126 FERC ¶ 61,275
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

PJM Interconnection, L.L.C.	Docket Nos.	ER05-1410-000 EL05-148-000
		ER05-1410-010 EL05-148-010
		ER05-1410-011 EL05-148-011
		ER05-1410-012 EL05-148-012
		ER09-412-000 ER09-412-001

ORDER ACCEPTING TARIFF PROVISIONS IN PART,
REJECTING TARIFF PROVISIONS IN PART,
ACCEPTING REPORT, AND
REQUIRING COMPLIANCE FILINGS

(Issued March 26, 2009)

Paragraph Numbers

1. In this order, the Commission accepts in part and rejects in part tariff provisions submitted by PJM Interconnection, L.L.C. (PJM), revising certain provisions of its Reliability Pricing Model (RPM). In addition, we accept a report filed by PJM and require compliance filings, as discussed below.

1. Background

1.1. Reliability Pricing Model (RPM)

2. As discussed in prior orders,[1] in December 2006, the Commission found that PJM's existing capacity market was unjust and unreasonable, because it failed to procure sufficient capacity to enable PJM to maintain a reliable transmission system. To remedy this concern, the Commission approved the RPM program, a capacity market under which PJM purchases capacity on a multi-year forward

[1] *See PJM Interconnection, L.L.C.*, 122 FERC ¶ 61,264 (2008); *PJM Interconnection, L.L.C.*, 124 FERC ¶ 61,272 (2008) (September 19 Order).

basis through an auction mechanism.[2] The prices for capacity are determined by these forward auctions. To date, PJM has conducted five Base Residual Auctions, which have determined the level of capacity and prices for Delivery Years 2007-2012. PJM's next Base Residual Auction will be conducted in May 2009, and will procure capacity for the 2012-2013 Delivery Year.

3. Several parties have expressed concern that the capacity prices generated by the RPM process to date are not just and reasonable.[3] In March 2008, a group of PJM customer representatives (RPM Buyers[4]) asked the Commission to examine the performance of RPM and hold a technical conference to discuss the RPM construct. PJM, in response, asked the Commission to delay any action until after PJM and its consultant, the Brattle Group, had reviewed the effectiveness of RPM. The Commission agreed to delay its own examination of RPM until completion of the Brattle Report.[5]

4. On June 30, 2008, PJM filed the Brattle Report with the Commission, as well as its informational report containing the study by the Brattle Group (the

---

[2] *See PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 (2006).

[3] *See* protests and comments in Docket No. ER09-412-000 by PSEG, Mirant, Reliant, PPL and others.

[4] RPM Buyers consist of Blue Ridge Power Agency; the Maryland Public Service Commission; Office of the People's Counsel for the District of Columbia; Office of the Ohio Consumers' Counsel; the PJM Industrial Customer Coalition; United States Department of Defense and other affected Federal Executive Agencies; Delaware Public Service Commission; Public Service Commission of the District of Columbia; New Jersey Board of Public Utilities; the Pennsylvania Office of Consumer Advocate; Pennsylvania Public Utility Commission; the Public Power Association of New Jersey; Southern Maryland Electric Cooperative, Inc.; Commonwealth of Pennsylvania Department of Environmental Protection; Industrial Energy Users -- Ohio; Maryland Office of People's Counsel; American Forest & Paper Association; Illinois Municipal Electric Agency; American Municipal Power - Ohio, Inc.; Duquesne Light; and Portland Cement Association.

[5] *PJM Interconnection, L.L.C.*, 123 FERC ¶ 61,037 (2008).

Brattle Report).[6] On September 19, 2008, the Commission issued an order addressing the Brattle Report and directing further proceedings.[7]

5. In that order, the Commission found that the Brattle Report had identified important issues with respect to the effectiveness of RPM, and stated that it supported PJM's proposal to institute a stakeholder process to address the issues raised by RPM Buyers and the Brattle Report.

6. The Commission stated that:

> We agree with PJM's stakeholder review approach and strongly encourage stakeholders to make efforts to achieve consensus on the issues discussed above in time for implementation prior to the May 2009 RPM auction. To the extent stakeholders are able to reach agreement on changes to RPM with respect to these issues, we strongly encourage PJM to file tariff sheets no later than December 15, 2008 . . . in order for the changes to be implemented for the May 2009 RPM auction. . . . At that time, the Commission will determine whether it would be appropriate for us to take action under section 206 of the FPA to require additional changes to RPM. If, at that time, we determine that such action would be appropriate, the Commission intends to take this action in time to ensure that any additional necessary changes take effect prior to the May 2009 auction, where feasible.[8]

1.2. The Instant Filings

7. On December 12, 2008, in Docket Nos. ER05-1410-000 and EL05-148-000, PJM filed the report required by the Commission on its stakeholder process. Also on December 12, 2008, PJM made a filing in Docket No. ER09-412-000

---

[6] "Review of PJM's Reliability Pricing Model (RPM)," report by Brattle Group, Attachment A to June 30, 2008 informational filing by PJM.

[7] September 19 Order, 124 FERC ¶ 61,272 at P 1.

[8] *Id*. P 52.

under section 205 of the Federal Power Act (FPA),[9] proposing changes to the PJM Open Access Transmission Tariff (Tariff) and Reliability Assurance Agreement (RAA). PJM indicates that it held an extensive stakeholder process to develop these changes to RPM, and that, although its stakeholders were not able to reach consensus, PJM utilized those discussions to enhance the RPM procedures for the May 2009 auction. PJM asks for an effective date of March 27, 2009.

1.3. Notice of Filings

8. Notice of PJM's section 205 filing in Docket No. ER09-412-000 and PJM's report filed in Docket Nos. ER05-1410-000, *et al.*, was published in the *Federal Register*, with motions to intervene, notices of intervention, comments and protests due on or before January 2, 2009 (ER09-412-000) and January 9, 2009 (ER05-1410-011).[10] The Commission subsequently extended the intervention and comment date in Docket No. ER09-412-000 to January 9, 2009.

9. The list of parties filing motions to intervene or Notices of Intervention, and parties filing comments, protests and reply comments, is at the Appendix to this order. Additionally, EnergyConnect, Inc. and ClearChoice Energy filed timely motions to intervene, protest, and request for expedited partial summary disposition. PJM answered their motions for expedited partial summary disposition. Those motions were later withdrawn in part, conditioned on the Commission's acceptance of new tariff provisions with regard to demand response to be filed by PJM, which PJM committed to file in its February 2, 2009 answer.

1.4. Offer of Settlement

10. PJM and its stakeholders pursued settlement negotiations before a Commission administrative law judge. Those negotiations were unsuccessful, and the Chief Administrative Law Judge issued an order terminating Commission settlement judge proceedings on January 15, 2009.

11. On February 9, 2009, however, a Settlement Offer and Settlement Agreement were filed by PJM and certain parties, primarily load interests and state commissions.[11] The parties who executed that Settlement Agreement state

---

[9] 16 U.S.C. § 824(d) (2000).

[10] 73 Fed. Reg. 79,461 (2008).

[11] The parties filing the Settlement Agreement are PJM, Allegheny Electric

(continued…)

that, after January 15, 2009, settlement discussions continued among PJM, the IMM, the RPM Load Group, and some state utility commissions, resulting in a settlement that most parties among this group either supported or did not oppose.

12. The February 9 filing takes PJM's December 12 filing as its starting point, and states that, unless otherwise provided by the February 9 filing, the provisions that PJM filed on December 12 apply. The February 9 filing then proposes changes to the Cost of New Entry (CONE) levels filed by PJM, and also proposes a stakeholder process to develop an automated adjustment procedure for Net CONE.

2. PJM's December 12, 2008 Report in Docket Nos. ER05-1410-000, *et al.*

13. PJM reports on the efforts of PJM and its stakeholders to address the various changes to RPM suggested in the September 19 Order, and states that it has been able to develop improvements to RPM in nearly all areas identified in the September 19 Order in time for the May 2009 Base Residual Auction.

14. The September 19 Order set forth eight issues that should be considered for possible changes:

> (1) use of historical averages of energy and ancillary services revenue offsets to determine Net CONE;
>
> (2) rules for the participation of energy efficiency and

Cooperative, Inc., ArcelorMittal USA Inc., the Borough of Chambersburg, Duquesne Light Co., the Indiana Commission, North Carolina Electric Membership Corp., Old Dominion Electric Cooperative, PJM Industrial Customer Coalition, Portland Cement Association, the Rockland Electric Company, and Southern Maryland Electric Cooperative, Inc. The Settling Parties also state that the following parties to the proceeding committed that they would not oppose resolution of this proceeding on the terms set forth in the Offer of Settlement: American Municipal Power-Ohio, Inc., Blue Ridge Power Agency, the Delaware Office of Public Advocate, the Delaware Commission, the D.C. Commission, the Long Island Power Authority, the Maryland Public Service Commission, the Independent Market Monitor for PJM (IMM) (conditionally), the New Jersey Board of Public Utilities, the New Jersey Rate Counsel, the Pennsylvania Department of Environmental Protection, the Pennsylvania Office of Consumer Advocate, the Pennsylvania Commission, and the Public Power Association of New Jersey. Explanatory Statement to Settlement Offer at 1 fn.1.

demand-side resources in the RPM auctions;

(3) market power and mitigation rules;

(4) reliability requirements/criteria and defining Locational Delivery Areas (LDAs);

(5) must-offer rules relating to the exclusion of capacity due to (i) the sales cap imposed on Fixed Resource Requirement entities and (ii) partial-year ownership and availability;

(6) performance penalties;

(7) incremental auctions; and

(8) length of forward commitment for new capacity resources.

15. As to the remaining issues, PJM stated that its Capacity Market Evolution Committee (CMEC) completed development of three alternative approaches – a comprehensive proposal by PJM to resolve all issues and two variants of that proposal by a group of capacity buyers and a group of capacity sellers – and negotiated in an effort to resolve differences between the three approaches and reach a consensus.[12] PJM reports that none of the alternatives received the two-thirds super-majority sector vote required by PJM's rules for a senior standing committee's endorsement. PJM states that its Board of Managers then approved filing of a slightly modified version of PJM's comprehensive proposal with the Commission as a tariff filing under section 205, coupled with an effort to build on the progress made in the stakeholder process to attempt to settle at the Commission the rules for the May 2009 auction.

16. With regard to the issues discussed in the September 19 Order that PJM was not able to resolve, PJM states that the LDA definitions and once-in-25-years Loss of Load Expectation are planning standards that predate RPM and have been in place for many years. In order to ensure that applicable national and regional reliability standards are satisfied, any change to these standards will require an

[12] Similarly, PJM's Demand Response Steering Committee had developed alternative recommendations for the incorporation of energy efficiency resources into RPM, which PJM incorporated into the comprehensive alternative recommendations of the CMEC.

extensive planning analysis that could not be completed swiftly. PJM states, however, that it is willing to consider changes in those areas going forward.

17. PJM additionally states that the December 12 filing responds to the September 19 Order with changes that make more resources eligible to offer into RPM, but it does not address concerns raised in the Brattle Report regarding limitations on capacity sales into RPM by resources that do not participate in RPM but rather provide capacity in their own areas under the Fixed Resource Requirement rules.

3. Procedural Issues in Docket No. ER09-412-000

18. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2008), the notice of intervention and the timely-filed unopposed motions to intervene and motions to intervene out of time serve to make the entities filing them parties to this proceeding. Granting late intervention at this stage of the proceeding will not disrupt the proceeding or place additional burdens on existing parties.

19. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2008), prohibits an answer to a protest or an answer unless otherwise ordered by the decisional authority. We will accept the answers and reply comments filed above, because they have provided information that has assisted us in our decision-making process.

4. Discussion

20. PJM's filing of the February 9 Settlement Agreement constitutes an amendment by PJM of its original December 12 filing.[13] Therefore, in this order, we will be evaluating under section 205 the proposals contained in the February 9 filing that supersede equivalent provisions in the December 12 filing, and the remaining (non-superseded) proposals made by PJM in the December 12 filing.

---

[13] *See Arkla Gathering Services Co.*, 69 FERC ¶ 61,280 at 62,079, footnotes omitted (1994) ("Indicated Parties' proposal is a settlement in name only. . . . Here, Indicated Parties' proposal is a unilateral act, by Indicated Parties' own admission, where none of the other parties to the proceeding had an opportunity to participate and have their views considered"), citing *Transcontinental Gas Pipe Line Corp.*, 37 FERC ¶ 61,288 at 61,868-869 (1986), *El Paso Natural Gas Co.*, 50 FERC ¶ 61,202 at 61,653 (1990).

21. We will also accept PJM's informational report regarding the status of RPM reform, and PJM's commitment to continue stakeholder negotiations on the issue of LDA definitions and Loss of Load Expectation standards, and changes to the Fixed Resource Requirement rules.

4.1. Auction Parameters

4.1.1. Increase in Construction Costs

PJM's Proposal

22. PJM's Tariff requires it to review the calculation of CONE at least every three years. The Tariff defines CONE as "the nominal levelized cost of a Reference Resource," and defines the Reference Resource as "a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology, dual fuel capability, and a heat rate of 10,500 Mmbtu/MWh."[14]

23. PJM first states that it proposes to update Gross CONE to reflect significant increases in the cost of construction since 2005, when the administrative parameter, Gross CONE, was first derived. PJM cites to reports by the Commission's staff in 2008 and by Cambridge Energy Research Associates (CERA) and the Brattle Group (separately from the Brattle Group's report specifically with regard to RPM) stating that new construction was becoming more expensive.[15] PJM also notes that the Commission approved a substantial

---

[14] PJM Tariff, Attachment DD, section 2.58.

[15] PJM states that CERA reported that its proprietary Power Capital Costs Index "has been on an upward trend since 2000 [with] a surge that began in 2005 [that] has [pushed] costs up 76 percent in the past three years." News Release, "North American Power Generation Construction Costs Rise 27 Percent in 12 Months to New High," IHS/CERA Power Capital Costs Index (Feb. 14, 2008), submitted in Docket No. ER08-516-000 as Attachment A to the Motion to Intervene and Comments of Constellation Energy Commodities Group, Inc. (Feb. 21, 2008). PJM further cites to a study by the Brattle Group (separate from the Brattle Report on RPM) that asserts that "the cumulative increase in the installation cost of new combined-cycle units [from 2000 to 2006] was almost 95 percent, with much of this increase occurring in 2006." Rising Utility Construction Costs: Sources and Inputs, the Edison Foundation, at 8 (Sept. 2007). submitted in Docket No. ER08-516-000 as Attachment B to the Motion to Intervene and Comments of Constellation Energy Commodities Group. Inc.. (Feb.

(continued…)

increase to the CONE figure used by the New York Independent System Operator (NYISO) for the demand curve in its capacity market.

24. PJM further states that it commissioned a study from Power Project Management (the PPM study), which followed the same approach as the original 2005 study on which PJM's current CONE is based – i.e., use of a combustion turbine peaking plant. Since the tariff stipulates three "CONE areas" with three different CONE values, the study estimates the cost of such a new plant in each of those areas. PJM also retained other consultants to provide additional information. PJM states that it supplemented its analysis based on a review of its assumptions with Mr. Pasteris and with a group of stakeholders with expertise in this area. For purposes of this filing, PPM produced a single consolidated report including these inputs, which concludes that the cost of new entry is $135,600/MW-year for PJM's Area 1 (an 88 percent increase over the current value of $72,207/MW-year), $125,409 for Area 2 (a 69 percent increase over the current value of $74,117/MW-year), and $128,310 for Area 3 (a 74 percent increase over the current value of $73,866/MW-year).[16] PJM's December 12 filing proposes to revise the current values of the CONE to reflect the conclusions of this report.

25. With regard to the use of a combustion turbine as the Reference Resource, PJM studied the use of both a combustion turbine and a combined cycle unit. It states that the combustion turbine's capital and fixed operating and maintenance costs were lower than those of the combined cycle unit, and the question of which plant type produced the lowest Net CONE was completely dependent on the estimate of EAS revenues, which are more variable for

---

21. 2008). Finally, PJM asserts that according to the Handy-Whitman Index, which tracks electric plant cost escalations, the costs of combustion turbine power plants have increased by about 35 percent in the last three years. See 2008 CONE Update Report attached to the Affidavit of Michael J. Fox, Attachment B to December 12 filing in Docket No. ER09-412-000 (December 12 Fox Affidavit), at Page 6, Table 4.

[16] For purposes of determining CONE, PJM is divided into three areas: Area 1, centered in New Jersey (the PSEG, Jersey Central, Atlantic Electric, Philadelphia Electric, Delmarva Power and Light, and Rockland Electric zones); Area 2, centered in Maryland (the PPL, Baltimore Gas and Electric, PEPCO, Metropolitan Edison, Penn Electric, APS and Duquesne zones); and Area 3 (the Dominion, Dayton, and ComEd zones), which covers the Midwest and Virginia portions of PJM.

combined cycle plants than for combustion turbine plants. PJM further notes that switching between a combustion turbine and combined cycle unit could cause owners of combustion turbine units not to recover their costs over time. Thus, PJM states, it concludes that retention of the combustion turbine is appropriate.

26. In the February 9 filing, the PJM proposes to decrease the CONE values proposed in the December 12 filing to the following levels: $122,040/MW-year for PJM's Region 1, $112,868/MW-year for Region 2, and $115,479/MW-year for Region 3. PJM states that these numbers represent a 10 percent reduction from the CONE values in PJM's original filing. It states that the Commission has substantial evidence on which to base its acceptance of these values.

27. PJM first points to the affidavit of PJM's expert Michael J. Fox, on which PJM based its original CONE values. It then notes that the RPM Load Group (and its expert, James Wilson), the Indicated State Commissions, and the Illinois Commission have all raised issues concerning the current level and future direction of the CONE levels "in light of dramatically worsening global economic conditions." [17] It further notes that, in answer to protests, prior to the February 9 filing, PJM submitted a further affidavit from Mr. Fox concluding that, if costs were re-estimated today, they would be "somewhat lower, although not substantially lower," than his previously filed estimate.[18] PJM states that, "[t]aking into account both the estimates by Mr. Fox and the analyses by Mr. Wilson and the other parties highlighting some of the risks and uncertainties in those estimates, the Commission has ample support for the settlement CONE values." [19]

---

[17] Explanatory Statement to February 9 Settlement Agreement (Explanatory Statement) at 9.

