reliability problems.

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[70] *See generally* Dominion, EPSA, Exelon and PHI comments, and Reliant protest.

[71] CCR protest at 57-58, Pennsylvania Commission protest at 17, PJMICC protest at 48, 58, OPSI comments at 15.

[72] New Jersey Commission comments at 10-11.

By the time PJM proposes to hold the backstop auction, it may well be that a demand resource is the only type that can be online immediately; yet, it appears that only generation resources are allowed to bid in the backstop auction.[73]

64. Some protesters argue that RPM's forward commitment requirement is an administrative rather than a market solution. CCR states that RPM will put PJM into the inappropriate role of procurer of capacity, rather than allowing buyers and sellers to negotiate with one another. Morgan Stanley asserts that RPM is a return to the kind of cost-of-service ratemaking driven by centralized planning in which the Commission engaged prior to wholesale deregulation. OPSI states that the prevention of volatility is not a sufficient reason for requiring a four-year-forward commitment, and CCR asserts that RPM's forward commitment requirement is unnecessary because the existing capacity market already provides accurate price signals and encourages new investment. PJM responds in its answer that the market alone will not elicit the amount of generation necessary to meet the region's reliability needs, and that currently, "several factors, including necessary price mitigation and insufficiently developed demand response, limit the market's ability to attract investment in a timely manner."[74] Given this current insufficiently developed state of the market, PJM believes that the market cannot be relied on to correct the current imbalance of generating capacity with demand sufficiently to meet system reliability standards. .[75]

65. CCR, Coral Power and Duke claim that RPM will impair parties' willingness and ability to manage risk: since all parties will be fully hedged prior to each Delivery Year, there will be no incentive for parties to manage their own risk by entering into additional bilateral contracts. Coral Power additionally argues that if the market becomes less volatile, parties will be less motivated to enter into bilateral agreements even before entering the capacity markets. PJM in its answer states that, although the Commission has previously recognized that long-term contracts are beneficial to bring about system reliability,[76] LSEs currently are oriented towards short time horizons and are not currently entering into long-term contracts, and that RPM will encourage LSEs to enter into bilateral contracts of sufficient duration to bring about improvements to system reliability.

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[73] CCR protest at 61.

[74] PJM answer at 6.

[75] *Id.* at 6.

[76] *Id.* at 35, *citing* Reliability Compensation Policy Order at P 20 n. 12.

66. Protesters also assert that RPM may expose customers to greater risks than they now face. Morgan Stanley asserts that RPM will force captive customers, rather than investors, to bear the risks that such centralized planning will be inefficient (such as, for instance, the inherent risk that a four-year-forward estimate of how much capacity will be needed five years later will prove to be unreliable).

c. Commission Determination

67. The Commission finds that the requirement in RPM that LSEs be required to make forward commitments several years in advance is just and reasonable. We therefore accept this aspect of PJM's proposal.

68. As the Commission previously stated, the use of improved market design features is "the preferred choice for solving material Reliability Compensation Issues."[77] The Commission recognized, however, that market design changes alone might not be sufficient to ensure compensation sufficient to elicit reliability, and that extra-market mechanisms might be necessary. The Commission further noted that:

> [W]e are mindful of the comments made to us by representatives of the financial community, that dependence on price volatility for investment is an inadequate foundation for cost-effective financing of new infrastructure. A clear preference for long-term contracts and/or reliable revenue streams was stated.[78]

69. The Commission also recognized that, in circumstances where purely market design changes would not elicit sufficient compensation, it was willing to consider proposals that "create a long-term commitment which can support cost-effective financing where the problem is projected to be a long-term one."[79] The Commission also specifically endorsed in principle a long-term forward commitment period, stating:

> [W]e are still open to a last-resort auction that will address long-term reliability problems within PJM. Such an auction should reflect the following issues. First, the default transmission solution feature of the PJM proposal should be retained. Second, the proper role for the RTO is to

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[77] Reliability Compensation Policy Order at P 20.

[78] *Id.*

[79] *Id.* at P 21.

> identify areas where there is a reliability problem that can be addressed by generation, transmission or demand response. *Third, the Commission supports the use of a multi-year planning horizon (e.g., three years).*[80]

70. The Commission does not consider it likely that RPM will lessen parties' motivation to purchase more of their forward-looking capacity needs through bilateral contracts, or to manage their risk in other ways, such as releasing or purchasing additional capacity in the auctions following the Residual Base Auction during the four years prior to each Delivery Year. First, those states or LSEs who wish to maintain maximum flexibility to manage their own risk will be able to fulfill their own capacity needs by providing their own fixed resource requirement. Second, as PJM has alleged, parties are not engaging in significant amounts of forward contracting now: RPM will provide more information to all market participants, and all parties will be able to use this information to manage their risk more effectively, whether through bilateral contracting or otherwise. Moreover, the series of follow-on auctions for each Delivery Year will enable LSEs to adjust the amounts of capacity they hold, or to seek to obtain capacity at a better price, until four months before the Delivery Year.[81]

71. We agree with protesters that RPM is an administrative mechanism. However, the current capacity construct is also an administrative mechanism, so the administrative feature can have no bearing on the choice between the current capacity construct and the capacity construct under the RPM proposal. In response to CCR's comment that RPM will put PJM into the role of procurer of capacity, we agree with PJM that a forward procurement auction is necessary because the market alone under the existing market rules and market conditions is not eliciting the amount of resources needed to meet reliability needs. Thus, we conclude that, after LSEs have had an opportunity to procure capacity on their own, it is reasonable for PJM to procure capacity in an open auction at a time when further delay in procurement could jeopardize reliability. This, however, should be a last resort. We disagree with Morgan Stanley that RPM is a return to cost-of-service ratemaking; a winning seller in the auctions will receive a market-based price reflecting the interplay of the supply bid with the demand curve. We agree, in part, with Morgan Stanley that RPM may cause customers to bear risks such as the risk that a four-year forward estimate of needed capacity may turn out to be inaccurate. However, we think that the risk is reasonable when it is compared to the risks of the current construct, namely that sufficient capacity resources may not be constructed to ensure the

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[80] *Id*. at P 74, emphasis added.

[81] *See* August 31st Filing, Transmittal at 52.

preservation of reliability. That is, the capacity requirement currently need not be met until a day in advance, at which time it may be too late to procure adequate capacity. Moreover, as will be discussed further under the section addressing the downward sloping demand curve, an LSE may avoid this risk entirely by electing not to participate in the RPM mechanism, but to supply its own long-term fixed resource requirement, as long as it does so for a sufficient period.

72. We find that a four-year-forward procurement period is a reasonable requirement. We appreciate PJM's concern that the auction needs to occur far enough in advance to allow new entry by resources to compete with existing capacity. There appears to be a trade-off in deciding how far in advance to hold the Base Residual Auction. Holding it closer to the Delivery Year may increase the participation of demand response resources, but may reduce the participation of new generation and transmission entrants. Holding the auction farther in advance may have the opposite effects. In balancing the concerns for appropriate length of the procurement requirement, the Commission finds that, at a minimum, the requirement must be of sufficient length to allow for planning and construction of new resources which can address the reliability issue. We agree with PJM that four years is a reasonable period in which solutions can be placed in operation in response to the RPM's base residual auction. With respect to arguments that baseload generation and major transmission projects will require much longer planning and construction periods, we think that the four year procurement requirement will not discourage their entry into the market. The existence of reliable and non-volatile forward prices in the capacity market will provide appropriate market signals to all resources. With regard to demand resource participation, some commenters state that most demand response resources will not be able to participate in a capacity auction so far in advance of the delivery year. However, we find that the interim auctions (held at specified intervals before the delivery year) will provide demand resources a shorter horizon and a reasonable opportunity for participation. We encourage PJM to examine and incorporate reasonable accommodations to maximize demand response participation in the capacity market.

73. The Commission is also concerned that the reliability backstop provision may not address reliability issues within an acceptable timeframe and might exclude demand resources unnecessarily. Accordingly, PJM and the parties should also address in the paper hearing the concern raised by CCR with regard to whether the reliability backstop provision will provide a trigger soon enough to avoid an extended period of capacity deficiency, and also whether the reliability backstop provision unnecessarily excludes demand resources.

74. The Commission will require further proceedings to address the appropriate period of contractual commitment and also to address the merits of separate seasonal

auctions and the resulting seasonal price differences. We wish to explore further whether a one-year contractual commitment is an appropriate duration to encourage new entry, or whether a longer or shorter contractual commitment is appropriate. In a paper hearing (as discussed in Appendix A), we will require PJM to make a filing supporting its choice of a one-year commitment period and the use of seasonal pricing. Thereafter, intervenors will have an opportunity to fully articulate their arguments on these issues. PJM and the parties should also address the merits of separate seasonal auctions and the resulting seasonal price differences.

3. Integration of Generation/Transmission/Demand Response

a. PJM's Proposal

75. According to PJM, the short-term nature of commitments in PJM's existing capacity markets and a lack of locational valuation of capacity impede the ability of transmission and demand resources to participate in capacity auctions. The longer-term outlook of the RPM proposal, and its ability to differentiate capacity prices by location, will promote interaction of transmission and demand response with generation solutions by allowing new investors in all resources, as well as ongoing participants, to have appropriate lead time to compete in the capacity markets.[82]

76. PJM proposes to allow LSEs to satisfy their capacity obligations not only with generation, but also with existing and planned demand resources.[83] Demand resources will be able to participate in both Base Residual and incremental auctions, committing resources years or months in advance. PJM explains that, since demand resources that participate in the capacity auctions will be guaranteed future revenues, this is expected to spur greater capital investments in new load-reducing capabilities or enhancement of the existing capabilities.[84] In addition to having the opportunity to compete with generation in the RPM auctions, load management programs could be nominated three months before a Delivery Year as Interruptible Load for Reliability (ILR). Under RPM, PJM will certify the nominated resources as ILR if they meet the criteria established for load management, such as being available for interruption at PJM's direction for a minimum

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[82] August 31st Filing, Transmittal, at 10 and 75. *See also* Prepared Statement of Andrew Ott, PJM, February 3, 2006 technical conference, P 4.

[83] August 31st Filing, Transmittal at 79-81.

[84] *Id.* at 80.

number of hours, for a minimum number of times per year.[85] Certified ILR will receive the same type of payments as demand resources that are offered and cleared in the auctions, similar to PJM's existing active load management (ALM) rules. By providing demand response resources with alternative means of participation, PJM contends that demand response will engender a more robust competitive capacity market.[86]

77. PJM states that participation by transmission providers will also be integrated into the RPM capacity market, by allowing for planned transmission upgrades that provide incremental increases in import capability into constrained areas to be offered into the auctions. PJM argues that this will further foster competition between resources by allowing individual market participants the option of combining generation and transmission resources to meet their auction commitments. To participate in an RPM auction, a qualified transmission upgrade must (1) increase the transfer limit into an LDA, (2) demonstrate that it will be in service on or before the first Delivery Year for which it is offered, and (3) be funded by a customer or owner through a rate specific to the facility.[87] PJM maintains that the last requirement ensures that a party receiving RPM revenues for a transmission upgrade is the party that bears the cost of the upgrade. When a seller offers a transmission upgrade into an RPM auction, it will state its offer price in terms of a price difference between a capacity resource located outside the LDA and a capacity resource located inside the LDA.[88] Thus, argues PJM, a market participant, whether it is transmission, generation or demand resource, that offers the lowest price needed to satisfy loads in the LDA, will set the clearing price for the auction, and all sellers offering up to that price will clear the auction.

78. Further, PJM explains that RPM's use of locational capacity pricing is intended to promote the development of new generation, new demand response or new merchant transmission projects to resolve local deliverability issues.[89] However, in the event new entry does not participate in a particular zone, RPM is designed to respond by permitting

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[85] Ott Affidavit at 6.

[86] August 31st Filing, Transmittal at 81.

[87] Proposed PJM OATT, Original Sheet No. 555, Section 2.56.

[88] Proposed PJM OATT, Original Sheet No. 565, Section 5.6.1 (g).

[89] August 31st Filing, Transmittal at 17.

PJM to address, through the RTEP process, the costs and benefits of a transmission upgrade for relieving constraints on delivery into that zone.[90] If the benefits of the transmission upgrade are found to be greater than the costs, PJM could direct the transmission upgrade to be built through the RTEP process.[91]

b. Comments and Protests

79. Most commenters agree with PJM that RPM represents an improvement over the present capacity construct in that demand response and transmission projects can compete in the Base Residual Auction.[92] Others, however, have reservations about how this would be achieved and what relationship RPM would have with the existing transmission planning process.