[18] *Id*., citing to PJM's Answer to Protests and Comments, February 2, 2009, Attachment A, Affidavit of Michael J. Fox (February 2 Fox Affidavit) at 4 (lines 4-9).

[19] Explanatory Statement at 9. Additionally, PJM points to a filing made in February 2008 by the PJM Power Providers, a supplier group, in Docket No. ER08-516-000 on the issue of the gross cost of new entry for a peaking plant in the PJM Region. It notes that the PJM Power Providers submitted a detailed estimate of the costs to construct and operate a combustion turbine plant in Region 1 of PJM (i.e., New Jersey) in 2008, and estimated those costs as ranging from $99,850/MW-year to $122,100/MW-year. PJM therefore asserts that the CONE value for New Jersey provided in the Settlement Agreement

(continued…)

28. The February 9 filing also provides for PJM to convene a stakeholder process to develop a procedure for automatic adjustments to Net CONE, using certain design principles set forth in the February 9 filing (discussed *infra*). The filing provides that this new procedure will supersede the existing tariff provisions regarding formulaic changes to CONE and the existing provisions on triennial review of the shape and parameters of the Variable Resource Requirement (VRR) Curve. The February 9 filing further provides that PJM will file tariff provisions containing this automated Net CONE adjustment procedure with the Commission no later than September 1, 2009, for implementation beginning with the May 2010 Base Residual Auction conducted for the 2013-14 Delivery Year. Under this provision, PJM will file to implement either a stakeholder consensus procedure, or, absent consensus, a mechanism proposed by PJM.

29. Additionally, PJM proposes to consider, in that stakeholder process, the need for additional CONE Areas, and intend that, in the filing that PJM makes to the Commission on or before September 1, 2009, it will either implement changes to the current CONE areas, or explain why no change is necessary.

Protests and Answers Regarding the CONE Values Contained in the February 9 Filing [20]

30. As a threshold matter, several parties urge the Commission to reject the February 9 filing on procedural grounds. Specifically with regard to CONE values, the PJM Supplier Caucus states that PJM failed to follow its own tariff

---

($122,040/MW-year) was supported by the PJM Power Providers just a year ago. PJM further notes that, to project the estimate forward to a future Delivery Year, the PJM Power Providers escalated the estimate by 20 percent, producing a range of $119,600/MW-year to $148,670/MW-year. Thus, PJM argues, even if the PJM Power Providers' 2008 range of reasonable estimates for the New Jersey CONE is escalated by twenty percent, the settlement CONE of $122,040/MW-year remains within that range. *Id*. at 10. It also states that, "[g]iven that twenty percent seems an extremely generous allowance for construction cost increases in a soft economy over the next several years, it does not seem likely that the settlement CONE is understated." *Id.*

[20] As noted above, we consider the CONE values filed in the February 9 filing to have amended and superseded the CONE values filed in the December 12 filing. Protests to the December 12 CONE values, therefore, have similarly been superseded.

procedures in resetting CONE, and the February 9 filing's CONE values should be rejected on that basis. Indicated Asset Owners similarly state that PJM's tariff provisions require that:

> 1) PJM's Office of the Interconnection shall propose new Cost of New Entry values on or before September 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied; 2) The PJM Members shall review the proposed values; 3) The PJM Members shall either vote to endorse the proposed values or propose alternate values by January 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied; 4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by January 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.[21]

According to Indicated Asset Owners, because PJM failed to follow these procedures before presenting the CONE values contained in the February 9 filing, the Commission should reject those CONE values.

31. In its answer, PJM states that it did, in fact, follow its own procedures:

> The PJM Tariff provision at issue [section 5.10(a)(vi)(C)] requires PJM to review CONE values at least once every three years and notify stakeholders whether PJM proposes to revise CONE. PJM must provide this notice by September 1 of the year before the Base Residual Auction in which such revised value will be used. Following a stakeholder review, including an opportunity for stakeholders to propose alternative values, PJM must file the CONE value approved by its Board by no later than January 31 of the year of the relevant Base Residual Auction.
>
> PJM fully complied with these provisions. PJM advised parties on August 30, 2008 of its recommended revised CONE values. Following

[21] Indicated Asset Owners comments filed on February 23 at 20.

> extensive stakeholder discussions, PJM filed its proposed CONE change with the Commission on December 12, 2008, well in advance of the Tariff-stipulated deadline, to ensure that the Commission would have ample time to decide this matter before the next Base Residual Auction.[22]

32. However, PJM argues, the subsequent events – namely, the filing of the Settlement Agreement between PJM and some load representatives – were not contemplated by that tariff provision, and are therefore not governed by it:

> Suppliers raise an issue on which the Tariff is completely silent: what may happen in the ensuing Commission proceedings. Here, PJM's filed value was vigorously contested by numerous parties contending that PJM's proposed CONE was too high. Settlement is a customary option in such circumstances; indeed, as noted above, Commission policy strongly favors settlement. Evidently, suppliers' view is that if PJM agrees in settlement to change its litigation position on CONE, then the procedures specified in section 5.10(a)(vi)(C) must be followed again. But PJM obviously could never turn back the clock in any ensuing Commission proceeding to the prior September 1, so suppliers' interpretation is that PJM may never implement a settlement CONE value in the current year's auction.[23]

33. With regard to the substance of the February 9 filing, particularly its reduction in CONE values, while several parties representing load interests support or do not oppose the filing, some parties representing load interests oppose it. The Illinois Commission and the Maryland Office of People's Counsel (MPC) argue that the February 9 filing's CONE values are too high. MPC argues that no increase is necessary based on the results of the past two auctions, in conjunction with PJM's own reduced load forecasts. MPC states that PJM achieved a reserve margin 1 percent higher than its required reserve margin in the Base Residual Auction for 2010/2011, and a reserve margin 2.6 percentage points

[22] PJM reply comments filed on March 2 at 29-30.

[23] *Id.* at 30.

above the required margin in the Base Residual Auction for 2011/2012. In MPC's view, the February 9 filing's CONE proposal is flawed because it presumes that the only type of new entry is a combustion turbine, while the evidence is that most recent new entry in PJM has not been combustion turbines. The Illinois Commission recommends lowering CONE numbers by even more than 10 percent.

34. PJM responds to MPC's argument that, because ample capacity cleared at prices below Net CONE in the May 2008 Base Residual Auction, no increase to Gross CONE may be needed. In PJM's view, the results of that single auction should not prevent an update to Gross CONE, given evidence indicating that PJM's existing CONE value of approximately $72,000/MW-year is substantially below the cost to build and operate a new peaker. PJM further notes that offers below Net CONE into the May 2008 auction could reflect generators' belief that capacity prices in future years will be higher. PJM also points to the fact that, in the May 2008 auction, because Duquesne Light Company was planning to withdraw from PJM, loads from the Duquesne zone were excluded, but generation from that zone could offer into the auction (another factor which, in PJM's opinion, demonstrates the danger of assigning too much weight to the results of a single auction).[24]

35. Multiple suppliers protest the February 9 filing's 10 percent reduction in CONE values. CPV Maryland and Reliant assert that this reduction is purely arbitrary and not supported by any evidence. Dominion urges the Commission to base its decision on the merits of the entire record underlying the December 12 filing, rather than solely on the February 9 filing. Mirant states that PJM has not met its burden under either section 205 or section 206 to show that the new CONE values are just and reasonable. PSEG reiterates its view that even the CONE values in the December 12 filing were insufficient, and therefore the lowered CONE values in the February 9 filing are certainly insufficient.

---

[24] On December 10, 2008, Duquesne, PJM and 15 intervenors submitted for Commission approval a Settlement Agreement proposing to withdraw any further consideration of Duquesne's conditional request to: (i) terminate its membership in PJM; and (ii) establish its membership in the Midwest Independent Transmission System Operator. The Commission's approval of the Settlement Agreement allowed for PJM to include Duquesne's zone in the RPM auction parameters for the upcoming May 2009 Auction. *See Duquesne Light Co.*, 126 FERC ¶ 61,074 (2009).

Commission Conclusion

36. Under section 5.10(a)(vi)(C) of its tariff, PJM has the authority to propose new CONE values. PJM provided a detailed engineering study to support the CONE values contained in the December 12 filing. That study also shows that the CONE values contained in the February 9 filing are just and reasonable, as discussed below. We therefore accept it. PJM must therefore apply these CONE values in all portions of the tariff, including the Minimum Offer Price Rule provisions where CONE values apply.[25]

37. We are not persuaded by the argument that no CONE increase is justified because the previous Base Residual Auction, which relied on the existing CONE, procured capacity in excess of the target installed reserve requirement. First, PJM's proposal is consistent with its Tariff, which defines CONE as the cost of a combustion turbine unit; that definition is not linked with the outcome of a Base Residual Auction. Because the Base Residual Auctions rely on a sloped demand curve (or VRR curve), it is to be expected that the amount of capacity cleared in any individual auction will often differ from the target installed reserve margin. Cleared capacity can sometimes exceed the target and sometimes fall short of it, depending on a host of market conditions. As PJM has pointed out, in the previous Base Residual Auction (held in May 2008), the load in the Duquesne service territory for the first time was excluded from the auction, while most of the generating resources in the Duquesne service territory participated in the auction, resulting in a larger surplus of capacity than would otherwise have occurred. Such a surplus in the May 2008 auction does not, therefore, support a conclusion that the current CONE accurately reflects the cost of building a new combustion turbine.

38. A number of generators contend that the data put forward by PJM could justify the higher CONE values in PJM's December 12 filing.[26] That may be true. However, in its February 9 filing, PJM amended its original filing to

[25] We find that PJM has correctly stated that its Tariff does not require it to again consult with its stakeholders, before submitting its revised CONE values in the February 9 filing, because the Tariff does not speak to situations such as this, where PJM has already followed the section 5.10 (a)(vi)(C) procedures, and the filing that resulted from those procedures has been superseded by an amendment, as here.

[26] *See* protests to the February 9 filing of Reliant, Constellation and Indicated Asset Owners.

propose lower CONE values than those proposed in the December 12 filing, and as we find those lower CONE values to be just and reasonable based on the evidence in the record.[27] Whether or not a different rate might *also* be just and reasonable does not allow us to reject a utility's just and reasonable proposal under section 205. The fact that there may be CONE values other than the ones proposed by PJM that are also just and reasonable does not mean that we must reject the proposed CONE values.[28]

39. We will also accept PJM's proposal to continue to base CONE on a combustion turbine plant. As PJM pointed out in its December 12 filing, combined cycle units may in certain scenarios have a lower Net CONE. However, combined cycle plants have more variable EAS revenues, and therefore, present significant estimating uncertainties. Moreover, PJM and the stakeholders argue, and we agree, that shifting between a combined cycle and combustion turbine unit from year to year could prevent owners of combustion turbines from recovering their costs over time.

4.1.2. EAS Offset and Scarcity Pricing True-up

PJM's Proposal

40. As noted above, Net CONE consists of Gross CONE minus an offset for energy and ancillary services revenues. PJM states that it currently estimates

[27] *See FPC v. Tennessee Gas Transmission Co.*, 371 U.S. 145 (1962) (utility cannot recoup its losses due to a reallocation of costs between rates if the higher rate exceeds the filed); *NorthwestPipeline Corp*., 76 FERC ¶ 61,068, at 61,425 (1996) (utility cannot charge more than the rate it files even if that results in a loss due to cost reallocation).

[28] *Louisville Gas & Elec. Co.*, 114 FERC ¶ 61,282, at P 29, *order on reh'g sub nom. E.ON U.S. LLC*, 116 FERC ¶ 61,020 (2006) ("[T]he just and reasonable standard under the FPA is not so rigid as to limit rates to a 'best rate' or 'most efficient rate' standard. Rather, a range of alternative approaches often may be just and reasonable."); *FPC v. Conway Corp*., 426 U.S. 271, 278, 96 S. Ct. 1999, 48 L. Ed. 2d 626 (1976) (finding "there is no single cost-recovering rate, but a zone of reasonableness"); *Permian Basin Area Rate Cases*, 390 U.S. 747, 791-92, 88 S. Ct. 1344, 20 L. Ed. 2d 312 (1968); *Colorado Interstate Gas Co. v. FPC*, 324 U.S. 581, 589 (1945) ("Allocation of costs is not a matter for the slide-rule. It involves judgment on a myriad of facts. It has no claim to an exact science") (internal citations omitted).

those revenues based on the average energy and ancillary services revenues that would have been received by the Reference Resource for the three most recent calendar years, plus an estimate of reactive service revenues. The Brattle Report and the Commission urged PJM to develop a forward-looking approach, but PJM states that its stakeholders preferred to retain the current method of estimating the EAS offset because of the difficulties associated with forecasting EAS revenues. After further consideration of the two approaches, PJM proposes to retain the current methodology for calculating EAS offset and include, as recommended by the Brattle Report, a true-up for scarcity pricing revenues that reflect the Reference Resources that would have been in service for the Delivery Year in which scarcity revenues are paid. PJM will estimate these scarcity pricing revenues based on the unit's heat rate and other characteristics, as well as the actual locational marginal prices and actual fuel prices during the Delivery Year for the applicable location.

41. PJM's true-up proposal involves two changes to the current method for deducting EAS revenues. The first step is to remove EAS revenues earned during periods of scarcity over the three-year historical period from the EAS offset. The second step, which is the true-up step, is to add back the EAS revenues that would have been earned by the Reference Resource during the year immediately preceding the Base Residual Auction.[29] As a result, scarcity energy and ancillary services revenues earned in one year will be reflected in the VRR curve for the auction to be held in the next year, which will procure capacity for a Delivery Year three years after the auction.

Protests and Answers

42. The IMM supports continuing the current EAS offset method. He states that the goal of the scarcity revenue offset is, appropriately, to ensure that there is no double payment for capacity revenues, while at the same time ensuring that the appropriate revenues are available to cover fixed costs. However, the IMM is troubled by the fact that, under PJM's proposal, Net CONE will be reduced by scarcity revenues received for energy not in the year that they were earned, but rather, in a Delivery Year three years later. Thus, the IMM argues that there is a mismatch between those who received the scarcity revenues and those who will

---

[29] For example, as PJM prepares for the auction to be held in May 2009, it proposes first to develop its EAS offset based on non-scarcity energy and ancillary services revenues for 2006, 2007 and 2008. Then, when PJM takes the true-up step, it will add to that amount the scarcity revenues solely for 2008. This sum will constitute the EAS offset.

have their revenues reduced by the scarcity offset. The IMM therefore states that his preferred approach would be to avoid paying scarcity revenues to capacity resources in the first place. He notes, however, that the reform of scarcity pricing in PJM is on the stakeholders' agenda for this year, and recommends that the Commission implement the approach proposed here by PJM as a sound basis for further reforms.

43. Constellation, Allegheny and Duke Energy support retention of the historic method of estimating the EAS offset. CPV Maryland, however, protests the use of separate EAS offsets for each PJM region, which it believes will have the effect of discouraging new supply resources in transmission constrained regions by reducing CONE in those regions. CPV Maryland contends that a single PJM-wide EAS offset would be more appropriate because it encourages the construction of new supply resources in regions where supply is most needed. Reliant supports PJM’s proposal to continue to use historical market data, but urges the Commission to reject PJM’s proposal to base the scarcity revenue true-up on a single year's data. PPL states that scarcity revenues should be treated similarly to other offset revenues, since scarcity prices are simply high energy prices. Mirant argues against the scarcity pricing true-up, on the basis that it will delay the return of scarcity pricing revenues to consumers and add unjustified volatility to the RPM market construct.

Commission Conclusion

44. The Commission will accept PJM's proposal to retain the current historic method of evaluating the appropriate EAS offset, as well as its proposed scarcity true-up mechanism. We support continued use of the three-year average of historical revenues from the energy and ancillary services markets. While such a measure is not, by definition, forward looking, the cyclical changes in net revenues are likely to average out. It is very difficult, if not impossible, to design a forward looking method without incorporating an after the fact true-up mechanism. Such a mechanism would create its own set of issues related to expectations and hedging options by participants. The three year average approach, when combined with the proposed scarcity revenue adjustment below, is likely to capture appropriately the other sources of revenue available to cover fixed costs. With regard to CPV Maryland's concern regarding the use of separate EAS offsets for different regions, as we state below, EAS revenues earned by generation in a constrained LDA are not available to a new peaking unit that locates in unconstrained areas. Therefore, CPV Maryland's proposal could result in capacity prices below the actual Net CONE in unconstrained regions.

45. With regard to the scarcity true up, the IMM and others have expressed concern about the use of a single year’s data to determine scarcity revenues, and the method by which the true-up operates. We recognize that the amount of

scarcity pricing may vary from year to year and determining a value to be used for the offset, while still providing resources with certainty as to their capacity payments, is therefore difficult. We find that PJM's proposal to use the most recent single year for its scarcity pricing offset is a reasonable method and we accept it. Moreover, as the IMM noted, this issue is already on the agenda to be discussed by PJM stakeholders in the upcoming year, so we need not rule on this question now. We will, therefore, approve PJM's proposal with regard to using its current method of calculating the EAS offset, in order to set the Net CONE value, for the May 2009 auction. However, we direct PJM and its stakeholders to address and resolve the various concerns raised by stakeholders about how to calculate the scarcity pricing revenues in the EAS offset in its upcoming stakeholder process, and file revised tariff provisions, if necessary, in time for the May 2010 auction.

4.1.3. Net CONE for Rest-of-Market Region

PJM's Proposal

46. PJM states that it proposes to provide that the Net CONE for the PJM region as a whole (i.e., the portion of PJM that establishes the "base" capacity price, prior to any adder for specific locations) will be the lowest Net CONE determined for any of the three CONE areas.

47. Currently, the tariff states a Gross CONE for the PJM region as a whole, and offsets that value with energy revenues calculated from average LMPs for the entire system. PJM points out, however, that theoretically, this could produce a Net CONE for the region as a whole that is higher than the Net CONE calculated for portions of the PJM system, if those portions have a similar Gross CONE but higher EAS revenues than the system average. Since the intent of developing an "RTO price" is to establish a base price for capacity with no adders for specific Locational Delivery Areas, PJM states that using a potentially higher Net CONE for the RTO as a whole could undercut this goal. PJM therefore proposes that the Net CONE for the PJM Region as a whole shall be the lowest Net CONE determined for any of the three CONE Areas.

Protests and Answers

48. While some commenters (Constellation, PPL) support using the price in the lowest Net CONE Area for all of PJM, others do not. Joint Protestors[30] state

[30] Mirant, FPL, IPA.

that the Commission should reject PJM's proposal to establish an RTO-wide Net CONE based on the lowest-cost CONE Area, because it would shift the CONE benchmark from year to year based on the lowest Net CONE for the applicable year, and thus have an adverse effect on market stability and create unnecessary risks in the RPM market design. According to Joint Protestors' witness, Robert Stoddard, potential EAS earnings within and across CONE Areas will shift from year to year for structural reasons, such as transmission upgrades, and non-recurring reasons such as localized heat-waves or outages. Joint Protestors assert that PJM's existing RPM provisions correctly ensure that price differences among CONE areas will ultimately be eroded by entry of new resources, retirement of uneconomic resources, and construction of new transmission, and that competitive forces will ultimately bring Net CONE into equilibrium across all CONE areas. According to Joint Protestors, PJM's proposal short-circuits this process by forcing developers to chase profits across LDAs on a shifting basis.

49. Similarly, Duke Energy states that the "rest-of-market" region is PJM's largest, and currently has its own Net CONE calculation, with an EAS offset based on average energy prices throughout the system. Duke believes that PJM's proposed change will harm the markets, in that constrained LDAs are likely to have higher energy prices and higher EAS offsets, and applying these higher EAS offsets to the unconstrained rest-of-market region could understate Net CONE in the rest-of-market region, stifle price signals for new entry in the RTO region, and artificially reduce incentives for capacity imports into PJM. FirstEnergy similarly states that the proposal may result in price signals that will not sufficiently incent new resources at the right locations, thus jeopardizing local reliability in PJM.

50. In response, PJM reiterates that the proposal is an improvement over the current methodology, which could theoretically produce a Net CONE for the unconstrained portions of PJM that is higher than the Net CONE calculated for capacity-constrained portions of the PJM system, if the constrained areas have a similar gross CONE but higher energy revenues than the system average. PJM states:

> This is inconsistent with the RPM Tariff provisions that define auction clearing prices in terms of two components: a base level that reflects no capacity constraints, and a "locational price adder" to reflect the higher value of capacity in constrained areas. Using a potentially higher net CONE for the unconstrained portions of the RTO could result in

> higher reference prices than necessary in the unconstrained region.[31]

51. In response to Duke Energy's argument that the Net CONE value in the unconstrained region could oscillate among the Net CONE values set by the constrained areas from year to year, PJM states that any change in reference price from year to year would properly reflect the change in energy revenues from year to year and the changes in market conditions over time that lead to accurate capacity price signals.

Commission Conclusion

52. We reject at this time PJM's proposal to establish a Net CONE value for the PJM region as a whole equal to the lowest Net CONE determined for any of the three CONE areas. PJM has not adequately justified this proposed change. PJM argues that its proposal is necessary to ensure that the Net CONE value in the unconstrained region does not exceed the Net CONE value in any constrained LDA, where capacity is imported. But PJM has not explained why its proposal would ensure that the resulting capacity prices would be adequate (i) to cover the actual cost of entering the unconstrained region and (ii) to incent new entry in the unconstrained region when such entry is necessary. The goal of capacity markets is to send a correct locational price signal, not just in constrained capacity regions, but in every capacity region.

53. The actual net cost incurred by a new peaking unit entering the unconstrained region of the PJM footprint is equal to (i) the gross cost to build such a unit in the unconstrained region, minus (ii) the energy and ancillary service revenues that could be earned *in the unconstrained region.* PJM proposes to establish a Net CONE for the unconstrained region that is lower than this actual net entry cost in instances where the Net CONE in another, constrained LDA is lower than this actual net cost.

54. The Net CONE in a constrained LDA could be lower than the actual net entry cost in the unconstrained region when the energy and ancillary service revenues in the constrained LDA are substantially higher than those in the unconstrained region. But we do not understand why it would be reasonable to establish a Net CONE in the unconstrained region as the lowest Net CONE of any constrained LDA. EAS revenues in a constrained LDA are not available to a new peaking unit that locates in PJM's unconstrained region. Such a generator must

[31] PJM reply comments filed on March 2, 2009, at 32-33.

content itself with the smaller level of EAS revenues available where it locates – in the unconstrained region.[32] Therefore, PJM's proposal could result in capacity prices below the actual net cost of new entry in the unconstrained region. Duke, First Energy, and Joint Protestors argue that PJM's proposal could stifle price signals for new entry and fail to sufficiently incent new resources to enter the unconstrained region of PJM when such entry is needed. PJM has failed to adequately address these concerns. We therefore reject PJM's proposal without prejudice to a future filing that adequately justifies its proposal.[33]

4.1.4. Automatic Adjustment Procedure for CONE

PJM's Proposal

55. The existing Net CONE values are determined administratively, and PJM's tariff currently contains provisions to adjust CONE based on auction-clearing results. In the February 9 filing, PJM proposed to convene a stakeholder process to develop an automated Net CONE adjustment procedure, using certain

---

[32] Suppose the Gross CONE (cost of building a peaking unit) is $500/MW in both the constrained and unconstrained areas, but the energy and ancillary service revenue in the constrained area is $200, while being only $100 in the unconstrained area. Thus, the actual net cost of entry would be $300 (i.e., $500-$200) in the constrained area and $400 (i.e., $500-$100) in the unconstrained area. Under PJM's proposal, the Net CONE in the unconstrained area would be set at the lowest Net CONE of any area – $300 in this example – even though the actual net cost of entry in the unconstrained area would be higher, i.e., $400. Thus, under PJM's proposal, a generating unit being built in the unconstrained area would not recover its $500 cost of construction when the amount of capacity cleared equaled the target level.

[33] We note that the demand curve used in NYISO's capacity market is developed using a Net CONE value calculated based on the net energy and ancillary service revenues that would be earned under conditions in which the available capacity would equal or slightly exceed the minimum Installed Capacity requirement. (See NYISO Services Tariff, section 5.14.1 (b)). By calculating Net CONE based on an equilibrium value of EAS revenues, rather than on an EAS revenues value that varies as installed capacity varies relative to the capacity target, the Net CONE in the unconstrained area may be less likely to exceed that for a constrained LDA. We are not requiring that PJM adopt the NYISO methodology on this issue, but PJM and its stakeholders may want to consider whether the NYISO's approach addresses its concerns.

design principles set out at Attachment D to the February 9 filing. It proposed that this adjustment procedure will supersede the existing provision regarding formulaic changes to CONE in section 5.10(a)(iv)(B) of Attachment DD to the tariff, as well as the existing provisions on triennial review of the shape and parameters of the Variable Resource Requirement curve.

56. The February 9 filing also provides that, no later than September 1, 2009, PJM will file an automated Net CONE adjustment procedure with the Commission as a PJM Tariff change under section 205 of the FPA (either as a consensus proposal if stakeholders can reach consensus, or, absent consensus, by PJM alone) for implementation beginning with the Base Residual Auction to be conducted for the 2013-2014 Delivery Year. If the stakeholders cannot reach consensus, PJM must provide a substantive explanation to the extent that its proposed automated Net CONE adjustment procedure departs from the aforementioned design principles.

57. PJM states that, although its stakeholders have made little progress on this issue to date, many parties have highlighted the advantages of automated updates to Net CONE that would draw upon market participants' expectations about the revenues needed from the capacity market to support new entry. It states that the proposal provides a means to realize this objective, because it establishes a clear end date by requiring PJM to submit a filing with the Commission, and advances the process by defining substantive design principles for an automated process but also preserves a meaningful role for stakeholder participation.

<u>Protests and Answers</u>

58. Some parties, such as the Illinois Commission, support the proposal for a process to develop an automated CONE adjustment process. In its reply comments, the RPM Load Group points out that this stakeholder process ensures against the situation faced in the December 12 filing, in which no automated Net CONE mechanism was developed to replace today's contentious and complex administrative CONE process because stakeholders could not make sufficient progress.

59. The IMM has concerns with regard to the proposed automated CONE process, stating:

> It is essential that any method of calculating CONE determine an accurate price signal over the long run that reflects the actual current cost of new entry. . . . The principles in the settlement state that an upward or downward adjustment to net CONE will occur only

> if there has been a sustained excess or deficiency of capacity. Such an approach is questionable in light of the fact that requiring a sustained excess or deficiency [before adjusting CONE] forces the market to oscillate more rather than permitting a faster adjustment that accounts for the current cost of new capacity, regardless of whether there is a sustained excess or deficiency. . . . This change would represent a fundamental modification to the RPM market design which assumed that gross CONE changes would reflect current market conditions for new generation.[34]

60. Reliant asserts that the February 9 filing imposes unreasonable limits on substantive aspects of future PJM stakeholder proceedings pertaining to automatic Net CONE adjustments, and the Commission should neither accept the implicit assumption in the filing that an automatic Net CONE update mechanism is necessary, nor impose an arbitrary deadline. Reliant and EPSA ask the Commission, if it approves the stakeholder process to develop an automated CONE adjustment procedure, not to foreclose any options or pre-ordain any particular outcome such as the proposed design principles. Constellation urges the Commission to reject the design principles altogether, on the basis that those principles will bias the outcome of the process.

61. With regard to elimination of the triennial review provisions of PJM's tariff, Constellation and Indicated Asset Owners state that PJM has demonstrated no basis for eliminating this review, and that a specific requirement for periodic review of CONE values is critical to ensure that they are accurate and up-to-date, and the VRR curve is adjusted as necessary to satisfy changing system conditions.

62. PJM states, in reply comments, that its proposed design principles will not bind stakeholders. It further states that the proposal to eliminate triennial review is reasonable; PJM further states that it already has a well-established stakeholder review process for all tariff changes it files and does not need a distinct review process for RPM tariff changes. Finally, PJM states that the current triennial review provisions are fraught with ambiguity, since on their face they do not apply to every section 205 change that PJM might file on CONE, the VRR Curve or its parameters, and rather, only apply to those arising from a review that PJM must conduct at least once every three years.

[34] IMM comments filed on February 23 at 4.

Commission Conclusion

63. PJM has proposed no change in its current tariff with respect to the determination of an empirical adjustment to CONE. However, we do agree with the need for a stakeholder process to determine a procedure for automated adjustments to CONE as opposed to the current method of hypothetical cost projections. As has been amply demonstrated in the proceedings leading up to the December 12 filing and the February 9 filing, and the comments filed here, the current process of making adjustments to CONE based on cost estimates and projections is difficult and complex, leading to disputes over cost assumptions as well as the need for predicting future costs leading up to the Delivery Year. This process is more difficult than the typical rate case based on an existing rate base, because there are no accepted accounting numbers with which to begin the analysis and the cost projection is for the future, not the present. Moreover, because of the need for certainty in the RPM auction, the normal section 205 process of suspending the filing, subject to refund, while a hearing is conducted is often not available. When a utility makes its filing on short notice (as in this case), hearing procedures for such cost data become even more impractical. Once an automated process is approved, we anticipate that the process of adjusting CONE will become smoother and less contentious, and the stability of the capacity market will benefit thereby.

64. We recognize that, besides the intent to establish an automated CONE process and revise other aspects of RPM as detailed in this proceeding, PJM plans to further "identify[] and resolv[e] longer term issues and opportunities for enhancements to the capacity markets" through its stakeholder process.[35] We support this approach and encourage PJM and its stakeholders to explore alternative mechanisms to simplify and streamline the determination of capacity prices, including reconsideration of the use of CONE in conjunction with the VRR curve, and consideration of mechanisms such as a descending clock auction. In the filing that PJM plans to make with the Commission on or before September 1, 2009, we expect PJM to report to us on the progress of this effort toward simplifying and streamlining the determination of capacity prices.

65. In accepting PJM's February 9 submission as an amendment to its December 9 filing, we do not require the stakeholder process to follow any particular set of principles. Instead, we will take PJM at its word that the design

[35] Capacity Market Evolution Committee, Meeting Notes, August 8, 2008 [http://pjm.com/Media/committees-groups/committees/cmec/20080904-item-02-draft-notes.pdf].

principles at Attachment D of the February 9 filing merely provide a non-exclusive list of topics that may serve as a starting point for the discussion. Attachment D is not a rigid commitment to particular rules for the automated CONE process. No entity is bound to the principles in Attachment D, nor should any outcome of the stakeholder process be evaluated against the contents of Attachment D. We also agree with PJM that this process will serve as an acceptable substitute for, and should render unnecessary, the triennial CONE review process. We also find just and reasonable PJM's commitment to make a filing on or before September 1, 2009, with or without the agreement of its stakeholders. Because this process must be resolved, we strongly encourage the stakeholders to find a method to replace the current procedure, and we direct PJM to make a unilateral filing if no agreement can be reached. We also agree with PJM's suggestion to convene a stakeholder process to address the need for additional CONE Areas.

4.1.5. Incremental Auction Redesign

PJM's Proposal

66. Under RPM, almost all capacity committed for a particular Delivery Year is cleared in the Base Residual Auction conducted three years prior to the Delivery Year, but a small fraction of capacity can be committed in three subsequent incremental auctions. Also, in the current RPM framework, a portion of the reliability requirement target is not procured in the Base Residual Auction, but rather is explicitly reserved to be served by Interruptible Load for Reliability (ILR) resources,[36] which are certified no later than three months prior to the Delivery Year. This provision was intended to allow the participation of demand-side resources with short implementation lead times. To accomplish the current ILR set-aside, PJM currently adjusts the demand curve to take into account anticipated ILR, but the existing rules do not place limits on how much, or in what locations, ILR may be certified. Thus, when the amount of certified ILR exceeds the amount by which the demand curve was reduced, PJM procures (and buyers pay for) more resources than are needed. Since the excess ILR does not

[36] The ILR provision permits qualifying demand response resources (ILRs) to be certified, in accordance with specified requirements, to offer capacity as late as three months prior to the Delivery Year and without having to participate in the RPM auctions.

displace higher-cost generation, but merely adds more total capacity, this translates into higher total cost for load serving entities.[37]

67. PJM proposes to eliminate the ILR provisions of its tariff. It asserts that the ILR provision incents such resources to hold their capacity back from the Base Residual Auction, because that enables them to receive the benefits of clearing the auction without competing in it. PJM further asserts that ILR resources receive treatment other resources cannot, in that no other short-term resources can take advantage of the auction clearing price without being required to take any action that could reduce that price (i.e., submitting their capacity into the Base Residual Auction).[38] Accordingly, PJM proposes to eliminate the current ILR payment option beginning in the 2012-13 Delivery Year.

68. PJM further states that, to accommodate resources that cannot feasibly commit far enough in advance of the Delivery Year to participate in the RPM forward auctions, it is revising its incremental auction rules to enhance the options and flexibility available to such resources. It proposes to deduct from the Base Residual Auction a short-term resource procurement target, or "hold-back" amount, of 2.5 percent of the reliability requirement, one-third of which will then be procured in each of the three incremental auctions. PJM argues that this amount does not differ significantly from the current ILR forecast adjustment. The hold-back amount will not be reserved exclusively for ILR resources, but will be open to competition from all resources.

69. PJM also proposes changes that it argues will make the incremental auctions more efficient. The changes will (a) allow parties buying or selling replacement capacity to undertake transactions in any of the three auctions, and (b) allow PJM to buy or sell capacity in any of the three auctions,[39] thus enabling

[37] According to PJM, the certified ILR for the 2008-09 Delivery Year in excess of the forecast level resulted in additional cost to LSEs of over $79 million.

[38] Moreover, PJM states, if demand response resources offer into and clear in the auction, they are subject to an additional commitment charge (the RPM Capacity Resource Deficiency Charge) that ILR resources do not face.

[39] Under this proposal, if the Reliability Requirement for PJM decreases by more than 500 MW, and that difference is equal to more than one-third of the short-term resource megawatts held back from the Base Residual Auction, PJM will offer to sell back capacity equal to the difference between the prior and updated Reliability Requirements; conversely, if the Reliability Requirement for

(continued…)

adjustment of the total committed resources either up or down to reflect increases, or decreases, respectively, in the load forecast or other parameters as the Delivery Year approaches. Thus, PJM claims, the changes will eliminate the inefficient exclusion of replacement bids from the second incremental auctions and the exclusion of PJM procurement bids from the first and third incremental auctions.

70. PJM also proposes a conditional incremental auction, which, unlike the other incremental auctions, will have no established schedule. This will enable PJM to address significant unexpected changes that occur after the Base Residual Auction, such as an unexpected delay in planned large transmission upgrades that can significantly affect whether capacity can be delivered into a constrained Locational Delivery Area, which may then necessitate procurement of more capacity within the Locational Delivery Area.

71. PJM proposes that, as described in PJM's December 12 filing, the short-term resource procurement target for the Base Residual Auction for the 2012-2013 Delivery Year shall be 2.5 percent, and that no later than three months following the second and third incremental auctions for the 2012-2013 Delivery Year, PJM must provide stakeholders a recommendation as to whether that resource procurement target should be modified for future Base Residual Auctions.

72. Additionally, PJM asks the Commission to waive the provisions of the PJM tariff so as to enable Load Serving Entities (LSEs) to obtain certification by May 1, 2009 (rather than March 2, 2009) of the load management capability that such Load Serving Entities seek to qualify as ILR for the 2009-2010 Delivery Year. PJM asserts that the resetting of that deadline will enable the parties considering whether to seek to qualify capacity as ILR to have the benefit of the Commission's decision on the December 12 filing (which they expect on or before March 27) before determining whether and to what extent they wish to seek certification of their resources as ILR.