80. With regard to demand response, some intervenors argue that ILR resources should not be able to submit resources for certification as late as three months prior to a Delivery Year when traditional capacity resources have a four-year commitment requirement. Allegheny and NRG argue that this would permit ILR resources to take advantage of the RPM markets and receive zonal capacity prices, without ever participating in the capacity auction that created those prices almost four years earlier.[93] OPSI and the Pennsylvania Commission, on the contrary, argue that the ILR program that allows demand resources to avoid RPM costs up to three months in advance of the Delivery Year does not provide demand resources a meaningful opportunity to impact Delivery Year prices.[94] PJMICC also asserts that demand resources do not have a meaningful opportunity to compete with generation and transmission solutions, and that the ILR program will not sufficiently address this problem.

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[90] Proposed PJM OATT, Original Sheet No. 598, Section 15.

[91] *Id*.

[92] Dominion comments at 5.

[93] Allegheny protest at 11-13 and NRG protest at 20.

[94] OPSI comments at 16 and Pennsylvania Commission protest at 18.

81. Many commenters also strongly support initiatives by PJM to incorporate transmission projects into the capacity markets, but argue that RPM's four-year lead time is inadequate for transmission solutions.[95] Yet others argue that without a fully-developed and integrated long-term RTEP, the RPM proposal is unjust and unreasonable because it is skewed towards small, "quick fix" upgrades, rather than the type of larger projects that may be needed to improve generation deliverability on a regional basis.[96] Accordingly, they suggest that RTEP reforms, aimed at extending the planning horizon and modifying the economic planning process, should be made preconditions to RPM approval.[97]

82. Some protesters also argue that RPM will not stimulate transmission investment because the RPM mechanism is targeted toward transmission projects funded on a merchant basis, rather than a traditional rolled-in cost-of-service basis. Thus, MSATs argue that transmission alternatives considered in the RPM must be funded by a customer or owner using a facility-specific rate.[98] According to MSATs, this approach creates a free rider problem to the extent that facilities funded by individual customers become an integrated component of the grid and used by others. The Delaware Commission and Virginia-Illinois Municipals are specifically concerned with how RPM will function in the markets dominated by the vertically integrated companies. They argue that vertically integrated sellers will not always build transmission on their own if they earn significant profits from generation due to congestion.[99] National Grid is also concerned with how RPM will deal with such transmission projects going forward. Even if PJM could solve the pricing problem and a transmission project were successfully bid into the RPM

[95] Virginia Commission protest at 7, Delaware Commission protest at 5, and New Jersey Commission comments at 8.

[96] Dominion comments at 4, FirstEnergy protest at 16, and Virginia-Illinois Municipals protest at 5-22.

[97] National Grid comments at 16, Virginia-Illinois Municipals protest at 5, Delaware Commission protest at 6-7, MSATs at 10, and New Jersey Commission comments at 2,5.

[98] MSATs comments at 8.

[99] Virginia-Illinois Municipals protest at 8-12 and Delaware Commission protest at 5.

auction for one Delivery Year, the very nature of the RPM auctions and PJM's proposed treatment of such transmission facilities as competitive products would assume the possibility that the transmission owner's bids into subsequent auctions may be unsuccessful. In such event, argues National Grid, the transmission owner would need to disconnect its "out-of-merit" transmission facilities to prevent access by transmission customers.[100]

83. Cinergy requests that the tariff clarify whether there is any time limitation on the Capacity Transfer Rights earned by participant-funded transmission, pursuant to section 5.16, and whether and what tests will be required to demonstrate that the transmission upgrades have continued to provide the level of transfer consistent with those rights.[101] Coral Power is concerned that transmission projects that participate in the auctions are entitled to capacity payments without any corresponding obligation to ensure deliverable energy supply (i.e., a party offering the transmission upgrade also may be completely independent of any seller of generation, and need not specify the source of the energy that will be brought into the constrained area in order to participate in the LDA market).[102]

c. <u>Commission Determination</u>

84. We are encouraged by PJM's proposal for considering generation, transmission, and demand response together in the Base Residual Auction. Only when these three interrelated components of the PJM market place are working together will PJM be able to meet established reliability criteria, keep markets robust and competitive, and ensure stable operations. The inclusion of these resources is consistent with Commission policy supporting development of these resources. However, we agree with some of the protesters that, in some respects, the proposal needs to be further refined.

85. We will not require any modifications with regard to ILR-related provisions. In our view, ILR provisions allow demand response to participate in capacity markets in a way that is similar to ALM, which is the current means of recognizing demand response capability in the capacity construct.[103] Like ALM, this approach recognizes that, due to

[100] National Grid comments at 14-15.

[101] Cinergy protest at 16.

[102] Coral Power protest at 11.

[103] PJM answer at 36.

its operational characteristics, demand response is different from traditional capacity resources, and therefore should be treated differently than other generation or transmission resources. PJM argues that the ILR option under RPM provides demand response that cannot lock in on a four-year-forward basis a direct opportunity to participate as an interruptible load, and we support this approach. This makes sense because there are many types of demand response, which may not exist today and which would benefit from the ability to lock into a forward revenue stream to support infrastructure investments. Therefore, we find that RPM is designed both to provide existing demand response providers with participation opportunities similar to those they have today, while expanding opportunities for new innovation in demand response by providing a forward investment signal.

86. With regard to transmission participation, we generally support PJM's proposal to allow transmission upgrades to compete in the Base Residual Auctions. Nevertheless, we share the concern raised by MSATs, National Grid and other protesters who pointed out that the cost allocation methodology used in RPM might be contrary to how transmission upgrades are financed outside of the RPM process, and, as a result, may not achieve the desired results in terms of new transmission construction. We will, therefore, require PJM and the parties to further discuss this cost-allocation issue in the paper hearing ordered herein. Specifically, the parties should focus their discussion on coordinating cost allocation methodology used in RPM with that utilized in the RTEP process. In addition, the parties should clarify whether there is any time limitation on the Capacity Transfer Rights earned by participant-funded transmission, what tests will be required to demonstrate that the transmission upgrades have continued to provide the level of transfer consistent with those rights, and explain the process through which transmission owners will specify the source of the energy that will be brought into the constrained area in order to participate in the LDA market.

87. Lastly, we strongly encourage PJM to continue its efforts in reforming its regional transmission planning process in order to better coordinate RPM with RTEP, and to provide incentives for construction of bulk lines that serve as a backbone of the transmission system. Although we believe that forward procurement provides a much better solution to RTEP integration than the current generation interconnection procedures, which are subject to high levels of project withdrawals, generation and transmission planning processes must be better coordinated. In its answer, PJM stated that the first component of transmission reform, extending the planning horizon for reliability baseline additions from the current five years to as much as fifteen years (depending on the project), has already been approved by the PJM Reliability Committee and incorporated in the RTEP process beginning January 1, 2006. As PJM's Regional Planning Process Working Group is continuing its work on other RTEP process enhancements, including economic planning, market efficiency upgrades, and alternative

scenario planning, we want to emphasize that RPM should be complementary with reform of the regional planning process. We emphasize, however, that the particular features important in each program should not interfere with implementing features that may be different from, but more appropriate to, the other program, so that, for instance, the fact that a 15-year or longer planning horizon may be appropriate to RTEP should not prevent parties from using a four-year planning horizon as appropriate for the capacity construct governed by RPM. We strongly encourage PJM and their stakeholders to make sure that appropriate revisions to both programs are made in a way that coordinates capacity markets with transmission planning. When PJM files its enhanced RTEP process, we intend to review that filing closely to ensure, among other things, that it coordinates appropriately with RPM, and we will require PJM to file a report on such coordination with us at the time that it makes its RTEP filing We note that PJM has stated that it intends to revise its RTEP program by June 2006, and we look forward to PJM's fulfilling that commitment.[104]

4. Mechanism for Acquiring Capacity

a. PJM's Proposal

88. As discussed above, under PJM's existing capacity construct, each LSE is required to procure capacity equal to a fixed percentage (currently 115 percent) of its peak load. This fixed percentage is the IRM. An LSE is assessed a fixed deficiency charge to the extent that it fails to satisfy its capacity requirement. Under RPM, neither the capacity requirement nor the charge for being deficient would be fixed. Instead, they would vary with market conditions based on the use of a downward sloping demand curve (VRR curve) in its forward procurement auction. The demand curve would be a set of price-and-quantity combinations for capacity.

89. In each four-year-ahead procurement auction, a supply curve would be determined for each capacity region (LDA) based on the capacity supply offers submitted to PJM. For each capacity region, PJM would plot the supply curve and the demand curve together, and the point where the two curves intersect would establish the capacity

[104] *See* comments of Audrey Zibelman, PJM, at February 3, 2006 technical conference, transcript at 38 ("What we're anticipating . . . is that by June of this year we'll have a revised RTEP that includes a 10 and 15 year look [at the need for upgrades] as well as economic efficiency. . . . [I]n June we expect to have the 15 year plan. So we are working aggressively to get these done.")

requirement and the capacity price for LSEs in that capacity region. Depending on the amount of supply offered into the auction, the capacity requirement could be more, less, or the same as the IRM under the current construct.

90. The parameters of the specific demand curve proposed by PJM were developed after analysis by its consultant, Professor Hobbs, and after stakeholder discussion. The curve provides for a price equal to the annualized net cost of new entry of a new peaking unit when the region's capacity level is 116 percent of peak load, i.e., one percent greater than the IRM. The annualized net cost of new entry reflects the cost of a new peaking unit less the annual revenue that the unit would be expected to receive from the energy and ancillary service markets. At capacity levels less than 116 percent, the price would increase linearly until the capacity level falls to 112 percent of peak load, at which point the price would reach two times cost of new entry. The price would remain constant at this level for all levels of capacity below 112 percent of peak load. At capacity levels greater than 116 percent, the price would fall linearly (but at a flatter slope than to the left of 116 percent) until a capacity level of 120 percent of peak load is reached, at which point the price would fall to zero.

91. Under RPM, LSEs may procure capacity in advance and outside of the four-year-ahead procurement auction. An LSE's capacity that is procured in advance would be offered into the procurement auction at a price of $0, but it would receive the applicable market-clearing capacity price established in the auction. The LSE would be required to pay the capacity price as determined in the auction for the amount of capacity needed to meet its full capacity obligation. But the auction revenues received by the LSE for its capacity would be used to offset the LSE's purchase payments, thereby reducing its net bill. To the extent that the amount of capacity procured in advance fell short of its capacity requirement, its net bill would reflect the capacity price for the amount of its net capacity deficiency. Conversely, to the extent that the amount of capacity procured in advance exceeded its capacity requirement, the LSE would be rewarded with a net payment.

92. PJM argues that its proposed sloped demand curve has several benefits that would remedy many of the defects that render the existing capacity construct unjust and unreasonable. First, PJM states, the sloped demand curve would reduce the volatility in capacity prices. That is because, with a sloped demand curve, capacity prices would change gradually as supply conditions change. By contrast, under the existing construct, capacity prices can change dramatically with small supply changes around the existing capacity requirement – that is, prices can increase to the deficiency charge rate when aggregate supplies fall just slightly short of the aggregate requirement, and they can plunge to near zero when aggregate supplies increase just slightly above the aggregate requirement. PJM argues that the lower price volatility resulting from a sloped-demand

curve would mean that the stream of capacity payments received by generators over time would be more stable and less risky. As a result, PJM asserts that risk-averse investors are likely to accept lower rates of return, which would ultimately reduce the costs and risks to consumers. In addition, PJM argues that a sloped demand curve would produce a higher level of reliability over time, because the investment response to more stable price signals means that the target IRM will be achieved in many more years than under the current capacity construct. Finally, in PJM's view, a downward sloping demand curve (unlike the current fixed capacity requirement) recognizes that additional capacity over and above the target IRM has some value by increasing reliability.

93. PJM points out that it considered several alternative demand curves before selecting the curve proposed in the instant filing. According to PJM, these alternatives included the existing capacity construct, in which the demand curve is effectively vertical because the capacity obligation is fixed at 115 percent of peak load regardless of the price; a curve reflecting the estimated value of lost load associated with varying capacity levels; and three curves of a similar shape that link the price on the curve at alternative capacity levels (i.e., the IRM, 1 percentage point above IRM, and 4 percentage points above IRM) to the net cost of new entry. PJM's consultant, Professor Hobbs, used a computer simulation to analyze the effects of these alternative curves. PJM elected to propose the curve that Professor Hobbs' simulations found would result in the lowest total consumer payments (including both capacity and energy payments). In the simulations, the proposed curve would also produce generation investment whose capacity met or exceeded the IRM 98 percent of the time; no other alternative curve considered by PJM produced a higher percentage.