Protests and Answers

73. Intervenors' protests address all three aspects of PJM's proposal to redesign the incremental auctions: (1) elimination of the ILR option; (2) changes that would allow PJM to buy additional capacity or sell unneeded capacity in any

---

PJM increases by more than 500 MW, PJM will offer to purchase additional capacity in an amount equal to more than one-third of the short-term resource megawatts held back from the Base Residual Auction.

of the three auctions, as well as allow parties to buy or sell replacement capacity in any of the three auctions; and (3) creation of a conditional incremental auction.

74. The majority of the protests address the issue of elimination of the ILR rules. Several generators (Duke, Mirant, Constellation, PSEG, Reliant, Dayton and Rockland) argue that the 2.5 percent holdback proposed by PJM would: (1) discriminate against generation resources, which are not allowed to withhold offers; (2) artificially reduce demand; (3) skew price signals and undermine investment incentives; (4) produce risk and higher costs to be borne by end users; (5) fail to give PJM the full picture of locational needs and impair the planning process; and (6) produce greater volatility in RPM results. They state that if PJM is using the Base Residual Auction to purchase only 97.5 percent of the reliability requirement, this entire tranche of capacity can be met by existing resources with going-forward costs well below Net CONE. Since these existing generation resources are required to offer their capacity into the Base Residual Auction, they will do so and effectively foreclose the opportunity for any planned generation resource to participate. All net purchases of new capacity would be deferred into the incremental auctions, but these occur too close to the Delivery Year to allow effective competition by new generation entrants. The generators argue that this is in direct contradiction to RPM's goal of sending appropriate price signals in a manner that allows new and existing resources to make informed decisions to support the region's reliability needs. Thus, most generators argue for the elimination of the hold-back provision.

75. Dayton argues that the hold-back should be reduced from 2.5 percent of the reliability requirement (or approximately 3,600 MW) to 2,000 MW. Rockland argues that PJM should implement a hold-back amount that varies based on the forecasted load growth, and the quantity of new longer term supply resources that may be needed to serve that load. PSEG argues that if special incentives for demand-side resources are viewed as needed by the Commission notwithstanding the success in procuring capacity from demand-side resources to date, allowing an explicit price adder for bids by demand-side resources in order to achieve a specified target procurement level would be much less disruptive of RPM outcomes. PSEG, as well as Reliant, argue that if the hold-back is retained, there should be corresponding changes to the treatment of generation resources. Thus, PSEG argues that if PJM plans to procure a portion of the reliability requirement in incremental auctions, generation resources should be permitted to withhold corresponding portions of their capacity from the Base Residual Auction. Reliant argues that the final 2.5 percent of capacity within the base offer segment should be exempt from offer capping.

76. Curtailment service providers (including EnerNOC, Comverge, ClearChoice Energy, EnergyConnect and CPower) and other DR providers such

as Steel Producers argue for the retention of the current ILR provisions. They argue that PJM's stated rationale for eliminating the ILR option – to force demand response customers to participate in the Base Residual Auctions – is dubious and speculative. They conclude that many ILR providers will simply stop providing demand response services altogether because (1) it is very difficult for them to forecast the customer's delivery obligations three years in advance; (2) credit deposits imposed on planned demand resources in the Base Residual Auction are too high; (3) PJM's proposal will substantially increase the amount of competition from generation resources that ILR resources will face; and (4) prices in the incremental auctions will be very volatile, thus raising barriers to entry for demand response resources.[40]

77. In response to the generators' arguments, PJM states that the "suppression" of prices that they claim would result from a short-term resource hold-back presumably already exists from the current ILR holdback, but has not prevented Base Residual Auctions from clearing at or above Net CONE, nor has it prevented new entry. PJM also addresses the ILR providers' arguments and contends that the current rules, even without the incremental auctions that are more conducive to short-term resource participation, have not prevented demand response participation in RPM auctions.

78. RPM Load Group and the Indicated PJM States support the hold-back, and argue that with PJM's proposed elimination of the tariff's current ILR provisions, the need to allow ILR to participate in incremental auctions is underscored by the practical difficulty of ILR participation in Base Residual Auctions. They argue that when global demand was strong and no foreseeable

[40] As an alternative, ILR providers propose modifications to the ILR option that they contend would address PJM's concerns. Those proposals are: (1) in acknowledgement of the value of making three-year forward commitments, ILRs would receive lower payments than the auction clearing price paid to demand resources that participate in the Base Residual Auction; (2) ILR certification could be rescheduled from three months before the Delivery Year to four or five months before the Delivery Year such that ILRs register before the third incremental auction rather than after, thereby enabling PJM to conduct the third incremental auction with full knowledge of the quantity of ILR available for the Delivery Year; (3) PJM could make changes to the ILR forecast methodology in order to reduce forecast errors and thereby unnecessary load payments to ILRs for excess capacity; and (4) PJM could charge a fee for the option to sell ILR capacity at a later date.

downturn was in sight, industrial customers would have had great difficulty predicting their ability to interrupt production in the summer of 2009, let alone three years forward.

79. Most parties support PJM's proposal for more frequent true-ups against increases in the forecasted load requirement, but PSEG and Mirant argue that eliminating shortages through additional procurements in the incremental auctions will reduce prices in the Base Residual Auctions that would otherwise have cleared at higher levels. This would, in turn, lead to less new entry and would ultimately call for a redesign of the underlying VRR curve.

80. The Illinois Commission and Mirant argue that the various triggers for submission of a buy bid or sell offer into the incremental auctions are inconsistent and ambiguous. The Illinois Commission specifically argues that section 5.4(c)(2) of the tariff, which uses the absolute value of the difference between the updated PJM region reliability requirement and the actual capacity procured in all prior auctions for the Delivery Year, should be adequate as a trigger.[41]

81. The Illinois Commission also objects to the conditional incremental auction. It argues that if such an auction is retained, then rather than only procuring additional capacity needed to make up for the reduced transmission capability into constrained areas, the auction should result in completely re-running the Base Residual Auctions for all affected areas, whether constrained or unconstrained, and recalculating the clearing prices for all areas.

82. Finally, AEP argues that it should be allowed to be released from forward capacity obligations, to which it previously committed as a Fixed Resource Requirement entity, when load forecasts change at the time of the incremental auctions. PJM responds by saying that Fixed Resource Requirement entities are not subject to the same risk as the rest of the load-serving entities that procure

---

[41] That section provides:

> [PJM shall] seek additional capacity commitments to serve the PJM Region if the updated PJM Region Reliability Requirement, less the PJM Region Short-Term Resource Procurement Target applicable to the current auction, exceeds the total capacity committed in all prior auctions for such Delivery Year by 100 MW or more[.]

capacity through the VRR curve, and therefore there is no reason to allow entities like AEP to be released from its prior commitments when load forecasts change.

Commission Conclusion

83. The Commission will accept, subject to conditions, PJM's proposal to (a) eliminate the ILR provision beginning in the 2012-13 Delivery Year and (b) provide for the participation of demand response resources in the incremental auctions, in addition to the Base Residual Auction, by setting a short-term resource procurement target of 2.5 percent to be procured in the three incremental auctions.

84. We agree with PJM that the current ILR framework unnecessarily leads to over-procurement of capacity in the Base Residual Auction and needlessly imposes additional costs on load. We also agree with PJM that it is more efficient for those demand response resources that are able to offer their resource three years forward in the Base Residual Auction to do so, rather than wait to certify as ILR three months prior to the Delivery Year. However, as discussed further below, we will require PJM to revise the structure of the incremental auctions in order to allow greater participation, as close as possible to the Delivery Year, of short lead time resources.[42]

85. PJM currently proposes simply to procure one-third of the "hold-back" in each of the three incremental auctions following the Base Residual Auctions. The Commission does not, however, consider this sufficient to ensure that those short-lead-time resources that are not able to submit offers into the Base Residual Auction or, in some cases, even into the first two incremental auctions, are able to participate in the capacity market. We will therefore accept this provision, subject to PJM revising the allocation of the 2.5 percent hold-back so that a substantial amount of short lead time resources ha a reasonable opportunity to be procured in the final incremental auction. We will require PJM to make a filing implementing this revision by September 1, 2009 (whether as part of the section 205 filing that PJM is planning to make on other issues by that date, or as a separate filing in compliance with this directive).

86. The Commission conditionally accepts PJM's proposal to restructure the incremental auctions to (a) enable PJM to procure additional capacity in the event

[42] Short lead time resources can include demand response and energy efficiency resources, upgrades to existing generation units, and imports of capacity from areas outside of PJM.

of under-procurement or sell excess capacity in the event of over-procurement in any of the three auctions and (b) allow parties to buy or sell replacement capacity to undertake transactions in any of the three auctions.

87. Additionally, as Joint Protestors and the Illinois Commission note, PJM does not clearly explain the procedures for determining whether and how it would secure additional commitments of capacity, or allow sellers to buy out of their prior capacity commitments, based on an update of the regional and LDA reliability requirements, and capacity held back from the Base Residual Auction for short-lead-time resources, before each of the three scheduled incremental auctions. We will therefore accept PJM's proposal, conditioned on its filing revisions to sections 5.4, 5.10, and 5.12 to clarify and render consistent those procedures and include the revisions in the filing to be made by September 1, 2009.

88. We also accept PJM's proposal to conduct conditional incremental auctions whenever it determines that such action is necessary, in accordance with the guidelines stated in the proposal. We find that a conditional incremental auction will provide a means to procure additional capacity if a transmission line that was assumed to be in service for the Delivery Year is delayed. We disagree with the Illinois Commission's proposal to rerun the markets every time there is a conditional auction. A fundamental element of RPM is that it is intended to provide significant forward certainty on capacity procurement and capacity pricing. PJM's approach honors that principle, leaving the Base Residual Auction results intact, and procuring additional capacity only as needed to address reliability criteria violations arising from a delay in a planned transmission upgrade.

89. We will also grant PJM's request for a waiver of the provisions of the PJM Tariff so as to enable Load Serving Entities to obtain certification by May 1, 2009 (rather than March 2, 2009) of the load management capability that such Load Serving Entities seek to qualify as ILR for the 2009-2010 Delivery Year. In light of the fact that we are acting on this proposal after the ILR certification deadline, we find it necessary to extend the timeline for ILR certification to allow LSEs a reasonable opportunity to assess the impact of this procedural change and determine if they will certify themselves as an ILR resource in the incremental auctions.

90. Finally, we agree with PJM that entities that chose to procure capacity through Fixed Resource Requirement should not be allowed to release capacity when load forecasts decrease at the time of the incremental auctions. The Fixed Resource Requirement option was developed largely at the behest of AEP to provide it with greater certainty and stability in its forward capacity obligations. LSEs that procure capacity through the VRR curve are subject to the risk that the

VRR curve may clear at some percentage above the install reserve margin. AEP sought to avoid that risk and uncertainty through an option to commit to a fixed forward capacity level. This is exactly what the Fixed Resource Requirement option provides. PJM's proposal treats Fixed Resource Requirement entities fairly – they are not allowed to release capacity when the load forecasts decrease, but neither are they required to procure additional capacity (like VRR entities) when the load forecasts increase.

4.1.6. Bright Line Tests to Include RTEP Transmission in System Model for RPM Auctions

PJM Proposal

91. PJM proposes to address the possibility that transmission upgrades that were planned under the PJM Regional Transmission Expansion Plan (RTEP), and which will be required to transmit capacity that cleared the auction, will not be completed by the Delivery Year.

92. Currently, PJM includes a proposed backbone transmission project (500 kV or higher) in the Delivery Year system model if the project, based on a transmission owner's schedule, is included in the RTEP for that Delivery Year. This gives rise to reliability concerns because the permitting and construction schedule for backbone transmission projects are unpredictable and initial schedules can be overly optimistic. Once included in the Base Residual Auction's system model, however, proposed projects increase transfer capability to transmission owners' load zones, thereby driving down auction clearing prices that load-serving entities ultimately have to pay. If transmission projects fail to enter service by the start of the Delivery Year, PJM will have under-procured capacity because the lower auction clearing prices in constrained zones would reduce the volume of supply resources (including demand response and energy efficiency resources) in those areas. The Brattle Report recommended the institution of bright line metrics against which PJM can assess whether to include proposed backbone transmission projects in transmission system models.

93. PJM proposes a set of bright line project development milestones for including RTEP upgrades in the system models used for the RPM auctions. Thus, to be included in a Base Residual Auction, at least 60 days before that auction, a corporate officer of the project sponsor must submit a critical path project development schedule containing intermediate milestones, showing the project in full commercial operation no later than the start of the relevant Delivery Year, and certifying that the schedule is reasonably achievable. The project development schedule must identify all states in which the project must obtain a certificate of public convenience and necessity, or equivalent regulatory approval, and must describe the current status of such approval requirement, and show the

scope, schedule, and current status of all other key milestones.[43] PJM also proposes to require that its Office of the Interconnection or an independent third-party auditor must audit the project development schedule and affirm, no later than 30 days before each auction, that the schedule is reasonable and will permit achievement of the transmission project's full commercial operation prior to commencement of the applicable Delivery Year.

94. With respect to the incremental auctions, the project sponsor must provide, 60 days before each auction, an updated development schedule showing that the transmission project is on schedule, and that 50 percent of the right-of-way by linear distance has been secured before the first incremental auction; 75 percent before the second incremental auction; and 100 percent before the third incremental auction. In addition, the development schedule submitted before the second incremental auction must show that all certificates of public convenience and necessity (or equivalent approvals) have been issued by the responsible regulatory bodies.

Protests and Answers

95. All the parties that filed comments and protests regarding PJM's proposed bright line tests for modeling backbone transmission projects agree that PJM's proposal presents a significant improvement to the current flawed system modeling procedure. However, parties are split on whether the proposed test is overly or insufficiently stringent.

96. One group of protesters (Allegheny and the RPM Load Group) argues for relaxing the rules that apply to modeling of transmission in both Base Residual Auctions and incremental auctions. The RPM Load Group argues that the requirement that a certificate of public convenience and necessity must be filed in all applicable states no less than 60 days before the Base Residual Auction is unreasonable and will result in viable transmission projects being excluded from the Base Residual Auction system model. They argue that even if a certificate of public convenience and necessity has not been filed three years in advance of the Delivery Year, it does not mean that the project will not be completed on schedule. They also argue that, given the requirement of an officer certification of the project's development schedule and the audit 30 days prior to the Base Residual Auction, PJM has proposed adequate safeguards that will prevent

[43] The certificates of public convenience and necessity must be filed in all applicable states.

system modeling of transmission projects that will not achieve timely commercial operation.

97. Allegheny and the RPM Load Group also argue that the bright line test for the incremental auctions is overly stringent. Allegheny, in particular, argues that the predetermined percentage of the required rights-of-way is arbitrary and fails to recognize that a transmission project may continue to be on schedule even though it does not meet the milestones for each incremental auction. In addition, Allegheny contends that the milestones are irrelevant if the project sponsor's corporate officers and PJM certify the project as being on schedule. The RPM Load Group argues that a backbone transmission project should be excluded from the system models only if a delay in the project schedule will cause significant adverse effect on locational capacity constraints or reliability requirements. The RPM Load Group proposes to replace the proposed milestones for the incremental auctions with a process similar to the Base Residual Auction standards, i.e., certification that the project is on schedule 60 days prior to the incremental auction, and an independent third-party audit no later than 30 days prior to the applicable incremental auctions. If the certification process reveals a delay in the commercial operation date of the project, the RPM Load Group proposes that PJM perform an assessment of whether the delay is likely to cause a shortfall, and only procure the additional capacity if necessary at that time.

98. The second group of protesters (PSEG, CPV Maryland, PPL, NRG and Constellation) argues that PJM's proposed bright line test is not sufficiently stringent. For example, PSEG argues that only those transmission projects that are already in-service or for which construction has actually commenced, should be included in RPM modeling. Under this method, if a planned transmission project meets its planned in-service date, the impact of not including the project in RPM modeling would be limited to one year. Constellation and CPV Maryland argue that PJM should modify the certificate of public convenience and necessity metric by requiring that the transmission project apply not only for state approval but also local or federal. In addition, Constellation argues that PJM should require that transmission projects should receive a certificate of public convenience and necessity 24 months prior to the Delivery Year. Finally, NRG argues that there should be an explicit requirement that transmission projects reach service prior to the Delivery Year, and if they fail to do so, they should pay penalties comparable to those a generation project would pay for failing to meet its in-service date.

Commission Conclusion

99. We will accept PJM's proposed bright line tests to include RTEP transmission in system modeling for RPM auctions as reasonable provisions to better assess the progress of transmission projects. PJM's proposal recognizes

and responds to the significant flaws in PJM's system modeling procedures that may give rise to reliability concerns and market uncertainty. Due to the significant scale and scope of the backbone transmission projects, we agree with PJM and the intervenors that it is critical to accurately reflect these projections in the assumptions and modeling used for the RPM auctions, so as to ensure that PJM procures the necessary amount of capacity through the RPM process. Currently, PJM includes all planned RTEP projects in the RPM modeling and assumes that the transmission project will be in service without delays. For many of these projects, however, permits have not yet been received, equipment has not been ordered and construction has not yet commenced. Assuming that there will not be any delays in these transmission projects potentially compromises system reliability by muting signals to generators and demand response in PJM. Prior to including planned transmission projects in the modeling for RPM, there should be a greater certainty that the project will be able to meet the in-service date to ensure that PJM has procured the necessary amount of capacity through the auction process to reliably operate the transmission system.

100. While several intervenors expressed various concerns regarding how the RTEP project should be modeled under RPM, we are not convinced that PJM's bright line test should be modified to reflect any of these standards. For example, we note that some intervenors would prefer a less stringent process, as the certification by the company officer and independent auditor should be enough support to demonstrate that the project is on schedule. We disagree. We cannot find that requiring the certificate of public convenience and necessity application is unreasonable, since the actual filing of an application provides objective support that the project is moving forward. While both officer certification and independent party audit are important in assessing the status of the project, they are subjective and could possibly even be speculative if not supported by documentation, such as the certificate of public convenience and necessity application. In addition, we believe this approach would not eradicate the uncertainty of various transmission projects being in service by the relevant Delivery Year.

101. We see no reason to find PJM's proposal unreasonable because it requires only an application for a certificate of public convenience and necessity at the state level and does not require applications for every federal or local permit that might be required. PJM's current tariff contains no test for adequate progress and we find that PJM has adequately justified the requirement for requiring a certificate of public convenience and necessity application, which is a major component of a transmission project, as an indicator that the project is making reasonable progress and should be included in the RTEP study process. We find that this is a reasonable improvement on the current process and the protests have not provided evidence that this proposal is unreasonable

102. We will also reject the arguments against PJM's proposed metrics for the incremental auctions, i.e., the percentages of rights of way that must be acquired prior to each incremental auction. On one hand, Allegheny and the RPM Buyers criticized this metric for being arbitrary and overly stringent. On the other hand, PSEG argued that this metric is meaningless (when many projects follow existing transmission routes) and thus not stringent enough. As an alternative, PSEG argues that only those transmission projects that are already in-service or for which construction has actually commenced, should be included in RPM modeling. We find that PJM has struck a reasonable balance with respect to this metric, which has to be stricter than the metrics used for the purposes of the Base Residual Auctions, because: 1) incremental auctions are much closer to the Delivery Year; and 2) PJM must be able to model assumptions with greater certainty. It would also be imprudent for PJM to rely only on officer certifications and audits in assessing the availability of certain transmission projects. Excluding all projects that are not in service or under construction, as PSEG suggests, would be overly cautious, because some auctions, such as the first incremental auction, are conducted 24 months prior to the start of the Delivery Year, well ahead of when the projects are supposed to be operational.

103. Finally, NRG argues that there should be an explicit requirement that transmission projects reach service prior to the Delivery Year, and if they fail to do so, they should pay penalties comparable to those a generation project would pay for failing to meet its in-service date. We will reject both arguments for the following reasons. First, we note that NRG ignores the fact that PJM is proposing to institute a conditional auction if necessary to procure additional capacity to address reliability criteria violations arising from the delay in a planned transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

104. Second, we note that RTEP transmission projects are not capacity resources. These projects do not participate in the RPM auctions and do not receive capacity payments from PJM; rather, PJM is simply seeking to model the state of the transmission system by the relevant Delivery Year correctly. Therefore, it would be inappropriate to penalize the sponsors of those projects.

4.1.7. Criteria to Establish Separate Variable Resource Requirement (VRR) Curves for Locational Delivery Areas

PJM's Proposal

105. Under PJM's current tariff, Locational Delivery Areas are presently defined, but do not have separate VRR curves. The current RPM rules set a separate VRR curve for any LDA that is constrained, or close to becoming constrained, based on a test that compares the LDA's capacity emergency transfer

objective (CETO) with its capacity emergency transfer limit (CETL). Whether an LDA is constrained is based entirely on a physical comparison of the amount of energy that the LDA needs compared to the transmission capacity available for such import. Specifically, if the CETL is less than 105 percent of CETO,[44] then PJM shall establish a separate VRR Curve for that LDA. In other words, a separate VRR curve is established only if the ability of the transmission system to deliver energy into the LDA (CETL) is within 105 percent of the transmission import capability required to meet the LDA's emergency reliability needs (CETO).

106. PJM proposes to change this test, so that CETL must be 115 percent of CETO. To ensure that the test does not overlook LDAs that might price-separate even without having sufficient congestion to meet this test, the revised tariff sheets provide that PJM also shall establish separate VRR Curves for (i) any LDA that had a locational price adder[45] in any of the three immediately preceding Base Residual Auctions; (ii) any LDA that PJM determines in a preliminary analysis is likely to have a Locational Price Adder, based on historic offer price levels; and (iii) for purposes of the Base Residual Auction conducted for the 2012-2013 Delivery Year, the PSEG North, EMAAC, SWMAAC and MAAC LDAs, because those LDAs have had locational price adders in previous auctions or may have locational price adders in the 2012-2013 Base Residual Auction. The tariff revisions also clarify that all generation resources in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year. The PJM comprehensive proposal included guidance on modeling steps PJM could take to improve the reliability of the results when CETL is above 115 percent of CETO which will be specified in the PJM manuals. The February 9 filing eliminates the proposal in PJM's December 12 filing to require that the PSEG North Local Delivery Area be assigned a separate VRR curve for the 2012-2013 Delivery Year Base Residual Auction without regard to the outcome of the other tests detailed in proposed sections 5.10(a)(ii)(A)-(C) for such treatment (i.e., the February 9 filing eliminates the waiver of the CETL/CETO 115 percent threshold test for PSEG

---

[44] *I.e.*, if CETO in an LDA is 100 MW, PJM must establish a separate VRR Curve for that LDA if CETL falls below 105 MW.

[45] The locational price adder is an addition to the base price of capacity for the PJM region, if an LDA is constrained. *See* PJM tariff, Attachment DD, section 2.40.

North); provided, however, the PSEG North Local Delivery Area remains subject to the other tests detailed in sections 5.10(a)(ii)(A)-(C) as proposed in the December 12 filing for the development of a separate VRR curve. PJM further proposes that it will convene a stakeholder process to develop additional procedures and objective criteria with regard to the establishment of separate VRR curves for Local Delivery Areas as a result of either (1) a preliminary analysis by PJM that a Locational Delivery Area is likely to have a Locational Price Adder based on historic offer price levels, or (2) a PJM finding that a separate VRR curve is required to achieve an acceptable level of reliability.

Protests and Answers

107. Several parties, including the IMM, Liberty Electric, CPV Maryland, PPL and Constellation, support PJM's proposal to change the test for developing separate VRR curves for LDAs to be the occurrence of a CETL/CETO ratio of less than 115 percent. Other parties feel that that test is not strict enough: Liberty Electric suggests that the Commission direct PJM to consider eliminating the CETL/CETO ratio entirely, or otherwise raising the ratio limit to provide a larger cushion. NRG similarly argues that a 160 percent threshold, rather than 115 percent, is appropriate. The Illinois Commission and PSEG support the Commission's taking necessary actions to ensure that price separation can occur when necessary.

108. The RPM Load Group argued, in its reply comments regarding the February 9 filing, that creation of a separate VRR Curve on the basis of the CETL/CETO ratio should be based on empirical data that does not require PJM to exercise discretion. It also states, however, that the remaining criteria for establishing a separate VRR Curve for an LDA – based on a preliminary analysis by PJM or if PJM finds that it is required to achieve an acceptable level of reliability – could require the exercise of discretion and because these two criteria are based on an analysis and/or finding by PJM, the parameters for these findings and analyses should be developed and documented. The RPM Load Group believes that the stakeholder process required by the February 9 filing provides this opportunity.

109. PSEG argues that PSEG North should be designated for a separate VRR curve in the 2012-2013 Base Residual Auction.

Commission Conclusion

110. The CETL to CETO ratio reflects the fact that the presence of physical transmission constraints within an LDA is an important factor affecting whether the LDA should be viewed as a separate market. In brief, CETL is the capability of the transmission system to import energy into the area. CETO measures the

need to import; it is the amount of energy that a given area must be able to import in light of the amount of load and the existing generation resources in the area.[46] If the area's need to import (CETO) is less than the transmission *capability* to import (CETL), that measurement demonstrates that the area has so much existing generation that it does not need to use all of its import capability to meet reliability standards. Thus, congestion will not arise into the area for reliability reasons. However, the area's existing generation may be more expensive than generation in neighboring areas, and as a result, the actual occurrence of transmission congestion[47] can arise not only because of reliability needs, but also because of economic conditions. That is, congestion can arise not only because of a lack of transmission relative to the reliability need to import; it is also a result of supply and demand conditions within the LDAs. For example, if capacity costs are less in one LDA than in another, parties in the higher-cost LDA would want to import more than the available CETL in order to avoid paying higher capacity costs. However, the existing capacity of the transmission system would prevent the importation of power, resulting in higher prices (congestion) in the import LDA than in the export LDA. When prices cannot equilibrate across areas due to transmission constraints, each of those areas is a separate market. We therefore find that PJM’s proposal to increase the CETL/CETO ratio will capture situations in which congestion occurs more effectively than the current tariff provisions, and we accept it on that basis. Some protesters would like a ratio higher than PJM proposed, but under section 205, we cannot require a utility to change its own proposal if that proposal is just and reasonable. As PJM states in its filing, because system modeling will be increasingly unreliable as the ratio grows, this provides a reasonable basis for its proposal.

111. We also support the proposed tariff modifications providing that PJM will establish separate VRR curves for LDAs that had a locational price adder in the

---

[46] CETO, the amount of energy that an area needs to import, depends on the amount of existing generation in the area relative to its load. If the existing generation is only slightly less than its load, the area will not need to import much (if any) energy in order to meet the reliability objectives. But if the existing generation is much less than its load, the area would need to import more energy to meet the reliability objectives.

[47] Transmission congestion exists when capacity prices in one area are higher than prices for available capacity in another, but insufficient transmission capacity exists to move lower-priced capacity into the higher-priced capacity until the capacity prices in the two areas are equalized.

preceding Base Residual Auctions or those likely to have locational price adders based on historic price levels. These proposals are consistent with the rationale for increasing the CETL/CETO ratio. Additionally, with respect to the issue of PSEG North, PJM did not propose in the February 9 filing to change the existing tariff so as to add a separate VRR curve for PSEG North. Thus, making such a change goes beyond the scope of this filing. Further, PSEG has made no showing as to why PSEG North should be designated a separate capacity area, other than purely speculative statements,[48] and we will therefore deny that request.

4.1.8. Economic Scheduling

Proposal

112. The February 9 filing proposes to amend the PJM Operating Agreement and Tariff to provide that Capacity Resources committed through RPM (or the Fixed Resource Requirement, under which Load Serving Entities self-supply their own capacity needs) must offer their output in the day-ahead energy market on economic schedule if not on forced maintenance outage, absent a Maximum Generation Emergency. [49] PJM argues that this proposal simply makes explicit the rules and practices already implied in the PJM Tariff; it recognizes, however, that this could be a topic for future stakeholder discussion. Because this proposal was discussed by PJM and its stakeholders, but was not approved by the required super-majority vote, PJM asks the Commission to order this change pursuant to section 206.

Protests and Answers

113. Parties commenting on this aspect of the February 9 filing do not appear to have the same understanding of what the clarification intends to accomplish.

---

[48]PSEG asserts that such designation is appropriate "given the tight capacity resource supply parameters in that area" (PSEG February 23 comments at 6) and states that, because a PSEG company recently received an extension of its Reliability Must Run contract from PJM for a unit in PSEG North, this "suggest[s] that PSEG North would also have separated in price if it had been modeled for the 2011/2012 auction" (id. at 14-15 n.45).

[49] *See* proposed addition to section 1.10.1A (d) of the tariff, Day-Ahead Energy Market Scheduling: "To offer its output 'on economic schedule' the Market Seller must designate the offered output as available for normal economic operation rather than only being available under emergency conditions."

They have different views about what the current must-offer rule should allow: (1) any offer including an offer that would provide energy on an emergency basis only; (2) any offer subject only to the $1000/MWh bid cap; and/or (3) only offers that are competitive where "competitive" means to some an offer that does not exceed the default values established for each unit.

114. The Indicated Asset Owners object to the February 9 filing's proposed requirement that Capacity Resources committed through the RPM must offer all available capacity in the Day-Ahead Energy market on an economic schedule. They disagree that the current language is ambiguous and that the proposed revisions only clarify what is already implied. They point to section 6A.1.3 of the Operating Agreement, which lists the conditions under which PJM shall consider units that have been classified as Maximum Emergency as evidence that there is no Tariff ambiguity that requires clarification.[50]

115. Furthermore, generators argue that in addition to scarcity pricing, offering only at maximum emergency generation serves other legitimate purposes. Mr. Robert Stoddard, in an affidavit submitted on behalf of the Mirant parties, states that he views the $1,000/MWh bid cap as insufficient, in some cases, for sellers to fully reflect opportunity costs or manage risk of equipment failure. The ability of a seller to designate some portion of its capacity as available only for an emergency, in his view, is an important mechanism for overcoming the limitations of the bid cap. At a minimum, he recommends that the Tariff should at least allow a waiver of a requirement to bid an economic schedule if the supplier offers a valid business reason for the waiver. [51]

116. The Indicated PJM States take the view that all offers from capacity resources in the day-ahead energy market should not exceed marginal cost and that the proposed clarification would eliminate the option to offer energy at the $1000/MWh bid cap, not merely the opportunity to offer capacity on an emergency basis only.[52] The Illinois Commission shares this view and argues that an “economic schedule” is one where the offers equal the unit marginal cost as represented by the reference prices used for market power mitigation. The IMM asserts that the tariff should require that offers into the day-ahead energy

---

[50] Comments in Opposition to the Settlement (February 23, 2009) at 57.

[51] Affidavit in Support of the Mirant Parties at 32-33.

[52] Protest and Comments at 14-15.

market be competitive.[53] However, he does not explicitly address what offers the present tariff allows that he might find non-competitive.

117. PJM, in its reply comments, further supports the need for the clarification.[54] It emphasizes that a resource may designate its capacity as available under Maximum Emergency conditions if it meets the criteria in section 6A.1.3 only. It replies that Mirant's concern is with the $1,000/MWh bid cap which effectively sets a limit on the degree to which suppliers might offer their capacity to manage the risk issues Mirant identifies. PJM states that there is no tariff authority for declaring available capacity as available under Maximum Emergency conditions outside the scarcity pricing rule. Mirant's argument, PJM claims, is an argument that condones withholding on the grounds that even the $1000/MWh bid cap is not adequate to reflect the incremental cost of at least some portion of a unit's output.

Commission Conclusion

118. We will reject PJM's tariff proposal because it is unclear what the new tariff would require. The term economic schedule is not defined and it can, and obviously has, led to different conclusions. Consequently, some parties seem to find that "economic scheduling" means "to offer at the default bid level" (PJM States and the Illinois Commission, for example) while others such as Mirant believe that "economic scheduling" eliminates the ability to offer capacity on an emergency basis when the $1000/MWh is not adequate whereas PJM seems to suggest that an "economic schedule" only subjects day-ahead bids to the $1000/MWh bid cap. The IMM also does not define "competitive offer" as the default bid or any bid less than $1000/MWh where the market power screens are not violated and transmission constraints are not binding.

119. This rejection, however, is without prejudice to PJM and its stakeholders, or PJM, refiling this request for relief, with a clearer explanation of what this provision is intended to accomplish.

[53] Comments of the Independent Market Monitor for PJM at 10.

[54] Reply Comments of PJM in Support of Offer of Settlement at 44-46.

4.2. Resources Participating in RPM

4.2.1. Energy Efficiency

PJM's Proposal

120. PJM proposes new tariff provisions to enable energy efficiency (EE) resources to participate in the RPM market, starting with the May 2009 Base Residual Auction. PJM states that, while currently RPM permits participation by demand resources that are dispatchable by PJM, the reliability value of non-dispatchable resources, such as EE, is recognized within RPM only after the impact of the EE resources is reflected in the historic load date. RPM's Base Residual Auction is conducted three years before the Delivery Year, but it relies on forecasts based on peak loads from the summer before the auction, i.e., four years before the Delivery Year.

121. To address this gap, PJM has proposed tariff revisions in a new section M to schedule 6 of its Reliability Assurance Agreement, which otherwise deals with the participation of demand resources in RPM. PJM proposes to allow energy efficiency resources that clear in the RPM auction to receive RPM capacity payments for up to four consecutive Delivery Years. PJM defines an EE resource as:

> a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak periods as described herein) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch or operator intervention.[55]

The project must also provide information regarding its Measurement and Verification (M&V) methods and procedures by which PJM will be able to

[55] Transmittal at 31, citing Reliability Assurance Agreement, schedule 6, proposed section M.1.

determine the amount of load reduction and confirm that such reduction is achieved.

122. PJM's proposal creates two alternative tracks for compensating energy efficiency resources in such a way that the party providing an EE resource can realize the benefit of that investment's reduction in the PJM region's capacity needs before that reduction can be reflected in the load forecast used for RPM auctions.[56] The first would compensate the energy efficiency resources for 100 percent of their capacity value times the RPM clearing price for each year in which the resource provider is willing to submit updated M&V data to PJM.[57] The second would compensate the energy efficiency resources on a declining scale (100 percent for the first year, 75 percent for the second year, 50 percent for the third year, and 25 percent for the fourth year) if the resource provider only submits M&V data the first year. Projects that fall short of meeting RPM commitment will be subject to penalties, similarly to other types of resources.

Protests and Answers

123. Several parties, including Con Ed,[58] argue that PJM's proposal will cause double compensation to energy efficiency providers, and thus, should be modified. They agree with PJM that there is a 4-year lag between when an EE investment becomes operational and when the associated load reductions are reflected in PJM's load forecast. But they argue that there is only a 1-year lag between the time of investment and the time when the LSE's capacity billing determinants are reduced (see shaded areas below).[59] That is because within the

[56] After that reduction is reflected in the load forecast, the customer's load obligation and capacity requirements are reduced to reflect the reduction in the region's capacity needs.

[57] The EE resource must bid into and be cleared in the RPM auctions each year.

[58] Consolidated Edison Energy, Inc. and Consolidated Edison Solutions.

[59] The reduction in load forecast reduces only the amount of capacity PJM must procure for the LSE's zone. The reduction in billing determinants reduces the cost to the LSE of procuring that amount of capacity. In other words, if the LSE's demand is 1000 MW and there is a 10 MW reduction due to EE, PJM would not reduce its load forecast to 990 MW until four auctions have passed. However, it will reduce the billing determinants to the LSE by the time of the second auction.

PJM market, an LSE's capacity payment to PJM is predicated on an average of the customer demand during the peak hour of the five peak days of the past year. Thus, they argue a double payment results because the energy efficiency provider receives an RPM payment (for years 2 through 4) and its LSE receives a reduction in peak demand obligation, which is passed through to retail customers.