94. Professor Hobbs' simulations concluded that, over the long run, total consumer payments would be higher under the existing capacity construct than under any sloped demand curve considered for at least two reasons. First, the greater revenue stability under the sloped demand curve would lower the cost of financing generation, resulting in a lower capacity price and a larger average level of capacity. Second, the larger average level of capacity would place downward pressure on energy prices in the energy markets.

95. PJM states that, while it has devoted considerable resources to selecting the parameters of the demand curve, the curve may need to be adapted over time. PJM suggests that the Commission may want to establish technical conference proceedings to establish the final just and reasonable parameters of the curve. PJM also commits to a stakeholder process to evaluate the performance of the curve at least every three years.

b. Comments and Protests

96. Supporters of the RPM proposal agree with PJM that a sloped demand curve would reduce price volatility, and thus encourage greater investment to ensure reliability at a lower long-run cost to consumers. Supporters also agree that the curve better reflects the value of alternative levels of capacity, and in particular, that it properly recognizes that capacity in excess of the IRM provides additional reliability value.

97. Other parties oppose the use of a sloped demand curve, for several reasons. First, they argue, the sloped demand curve is an artificial administrative construct and is not market-based. As a result, capacity requirements and price levels would bear no relation to the desires of consumers. Some argue that an administratively-determined demand curve is unnecessary and undesirable because market forces within the existing market clearing model for capacity better establish the value of capacity. The second reason offered is that the sloped demand curve is likely to require LSEs to purchase more capacity in some years than is needed to meet the IRM or to ensure reliability. As a result, it would impose higher costs on consumers, with no reliability benefit.

98. PPL asserts that RPM will not necessarily lessen price volatility, in that, if prices drop after the Base Residual Auction, a generator may cancel a planned unit or retire an existing one, and it is not clear that PJM's credit requirements will solve this problem. Rockland argues that the combination of the RPM four-year-forward commitment with the downward-sloping demand curve could support a capacity market that exceeds minimum reserve margin requirements and may lead to the construction of excess generation, with negative cost impacts for loads in PJM.

99. Commenters also raise questions about the specific parameters that establish the height, slope, and shape of PJM’s proposed demand curve. Several intervenors[105] support the use of the proposed demand curve but would require explicit review of the performance of the demand curve to assess whether it provides long term reliability benefits at reasonable prices. Dominion recommends a technical conference to set the initial parameters, while PSEG would reopen the setting of parameters after experience is gained. Other intervenors[106] find that while Professor Hobbs explains the value of the downward sloping curve and states that a fully-sloped demand curve would have negligible negative impacts, PJM nonetheless proposes a hybrid curve. Some

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[105] National Grid and Dominion comments, PSEG protest.

[106] Cinergy and PPL protests.

intervenors[107] protest the truncation of the demand curve at a level they describe as only slightly above the current required capacity level, stating that the curve will not provide adequate recognition of the variability in resource availability as a result of potential delays such as permitting and construction of new resources. They also request the issue be set for a limited technical conference. Lastly, AEP states that the demand curve will cause LSEs to purchase more capacity than is necessary to meet generally accepted reserve criteria. AEP questions the imposition of a 1 percent adder to the IRM requirements as an unnecessary cost burden. AEP questions why the zero intersection point was chosen at IRM + 5 percent and why the maximum price is reached at IRM – 3 percent. AEP notes that as a result of integrating AEP into PJM, PJM anticipated that the integration of AEP should result over time in lower reserves margins than AEP would otherwise be required to maintain.

100. In the stakeholder discussions held prior to PJM's August 31st Filing, AEP suggested that the demand curve feature of RPM discriminated against vertically-integrated utilities whose state regulators have traditionally established capacity requirements for utilities within their states. In particular, AEP expressed concern that the demand curve feature would require AEP to procure more capacity than the 115 percent of peak load that its state regulators have traditionally required. Similarly, the Kentucky Commission suggests that capacity constructs must be better adapted to the needs of fully regulated states with vertically integrated utilities to take into account state-imposed obligations.[108] As a solution, AEP suggested at the June 16, 2005 technical conference that individual LSEs should be allowed to "opt-out" of the forward procurement auction by identifying – prior to the four-year-ahead auction – enough capacity resources to satisfy the traditional 115 percent state requirement.

101. In response to AEP's suggestion, PJM included in the August 31st Filing draft business rules that could implement an alternative to RPM under which an LSE could provide its own long-term fixed resource requirement. Under these draft rules, an LSE electing this alternative would submit to PJM each year a capacity resource plan covering the next five years, including the RPM Delivery Year, designating the load to be covered, the unit-specific generation resources to cover the capacity requirement, and any transmission upgrades needed to ensure deliverability of the generation to the load. The LSE's fixed capacity requirement would equal the IRM then in effect for the PJM region plus a specified additional margin. PJM argues that the additional margin is necessary to cover the uncertainty associated with forward commitment and to ensure that the LSE

[107] Duke and Mirant protests.

[108] Kentucky Commission protest at 4.

contributes equivalent capacity to the market as LSEs participating in RPM. PJM does not endorse this alternative and has not included it in the tariff sheets submitted with its filing. Indeed, PJM states that it recognizes the concerns of some stakeholders that this type of modification could undercut the objectives of RPM. However, PJM states, it has developed this alternative in a form that would permit its integration into RPM and that would provide sufficient protection for the market against potential market manipulation.

102. In its post technical conference comments, AEP continues to argue for an option that would allow LSEs to avoid responsibility for the results of the forward procurement auction by procuring and identifying for PJM resources equal to the IRM in advance of the auction. AEP states that the long-term fixed resource requirement option should be available only for LSEs that commit to maintain that choice for a long period of time, perhaps 8 to 12 years.[109] AEP opposes PJM's suggested requirement that this alternative require the participating LSE to procure an additional margin above the IRM, arguing that the added required margin would unnecessarily penalize participating LSEs.

c. Commission Determination

103. The Commission finds that there is not a single just and reasonable method for satisfying capacity obligations. For example, in other situations, an uncapped energy market might provide the necessary signals to create an incentive for investment on a long-term basis. We have determined here that it is appropriate to adopt a dual method of satisfying capacity obligations from which states and utilities can choose. The first method would be an auction market utilizing a downward sloping demand curve, thereby producing a variable resource requirement over time. The second would be the traditional approach in which utilities will be responsible through self-supply or long-term contracts for assuring their capacity obligations, thereby producing a long-term fixed resource requirement over time. For both options, we are establishing a technical conference to work out details of the proposals.

i. Variable Resource Requirement: Forward Procurement Auction with a Downward Sloping Demand Curve

104. We find that the use of a sloped demand curve, in a forward procurement auction, as proposed by PJM, would be a just and reasonable option for acquiring capacity as long as load can choose to avoid the auction and, instead, satisfy a fixed resource requirement

[109] Comments of J. Craig Baker, AEP, at February 3, 2006 technical conference, transcript at 231-232.

through the more traditional alternative of self-supplying sufficient capacity to meet its obligations. We have accepted the use of downward-sloping demand curves as just and reasonable in the NYISO and ISO-NE capacity markets, [110] and the reasons that we articulated there for accepting a downward-sloping demand curve apply for PJM. A downward-sloping demand curve would reduce capacity price volatility and increase the stability of the capacity revenue stream over time. This is because, as capacity supplies vary over time, capacity prices would change gradually with a sloped demand curve. By contrast, under the current capacity construct, capacity prices vary substantially between the deficiency charge and zero even though supply varies only slightly between a slight deficit below IRM and a slight surplus above IRM. 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. In addition, we agree with PJM that a downward-sloping demand curve provides a good indication of the incremental value of capacity at different capacity levels. For example, incremental capacity above the IRM is likely to provide additional reliability benefits, which is reflected in the positive prices in the sloped demand curve to the right of IRM, but is not reflected in the current capacity construct. Finally, as we discussed in orders in which a sloped demand curve was approved for NYISO, a sloped demand curve would reduce the incentive for sellers to withhold capacity in order to exercise market power when aggregate supply is near the IRM. [111] Withholding capacity would be less profitable under a sloped demand curve

[110] Initial Decision, *Devon Power L.L.C.*, 111 FERC ¶ 63,063 at P 284 (2005) (*Devon*) (administrative law judge adopts ISO-NE's proposed downward-sloping demand curve); *New York Independent System Operator, Inc.*, 105 FERC ¶ 61,108 at P 39 (2003) ("[t]he Commission considers the ICAP Demand Curve to be an appropriate new tool in providing reliable service to consumers"), *aff'd Electricity Consumers Resource Council* v. *FERC*, 407 F.3d 1323 (D.C. Cir. 2005) (*ELCON*).

[111] *New York Independent System Operator, Inc.*, 103 FERC ¶ 61,201 at P 67 (2003) ("The Commission agrees that the removal of the 'boom-bust' nature of the ICAP market will significantly reduce the incentive to withhold when ICAP supply and demand are relatively close"). Subsequently, in an order reviewing NYISO's implementation of its demand curve, the Commission noted that "NYISO indicates that it has not observed, in the short time since the implementation of the ICAP Demand Curve, significant economic or physical withholding in the Installed Capacity market," and that "NYISO reports that the ICAP Demand Curve has reduced the incentive to withhold capacity, because the Market-Clearing Prices are not significantly affected by reductions in the amount of capacity bid into the market." *New York Independent System Operator, Inc.*, 108 FERC ¶ 61,280 at P 5 (2004).

because withholding would result in a smaller increase in capacity prices. By contrast, under the existing capacity construct, small changes in capacity near the IRM can result in a very large capacity price increase, so that withholding can be significantly more profitable under these supply conditions.

105. We disagree with commenters who argue that the sloped demand curve should be rejected on the grounds that the curve is administratively determined. All of the demand curves are administratively determined, including the existing requirements for LSEs to procure capacity equal to 115 percent of their peak load or pay the deficiency charge rate for the amount of their deficiency. Unlike the current vertical demand curve that requires load to procure exactly 115 percent of their peak load, the downward sloping demand curve can produce a range of prices and quantities, with the required percentage of peak load going below the 115 percent level in the current tariff, depending on generator bids. Therefore, we find that this administrative construct can provide load with a viable option for acquiring the capacity needed for reliability.

106. We also disagree with commenters who argue that the demand curve should be rejected because it would result in requiring LSEs to procure more capacity than the IRM in some years, and thus impose additional costs on consumers that are unnecessary to ensure reliability. First, it is not *per se* unreasonable for LSEs to procure more capacity than the IRM in some years since additional capacity beyond the IRM is likely to provide additional reliability benefits. Moreover, it is not clear that procuring additional capacity in some years under the demand curve will necessarily increase consumer costs. Indeed, the simulations by Professor Hobbs suggest that total consumer costs may actually be lower under the sloped demand curve than under the existing capacity construct because the sloped demand curve would lower financing costs and because the resulting increase in capacity would lower energy prices.[112]

107. We do not share PPL's concern that if prices drop in auctions after the Base Residual Auction, a generator may cancel a planned unit or retire an existing one. If a unit (either a planned unit or an existing one) is accepted in the Base Residual Auction, it will receive the applicable price established in that auction – a price which presumably supported the decision to begin construction (in the case of a planned unit) or to delay retirement (in the case of an existing unit) – regardless of the prices in subsequent incremental auctions. Of course, incremental auctions will be held that will allow resources that were not accepted in the Base Residual Auction to voluntarily take over the

[112] Hobbs Affidavit at 36-41.

supply obligations of resources accepted in the Base Residual Auction. However, such trading of obligations would be done voluntarily at prices that are mutually beneficial to the trading parties.

108. We also disagree with commenters that using the demand curve to establish capacity requirements intrudes on traditional state authority because some auctions may procure more than the stated reliability standard. The reliability standard that state authorities have established has been expressed as a maximum risk of involuntary curtailment due to inadequate capacity. That standard has been to acquire sufficient capacity so that involuntary curtailment of load will occur no more than once in 10 years. This reliability standard can be met in several different ways, for example, by procuring a fixed amount of capacity at every instant in time to ensure that the standard is met, or by procuring varying amounts of capacity that, over time, ensures that the standard is met. A sloped demand curve with appropriate parameters would not overturn this reliability standard as long as the demand curve parameters result in an average level of capacity over time that ensures meeting the once-in-10-year reliability standard. Also, states and utilities will not be required to use the downward sloping demand curve auction, but can procure capacity on their own by meeting a fixed resource requirement.