Energy Efficiency Projects' Impact on Load Forecast and Billing Determinant (Project installed prior to May 2012)					
Base Residual Auction	May 2009	May 2010	May 2011	May 2012	May 2013
Delivery Year	June 2012-May 2013	June 2013-May 2014	June 2014-May 2015	June 2015-May 2016	June 2016-May 2017
Load forecast based on load in the year prior to the Base Residual Auction	June 2008-May 2009	June 2009-May 2010	June 2010-May 2011	June 2011-May 2012	June 2012-May 2013
Billing determinant based on customer's load in the year prior to the Delivery Year	June 2011-May 2012	June 2012-May 2013	June 2013-May 2013	June 2014-May 2015	June 2015-May 2016

124. Con Ed advances a proposal to address this issue. Con Ed proposes that the energy efficiency resource will be paid the RPM price for the full four years, as proposed by PJM. However, Con Ed proposes that any demand reduction by the energy efficiency provider be added back to the LSE's coincident peak load to eliminate the double payment.[60]

125. Exelon, BG&E, the RPM Load Group, the public utility commissions of Pennsylvania, New Jersey, Maryland, Delaware and Washington, D.C., and a

---

[60] In response to this argument, PJM suggests that if any adjustment is needed in this area, it could be handled as a retail-ratemaking issue, and argues that if an add-back is ever warranted, it is only for customers with interval meters, and very few customers have such meters. For the vast majority of customers that do not have such meters, this is simply an issue of how the electric distribution company allocates costs among its retail loads. *See* PJM's March 2, 2009 answer at 22-23.

group of public interest organizations recommend the Commission's approval of the PJM proposal as a reasonable interim step that would allow energy efficiency resources to participate in the market.

126. Public Interest Organizations argue that in the longer term, energy efficiency resources should be paid for the useful life of the measure, rather than merely for the first 4 years.[61] They point to the fact that retail tariffs may fail to pass through the direct benefits in the wholesale market to the energy efficient project sponsor. In addition, they argue that reconstituting the load is complicated, and it creates split incentives between customer aggregators and their customers, with customer aggregators incented to earn capacity market revenues, and their larger customers incented to reduce their capacity costs through lower peak demand. They argue that there is a "no add back" rule used by ISO-NE, which causes LSEs to be charged based on their pro rata share of actual peak demand as measured at their customer locations with no attempt to add back the impact of demand reductions at those locations. However, they note that the effect of demand resources should be properly accounted for in computing the installed reserve requirement. Thus, in ISO-NE, there is a cross-subsidy amongst the customers, but that does not affect the net quantity of resources in the capacity market.

127. They also argue that the cross-subsidy amongst customers will likely be offset by the downward impact of the energy efficiency resources on the RPM clearing price. The precise impact of demand resources on the Base Residual Auction clearing price will vary from year to year depending on the overall quantity of resources bidding and the offers that they make, i.e., the shape of the supply curve and its intersection with the VRR demand curve. The RPM auction results to date show that the slope of the supply curve, at even modest clearing prices below CONE, can produce significant changes in the clearing price with small adjustments to that supply curve (for instance, PJM's correction of the 2009-2010 auction results showed a $2/MW-day impact based on a 70 MW change in supply resources). Additional benefits will be realized on the energy side of the market as well, through lower LMPs.

[61] They argue that a diverse group of EE measures as such compact fluorescent lights, appliances, commercial motors, and building envelope improvements produce an average measure life of 10-12 years. If a full measure life approach was adopted, the M&V process would establish the specific payment term for each measure (the term for which it qualified as a capacity resource) based on its individual measure life.

128. In addition, energy efficiency providers advocate against adopting PJM's proposal for a declining payment approach, which allows EE resources that fail to provide annual M&V updates to receive less than 100% of auction clearing prices in the subsequent Delivery Years. Parties argue that the declining payments option has no factual or analytical support for it, and that there is no reason to offer any capacity payments to a resource that cannot demonstrate its availability for the Delivery Year for which it is being paid. PSEG and Mirant also argue that allowing EE resources to participate without M&V would be discriminatory to other types of resources and could jeopardize reliability. ELCON, however, prefers PJM's proposal. A large group of stakeholders that may potentially offer EE resources into the forthcoming RPM auction filed comments asking that the Commission order a change, for 2009 only, in the proposed tariff's deadline for EE resources providers to submit their measurement and verification plans. Proposed new section M of Schedule 6 to the RAA, setting forth the energy efficiency rules, provides that M&V plans must be submitted to PJM 30 days before the Base Residual Auction. For the upcoming Base Residual Auction for the 2012-2013 Delivery Year, that deadline would be April 3, 2009. The parties that filed the supplemental comment ask that the deadline, for this year only, be extended 12 days, i.e. to April 15, 2009. In its March 2 Answer, PJM supports their requests.

129. ClearChoice also asks that the Base Residual Auction for the 2012-2013 Delivery Year be delayed by two months to accommodate their perceived need for more time to complete their strategies for offering energy efficiency projects into the auction.

Commission Conclusion

130. As the Commission indicated in our June 25, 2007, Order,[62] currently, PJM does not treat investment in energy efficiency as a type of capacity resource eligible to participate in the capacity market. The Commission further found that "to the extent possible, energy efficiency solutions should be able to compete on an equal footing with demand response, generation, and transmission solutions."[63] We commend PJM for developing a proposal to incorporate energy efficiency into its capacity markets. We believe that energy efficiency is a critical part of efficient energy markets, and should be treated comparably to other types of

[62] *PJM Interconnection, L.L.C.*, 119 FERC 61,318 (2007).

[63] *Id*. at P 18, citing *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 at P 9 n.7 (2006).

resources, by being allowed to participate in base residual auctions and be paid the auction clearing price when they are accepted in the auction.

131. The Commission finds PJM's proposal regarding EE resources reasonable and will accept it. Under PJM’s current wholesale market structure, many retail customers who install energy efficiency measures do not capture the capacity benefit of the resources they install. PJM’s proposal would allow an EE resource to bid into the auction, and if it is accepted, to bid for an additional three consecutive years. As a result, the resource may receive capacity payments for up to four consecutive years.

132. In addition, PJM’s proposal corrects a mismatch between EE-related load reductions and capacity requirement levels. As PJM has explained, there is a four year lag after an EE resource is initially installed before its load-reducing effects are reflected in PJM’s load forecast and the associated installed reserve requirement for the Delivery Year.

133. We disagree with Con Ed and others that PJM’s proposal is unreasonable because it fails to curtail payments after one year or in the alternative fails to “reconstitute” (add back) for billing purposes the load represented by EE. In the view of these parties, PJM’s proposal would provide excessive compensation to EE providers compared to that received by other capacity resources. This is because, they argue, the EE provider would not only receive the capacity price that other resources receive in the base residual auction, but would also receive a reduction in its capacity bill (which providers of other resources do not receive).

134. PJM, however, has shown that as a result of the lag in load forecasting, EE resources are not completely represented in the four years for which PJM is proposing to pay the EE providers. As a result of not including the EE in the load forecast, the VRR curve fails to move to the left, increasing the price paid and capacity acquired compared with a load forecast that correctly included EE. The load reduction in billing determinants applies to all of the capacity procured by the LSE, so that very little of that reduction is allocated to the EE provider, particularly one without an interval meter. Moreover, as PIO notes, many EE providers will not receive a significant reduction in their capacity bills as a result of PJM’s proposal. Thus, we cannot find that PJM’s proposal to pay EE for four years unreasonable.

135. Con Ed also contends that PJM allows an add-back for demand response, and so should do the same for energy efficiency, but the comparison is not valid. As PJM explains, the demand response “add-back” simply adds interrupted demand response to metered load to ensure an accurate system or zonal load forecast for future years. Demand resources are dispatchable, i.e., they remain a

load on the system unless and until PJM dispatchers request an interruption from them.

136. The proposed add-back for billing determinants related to energy efficiency is quite different. The rationale for the demand resource add-back does not apply, because energy efficiency is a permanent reduction in load, rather than a dispatchable reduction in load. So there is nothing to add back for that reason.

137. PIOs support PJM's 4-year proposal, but argue that EE resources should ultimately be able to sell their capacity into the market for the full measure life of the project. As PIOs note, PJM's proposal is a significant improvement over the current tariff, which excludes EE resources entirely. We believe that EE providers should have the ability to obtain the full economic benefits of their investments. While we accept PJM's proposal for EE providers to receive RPM capacity payments for up to four consecutive delivery years, the record is unclear as to whether this approach over time fairly and adequately allows EE providers to obtain the full economic benefit of their investments. Therefore, we direct PJM to explore with its stakeholders whether EE providers should receive RPM capacity payments for up to four years, their full measure life, or some other period of time. We also note that the rates resulting from any such rules must be just and reasonable.

138. We will also grant the request for a 12-day extension deadline for submitting the M&V plans by the EE resources. The requested short extension will better allow parties to prepare their M&V plans for this first year that EE resources are allowed to participate in the RPM auctions. We will reject, however, ClearChoice's request for postponing the Base Residual Auction. No other party has requested such a delay, and it would be highly disruptive to the RPM market.

139. Finally, we will reject PJM's unjustified proposal to compensate EE resources that do not supply M&V plans on a declining scale. This aspect of PJM's proposal was protested by both generators and proponents of energy efficiency as raising reliability problems and treating energy efficiency resources differently than demand response or generation resources. We agree with these protestors, and will require PJM to make a compliance filing that would eliminate this payment option from PJM's tariff.

4.2.2. Multi-Year Pricing Assurance for Qualifying New Entry Projects

PJM's Proposal

140. RPM's New Entry Price Adjustment (NEPA) provision allows a new capacity resource within an LDA to lock-in a "new entry price" for three years under certain conditions. One of the conditions is that entry of the new resource would result in a reduction in price from a level higher than 112.5 percent of Net CONE to less than 40 percent of Net CONE. Such a resource is then required to offer its capacity in the two subsequent Base Residual Auctions at a price that is either equal to the first year's sell offer or equal to 90 percent of the then-current Net CONE.

141. Noting that no resource has so far qualified or opted for the NEPA option, the Brattle Report concluded that the conditions that new entrants must meet in order to qualify for NEPA are too stringent and effectively eliminate the price lock-in option, and that it is unlikely that a new entrant could reduce price enough to qualify for the NEPA provision. The report therefore recommended that PJM should make the option – to lock-in prices for three to five years – more broadly available to all new capacity and existing generation with major capital expenditure requirements in constrained LDAs, with less stringent qualification criteria or no qualification criteria.

142. The February 9 filing proposes to (1) increase the commitment period to seven years; and (2) require capacity sellers to offer their resources into the RPM auctions for subsequent years of the commitment period (i.e., years two through seven) at either zero or the unit's avoidable cost rate (less the projected energy and ancillary revenues). PJM argues that this 7-year term appropriately balances developers' needs for price assurances against the burden on loads of out-of-market payments.

Protests and Answers

143. Some suppliers oppose the NEPA rule itself in principle, and/or the proposed modifications, on the basis that they are discriminatory. Other suppliers (mostly independent power generation firms) as well as load representatives and the state commissions support the changes and argue for even longer commitment periods of up to ten years on the basis that this will enable developers to finance new projects at lower cost, resulting in lower capacity prices and lower costs to consumers.

144. Constellation opposes the NEPA provision in principle, arguing that all "resources within an LDA should receive equitable pricing for their fungible

capacity" and that favoring one class of capacity resources over another is contrary to the essential logic of the RPM market. Mirant argues that allowing new entrants to obtain NEPA pricing for up to seven years has not been shown to be necessary to incent new investment, and will instead only result in increased uplift costs that are contrary to efficient market design. Mirant and Indicated Asset Owners assert that the requirement that new entrants seeking NEPA pricing bid into subsequent RPM auctions at zero or at their net Avoidable Cost Rate (ACR) will allow net buyers to attempt to suppress clearing prices to the detriment of other suppliers and load-serving entities that have secured capacity through bilateral contracts. Indicated Asset Owners further assert that PJM has provided no economic or other support to demonstrate that it would be appropriate to require new entrants to offer capacity at zero or at their ACR for subsequent Base Residual Auctions.

145. CPV Maryland and IPA Central, LS Power and Tenaska argue, to the contrary, that the February 9 filing's extension of the NEPA commitment period to seven years is inadequate and should be extended to ten years. They assert that PJM does not offer any evidence that seven years is the proper length of new entry pricing that would attract the construction of new generation where it is critically needed. They state that the single greatest barrier to entry by competitive suppliers is the difficulty of financing new construction.

146. Indicated PJM States also expressed preference for ten-year new entry pricing. In choosing not to oppose the February 9 filing, they state that the ability of new capacity to obtain price assurances for seven years should reduce the risk for new capacity and provide new entrants additional and more flexible financing opportunities. The RPM Load Group, as a party to the February 9 filing, argues that the requirement that NEPA resources offer their capacity in subsequent auctions after the first year at zero or the ACR prevents economic withholding and distorted clearing prices that do not accurately reflect the supply and demand balance in the auction. The RPM Load Group also contends that the NEPA provision does not unduly discriminate against existing generating resources because NEPA resources are new entrants into the market and are therefore not similarly situated to existing resources. Thus, because potential entrants at the present time face a substantially different market and regulatory environment than incumbents, longer-term revenue streams are needed in the current market environment to encourage investment in new generation resources.

147. The RPM Load Group also argues that a seven-year NEPA commitment period is a reasonable compromise and is consistent with investor needs for, and commission policy encouraging, longer-term contracts.[64]

148. In reply comments, PJM argues that the February 9 filing reasonably extends the term of the new entry pricing adjustment to seven years, while applying to new resources in subsequent years the same market power mitigation rules as apply to existing resources. PJM argues that seven years more than doubles the current NEPA term and should therefore provide a substantial added incentive for new entry. PJM further argues that, contrary to the arguments by proponents of longer terms, there is no single minimum term that will dictate in all cases whether or not a project is implemented. PJM also contends that the changes to the bidding requirements in the February 9 filing (i.e., offer at either zero or at the unit's avoidable cost rate less its projected EAS revenues) ensure that once a new entrant becomes an existing facility (after the first year), it is subject to the same offer caps as any other existing facility, and thus removes the incentive for economic withholding.

Commission Conclusion

149. The proposed relaxation of the pre-conditions and the extension of the lock-in period go beyond the intent of the original provision, intended only to address the issue of lumpy investments in a small LDA. PJM's proposal would further bifurcate capacity markets by giving new suppliers longer payments and assurances unavailable to existing suppliers providing the same service. Thus, it would result in further price discrimination between existing resources, including demand response, and new generation suppliers. We therefore reject the proposal to change the existing NEPA provisions.

150. We also recognize that a longer commitment period may aid the developer in financing a project. However, as PJM notes, RPM was designed to

[64] The Group also states that the Mirant Parties' argument that a seven year period would increase unhedgeable uplift costs and skew market signals ignores the reality that RPM is an administrative process and not a competitive market, as evidenced by the need for mitigation of all offers in every Base Residual Auction run to date. The Group's witness argues that the uplift payments in the subsequent year auctions will not distort the subsequent year auction clearing prices if the NEPA mechanism is designed to reflect the fact that these payments, like bilateral capacity contracts and self-scheduled capacity, should have no influence on auction clearing prices.

provide long-term forward price signals and not necessarily long-term revenue assurance for developers, and we must therefore balance the benefits of the longer commitment period (to the extent it fosters new entry by making project financing easier or cheaper) against the possible uplift payments in excess of auction clearing prices that loads may have to bear due an extension of the NEPA term. In our view, no party has made the case that extending the NEPA term to five or seven years strikes a superior balance to the existing provisions.[65]

4.2.3. Expanded Resource Eligibility and Seasonal Capacity

PJM's Proposal

151. PJM states that under the current RPM rules, capacity is an annual product, and therefore any resource that is not available or cannot be offered for the entire Delivery Year is not eligible to participate. Often, contracts terminate in the middle of a Delivery Year and, at the time of RPM auctions, it cannot be known with a reasonable degree of certainty whether these contracts will be renewed. In the case of some non-utility generators, the actual owner is not known by PJM, and therefore there is no party to accept a capacity commitment for the remainder of the Delivery Year.

152. Because this problem results in the exclusion of significant amounts of capacity from the RPM auctions, PJM proposes to permit prospective sellers with partial-year resources to use the electronic bulletin board supported by PJM to explore voluntary opportunities to combine their resources so that such resources can be offered together for a full Delivery Year in the RPM Auction. PJM states that once sellers with partial-year resources identify each other through the electronic bulletin board, they can negotiate between themselves the terms under which they will combine their resources in the RPM Auction. While the tariff revision affirms that the electronic bulletin board can be used to promote matches between partial-year resources, details of the information and data that PJM will require will be specified in its manuals.[66] PJM asserts that providing partial-year

[65] As some intervenors point out, the Commission approved a provision in ISO New England's Forward Capacity Market Settlement that allows a new capacity resource to select a commitment period of up to five years, as a design element specifically intended to provide predictable revenues and facilitate financing for new capacity if it meets certain auction criteria. However, this provision was approved as part of an overall settlement, not as an individual provision that was found to be just and reasonable in its own right.

[66] The manuals will require that the sellers agree on the various offer

(continued…)

resources a forum to identify potential counter-parties to combine their resources in the RPM Auction will help increase available resources that can participate in the RPM. Additionally, PJM will require the resources to be located in the same LDA, that the resources, once combined, form an annual capacity product, and will be required to submit documentation that the capacity is not available for the entire year.

153. Additionally, PJM's rules currently permit a Planned Generation Capacity Resource and an External Generation Capacity Resource to participate in the RPM auctions, but the rules do not provide for participation by a generation capacity resource that is in development outside of the PJM Region, i.e., a Planned External Generation Capacity Resource. So as to enable such planned external resources to participate in RPM, PJM now seeks to modify its rules by including a definition and certain requirements in section 2.50 of Attachment DD and section 1.69A of the Reliability Assurance Agreement (RAA) for Planned External Generation Capacity Resources.

154. The February 9 filing modifies these proposals. It revises section 1.69A of the Reliability Assurance Agreement such that they track comparable provisions in existing section 1.70 of the RAA for Planned Generation Capacity Resources located within PJM. PJM further provides that within 30 days after the Commission's final order approving the February 9 filing without change or condition, it will revise its applicable manual to include language governing the eligibility of Planned External Generation Capacity Resources in RPM Base Residual and Incremental Auctions that will treat such resources in a manner comparable to the participation of Planned Internal Generation Capacity Resources and Existing External Generation Capacity Resources in such auctions, and specifies certain manual changes to be included.

155. PJM also proposes to convene a stakeholder process to discuss the development of seasonal capacity pricing, and states that it will submit a filing to the Commission no later than December 1, 2009, either proposing tariff amendments to implement seasonal capacity pricing, or explaining why seasonal capacity pricing should not be implemented at that time.

---

parameters under RPM (e.g., Offer EFORD, Offer MW quantity, Offer Price, Scheduling Option, etc.).

Protests and Answers

156. Many parties support the proposals to add more capacity to RPM. The RPM Load Group, Indicated PJM States and Constellation support PJM's proposals. Some parties (RPM Load Group, AEP) also urge the development of ways to permit Fixed Resource Requirement entities, who do not participate in RPM, to contribute capacity to RPM.

157. Other parties point to possible problems. The IMM expresses concern that the tariff does not provide that an owner who plans to transfer ownership or control during the Delivery Year be required to satisfy the must offer requirement for the entire Delivery Year. The IMM suggests that this obligation could be met by providing for the assumption of this commitment by any transferee of ownership/control in the relevant agreement. For this reason, FirstEnergy urges the Commission to allow PJM and its stakeholders to negotiate regarding seasonal pricing without any deadline.

158. PJM states in its reply comments regarding the February 9 filing that its proposal that parties negotiate on seasonal pricing does not mean that seasonal pricing will inevitably be implemented: parties will seek to determine whether seasonal pricing can achieve more efficiency and lower costs. It further notes that nothing in its proposal would prevent parties from ultimately finding that seasonal pricing introduces excessive complexity into RPM, as they previously concluded in 2006.

Commission Conclusion

159. The Commission will accept, subject to conditions, PJM's revisions to its tariff to permit new types of capacity to participate in RPM. We will, however, require PJM, within 30 days, to make a compliance filing adding language to section 3.1 of Attachment DD that addresses the IMM's concern, to ensure that an owner who plans to transfer ownership or control during the Delivery Year is required to satisfy the must offer requirement for the entire Delivery Year and to allow this obligation to be met by providing for the assumption of this commitment by any transferee of ownership/control in the relevant agreement.

160. With regard to the concerns expressed regarding the stakeholder process that will consider seasonal pricing, the Commission will not remove the deadline that PJM has set for itself. If the parties are able to negotiate to a definitive resolution with regard to seasonal capacity in the stakeholder process, then PJM may, if appropriate, include that issue in the tariff amendments it intends to file on or before December 1, 2009, but it is not required to do so. If the parties cannot resolve their differences regarding seasonal capacity in that time, nothing precludes them from continuing their discussion.

4.3. Market Power Issues

4.3.1. Market Power Mitigation

PJM's Proposal

161. PJM proposes to revise its market mitigation rules, in the following ways. First, when a seller may have market power, as determined by structural screens included in Rest of Market, its sell offer is capped at its avoidable cost. The PJM tariff specifies the components of this avoidable cost rate, including an avoidable project investment recovery rate (APIR). To determine APIR, the relevant project investment costs are those capital projects reasonably required to enable a generating resource to continue operating or improve availability during the Delivery Year. The permissible addition to a capped offer to reflect such an investment is the amount of the project investment times an annual capital recovery factor (CRF). These capital recovery factors are stated in the tariff, and represent annual percentages of the project investment that allow that investment to be recovered on a levelized basis over a stated time period.

162. PJM, in consultation with its market monitor, developed a revised table of capital recovery factors. Under the revised table, plants that are 1-5 years old are assumed to have a 30 year remaining life, rather than a 20-year life. Plants that are 6-10 years old are assumed to have a 25-year remaining life, rather than a 15-year life. Plants that are 11-15 years old are assumed to have a 20-year remaining life, plants that are 16-20 years old are assumed to have a 15-year remaining life, and plants that are 21-25 years old are assumed to have a 10- year remaining life, rather than a 5-year life. The levelized capital recovery factors are reduced in each of the above cases, reflecting the longer recovery periods. PJM states that the overall assumed useful lives of 31 to 35 years (implicit in each of these recovery factors) are more realistic, and also reflect that plant owners are more likely to base their investment decisions on longer project lives than the current CRF table assumes.

163. PJM has included a multi-year pricing option for large capital project investments in existing generators, available to projects with a project investment of at least $450/kW. For such a project, the terms and conditions of the pricing option are essentially the same as those available to new entry projects under the New Entry Price Adjustment: pricing is allowed for up to five years; the LDA must have a separate VRR Curve; the offer clears in the first year; and the seller must continue to offer the resource in each subsequent year at its first-year offer price. When those conditions are met, the resource is deemed cleared in each subsequent year, and is paid its first-year offer price, regardless whether that offer price is above or below the subsequent-year clearing price. Load-serving entities in the LDA that benefit from the resource are charged or credited for the

difference between the seller's offer price and the clearing price. PJM asserts that this provision recognizes that multi-year price assurances can provide an appropriate incentive not only to encourage a new plant but also to retain an existing plant, as the grid benefits from preventing the loss of a megawatt of capacity just as it benefits from the gain of a megawatt of capacity, and that it also ensures comparable treatment (along with the New Entry Price Adjustment) for all substantial investments in new or existing plant.

164. Finally, RPM requires all generation qualifying as capacity resources in the PJM region to be offered into the RPM auctions, subject to certain specified exceptions. Since the capacity product in PJM is unforced capacity, the amount of capacity that must be offered depends on the average forced outage rate (Equivalent Demand Forced Outage Rate or EFORD) used to convert installed capacity into unforced capacity. In addition, RPM allows sellers in price-capped areas to include an element in their mitigated offers that reflects the risk of possible changes in their resource's average forced outage rate from the time the resource is offered into the Base Residual Auction until the time it begins to provide capacity in the Delivery Year. This element, known as the EFORD Offer Segment, typically is based on the difference between the most recent five-year average EFORD and the most recent single-year EFORD. Sellers may offer this increment of capacity at a price up to Net CONE, thereby, in theory, helping mitigate the risk that the seller may be liable for commitment penalties if its outage rate increases, and unforced capacity decreases, by the Delivery Year.

165. PJM proposes to remove the EFORD Offer Segment, and all provisions that refer to it, from the tariff. PJM also is making a related modification to the must-offer rule. That rule currently requires that the capacity of all existing generation in the PJM region must be offered into the RPM auctions (subject to certain exceptions not relevant here), based on unforced capacity calculated using an EFORD for the twelve months ending on the September 30 preceding the submission of the offer. While eliminating the EFORD Offer Segment, PJM is preserving the flexibility that rule provided sellers to base their offers in part on the difference between the most recent five-year average EFORD and the most recent single-year EFORD. In particular, PJM is revising the must-offer rule to allow sellers to determine their unforced capacity using an EFORD within the greater of the most recent five-year average EFORD and the most recent single-year EFORD.

Protests and Answers

166. The proposed revisions to market power mitigation rules are generally acceptable to most parties. However, some raise concerns about the proposal to eliminate the EFORD Offer Segment and give sellers more flexibility to select an

EFORD measure. Also, some raise concerns about proposed changes to default bids to reflect capital investments.

167. Mirant and PSEG recommend against PJM's proposal to eliminate the EFORD Offer Segment. Dr. Shanker, on behalf of PSEG, argues that the EFORD Offer Segment is a good option that provides an appropriate incentive for a seller to take the risk of supplying capacity beyond what PJM has assumed for its unit for planning purposes.[67] Mr. Stoddard, on behalf of Mirant, concludes that elimination of the EFORD Offer Segment at least should be accompanied by other changes to the must-offer rule that would require a lower limit to the EFORD to prevent sellers from engaging in harmful arbitrage between the Base Residual Auction and incremental auctions. He finds that the current revisions could give sellers an incentive and ability to offer capacity in the Base Residual Auction that will not likely be available with a subsequent buy out of that offer, if necessary, in an incremental auction when prices are lower.[68] Allegheny does not support the flexibility PJM proposes to give sellers in determining the amount of capacity that is subject to the must-offer rules. Instead of choosing between the most recent five-year average EFORD and the most recent single-year EFORD, Allegheny proposes that sellers be allowed to choose an EFORD equal to the greatest of the EFORD measurements from the last five years.[69] Default avoidable cost bids that serve as a market power mitigation bid cap are allowed to reflect the cost of capital investment in a variety of ways depending on the size and purpose of the investment and the expected remaining life of the facility.

168. Constellation Parties, PPL, Dayton, the RPM Load Group, and Mirant raise concerns with several of the proposed changes, although Constellation, PPL, and Dayton are generally supportive. Dayton expresses reservation about the adjustment because it is concerned that new investment might significantly alter the investment life of a project in a way that was not envisioned when the project was originally undertaken, and it finds the possibility inappropriate.[70] Mirant's

---

[67] Affidavit of Roy J. Shanker, Ph.D., at P 103, attachment to PSEG protest filed on January 7, 2009.

[68] Affidavit of Robert B. Stoddard at P 29-31, attachment to Mirant protest filed on January 7, 2009 (Stoddard affidavit).

[69] Comments and Protest of Allegheny Power and Allegheny Energy Supply Company, LLC at 19.

[70] Dayton comments at 15.

witness, Mr. Robert Stoddard, argues that the Commission should reject the lower default values based on longer amortization periods because such a change fails to adequately reflect supplier risk. In his view, for example, risk created by uncertain environmental regulations likely has shortened the remaining useful life of many facilities.[71]

Commission Conclusion

169. We accept PJM's proposed updates to ACR values as provided by the IMM to PJM with supporting detailed spreadsheets subject to additional review by the IMM to make any necessary adjustments consistent with the adjusted CONE values of the February 9 filing. We also accept PJM's proposed revisions to the default bids to account for investment, principally to lower default bids to reflect longer expected remaining life of facilities. The calculation of default bids involves judgment and cost estimates for identified generator types, and we are satisfied that reasonable estimates have been made, especially in light of the fact that any specific generator that finds the applicable default value inadequate may submit unit specific data for the calculation of its default value, at its election.

170. Although points of view differ on the merits of eliminating the EFORD offer segment, we find PJM's proposal to do so reasonable, given that PJM is now allowing sellers to manage risk by selecting their own EFORD measure. We further note that PJM has reduced the risk of penalties. On this basis, we accept the elimination of the EFORD offer segment on the basis that PJM's proposal to eliminate the EFORD segment is just and reasonable.

4.3.2. Reforms to Capacity Commitment and Performance Measurement Provisions and Charges

PJM's Proposal

171. PJM states that it is proposing to change its penalties so as to more closely match penalties to the failure of a capacity resource to perform, in the following ways.

172. Under the current RPM rules, a penalty is imposed on a Capacity Market Seller if it is unable or unavailable to deliver its committed capacity for all or any part of the Delivery Year. The deficient Capacity Market Seller must pay the Daily Deficiency Rate which is currently the greater of: (i) two times the

[71] Stoddard affidavit at 9-11.

weighted average resource clearing price it received in the LDA; or (ii) Net Cost of New Entry in the LDA. The intended purpose of the Daily Deficiency Rate is to provide an incentive for suppliers to ensure that their committed resources are online and operating properly at the start of and during the Delivery Year, and in the event this is not possible, to procure replacement capacity for any deficiencies. PJM states, however, that it views the current penalty (the higher of Net CONE or two times the clearing price) as much larger than necessary to achieve the intended purpose, and believes the penalty can serve as a disincentive to participation in RPM. Therefore, PJM has revised the Daily Deficiency Rate to be the weighted average resource clearing price it received in the LDA plus the greater of 0.20 times such weighted average clearing price or $20/MW-day. By making this revision, a deficient Capacity Market Seller would pay a 20 percent penalty in addition to paying back the capacity payments it has already received as a result of having been awarded such payments through the Base Residual Auction. PJM states that this penalty should still provide a sufficient incentive to sellers to meet their capacity obligations.

173. In other changes, for purposes of the Peak-Hour Period Availability Charge in section 10 of Attachment DD, PJM proposes that the outage rate for resources that run fifty hours or less during peak periods shall be the lower of the resource's outage rate considering the full year and its outage rate considering only the peak hours. PJM also is revising section 10 to broaden the definition of resources that can be relied upon as replacement resources when a seller's unit faces peak-hour outage concerns.

174. PJM also proposes to revise the Demand Resource and ILR Compliance Penalty Charge, to permit a market participant to net the performance of all Demand Resources and ILR it commits in a single zone for purposes of determining whether it has met its capacity obligations in response to a load reduction request by PJM dispatchers. PJM also is revising the details of the penalty charge calculation to weight the charge by a factor equal to one divided by the number of load management events called during the year (but no greater than 0.50), and to define a Weighted Annual Revenue Rate for each provider. PJM also is adding, as new section 11A, a Load Management Test Failure Charge. PJM states that this provision places demand resources on a comparable basis to generation resources, which are subject to annual ratings tests, and penalties for failing to provide committed capacity levels. PJM also is making changes to several of the commitment and performance charge provisions to ensure consistency among those provisions. Many of those provisions state that, if a resource is not expected to perform, the seller that committed that resource may avoid penalties if it commits replacement capacity. Some of those provisions state that the replacement capacity must meet the same locational requirements as the replaced capacity, but some do not. PJM's intent always has

been that replacement capacity must satisfy the same locational requirements; accordingly, PJM is adding this clarification to section 8.1, concerning the Capacity Resource Deficiency Charge, section 9(b), concerning the Peak Season Maintenance Compliance Penalty Charge. PJM also is adding to section 9(d) language detailing the method to determine the quantity of capacity a seller has committed, similar to the language used for the same purpose in sections 7(b) and 8.1.

175. The February 9 filing makes minor amendments to the proposal. PJM seeks to amend the Load Management Failure Test Charge, above, by clarifying the procedures for testing and retesting load management capability and providing that any charge under such section shall be assessed daily and billed monthly, subject to any lump charges that may be required from the start of a Delivery Year to the date a load management test failure is initially assessed.

Protests and Answers

176. There is broad support for PJM's proposed changes to penalties. However, demand response providers such as ClearChoice and EnergyConnect raise several objections. They object to the penalty provision applying to the 2009-2010 Delivery Year. They argue that marketing activities pertaining to that year were based on previous rules and changing them now amounts to a "bait and switch." They emphasize that the Commission's guidance to modify RPM also focused on the 2012-2013 Delivery Year, not 2009-2010. Finally, if the Commission does not reject the proposed penalty provisions, it should at least defer their applicability to the 2010-2011 Delivery Year and cap the penalties for load management test failure at 100 percent of the revenues. The RPM Load Group also suggests several minor modifications. They recommend clarifying language that states a load management event between June 1 and September 30 should be a sufficient substitute for a physical testing requirement, which they believe is the intent. The also recommend that the selection of EFORD or another type of outage measurement, the RPM Peak Hour Availability Metric (EFORp), should be made for a four year period to prevent gaming. The PJM States and Mirant raise a concern that the proposed penalties are not strict enough for demand resources. They point to the fact that if a demand resource fails to respond in a year with only one load management event, the resource would still receive 50 percent of its revenues, an outcome that should not be allowed and that is not consistent with the Brattle Report recommendation.

177. PJM defends its penalty provisions as reasonable and offers certain clarifications. A demand resource that fails to respond to a load management event would be penalized a percentage based on the number of load management events called in a particular year, specifically the lesser of 50 percent or 1 divided by the number of load management events called for the year. PJM notes that

although this change makes demand resources more comparable to generation resources, it does not make them completely comparable. A generation resource that does not make committed capacity available faces a non-performance penalty of approximately 120 percent.

178. PJM is also adding a testing requirement and test failure charges for demand resources that apply only when no load management events are called during the summer season in a particular zone. A testing failure charge equal to the Weighted Annual Revenue Rate for all its resources in the zone, plus the greater of 20 percent times that rate or $20/MW-day, will be applied to any shortfall between the tested level and the committed level. PJM also responds that it is willing to provide alternative testing arrangements in certain circumstances, and, if it is acceptable to the Commission, to submit changes to section 11 A in a compliance filing in this proceeding. PJM also describes how its physical testing procedures allow the provider to choose its testing time within stated parameters so that disruption to end-use load is not a burden.

179. Finally, PJM emphasizes that implementation of the penalty provisions should not be delayed. All agree that the current rules are inadequate and create a counter-productive incentive for reliability. However, PJM has agreed to extend the certification date for ILR for the 2009-2010 Delivery Year from March 2 to May 1, 2009 to ease uncertainty to providers and will formally request a waiver of its tariff to enable this extension.

Commission Conclusion

180. The Commission accepts PJM's proposed changes to the penalty structure. We note, in particular, that the new netting provisions will benefit resources by giving them an opportunity to avoid penalties that they did not have before. We find that PJM's proposed changes improve the comparability between demand response and generation resources, as the Brattle Report suggested.

181. We reject the argument of ClearChoice Energy and others that the new penalty structure should be deferred for one year because their marketing activities were based on previous rules. Any entity that chooses to take on forward obligations in a regulated market is on notice that the regulatory structure may change. Furthermore, PJM has also agreed to make certain accommodations with regard to certification which we find reasonable.

4.3.3. **Elimination of Minimum Offer Price Rule**

PJM Proposal

182. PJM's Tariff, Attachment DD, section 5.14 lays out a rule for mitigating new entry by participants with the incentive and ability to depress market clearing capacity prices below the competitive level. Similar types of mitigation measures have also been adopted for capacity markets in NYISO and ISO-NE. These mitigation measures recognize that states may have the incentive and ability to encourage or require their regulated utilities or others to acquire new capacity that could not be supported by market-based revenues alone, require retail out-of-market payments to support such investment, offer the capacity into the market as a price-taker, and thereby depress market-clearing prices received by other at-risk existing suppliers. The basic framework for preventing this anti-competitive behavior is to establish minimum offer prices for such new capacity.