109. While we agree with PJM that a sloped demand curve may be just and reasonable, we conclude that additional information is necessary in order to determine what specific parameters should be established that affect the height, slope, and shape of the demand curve. Therefore, we will direct our staff to hold a technical conference to gather further evidence regarding the parameters affecting the height, slope, and shape of the demand curve. We seek comment on whether the demand curve should be based on the cost of new generation entry, as PJM has proposed, or on other factors such as the value to customers of alternative levels of capacity. If the demand curve is to be based on the cost of new generation entry, we seek evidence on the cost of new entry, the expected revenues from sources other than the capacity market, the appropriate capacity level at which the price should equal the net cost of new entry, the appropriate slope or slopes for various portions of the demand curve, the appropriate maximum price, the appropriate capacity level at which the price of capacity should fall to zero, and any other issues that commenters wish to raise regarding the height, slope, and shape of the demand curve. We will issue a subsequent order that lays out the details of the technical conference.

ii. <u>Long-Term Fixed Resource Requirement</u>

110. We agree with AEP that LSEs and states should have the option of choosing an alternative to the forward procurement auction if they identify sufficient capacity to meet their loads, which capacity is physically deliverable and which is under contract to the LSE or under the LSE's ownership or control, in advance of the forward procurement auction. Further, LSEs choosing this option must commit to procure this capacity for an

extended period of time. The forward procurement auction is intended to create market conditions that will elicit a reliable supply of capacity over the long term. We conclude that this objective would not be compromised by allowing individual LSEs to choose not to participate in the forward procurement auction – so long as the LSE is willing to commit to procure an adequate, reliable and pre-specified amount of capacity for an extended period.

111. However, to ensure that reliability is not compromised, an LSE must not be allowed to move in and out of the forward procurement auction from year to year. An LSE must not be able to choose the long term fixed resource requirement option during periods of capacity surplus (when the RPM capacity requirement will exceed IRM) and then quickly return to the forward procurement auction without penalty during capacity shortages (when the RPM capacity requirement may be less than IRM). Such flexibility could allow an LSE to procure capacity quantities that, on average over time, was less than IRM and, thus, compromise reliability. We agree with AEP that an LSE that wishes to choose the long term fixed resource requirement option must commit to do so for an extended period. However, we require more information to determine the period of time LSEs must commit to using the long-term fixed resource requirement and whether LSEs choosing RPM should be required to commit to RPM for more than one year (and, if so, for how long). We also seek additional information to determine how to establish the level of deficiency charge needed to ensure compliance, and whether an LSE that fails to procure the full amount of capacity should be precluded thereafter from using the long-term fixed resource requirement option. The staff technical conference will provide parties with the opportunity to discuss these issues.

5. <u>Mitigation</u>

a. <u>PJM's Proposal</u>

112. Section 6 of PJM's proposed tariff explains the generator-specific market power mitigation rules that will apply under the RPM capacity construct. PJM argues that mitigation is necessary since bids by individual resources are used to determine market clearing prices. PJM states that the rules address the exercise of market power by existing capacity resources that may physically or economically withhold capacity to increase market clearing prices in the base or residual auctions. New generator entry, demand response, and energy resources[113] are not subject to market power mitigation.

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[113] Energy resources, in contrast to capacity resources, are those that chose not to satisfy deliverability requirements when interconnecting, and do not participate in the capacity markets.

113. According to PJM, no later than three months before a Base Residual or incremental capacity auction, the Market Monitoring Unit (MMU) will evaluate preliminary market structure screens to determine if more detailed market power analyses are warranted. The preliminary analyses will apply to PJM overall and to any identified LDAs with a locational price adder greater than zero. The analyses rely on data on available unforced capacity from generation capacity resources in each area, corresponding reliability requirements for each area, and any firm obligation to sell unforced capacity. Three concepts are evaluated in the initial screening process: (1) whether any capacity seller's capacity market share exceeds twenty percent; (2) whether the Herfindahl-Hirschman Index (HHI)[114] for any area equals or exceeds 1800; or (3) whether there are not more than three jointly pivotal suppliers. If any of the three screens are not passed, further market power analyses will be required. However, failure of the three jointly pivotal suppliers test will trigger mitigation.

114. For economic withholding, mitigation entails imposing bid caps on existing capacity resources if new entry is not required to clear the market. No mitigation applies to existing capacity resources in the event that new entry is required. The proposed tariff provides details on how bid caps will be determined. First, the output of each generator is divided into a base offer segment[115] and a forced outage factor (EFORd) offer segment.[116] Second, based on data provided by the generator and verified by the MMU,

[114] HHI is a commonly accepted measure of market concentration. The closer a market is to being a monopoly, the higher the market's concentration (and the lower its competition). If, for example, there were only one firm in an industry, that firm would have 100% market share, and the HHI would equal 10,000, indicating a monopoly. If there were thousands of firms competing, each would have nearly zero percent market share, and the HHI would be close to zero, indicating nearly perfect competition.

[115] A component of a sell offer based on an existing generation capacity resource, equal to the summer net capability of the installed capacity of such resource, as determined in accordance with the PJM Manuals, minus the EFORd Offer Segment.

[116] To account for the fact that installed capacity, adjusted for forced outages, may vary between the time a generator participates in the base auction and the Delivery Year, an EFORd offer segment may be defined. The EFORd offer segment is the unit's installed capacity level, multiplied by the potential difference between the EFORd required to be used in the auction and the EFORd required to be used in the Delivery year. This potential difference may be calculated as the positive difference between the five-year average EFORd and the 12-month average EFORd. The base offer segment equals EFORd less the EFORd offer segment.

a bid cap equal to an avoidable cost rate is applied to the base offer segment, and a bid cap equal to the cost of new entry is applied to the EFORd offer segment. Third, an opportunity cost bid cap can be substituted for the specified bid caps with appropriate documentation. Bid caps are generator-specific, and become binding only when the market screen tests are failed and when substituting the bid caps for the offers results in at least a five percent lower market clearing capacity price.

115. To prevent physical withholding, all existing generator capacity resources have a must offer requirement with regard to all unsold capacity. To encourage compliance with the must offer rule, generators that fail to comply in each auction will not be allowed to use its resource to satisfy any capacity requirement or receive any capacity payments in the Delivery Year. Furthermore, the MMU may apply to the Commission for appropriate enforcement action which could delay an auction.

b. Comments and Protests

116. Eighteen parties commented on the mitigation plan. Eight capacity suppliers oppose it for the potential to over mitigate. Four parties representing customers raise the opposite concern of under mitigation. The New Jersey Commission, Morgan Stanley, the Tennessee Commission, and PSEG find the plan acceptable in its proposed form. PHI and DP&L raise concerns that they believe merit a hearing or at least a technical conference.

117. Opposition to PJM's mitigation plan is centered on criticism of: (a) its failure to account for design features that mitigate market power; (b) the pivotal supplier analysis that triggers the imposition of bid caps on existing capacity resources whenever it is failed; and (c) bid caps that are too stringent and overly optimistic revenue offsets.

118. Mirant, for example, stresses that PJM has not shown a need for mitigation and that the design of RPM encompasses features that mitigate market power. In particular, Mirant argues that the VRR curve reduces incentives to exercise market power, and the four-year forward construct allow for competitive entry that will discipline offers from existing resources.[117] NRG also emphasizes these points and argues that the proposed

[117] Mirant protest at 4-5.

mitigation inappropriately is modeled on mitigation of short-term energy markets.[118] Reliant emphasizes that the VRR bid cap and the must-offer rule are completely adequate to address all market power concerns.[119]

119. Those opposing the mitigation plan as excessive reject the use of the proposed market power screens, especially the pivotal supplier analysis. PPL which is critical of all the proposed market power screens, for example, refers to the three pivotal supplier test as a "made up" test by PJM that is not based on any established or accepted economic premise. NRG would also reject the pivotal supplier analysis as inappropriate, and emphasizes that the Commission has also determined that the test may be too restrictive and result in mitigation in markets that are workably competitive. This point was reiterated by Cinergy.[120] Reliant also argues that the market power screens, especially the pivotal supplier test, are too restrictive and that their use virtually guarantees mitigation, especially as the number of LDAs increases.[121] Reliant emphasizes that construction lead-time is the chief barrier to entry, and the four-year-forward commitment of RPM's Base Residual Auction addresses this concern—market power screens, such as the pivotal supplier test, only lead to over-mitigation.[122]

120. Parties opposing the RPM mitigation also object to the bid caps as overly restrictive and the revenue offsets as too high. For example, PPL complains that the offer-capped prices do not reflect the risks associated with committing capacity four years forward. NRG stresses that there are important distinctions between short-run energy markets, where suppliers bid their marginal cost, and long-term pricing decisions where capacity prices may change between the auction and Delivery Year. A bid cap that equals going-forward cost does not account for this opportunity cost.[123] Constellation believes that mitigation should reflect differences between energy and capacity

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[118] NRG protest at 16.

[119] Reliant protest at 20.

[120] Both NRG and Cinergy cite *Midwest Independent Transmission System Operator*, 105 FERC ¶ 61,147 at PP 43, 46 (2003) to support their claim.

[121] Reliant protest at 18-19.

[122] *Id*. at 6.

[123] NRG protest at 16.

markets.[124] Duke emphasizes that pricing decisions for a long-run product must take account of factors not included in short-run energy markets and that the caps proposed for RPM will inappropriately constrain revenues for a year or more at a time, not for an occasional hour as is the case in energy markets.[125]

121. Testimony from James F. Wilson presents the PPANJ argument that the proposed mitigation is inadequate.[126] Mr. Wilson raises concerns about the possibility that new entrants that are exempt from mitigation could, in fact, have some potential to exercise market power. He argues that a new generator is not subject to mitigation until its interconnection service begins. Thus, it is possible that a winning project in one year may result in the cancellation of competing alternatives, especially in the case of supplying a particular local need. Until the winning project actually is connected, it could submit unmitigated bids for later Delivery Years even though competition could be limited. PPANJ is also concerned that a large incumbent could exercise market power by planning new units and withholding older units through retirement, which would not be addressed by the mitigation proposal.

122. The Pennsylvania Commission and PJMICC are concerned that the creation of LDAs will exacerbate the market power problem in capacity markets generally and that this problem has not been adequately addressed by the mitigation proposal.[127] PJMICC disagrees that a sloped demand curve will reduce incentives to mitigate market power, and it submits expert testimony that argues PJM's proposal to mitigate physical withholding is no penalty at all. PJMICC also raises concerns that RPM fails to recognize the market power potential of transmission owners that also own generation. Such entities might have incentives to exercise market power by thwarting an efficient economic transmission planning process, a concern not addressed by the mitigation proposal.

123. The Delaware Commission argues that PJM has not established that its proposed mitigation will prevent generators from charging unjust and unreasonable prices, and it emphasizes that scarcity pricing is not just and reasonable if non-market factors make entry infeasible. For example, the Delaware Commission believes that if environmental

[124] Constellation comments at 2.

[125] Duke protest at 12-13.

[126] PPANJ protest, Attachment, Affidavit of James F. Wilson at 20-26.

[127] Pennsylvania Commission protest at 18; PJMICC protest at 55

restrictions or the absence of fuel supply lines limit entry, scarcity pricing should not be allowed, even if there is a genuine scarcity. It requests that the Commission set for hearing whether generators in load pockets should be subject to stricter bid caps than those proposed by PJM.[128] PHI and Dayton, both generally supportive of RPM, also recommend a hearing or technical conference to consider issues that they believe PJM's proposed mitigation has not adequately addressed.

c. Commission Determination

124. The Commission agrees that market power may be a concern within the RPM proposal, but the nature of those market power concerns differs between short-term markets and a longer-term forward market involving contracting for commitments to last at least a year. Thus, the plan we recently accepted with respect to mitigation in short-term energy markets (the three-pivotal-supplier test, under which offer caps are suspended in any hour in which PJM has more than three jointly pivotal generator suppliers available for redispatch to relieve a transmission limit)[129] may not be appropriate to address potential market power problems in a market involving longer-term contracting for capacity. We are concerned that PJM's proposed mitigation under RPM may rely improperly on mitigation mechanisms that are more applicable to short-term markets.

125. We will therefore require the parties to address the issue of mitigation in the paper hearing, including whether mitigation is in fact necessary. PJM should state why it believes mitigation is necessary, and why it views the three pivotal supplier test as the most appropriate test to measure market power in the context of the long-term RPM capacity construct, and how that view might change depending on the ultimate determination as to the appropriate number of LDAs. The Commission will also require PJM to address the possibility that, in areas where there is not currently a need for new entry, the potential for entry imposes a reasonable limit on the possibility of current generators' exercising market power. PJM should also address the question of whether the proposed offer cap is so stringent so as to make impossible for new entrants into small LDAs (where entry is not needed very often) to recover their costs. Additionally, PJM should also respond to contentions that RPM already contains design features (such as four-year-forward procurement and a downward-sloping demand curve) that mitigate market power. Parties commenting on PJM's proposal should defend their view that

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[128] Delaware Commission protest at 11.

[129] *PJM Interconnection, L.L.C.*, 114 FERC ¶ 61,076 (2006).

PJM's proposal is too stringent, and why they believe that the revenue offsets proposed by PJM are too high.

6. Quick-Start and Load-Following Component

a. PJM Proposal

126. According to PJM, while it presently is capable of meeting load-following criteria on a reliable basis, it has experienced a significant decline in recent years in load-following and 30-minute-start capabilities. According to the affidavit of Andrew Ott on behalf of PJM,[130] over the past four years, the amount of load-following generation offered in PJM has declined by nearly one-quarter, from approximately 44 percent of all generation megawatts offered in PJM in 2000, to only 34 percent of total generation offered in 2004. PJM data also shows a decline of about one third in the number of available starts-per-day (i.e., the number of times the unit can be turned on, turned off, and turned back on during the day to help the system balance generation resources with rapid changes in load) offered by combustion-turbine units. These offered available starts decreased from an average of 4.6 starts per day in June 2000 to 3.1 starts per day in August 2004.

127. Further, PJM explains that most of the units retired in PJM recently had load-following capability, and that capacity is not being replaced by new load-following units. PJM observes that a significant reason for the decline in the availability of quick start and load-following resources stems from the high costs of maintaining older fossil-fueled steam units in a condition that allows them to ramp quickly and cycle frequently. Frequent cycling of such units accelerates wear and tear and increases maintenance costs. Owners of such units need an increased economic incentive in order to counter these increased maintenance costs, and to preserve the economically dispatchable range and cycling capabilities of these units. PJM’s current capacity payment mechanism does not separately value these generating resource flexibilities, nor are they separately compensated in the energy or ancillary service markets.

128. PJM’s current capacity construct treats all installed generation capacity as being of the same value, even though some units have added capabilities that bring added value to preserving system reliability. To ensure reliable service, PJM argues that the PJM region must have available an adequate amount of resources that can respond to rapid increases in load, i.e. "load-following" resources, and resources that can start and stop several times a day on relatively short notice, i.e., "30-minute-start" or "quick start" resources.

[130] Ott Affidavit at P 30.

129. PJM explains these additional capabilities do not lend themselves to valuation in the energy or ancillary services markets.[131] They are better suited to compensation through a capacity market. Further, PJM argues that RPM also provides an appropriate vehicle to help address the decline in load-following and 30-minute-start capabilities. Specifically, the RPM auction-clearing algorithm will produce higher compensation for load-following resources and 30-minute-start resources to the extent needed to meet the system's requirements for such resources. Prior to the RPM auctions, PJM will determine the region's minimum requirement for each of these types of resources, and certify units capable of meeting those requirements. Market sellers with such resources can specify in their offers the added price, if any, that, they would require to offer these capabilities. If either of the operational reliability constraints bind in the auction, then the price will clear higher as necessary to ensure the minimum required amount of resources, with such capability, are committed in the auction. All generation resources in the region that provide that needed capability then will receive the same price adder. The price adder will not apply to any generation that is accepted, but lacks the needed load-following or 30-minute-start capability. In addition, the price adder may differ for the two capabilities, i.e., load-following versus 30-minute-start. If the load-following constraint binds in the auctions, all load-following resources will receive the adder for that constraint; and if the 30-minute-start constraint binds in the auction, all 30-minute-start resources will receive that adder.

130. To ensure the capability is provided, resources committed in the auctions to resolve the operational reliability constraints must pass capability tests in the Delivery Year, and must specify and offer such capabilities in their offer data for the PJM energy market.

b. <u>Comments and Protests</u>

131. Duke states that the proposed operational capacity requirement ensures that resources will receive appropriate compensation, acknowledges the added value of capacity resources that meet these requirements, and provides an incentive for generation operators to maintain units with capabilities that assist PJM in meeting its operational needs. AEP asserts that the stakeholder process, where these issues are currently being addressed, is the appropriate forum in which to discuss these issues. Moreover, AEP notes that neither load-following nor quick start capabilities are true "capacity" services.[132]

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[131] *Id*.

[132] Duke protest at 9, AEP protest at 18.

c. Commission Determination

132. We will accept PJM's proposal to include a separate requirement and potentially higher price for procuring quick-start and load-following capability. We agree with PJM that the region must have at least a minimum amount of these capabilities in order to meet load reliably and that it is reasonable to compensate for these capabilities in the forward procurement auction if the auction's market clearing prices do not otherwise elicit the required minimum amounts. In response to AEP's comments, we conclude that quick-start and load-following capabilities are characteristics of capacity, just as location is a characteristic of capacity. And, just as a higher price may be necessary for capacity in some locations in order to elicit adequate capacity in those locations, a higher price may be necessary in order to elicit an adequate amount of quick-start and load-following characteristics.

7. Miscellaneous Issues

a. Alternatives to RPM

i. The Enhanced Integrated Transmission and Capacity Construct (EITCC)

(a) Comments and Protests

133. CCR proposes an incremental, market-oriented approach to address capacity issues and future long-term reliability in PJM. CCR states that its EITCC model has three fundamental parts. First, through voluntary commitments, load may acquire required capacity during the three years prior to a planning year, but would be subject to stringent penalties for failing to secure sufficient capacity requirements prior to the planning year.[133] Under the CCR proposal, the capacity requirements could be met either through bilateral contracts or through capacity auctions administered by PJM.[134]

134. Second, CCR suggests that for areas with limited local resources and limited transmission transfer capability, an appropriate portion of capacity should be purchased

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[133] CCR protest at 66.

[134] *Id*.

from within the designated area. As a result, unless generation scarcity is transitory, pending construction of new transmission resources, prices would rise and signal opportunity to generation developers.[135]

135. Third, the EITCC proposal recommends enhancing PJM's RTEP so that (1) planning is more sensitive to the risks of generation retirement, (2) longer lead times for major transmission system upgrades are incorporated, (3) local issues between a transmission owner and an LSE are more consistently addressed, and (4) currently unconnected planning functions related to reliability, operations and congestion relief are integrated.[136] To accomplish these goals, CCR recommends expanding the RTEP planning horizon from five years to as many as ten years, and increasing the notification period for generation retirement from 90 days to twelve months.[137]

136. In addition, CCR emphasizes that the EITCC model does not require a demand curve due to the incremental nature of suggested changes.[138] Furthermore, CCR argues that the EITCC model treats demand response, as provided by market participants whose primary business is not providing capacity, the same way that it treats generation.[139] Finally, CCR states that EITCC incorporates local capacity price premiums into the calculation of unhedgeable congestion in the planning process, enhances local planning standards and protocols, ensures local capacity adequacy through local assessments, and encourages use of merchant transmission to satisfy capacity requirements.[140]

(b) <u>Commission Determination</u>

137. While the Commission does not support the EITCC proposal in its entirety as an alternative to the PJM RPM proposal, features of the EITCC proposal have been discussed above in connection with the RPM proposal. First, the EITCC proposal advocates adding a locational feature to the capacity obligation, although with fewer

[135] *Id*.

[136] *Id.* at 67.

[137] CCR protest, Attachment, Affidavit of Jonathan Wallach, Tab B.

[138] CCR protest at 67.

[139] CCR protest, Attachment, Affidavit of Jonathan Wallach, Tab B.

[140] *Id*.

capacity zones than PJM's RPM proposal. As discussed above, we agree that a locational feature is necessary for PJM's capacity construct and we have set the issue of the specific number of capacity locations for further proceedings. Also, the EITCC proposal advocates reform of the RTEP process, including extension of the transmission planning horizon. PJM agrees and has indicated its intention to file RTEP reforms in the near future, and as discussed above, we encourage such a filing. The EITCC proposal would conduct mandatory auctions to satisfy capacity obligations only a few months before the Delivery Year. As discussed above, we agree with PJM that it is reasonable to hold an auction four years in advance of the Delivery Year to procure capacity. Finally, the EITCC proposal would continue to use a vertical demand curve.

138. As discussed above, we have concluded that the existing capacity construct, which relies on a vertical demand curve in combination with a lack of forward procurement, is not just and reasonable. We have concluded that states and LSEs should have choice between a system whereby PJM would procure capacity in a forward procurement auction with a sloped demand curve and a system whereby the LSE commits for an extended period to procuring a fixed amount of capacity.

ii. Forward Procurement of Capacity: A Longer Commitment (PPL)

(a) Comments and Protests

139. PPL states that as proposed, RPM will not work to encourage investment. PPL is primarily opposed to the forward procurement component of RPM, which, according to PPL, will interfere with short-term and long-term bilateral markets for capacity.[141] PPL argues that RPM forces generators into the position of participating in the auction and waiting four years to obtain a one-year capacity revenue stream, which PPL states is insufficient for long-term capital allocation decisions.[142] According to PPL, a longer-term contract of five, ten or twenty years would be more effective in eliciting new investment.[143]

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[141] PPL post-technical conference comments at 7.

[142] *Id*. at 8.

[143] PPL protest at 27.

140. As an alternative, PPL suggests that should the Commission accept RPM, it should do so with enhancements to the energy and ancillary services markets. Specifically, PPL advocates the adoption of a true energy-only market with scarcity pricing, which would compensate peaking units and encourage demand side response.[144] PPL argues that, if RPM were implemented in conjunction with allowing scarcity pricing in energy markets, reliability would be preserved and bilateral markets, self-supplied generation, hedging, and financial instruments would be permitted to operate.[145] In addition, PPL urges the Commission to eliminate RPM's forward base and incremental auctions, and replace them with a single mandatory auction just prior to the Delivery Year.[146]

(b) <u>Commission Determination</u>

141. The Commission declines to select PPL's proposal as an alternative to the PJM RPM proposal. Like the EITCC proposal, the PPL Parties emphasize a voluntary, bilateral market and an auction held prior to the Delivery Year. For the reasons discussed *supra*, the Commission does not find this aspect of the proposal to be adequate, nor will the Commission accept an energy-only alternative at this time. However, as discussed above in Section III.B.2, we are setting for paper hearing the appropriate duration of the contract, and the parties should consider the issue PPL raises about the appropriate length of the contract (i.e., longer than a single year) in the paper hearing.

iii. <u>Energy Only Markets</u>

(a) <u>Comments and Protests</u>

142. Morgan Stanley argues that PJM's RPM is an artificial, non-economic, centrally-planned structure that will further diminish the connection between major investment decisions and energy market incentives and create significant regulatory risk.[147] Morgan Stanley therefore suggests the immediate implementation of an energy-only market model.[148]

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[144] PPL post-technical conference comments at 4-5.

[145] *Id*. at 6.

[146] *Id*. at 8.

[147] Morgan Stanley comments at 2, 22.

[148] *Id.* at 17.

143. Morgan Stanley states that "[e]nergy markets, where an unmitigated spot price signal acts to cause supply to equal demand in real time, combined with a requirement that [LSEs] procure energy through forward contracts to protect against price spikes and protect consumers, will bring the proper amount of generation to PJM."[149] To accomplish this goal, Morgan Stanley advocates that regulators require forward contracting, and eliminate energy price caps.[150] Morgan Stanley suggests that LSEs could use a variety of methods to procure power, such as Basic Generation Service-style auctions, similar to those used in New Jersey, and Standard Offer Service request for proposal procurements, such as those used in Maryland and the District of Columbia. Morgan Stanley also posits that demand response should not be ignored, as it should not slow PJM's implementation of an energy-only market design.[151]

144. OPSI also argues that any long-term vision of the wholesale power market must have at its core an efficient, robust energy market; and that PJM has not yet been able to show its long-term vision of an energy-only market or how PJM will transition from RPM to an energy-only market. OPSI argues that for the immediate future, there needs to be some form of a capacity construct and an ancillary generating services market. OPSI states that, nevertheless, a long-term objective to consider should be reducing the need for these administrative market constructs to the extent possible. OPSI argues that such market constructs should not be administrative, but buyer and seller based.[152]

(b) <u>Commission Determination</u>

145. We do not adopt Morgan Stanley's energy-only proposal to replace the capacity construct in PJM. We have found to be just and reasonable the basic outlines of PJM's proposal for a capacity construct that includes a locational element and forward procurement auctions. For the reasons discussed earlier, we are persuaded by PJM and the supporters of RPM that a capacity market, suitably modified from the current construct, would elicit adequate capacity for reliability.

146. We note that PJM's proposal includes a feature that reduces capacity market revenues (and thus, the importance of capacity markets in eliciting adequate

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[149] *Id.* at 8.

[150] *Id.* at 11, 12.