183. The February 9 filing proposes to eliminate the Minimum Offer Price Rule and instead give responsibility to the IMM to determine whether a seller's new generation resource offer constitutes an exercise of market power. The IMM must determine whether (a) the seller's offer would result in a significant decrease in the price, compared to the price that would otherwise have resulted from a competitive offer; (b) the seller has an incentive to reduce the RPM auction price; and (c) such offer is an attempt to exercise market power. If the IMM concludes that these standards are met, it is required to report the determination to PJM, which is then required to apply to the Commission on an expedited basis for appropriate relief. PJM will then delay clearing the auction pending the Commission's decision.

184. PJM states that this mechanism will replace the current complex formula contained in the Minimum Offer Price Rule.

Protests and Answers

185. Parties representing sellers that commented on the MOPR updates proposed in the December 12 filing (PPL Companies, Mirant, the PJM Power Providers, and PSEG) are supportive of the changes and recommend that the Commission adopt the proposed values provided by the IMM. In contrast, the Pennsylvania Commission and the RPM Load Group suggest that the Commission reject the updated values and eliminate the MOPR from PJM's Tariff. The Pennsylvania Commission, in particular, claims that the MOPR only serves to protect incumbent suppliers from competition, although Mirant and PSEG disagree with this view. In addition, the PJM Power Providers respond that arguments to eliminate the MOPR are a collateral attack on the Commission's order accepting the RPM mechanism and should be rejected.

186. The IMM supports the February 9 filing on condition that the Tariff be modified to explicitly require that an IMM determination that a seller was attempting to exercise market power require PJM to make a filing with the Commission and postpone clearing the auction pending the Commission's decision. Furthermore, the IMM conditioned its support on the understanding that the role envisioned for the IMM in the February 9 filing is acceptable under Order No. 719. The IMM notes, however, that the MOPR has not been triggered and criticized it as a complex rule that does not assure that actual attempts to exercise market power would be correctly identified or that attempts to exercise market power would not be correctly identified.[72] Exelon agrees with Dr. Bowring and would support elimination of the MOPR with the stated conditions. Exelon does not agree that a future compliance filing under Order No. 719 could change the IMM's authority in this matter. The Indicated PJM States also support the IMM's position and do not oppose the proposed replacement procedure on an interim basis. The Indicated Asset Owners and Resource Providers, EPSA, the Mirant Parties, and PSEG object to the elimination of the MOPR as not just and reasonable. They point to the Commission's previous determinations in various orders that uneconomic entry can undermine reliability and discourage private investment and that the MOPR was a reasonable method of preventing net buyers from exercising market power to depress price below a competitive level.

187. Mr. Stoddard, witness for the Mirant Parties, disputes the IMM's contention that the fact that the MOPR has not been triggered is an indication that it is ineffective. He argues that this observation could equally support the view that the MOPR is effective at deterring uneconomic entry. Furthermore, he notes that complexity does not render a rule unjust or unreasonable. Finally, Mr. Stoddard finds that Dr. Bowring has not supported his claim that the MOPR fails to correctly identify attempts to exercise market power.

188. Indicated Asset Owners emphasize that the replacement MOPR violates the Commission's prohibition on tariff provisions that give market monitors excessive discretion. They contrast the February 9 filing's provisions that give total discretion to the IMM with the Commission's requirement in the Original RPM Settlement to replace discretion with "objective factual criteria to be used by the Market Monitor in reviewing bids." As an example, they point to section 6.6 (g) of Attachment DD which addresses seller market power and that requires a specific five percent price effect to trigger mitigation and contrast that with the

[72] Attachment E to February 9 filing, Affidavit of Joseph E. Bowring at P 4.

proposed MOPR allowing the IMM to decide alone what constitutes a significant price effect.

189. PSEG similarly objects to the proposed replacement of MOPR and offers Dr. Shanker's previous testimony demonstrating the necessity of preventing the exercise of market power by depressing market clearing prices as critical to the long-term viability of the electricity markets.

Commission Conclusion

190. The Commission rejects the provision in the February 9 filing to eliminate the MOPR provisions, because PJM provides no justification for providing the IMM with unfettered discretion to determine whether an offer violates the MOPR. As we stated in previous RPM orders,[73] to provide needed certainty to all participants, PJM must provide objective tariff provisions that will determine when mitigation measures will be applied, including application of the MOPR rule.

191. The Commission has previously expressed concern that uneconomic entry can be used by certain buyers to depress market clearing capacity prices and has authorized MOPR-type rules in both NYISO and ISO-NE. For example, in an order issued on March 7, 2008, regarding NYISO's ICAP market, we found, among other things, that NYISO's proposal would "prevent net purchasers from artificially depressing capacity prices with uneconomic generation."[74] NYISO's mitigation measures entail use of a minimum offer price floor of 75 percent of Net CONE with the option to support an exemption if NYISO determines that a new entrant's costs are lower.[75] The elements of PJM's MOPR have a similar framework for identifying those entities subject to the MOPR and applying a price floor.

192. Because we have accepted PJM's revised CONE figures, PJM's existing tariff is therefore retained, but with updated values that reflect our acceptance of the revised CONE. PJM is required to make a compliance filing within 30 days of this order, to reflect the revised figures.

---

[73] *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331, at P 115.

[74] *New York Independent System Operator*, 122 FERC ¶ 61,211, at P 1 (2008).

[75] *Id*. P 87-88.

4.4. **Load Forecast for May 2009 Auction**

193. The Public Power Association of New Jersey, the Blue Ridge Power Agency, and the Pennsylvania Commission (Protesting Parties) seek immediate relief under section 206 to authorize PJM to revise in late March 2009 the peak load forecast that will be used to determine the amount of capacity to be procured in the May 2009 Base Residual Auction. The Protesting Parties also request the Commission to instruct PJM to institute a stakeholder process to further review the forecast and to use the technical conference that was previously planned for February 2009[76] to further study the load forecast to determine whether changes are needed.

194. According to the protesters, their witness, Mr. James Wilson, tentatively concluded that PJM's draft peak load forecast value for 2012 "may fall outside of a range of reasonable values that is very wide at the present time, in light of uncertainties about the economy and also recent trends in electricity demand." Mr. Wilson asserts that the economic forecast used by PJM for 2012 is much higher than the consensus forecast, and is even higher than the average of the ten highest forecasts, in Aspen Publishers' survey of professional forecasts. Wilson estimates that inserting the Blue Chip consensus forecast into PJM's load forecast model would reduce the forecast peak load for 2012 by approximately 3,000 MW.

195. The Protesting Parties therefore argue that allowing revision of the load forecast in March 2009 does not create uncertainty about the upcoming auction that does not already exist, since PJM has already requested an order by March 27, 2009, and so many aspects of RPM's design and parameters will remain uncertain until that date, including some that have the exact same impact as a change in the load forecast. In this regard, they note, in particular, PJM's proposal to plan to procure 2.5 percent of the reliability requirement in the incremental auctions rather than the Base Residual Auction. The protesters further note that PJM officials have repeatedly stated that they intend to continue to re-run the forecasting model during Spring 2009 as revised economic forecasts are received; therefore, revised forecasts will exist, and so the question is whether these, rather than out-of-date forecasts, will be used.

196. PJM responds that there is no basis for requiring a change to, or delay in, PJM's peak load forecast. It states that the PJM Tariff requires PJM to post its

---

[76] In a notice issued on February 18, 2009, the Commission postponed the technical conference.

peak load forecast for a Delivery Year no later than February 1 of the calendar year in which the Base Residual Auction is held for that Delivery Year. PJM argues that the peak load forecast and other major auction parameters are posted three months before the auction to enable other decisions, actions, and postings over the course of the three months leading up to the Base Residual Auction, each step building on the one that comes before so that all needed information is posted, and all needed actions by PJM, the IMM, and market participants are completed, before the auction is held.[77]

197. PJM states that the Commission should not grant the protesters' request because, as even the Protesting Parties admit, PJM did not submit its peak load forecast as part of the December 12 filing, nor was it required to do so by the September 19 Order, and, therefore, the protest is beyond the scope of this proceeding and should be rejected as procedurally improper. Furthermore, PJM asserts, the Protesting Parties' allegations that its 2012-2013 peak load forecast is overstated do not withstand scrutiny, and there is therefore no reason to delay posting of the peak load forecast and disrupt the capacity auction preparations. PJM also asserts that its load forecast is reasonable.

198. PJM argues that the Protesting Parties' request that the Commission direct PJM to set the load forecast only one month before the May 2009 Base Residual Auction would have a significant adverse effect on necessary preparations by PJM, the IMM, and market participants, for the conduct of the Base Residual Auction. According to PJM, the PJM Tariff requires a number of crucial parameters to be posted by February 1, including peak load and other parameters affected by the peak load forecast such as the CETO. PJM explains that CETO calculations in turn determine the locational deliverability areas that will have separate demand curves for the Delivery Year, among other issues. Furthermore, several other actions and postings, including the IMM's determination of results under the Preliminary Market Structure Screen, accompany or follow the posting of peak loads, and rely on the forecast. According to PJM, the IMM posting, three months before the auction, is followed by the deadline, two months before the auction, for prospective sellers to provide their cost and other information to the IMM for purposes of offer-capping, and that deadline is followed, in turn, by the deadline (one month before the auction)

[77] PJM notes that, in compliance with this requirement, PJM posted on January 30, 2009, its peak load forecast for the 2012-2013 Delivery Year, for which the Base Residual Auction will be held in May 2009.

by which the IMM must provide the calculated offer caps. Similarly, PJM's posting of the fundamental auction parameters on February 1 is an important precondition for parties to make decisions regarding bilateral contracts, capacity imports or export, and the manner in which they participate in the Base Residual Auction.

199. In response to the protesting parties, PJM Power Providers Group argues that (a) there is no justification for changing the timing of PJM's load forecast, (b) the issue is outside the scope of the instant filing, and (c) the parties have not shown that a section 206 investigation is warranted. The Illinois Commerce Commission states that the protest has merit and urges the Commission to consider the protesters' arguments and condition action on the February 9 filing's statement regarding the load forecast accordingly.

Commission Conclusion

200. We decline to initiate a section 206 proceeding at this time to examine the load forecast issue, particularly given the short time period to act on this filing. We agree with PJM that, in the current RPM construct, several market parameters are critically dependent on the load forecast being available to market participants and the IMM three months prior to the auction. It will therefore be disruptive to the market to change the forecast only one month before the auction. Further, we are not convinced that the PJM load forecast is so unreasonable as to warrant such disruption of the market. Protesting Parties can pursue this goal through the stakeholder process that is already addressing this issue.[78]

The Commission orders:

(A) The Commission hereby accepts PJM's report filed on December 12, 2008.

(B) With regard to the tariff provisions filed in Docket Nos. ER09-412-000 and ER09-412-001, the Commission accepts the following provisions, as discussed above: determination of CONE, determination of the EAS offset, revisions to the incremental auctions and ILR provisions, use of bright line tests for transmission upgrades, use of a 115 percent CETL/CETO ratio for VRR curves for separate LDAs, PJM's proposal regarding EE resources, new types of

[78] This issue is already under discussion in the PJM stakeholder process (Load Analysis Subcommittee -- see http://www.pjm.com/committees-and-groups/subcommittees/las.aspx).

capacity, mitigation provisions and elimination of the EFORD offer segment, and changes to penalties.

(C) With regard to the tariff provisions filed in Docket Nos. ER09-412-000 and ER09-412-001, the Commission rejects the following provisions, as discussed above: determination of Net CONE for the rest of market, economic scheduling, and revisions to the NEPA rule.

(D) We direct PJM and its stakeholders to address the concerns raised by stakeholders with regard to calculation of scarcity pricing revenues and automated adjustment procedures for CONE in its stakeholder process and file revised tariff provisions, if necessary, in time for the May 2010 auction.

(E) With regard to the 2.5 percent hold-back for short lead time resources, we will require PJM to make a filing implementing this revision, and also revising sections 5.4, 5.10, and 5.12 of its tariff to clarify and render consistent its procedures for determining whether and how it would secure additional commitments of capacity, or allow sellers to buy out of their prior capacity commitments, based on an update of the regional and LDA reliability requirements, and capacity held back from the Base Residual Auction for short-lead-time resources, before each of the three scheduled incremental auctions. PJM is required to make this filing by September 1, 2009, whether as part of the section 205 filing that PJM is planning to make on other issues by that date, or as a separate filing in compliance with this directive.

(F) With regard to PJM's revisions to its tariff to permit new types of capacity to participate in RPM, we will require PJM, within 30 days, to make a compliance filing adding language to section 3.1 of Attachment DD that addresses the IMM's concern, by ensuring that an owner who plans to transfer ownership or control during the Delivery Year is required to satisfy the must offer requirement for the entire Delivery Year but that this obligation can be met by providing for the assumption of this commitment by any transferee of ownership/control in the relevant agreement.

(G) We will also grant the request for a 12-day extension deadline for submitting the M&V plans by the EE resources. PJM must make a compliance filing within 30 days to implement this change.

(H) We will require PJM, within 30 days, to update its tariff provisions with regard to the MOPR values.

(I) We grant PJM's request, in the February 9 filing, for a waiver of the provisions of the PJM Tariff so as to enable Load Serving Entities to obtain certification by May 1, 2009 (rather than March 2, 2009) of the load management capability that such Load Serving Entities seek to qualify as ILR for the 2009-2010 Delivery Year.

(J) The motions for summary relief by ClearChoice and EnergyConnect are denied, in light of the resolution PJM has offered to address the concerns raised in those motions.

By the Commission.

(S E A L)

Kimberly D. Bose,
Secretary.

Appendix

The following parties filed (a) motions to intervene or Notices of Intervention, (b) protests or comments, or (b) reply comments or answers in Docket Nos. ER05-1410-000; -010; -011; -012; EL05-148-000; -010; -011; -012; and ER09-412-000 and -001.

Allegheny Electric Power Cooperative, Inc.

Allegheny Power and Allegheny Energy Supply Company (Allegheny)

American Electric Power Service Corporation (AEP)

American Municipal Power - Ohio

American Public Power Association

Baltimore Gas and Electric Company (BG&E)

Blue Ridge Power Agency

Borough of Chambersburg, Pennsylvania

ClearChoice Energy

Commonwealth Chesapeake Company, LLC

Comverge, Inc.

Consolidated Edison Energy, Inc. and Consolidated Edison Energy Solutions (Con Ed)

Constellation Energy Commodities Group, Inc. and Constellation NewEnergy, Inc. (Constellation)

CPower, Inc.

CPV Maryland, LLC

Dayton Power and Light Company

Dominion Resource Services (Dominion)

Duke Energy Ohio, Inc. (Duke Energy)

Duquesne Light Company

Dynegy Power Marketing, Inc. (Dynegy)

East Coast Power, LLC

Edison Mission and IPA Central, LLC

Edison Mission Marketing and Trading, Inc.

Electricity Consumers Research Council

Electric Power Supply Association (EPSA)

EnergyConnect, Inc.

EnerNOC, Inc.

Exelon Corporation (Exelon)

FirstEnergy Service Company (FirstEnergy)

FPL Energy (FPL)

Hess Corporation

Illinois Municipal Electric Agency

Indicated Asset Owners

Indicated PJM States

Integrys Energy Services, Inc.

IPA Central, LLC

J. P. Morgan Energy Ventures Corporation

Liberty Electric Power, LLC

Long Island Power Agency (LIPA)

LS Power Associates

Macquarie Cook Power, Inc.

Maryland Office of People's Counsel (MPC)

Mirant Parties (Mirant)

Monitoring Analytics, Inc. (the Independent Market Monitor for PJM)

North Carolina Electric Membership Corporation

NRG Companies

Old Dominion Electric Cooperative (ODEC)

Pennsylvania Department of Environmental Protection

Pennsylvania Office of the Consumer Advocate

Pepco Holdings, Inc

PJM Industrial Customer Coalition (PJMICC)

PJM Power Providers Group

Project for Sustainable FERC Energy Policy/Public Interest Organizations (PIOs)[79]

Public Power Association of New Jersey

PPL Companies

PSEG Companies (PSEG)

EnergyConnect, Inc.

Reliant Energy (Reliant)

Rockland Electric Company

---

[79] Project for Sustainable FERC Energy Policy, American Council for an Energy Efficient Economy, California Wind Energy Association, Citizen Power, Citizens Utility Board of Illinois, Conservation Law Foundation, Delaware Division of the Public Advocate, Energy Consumers Alliance of New England, Environmental Law and Policy Center, Fresh Energy, Friends of the Earth, Institute for Market Transformation, Maryland Energy Administration, National Association of Energy Service Companies, Natural Resources Defense Council, Northeast Energy Efficiency Partnerships, Inc., PennFuture, and Union of Concerned Scientists.

RPM Load Group[80]

Southern Maryland Electric Cooperative, Inc.

Steel Producers

Shell Energy North America

Tenaska, Inc.

State Commissions:

Illinois Commerce Commission (Illinois Commission)

Indiana Utility Regulatory Commission (Indiana Commission)

New Jersey Board of Public Utilities (New Jersey Commission)

Pennsylvania Public Utility Commission (Pennsylvania Commission)

Public Service Commission of Maryland (Maryland Commission)

Public Utilities Commission of Ohio (Ohio Commission)

[80] ODEC; PJMICC; Allegheny Electric Cooperative, Inc.; Southern Maryland Electric Cooperative, Inc.; Borough of Chambersburg; Duquesne Light Company; Public Power Association of New Jersey; Blue Ridge Power Agency; Pennsylvania Office of Consumer Advocate; American Municipal Power — Ohio, Inc.; MD OPC; North Carolina Electric Membership Corporation, Pennsylvania Department of Environmental Protection; ArcelorMittal USA, Inc.; Portland Cement Association; and New Jersey Division of Rate Counsel.