[151] *Id.* at 8, 15.

[152] *Id.* at 20.

infrastructure) as energy market revenues increase, albeit with a lag. That is, expected revenue from the energy and ancillary service markets (measured as a rolling simple average of net revenues that a peaker would have earned in the PJM spot markets over the most recent six years)[153] would reduce the height of the demand curve, and thus, reduce the prices and revenues received by resources in the capacity market. Thus, to the extent that energy market revenues increase, capacity market revenues could be reduced proportionately so that the overall rate remains just and reasonable.

147. Given the lack of broad support for, and in some cases lack of detailed development of, alternatives to RPM, the Commission declines to select any of the aforementioned alternatives to RPM as a replacement for the PJM RPM proposal.

iv. Seams Issues

(a) Comments and Protests

148. Several parties express concerns about the effect of RPM on seams between RTOs, specifically, between PJM and the NYISO and the Midwest ISO.

149. The Midwest ISO stated its strong interest in this matter stemming from the desire to ensure that the Commission's decisions on the RPM proposal recognize the need for compatible resource adequacy protocols that recognize differences in state regulation and ensure aligned investment incentives across regional seams. The Midwest ISO seeks to ensure that the final disposition of the RPM proposal does not preempt the Midwest ISO, its stakeholders and state regulators from continuing discussions and development of a long-term resource adequacy plan for the Midwest ISO region.[154] The Midwest ISO stressed that resource adequacy protocols affect investment decisions which in turn affect seams. The NYISO raised the potential for seams issues between NYISO and PJM capacity markets.[155]

150. Other parties express concerns regarding the consequences of RPM on seams issues. PJMICC alleges that PJM fails to consider unintended consequences of RPM, including effects on other markets.[156] The PPL Parties allege that RPM introduces a

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[153] Bowring Affidavit at 2-3.

[154] MISO comments at 11.

[155] NYISO comments at 4.

[156] PJMICC protest at 5.

seam between PJM and the NYISO, that RPM contains substantial and unnecessary differences from the NYISO-approved capacity market, and that these differences will interfere with efficient trans-border capacity transactions.[157] The MSATs request that the Commission clarify that the RPM obligation does not require the Midwest ISO to develop an RPM-type capacity market.[158] LIPA and ConEd believe the Commission should establish technical conferences to examine the effect of RPM proposals on neighboring markets.[159] Additionally, questions have been raised as to the possible incompatibility of RPM's forward commitment requirement with other regulatory regimes. PHI asks whether seasonal commitments create seams problems with Midwest ISO, which does not have seasonal pricing. Rockland asks the Commission to review the compatibility of RPM with the current Basic Generation Service[160] auction process, which already provide loads in New Jersey with an opportunity to purchase long-term products voluntarily in the PJM markets, fearing that the four-year requirement of the RPM model will encourage suppliers to offer only long term products to loads in the Basic Generation Service auctions, so that LSEs will be required to make risky long-term wholesale commitments for their customers, while the retail markets in PJM provide no assurance that the customers will remain with an LSE for the same commitment period.

151. PJM states in its answer that even if the Midwest ISO decides to pursue an energy-only market, RPM will not create significant seams issues. PJM asserts that the sale of capacity in RPM can be compared by participants to the sale of physically firm energy in the Midwest ISO: prices can equilibrate at the border. PJM goes on to state that any inconsistencies would occur only during extreme or emergency situations, such as operations during scarcity conditions and reserve sharing. According to PJM, the Midwest ISO and PJM can develop protocols to anticipate and address these situations.[161] Furthermore, states PJM, PJM and Midwest ISO expressed to the Commission in a joint report their confidence that they can effectively manage the differences between their

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[157] PPL protest, Attachment A at 42.

[158] MSATs comments at 2.

[159] LIPA comments at 5.

[160] In December of 2001, the New Jersey Commission authorized the auction of Basic Generation Service to meet the electric demands of all customers who have not selected an alternate electric supplier.

[161] PJM answer at 54.

resource adequacy methodologies.[162] Thus, maintains PJM, any seams issues with the Midwest ISO that may result from implementing RPM are manageable.[163]

152. PJM contends that RPM is comparable to NYISO's locational capacity rules. PJM states that the NYISO also uses a demand curve, with separate locational demand curves and seasonal capacity auctions.[164] PJM asserts that the only significant distinction between NYISO's rules and RPM is that RPM is based on auctions conducted four years before the planning year, while the NYISO locational capacity program takes a shorter-term view. PJM believes that under RPM market participants have an opportunity to make any necessary changes in their committed capacity a few months before the Delivery Year, allowing coordination with developments in the New York capacity market. PJM argues this difference will not adversely impact seams with NYISO.

(b) <u>Commission Determination</u>

153. The Commission will decline to institute technical conferences to examine the effects of RPM on neighboring markets at this time, but will affirm that implementation of RPM in PJM will not require the Midwest ISO to put in place a similar capacity market.

154. PJM has raised the possibility of difficulties developing during extreme or emergency situations, or during scarcity conditions and reserve sharing, and has explained that PJM and the Midwest ISO may develop protocols to anticipate these potential situations. We direct PJM to work with the Midwest ISO to develop protocols to address these concerns, as well as concerns arising from resource adequacy differences between PJM and the Midwest ISO. PJM and the Midwest ISO should submit these protocols to the Commission upon their completion, or submit a report to the Commission regarding efforts to develop such protocols consistent and coinciding with the Commission's requirement for reports in connection with the Joint Operating Agreement between PJM and the Midwest ISO.

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[162] *See* Transmittal Letter, *Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.*, Docket Nos. ER04-375-017 and ER04-375-018 (Oct. 31, 2005) (informational filing on status of joint efforts to achieve a joint and common market.)

[163] PJM answer at 54.

[164] *Id*. at 51.

8. <u>Appropriateness of PJM's amendments to the OA.</u>

a. <u>Comments and Protests</u>

155. A significant portion of PJM's current capacity construct is included in the OA.[165] PJM asserts that many aspects of its reliability planning are already contained in the RAAs, such as the means of determining capacity obligations of LSEs and the charges for failure to obtain sufficient capacity. PJM states that in this filing, it proposes to place the RPM version of these provisions in the new consolidated RAA (over which the PJM Board will have section 205 authority), and will transfer some of them to the OATT, on the basis that provisions involving reliability are appropriately within the core responsibility of PJM to ensure reliability of the system. In addition, PJM proposes to place the remaining RPM provisions (*i.e.*, the provisions currently in the OA) in the OATT. PJM may make filings under section 205 to amend its OATT and RAA. However, PJM may only seek to amend its OA under section 205 if it obtains a two-thirds supermajority sector approval of the Members Committee; otherwise it is limited to making filings to amend the OA under section 206.

156. Some protesters consider this an end run by the PJM Board around its stakeholders. CCR asserts that many of the provisions that PJM now seeks to place in the OATT and RAA more appropriately fall within the OA, since they deal with market mechanisms and marketplace interactions.[166] CCR asks the Commission not to allow PJM to change the OA requirements, in which the structure of PJM's markets require the vote of PJM's members, simply by shifting the capacity market provisions of the OA to the OATT or RAA,[167] stating that "the Commission should not condone PJM's attempt to expand its filing rights authority, and to treat its OATT and the RAA as a safe harbor for market changes that are not popular with its stakeholders." [168]

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[165] Schedule 11 of the OA contains the market rules for PJM's capacity credits markets.

[166] CCR protest at 11 ("Although RPM is an administrative program, its implementation mechanics are marketplace-based, complete with auction clearing rules, bidding rules, and mitigation rules"). CCR further states that "many of the implementation aspects of [the RPM] administrative model are based on marketplace interactions," *id.* at 12.

[167] *Id.* at 13.

[168] *Id.* at 19.

157. CCR states that the OA reflects a careful division of section 205 and 206 filing rights between the PJM stakeholders and PJM:

> At the time the stakeholders in PJM fashioned the PJM Operating Agreement, they determined that the rules governing the structure of PJM markets were of such critical importance to the financial interests of stakeholders that the stricter standard of proof under Section 206, limiting the authority of the PJM Board to make changes to those rules, was required. Essentially, the stakeholders transforming PJM into an RTO placed the rules governing the market transactions in the Operating Agreement so as to ensure that the stricter burden of proof applies to any changes to those market rules.[169]

158. CCR and PJMICC argue that PJM's transfer of provisions governing the PJM capacity market from the OA to the OATT and RAA ignores the Commission's prior acceptance of the OA.

b. Commission Determination

159. Since the Commission is not ruling definitively on RPM or on the particular tariff changes submitted by PJM, it is not yet necessary to consider this question. At the time that the Commission issues its definitive order on RPM, different tariff sheets may have been filed, so that the concern raised by CCR and PJMICC may be moot. Thus, the Commission will rule on this question if and when it becomes ripe.

9. Capacity Credits

a. Comments and Protests

160. Cinergy raises concerns regarding the PJM OATT's treatment of capacity credits. Cinergy alleges that section 14.2 of the PJM OATT should be corrected to specify: (1) the price at which capacity credits for the 2006/2007 Delivery Year entered into on or after April 1, 2005 should settle; and (2) that, in the case of contracts that specifically identify the physical source of capacity credits, the capacity credits should be valued at the marginal value of capacity in the LDA of the physical source.[170]

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[169] *Id.* at 14, footnotes omitted.

[170] Cinergy protest at 4.

b. Commission Determination

161. The Commission will direct PJM, in a future order, to clarify the value of capacity credits in the case of contracts that specifically identify the physical source of capacity credits as appropriate.

10. Emergency Procedures

a. Comments and Protests

162. Several parties request clarification with regard to PJM's requested provisions on emergency procedures. Cinergy states that section 13.1 of the PJM OATT would provide for payment of an Emergency Procedure Charge by capacity market sellers and ILR providers that failed to comply with, or failed to employ "best efforts" to comply with, instructions to implement PJM emergency procedures.[171] Cinergy registers its opposition to what it considers the improper delegation of penalty and enforcement authority, and ultimately ratemaking authority, to RTOs and independent market monitors. Cinergy submits that this delegation amounts to a determination of when a rate should be charged. Cinergy also questions what is meant by "best efforts."[172] Constellation argues that the Emergency Procedure Charge should be clarified, and asserts that PJM should define "emergency procedures," "emergency" and "best efforts."[173] Constellation recommends using "Good Utility Practice" instead of "best efforts" as a standard for responses to PJM directions.[174]

b. Commission Determination

163. Pursuant to PJM's current Operating Agreement and RAA, PJM may implement an Emergency Procedure Charge pursuant to provisions that address emergency

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[171] *Id* at 12.

[172] *Id.* at 13.

[173] Constellation comments 32, 33.

[174] *Id.* at 41.

situations that threaten system reliability.[175] The provisions explain that in the circumstance where a party is requested to comply with emergency instructions and fails to do so, while nevertheless being capable of producing energy, an emergency procedure charge equal to 365 times the average of the daily deficiency rate per MW is charged. Revenues from the charge are then distributed among complying parties.[176]

164. The Commission does not agree that PJM's Emergency Procedure Charge constitutes an improper delegation of our ratemaking authority. We find such a penalty to be just and reasonable under the FPA, having been accepted by the Commission after proper submission under section 205 of the statute and accorded the proper rate schedule designations. We also find that PJM has sufficiently specified the purpose and role of the Emergency Procedure Charge and its correlation to maintaining reliability to prevent any potential abuse of discretion. However, similar to the Commission's statement above regarding clarification of the value of capacity credits, in a future order, we will direct PJM to define the terms "emergency procedures," "emergency" and "best efforts," as appropriate.

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[175] PJM's tariff provides the following definition:

> Emergency shall mean (i) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or (ii) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or (iii) a condition that requires implementation of emergency procedures as defined in the PJM Manuals.

PJM Interconnection, L.L.C. Second Revised Rate Schedule FERC No. 27, Second Revised Sheet No. 10.

[176] Third Revised Rate Schedule FERC No. 24, Original Sheet No. 195, issued March 20, 2003; Second Revised Rate Schedule FERC No. 27, Substitute First Revised Sheet No. 59, issued July 29, 2003.

C. General Objections to RPM

a. Comments and Protests

165. In addition to the comments on specific features of RPM, some protestors provided general comments on the RPM proposal as a whole.

166. OPSI, the Virginia Commission, the Pennsylvania Department of Environmental Protection and DEMEC are concerned that RPM seems to do little to encourage the construction of new, more efficient base load and cycling generation, and instead will extend the service life of existing old peaking generation and result in an increase in the construction and operation of gas fired peaking units, while doing little to create incentives to build other kinds of generation resources or to decrease the reliance of the PJM region on natural gas-fired generation.

167. The Virginia Commission argues that a more logical approach would be to focus on those areas that are experiencing or approaching reliability criteria violations. This could be accomplished by implementing a different installed capacity requirement on the LSEs serving the problem areas or instituting RPM on a regionalized approach.[177]

168. Delaware argues that the Commission should not approve PJM's RPM proposal as just and reasonable without assuring that other methods of uncertainty reduction have been investigated, and that RPM does not preclude their implementation whenever their benefits exceed their cost. In particular, the Commission should (a) revisit the 90-day retirement right; and (b) consider longer term contracts requiring generators to run at cost-based prices.[178] Delaware also believes the Commission must make transmission construction more certain, paying special attention not only to long-distance transmission but to transmission closer to load. PPL states that without the liquid short-term capacity market that RPM eliminates, sellers will be exposed to substantial cost risks if capacity they have committed to LSEs becomes unavailable for any reason.

b. Commission Determination

169. The Commission recognizes the parties' concerns. It is our view, however, that PJM has demonstrated that the short term nature of the commitments required under PJM's current capacity construct has contributed to the lack of investment in keeping

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[177] Virginia State Corporation Commission protest at 4.

[178] Delaware Commission comment at 7.

generation operating and in building new generation. Contrary to protesters' arguments, RPM will not make PJM a centralized planner and procurer of capacity under a cost of service ratemaking regime. Rather, RPM has the potential to provide price signals and price stability that will enable LSEs to purchase capacity, and generators to offer to provide capacity, in a more informed and efficient fashion. Armed with this superior quality of information, however, LSEs will still make their own business decisions about how much capacity to build or procure in long-term contracts and at what cost, and how much to obtain through PJM's auction. As to the risks to captive customers raised by Morgan Stanley, customers face similar risks now: LSEs must either procure sufficient capacity, or procure capacity through PJM's capacity credits markets (as price takers), or face deficiency charges. Similarly, as to the risks cited by PPL that, absent the current PJM capacity credits market, generators may have more difficulty hedging themselves against the possibility that they are unable to deliver capacity to customers, generators will be compensated for that greater level of risk by the possibility of enhanced compensation that they will receive as a result of RPM. RPM will not put greater risks on market participants; rather, it will simply change the nature of those risks and the trade-offs associated with them.

170. Additionally, PJM has recognized that an administratively-determined capacity market is likely, of its own nature, to devolve in importance as revenues from the energy market increase, and enable generators to obtain sufficient revenue from energy sales that a capacity market mechanism may no longer be necessary. PJM states:

> PJM agrees [with state commission representatives] that capacity markets should diminish in importance to the extent energy markets in the future prove capable, standing alone, of offering adequate assurance of reliability. Accordingly, the RPM proposal . . . includes provisions that will automatically de-emphasize the capacity market as the energy market proves more effective at incenting capacity resources. Specifically, PJM has designed the [VRR] curve to reflect changes in the level of revenues received by generators from the energy and ancillary services markets; this revenue offset will reduce capacity prices as generation owners receive more net revenue from other sources. As a result, the RPM design will automatically track any transition towards greater emphasis on energy prices, whether in connection with changes to the offer price cap, development of scarcity pricing, or evolution of load management techniques and compensation.[179]

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[179] August 31st Filing, Transmittal at 16, footnote omitted.

171. We agree with PJM that under its proposal, capacity markets would automatically diminish in importance to the extent that energy market revenues increase, as might occur, for example, if the PJM-wide $1000/megawatt-hour energy bid cap were to be raised. A related issue is whether RPM should be accepted as a temporary measure. We think that accepting RPM as a temporary measure – without identifying a solution that would subsequently replace RPM– would not likely help remedy the problems of insufficient capacity that currently face PJM. That is because accepting RPM only for the interim would create regulatory uncertainty that would fail to address the root causes of PJM's current infrastructure inadequacies. In regions within PJM where infrastructure is inadequate, revenues under the current market rules are below the cost of building new peaking units. Investors cannot be expected to finance needed new infrastructure based on a temporary source of additional revenues derived from a temporary RPM mechanism.

172. Finally, the West Virginia Commission makes the related argument that, under the FPA and the Energy Policy Act of 2005 (EPAct), PJM does not have authority to order construction of new generation, and that this Commission has no jurisdiction over generating facilities. The West Virginia Commission asserts that by accepting the RPM proposal, we would be endorsing PJM's intrusion into state jurisdiction over generation. This is, however, an incorrect understanding of the RPM proposal. Under the RPM proposal as filed, LSEs may either (a) build their own needed capacity or create an incentive for the construction of new capacity by entering into long-term bilateral agreements, (b) refrain from entering into bilaterals and pay the (presumably higher) prices set by the demand curve, or (c) develop transmission or demand response solutions to capacity problems. PJM is not proposing to mandate or in any way require the construction of new generation. 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.

D. Refund Effective Date

173. While we are setting these matters for paper hearing and technical conference, we encourage the parties to make every effort to resolve their differences prior to a final Commission ruling on RPM. Pursuant to Rule 603(c)(1) of the Commission's Rules of Practice and Procedure, any party may file a motion with the Commission requesting the appointment of a settlement judge.[180] The parties may, by mutual agreement, request a specific judge as the settlement judge in the proceeding; otherwise, the Chief Judge will select a judge for this purpose.

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[180] 18 C.F.R. § 385.603(c) (1) (2005).

174. When the Commission institutes a section 206 proceeding, section 206(b) requires that the Commission establish a refund effective date that is no earlier than 60 days after publication of notice of the Commission's investigation in the Federal Register, and no later than five months subsequent to expiration of the 60-day period. While we do not anticipate requiring refunds here, we will establish the statutorily-directed refund effective date at earliest date allowed, 60 days after publication of notice of the initiation of the Commission's investigation in Docket Nos. EL05-148-000 and ER05-1410-000 in the Federal Register.

175. In addition, section 206 requires that, if no final decision has been rendered by the refund effective date, the Commission must provide its estimate as to when it reasonably expects to make such a decision. Given the times for filing identified in this order, and the nature and complexity of the matters to be resolved, the Commission estimates that it will be able to reach a final decision by 180 days from the date of publication of this order; if no final decision is rendered by the conclusion of that 180-day period, the Commission shall state the reasons why it has failed to do so and shall state its best estimate as to when it reasonably expects to make such decision.

E. Settlement and Alternative Dispute Resolution

176. The Commission encourages the parties to make every effort to settle these issues before conclusion of the paper hearing and technical conference procedures ordered here. If the parties believe that a Commission settlement judge would aid them in their settlement efforts, any party may file a motion requesting the appointment of a settlement judge with the Commission, pursuant to Rule 603(c)(1) of the Commission's Rules of Practice and Procedure.[181] If the parties desire, they may, by mutual agreement, request a specific judge as a settlement judge in the proceeding; otherwise the Chief Judge will select a judge for this purpose.[182] Alternatively, the parties may also make use of the Commission's Dispute Resolution Services.[183]

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[181] 18 C.F.R. § 385.603(c) (1) (2005).

[182] If the parties decide to request a specific judge, they should make their request to the Chief Judge by telephone at 202-502-8500 as quickly as possible following the motion for appointment of a settlement judge. The Commission's website contains a listing of Commission judges and a summary of their background and experience (www.ferc.gov - click on Office of Administrative Law Judges).

[183] The Director of the Dispute Resolution Services is Richard L. Miles, who may be reached at 202-502-8702 or 1-877-FERC-ADR (1-877-337-2237).

The Commission orders:

(A) The Commission finds pursuant to section 206 of the FPA that PJM's current capacity adequacy construct is not just and reasonable.

(B) The Commission finds that, as a general matter, the following aspects of PJM's RPM proposal are just and reasonable: locational capacity requirements; a four-year-forward procurement auction; a downward sloping demand curve, integration of generation, demand response and transmission; and the proposal for treatment of quick-start and load-following generation.

(C) The Commission finds that LSEs and states may also choose to use a fixed resource requirement rather than participating in PJM's capacity auction scheme.

(D) The Commission hereby institutes a proceeding in Docket Nos. EL05-148-000 and ER05-1410-000 under section 206 of the FPA concerning the justness and reasonableness of matters relating to the RPM proposal set forth in Appendix A.

(E) The Commission directs PJM to file a brief on the issues set for paper hearing in Appendix A by May 19, 2006. Parties who wish to file comments on PJM's brief must do so by June 2, 2006. Parties who wish to file reply comments must do so by June 16, 2006.

(F) The Commission sets for staff technical conference the matters relating to PJM’s RPM proposal set forth for technical conference in Appendix A.

(G) The Secretary shall promptly publish in the *Federal Register* a notice of the Commission's initiation of this proceeding under section 206 of the FPA in Docket Nos. EL05-148-000 and ER05-1410-000.

(H) The refund effective date established pursuant to section 206(b) of the FPA will be the date of publication in the Federal Register of the notice discussed in Ordering Paragraph (G) above.

(I) PJM is hereby ordered to file a report with the Commission setting forth the manner in which its RPM program coordinates with its RTEP program, at the time that PJM makes its upcoming RTEP filing, as discussed above.

By the Commission.

(S E A L)

Magalie R. Salas,
Secretary.

Appendix A

LIST OF ISSUES SET FOR PAPER HEARING

Number of Locational Deliverability Areas

The capacity areas used in RPM are known as locational deliverability areas (LDAs). In order to transition into RPM, PJM proposes two LDAs in Year 1 and three LDAs in year 2. After this transition period, the LDAs will be determined through the transmission planning process. PJM expects there to be 23 LDAs.

- What are the appropriate rules for determining the LDAs?

- What is the relationship between the LDAs delineated under RPM and the transmission constrained (scarcity pricing) regions set forth in the PJM parties' settlement in Docket No. EL03-236-006 (114 FERC ¶61,076)?

- How should LDAs be implemented? Should there be a phase-in period? Would the phase-in period allow PJM to remedy the current and impending reliability problems associated with inadequate capacity in New Jersey and other portions of eastern PJM in an acceptable timeframe?

- Does the implementation of the long-term fixed resource requirement affect how the LDAs should be determined? If so, how?

Length of Contractual Commitment

Under RPM, PJM will administer a series of auctions as a vehicle for loads to secure capacity commitments and to establish corresponding reliability charges for each year. The first auction, conducted four years ahead of the year at issue (known as the "Delivery Year"), will commit capacity resources for each of four seasons of a single year.

- Is a contractual commitment longer than one year necessary? What are the advantages and disadvantages of a longer commitment?
  What is the most appropriate period of contractual commitment and delivery to ensure optimal participation of new and existing generation, transmission planning and demand response?

- Would it be appropriate to implement a multi-year, staggered contractual commitment, and how would this be structured?

- What are the benefits of seasonal pricing for capacity?

Under RPM, PJM will hold reliability backstop auctions if insufficient capacity is committed in four consecutive Base Residual Auctions. Reliability backstop auctions will allow PJM to seek commitments of additional generation resources for a term of up to fifteen years, based on the sell offers that satisfy the posted reliability requirements at the lowest price. If a market seller's offer is accepted in the reliability backstop auction, then PJM will enter into a long-term purchase agreement (on behalf of all LSEs in the PJM region) with that market seller.

- Are the timeframes used in the reliability backstop auction acceptable? Could these timeframes create hurdles for demand resource participation?

Transmission cost recovery

PJM states that transmission participation will be integrated into the RPM capacity market by allowing for planned transmission upgrades that provide incremental increases in import capability into constrained areas to be offered into the auctions.

- How will the cost recovery mechanism used in RPM be coordinated with that utilized in the RTEP process? How would this cost recovery methodology ensure that all those benefiting from the upgrade will pay? What would happen with the transmission upgrade if it clears in the forward auction for one year but not in any subsequent years? How would cost allocation methodology function in vertically integrated markets?

- Are there any time limitations on the Capacity Transfer Rights earned by participant-funded transmission?

- What tests will be required to demonstrate that the transmission upgrades have continued to provide the level of transfer consistent with those rights?

- What is the process through which transmission owners will specify the source of the energy that will be brought into the constrained area in order to participate in the LDA market?

Market Power Mitigation

PJM proposes generator-specific market power mitigation rules to apply to the RPM capacity construct because, PJM argues, bids by individual resources are used to determine market clearing prices.

- Is mitigation necessary in capacity markets that contain features such as four-year-forward procurement and downward sloping demand curve?

- Is the three pivotal supplier test the most appropriate test to measure market power in the context of the RPM capacity regime? How would that view change, based on the ultimate determination as to the appropriate number of LDAs?

- If offer caps are imposed on sellers to mitigate market power, what factors should be used to establish the offer cap?

- In small LDAs where load growth will support new entry at an efficient size only once every several years, could a new entrant expect to recover its costs over time with a capacity offer cap reflecting going-forward costs imposed after it no longer qualifies as a new entrant? In such an LDA, what offer cap level would permit new entrants to recover their costs over time? If offer caps are to be imposed, should different criteria be used to establish offer caps in different LDAs?

- Parties commenting on PJM's proposal should defend their view that PJM's proposal is too stringent, and why they believe that the revenue offsets proposed by PJM are too high.

LIST OF ISSUES TO BE DISCUSSED IN A TECHNICAL CONFERENCE

Mechanisms for procuring capacity – Variable Resource Requirement

- How should the height and slope of the downward sloping demand curve be determined? Should the curve be based on the net cost of new generation entry, or on other factors such as the value to customers of alternative levels of capacity?

- If the demand curve is based on the cost of new generation entry, what is the cost of new entry?

- How should expected revenues from the energy and ancillary service markets be estimated and how should they be used to adjust the height and slope of the demand curve?

- What is the appropriate capacity level at which the capacity price should equal the net cost of new entry.

- What is the appropriate slope or slopes for various portions of the demand curve?

- What is the appropriate maximum price and the appropriate capacity level at which the price of capacity should fall to zero?

Long-term Fixed Resource Requirement Option

- What should be the time period for which LSEs must commit to using the long-term fixed resource requirement option?

- What should be the level of deficiency charge needed to ensure compliance?

- Should an LSE that fails to procure the full amount of capacity be precluded thereafter from using the long-term fixed resource requirement option?

- How much capacity should the LSE be required to procure under this option?

Appendix B

Parties seeking intervention in Docket Nos. EL05-148-000 and ER05-1410-000

1. Allegheny Electric Cooperative, Inc., Borough Of Chambersburg, Pennsylvania, Delaware Municipal Electric Corporation, District Of Columbia Office Of The People's Counsel, Illinois Citizens Utility Board, Maryland Office Of Peoples Counsel, North Carolina Electric Membership Corporation, Old Dominion Electric Cooperative, Pennsylvania Office Of Consumer Advocate, Pennsylvania Office Of Consumer Advocate, Pennsylvania Office Of Consumer Advocate, Virginia Division Of Consumer Counsel, Allegheny Energy Supply Company, L.L.C. ("Coalition of Consumers for Reliability" or "CCR")
2. Allegheny Energy Companies ("Allegheny")
3. American Electric Power ("AEP")
4. American Forest & Paper Association ("AFPA")
5. American Municipal Power-Ohio Inc. ("AMP-Ohio")
6. American Public Power Association ("APPA")
7. Blue Ridge Power Agency, Northern Illinois Municipal Power Agency, and Virginia Municipal Electric Association ("Virginia-Illinois Municipals")
8. BlueStar Energy Services, Inc. ("BlueStar")
9. Borough of Chambersburg, Pennsylvania ("Chambersburg")
10. BP Energy Company
11. Calpine Energy Services, LP ("Calpine")
12. Catoctin Power, L.L.C. ("Catoctin")
13. Central Hudson Gas & Electric Corporation ("Central Hudson")
14. City And Towns Of Hagerstown, et al. ("Hagerstown")
15. Chaparral (Virginia) Inc. ("Chapparal")
16. Cinergy Services, Inc. ("Cinergy")
17. Commonwealth Shore Power, L.L.C. ("Commonwealth Shore")
18. Connecticut Municipal Electric Energy Coop and Massachusetts Municipal Electric Energy Cooperative ("Connecticut and Massachusetts Cooperatives")
19. Con Edison Energy, Inc. (ConEd)
20. Consolidated Edison Company of New York, Inc.
21. Constellation Energy Group Inc. ("Constellation")
22. Coral Power, L.L.C. ("Coral Power")
23. The Dayton Power and Light Company ("Dayton")
24. Delaware Municipal Electric Corporation ("DEMEC")
25. Delaware Public Service Commission ("The Delaware Commission")
26. Direct Energy Services, L.L.C. ("Direct Energy")
27. Dominion Resources Services, Inc. ("Dominion")

28. DTE Energy Trading, Inc.
29. Duke Energy North America, L.L.C. ("Duke")
30. Duquesne Light Company ("Duquesne")
31. Dynegy Power Marketing, Inc. ("Dynegy")
32. Easton Utilities ("Easton")
33. Edison Mission Energy, Edison Mission Marketing & Trading, Inc., and Midwest Generation EME, L.L.C. ("Edison Mission")
34. Electric Power Supply Association ("EPSA")
35. Exelon Corporation ("Exelon")
36. FirstEnergy Service Company ("FirstEnergy")
37. FPL Energy Generators ("FP&L")
38. Illinois Commerce Commission ("The Illinois Commission")
39. Illinois Municipal Electric Agency ("IMPA")
40. Indiana Off. of Utility Consumer Counsel ("Indiana Consumer Counsel")
41. J. Aron & Company ("J. Aron")
42. Joint Consumer Advocates ("Joint Consumer Advocates")
43. Kentucky Public Service Commission ("The Kentucky Commission")
44. LS Power Associates, L.P. ("LS Power")
45. Long Island Power Authority and LIPA ("LIPA")
46. Michigan Public Service Commission ("The Michigan Commission")
47. Midwest Stand-Alone Transmission Companies ("MSATs")
48. Midwest Independent Transmission System Operator, Inc. ("MISO")
49. Mittal Steel USA ISG Inc. ("Mittal Steel")
50. Mirant Corporation ("Mirant")
51. Mirant Energy Trading, L.L.C.
52. Morgan Stanley Capital Group Inc. ("Morgan Stanley")
53. National Grid USA ("National Grid")
54. New Jersey Board Of Public Utilities ("The New Jersey Commission")
55. New York Independent System Operator. Inc. ("NYISO")
56. New York State Electric and Gas Corporation ("NYSEG")
57. New York State Public Service Commission ("The New York Commission")
58. North Carolina Electric Membership Corporation ("North Carolina Electric Membership Corporation")
59. North Carolina Utilities Commission ("The North Carolina Utilities Commission")
60. Public Staff-North Carolina Utilities Commission And North Carolina Attorney General's Office
61. NRG Energy, Inc. ("NRG")
62. Old Dominion Electric Cooperative ("ODEC")
63. Organization of PJM States, Inc. ("OPSI")
64. Pennsylvania Department of Environmental Protection ("Pennsylvania DEP")
65. Pennsylvania Public Utility Commission ("The Pennsylvania Commission")

66. Pepco Holdings, Inc. ("PEPCO")
67. PJM Industrial Customer Coalition et al ("PJMICC")
68. PPL Parties ("PPL")
69. PSEG Energy Resources & Trade L.L.C. ("PSEG")
70. Public Power Association of New Jersey ("PPANJ")
71. Public Utilities Commission of Ohio ("The Ohio Commission")
72. Public Service Commission Of The District Of Columbia ("Commission of the District Of Columbia")
73. Public Service Commission Of Maryland ("The Maryland Commission")
74. Public Service Commission of West Virginia ("The West Virginia Commission")
75. Reliant Energy, Inc. ("Reliant")
76. Rockland Electric Company ("Rockland")
77. Rochester Gas and Electric Corporation ("Rochester")
78. Select Energy, Inc ("Select Energy")
79. Southeastern Power Administration ("SPA")
80. Southern Maryland Electric Cooperative, Inc. ("Southern Maryland")
81. Southwestern PA Growth Alliance ("Southwestern PA Growth Alliance")
82. Strategic Energy L.L.C. ("Strategic Energy")
83. Tennessee Regulatory Authority ("The Tennessee Commission")
84. Virginia State Corporation Commission ("The Virginia Commission")
85. Virginia Division Of Consumer Counsel ("Virginia Consumer Counsel")
86. Wabash Valley Power Association, Inc. ("Wabash")
87. Williams Power Company, Inc. ("Williams")
88. Wisconsin Electric Power Company ("Wisconsin Electric")
89. WPS Resources Corporation ("WPS Resources")

Appendix C

Parties filing comments or protests in Docket Nos. EL05-148-000 and ER05-1410-000

1. Allegheny Electric Cooperative, Inc., Borough Of Chambersburg, Pennsylvania, Delaware Municipal Electric Corporation, District Of Columbia Office Of The People's Counsel, Illinois Citizens Utility Board, Maryland Office Of Peoples Counsel, North Carolina Electric Membership Corporation, Old Dominion Electric Cooperative, Pennsylvania Office Of Consumer Advocate, Pennsylvania Office Of Consumer Advocate, Pennsylvania Office Of Consumer Advocate, Virginia Division Of Consumer Counsel, Allegheny Energy Supply Company, L.L.C. ("Coalition of Consumers for Reliability" or "CCR")
2. American Electric Power ("AEP")
3. American Municipal Power-Ohio Inc. ("AMP-Ohio")
4. American Public Power Association ("APPA")
5. Blue Ridge Power Agency, Northern Illinois Municipal Power Agency, and Virginia Municipal Electric Association ("Virginia-Illinois Municipals")
6. BlueStar Energy Services, Inc. ("BlueStar")
7. Borough of Chambersburg, Pennsylvania ("Chambersburg")
8. Catoctin Power, L.L.C. ("Catoctin")
9. Central Hudson Gas & Electric Corporation ("Central Hudson")
10. Cinergy Services, Inc. ("Cinergy")
11. Con Edison Energy, Inc. (ConEd)
12. Consolidated Edison Company of New York, Inc.
13. Constellation Energy Group Inc. ("Constellation")
14. Coral Power, L.L.C. ("Coral Power")
15. The Dayton Power and Light Company ("Dayton")
16. Delaware Municipal Electric Corporation ("DEMEC")
17. Delaware Public Service Commission ("The Delaware Commission")
18. Direct Energy Services, L.L.C. ("Direct Energy")
19. Dominion Resources Services, Inc. ("Dominion")
20. Duquesne Light Company ("Duquesne")
21. Easton Utilities ("Easton")
22. Edison Mission Energy, Edison Mission Marketing & Trading, Inc., and Midwest Generation EME, L.L.C. ("Edison Mission")
23. Electric Power Supply Association ("EPSA")
24. Exelon Corporation ("Exelon")
25. FirstEnergy Service Company ("FirstEnergy")
26. FPL Energy Generators ("FP&L")
27. Illinois Commerce Commission ("The Illinois Commission")
28. Joint Consumer Advocates ("Joint Consumer Advocates")

29. Kentucky Public Service Commission ("The Kentucky Commission")
30. Long Island Power Authority and LIPA ("LIPA")
31. Michigan Public Service Commission ("The Michigan Commission")
32. Midwest Stand-Alone Transmission Companies ("MSATs")
33. Midwest Independent Transmission System Operator, Inc. ("MISO")
34. Mirant Corporation ("Mirant")
35. Mirant Energy Trading, L.L.C.
36. Morgan Stanley Capital Group Inc. ("Morgan Stanley")
37. National Grid USA ("National Grid")
38. New Jersey Board Of Public Utilities ("The New Jersey Commission")
39. New York Independent System Operator. Inc. ("NYISO")
40. North Carolina Utilities Commission ("The North Carolina Utilities Commission")
41. Public Staff-North Carolina Utilities Commission And North Carolina Attorney General's Office
42. NRG Energy, Inc. ("NRG")
43. Old Dominion Electric Cooperative ("ODEC")
44. Organization of PJM States, Inc. ("OPSI")
45. Pennsylvania Department of Environmental Protection ("Pennsylvania DEP")
46. Pennsylvania Public Utility Commission ("The Pennsylvania Commission")
47. Pepco Holdings, Inc. ("PEPCO")
48. PJM Industrial Customer Coalition et al ("PJMICC")
49. PPL Parties ("PPL")
50. PSEG Energy Resources & Trade L.L.C. ("PSEG")
51. Public Power Association of New Jersey ("PPANJ")
52. Public Utilities Commission of Ohio ("The Ohio Commission")
53. Public Service Commission Of Maryland ("The Maryland Commission")
54. Public Service Commission of West Virginia ("The West Virginia Commission")
55. Reliant Energy, Inc. ("Reliant")
56. Southwestern PA Growth Alliance ("Southwestern PA Growth Alliance")
57. Strategic Energy L.L.C. ("Strategic Energy")
58. Tennessee Regulatory Authority ("The Tennessee Commission")
59. Virginia State Corporation Commission ("The Virginia Commission")
60. Virginia Division Of Consumer Counsel ("Virginia Consumer Counsel")
61. Williams Power Company, Inc. ("Williams")
62. WPS Resources Corporation ("WPS Resources")