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September 29, 2006

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FEDERAL ENERGY
REGULATORY COMMISSION

2 of 4

Honorable Magalie R. Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E. Room 1A
Washington, D.C. 20426

Re: Settlement Agreement and Explanatory Statement of the Settling Parties Resolving All Issues in PJM Interconnection L.L.C., Docket Nos. ER05-1410-000 and -001, and EL05-148-000 and -001

Dear Ms. Salas:

PJM Interconnection, L.L.C. ("PJM"), pursuant to Rule 602 of the Commission's Rules, submits for filing, on behalf of itself and the parties listed in the enclosed Settlement Agreement (collectively "Settling Parties"), an original and 14 copies of the settlement documents described below.

I. Description of the Filing

The Settlement Agreement filed herein resolves all issues regarding the implementation by PJM of a reliability pricing model ("RPM") to replace PJM's existing capacity obligation rules, without the need for an evidentiary hearing or further proceedings. Therefore, the Settling Parties respectfully request that the Commission approve the Settlement Agreement, including the enclosed revised sheets of the PJM Open Access Transmission Tariff ("PJM Tariff"), PJM Operating Agreement, and the enclosed new Reliability Assurance Agreement for the PJM Region ("RAA"), as set forth in Attachments A through F to the Settlement Agreement.

II. Documents Enclosed

The Settling Parties submit the following settlement materials:

1. Explanatory Statement, including appendices containing supplemental affidavits of Mr. Andrew L. Ott, Mr. Joseph E. Bowring, and Mr. Benjamin F. Hobbs, on behalf of PJM; Mr. Paul Williams, on behalf of the Portland Cement Association; and Mr. Robert Stoddard, on behalf of Mirant.

2. Settlement Agreement, including appendices containing revised sheets to the PJM Tariff, Operating Agreement and RAA;

3. Proposed Letter Order; and

4. Certificate of Service.

III. Comment Dates

Pursuant to Rule 602(f)(2), comments on the Settlement Agreement must be filed with the Secretary within 20 days of the filing of the settlement, i.e., on or before October 19, 2006, and reply comments must be filed with the Secretary within 30 days of such filing, i.e. on or before October 30, 2006.

IV. Request for Review and Waiver

The Settlement Agreement provides that the RPM construct shall replace PJM's current capacity construct beginning on June 1, 2007, which is the first day of the next annual Delivery Year under the new capacity rules. To permit this implementation date, PJM must conduct the Base Residual Auction for the 2007-2008 Delivery Year in April 2007; therefore, PJM and the market participants must begin to implement the necessary systems and business practice changes as soon as possible. To that end, the Settling Parties are asking the Commission to approve the Settlement Agreement by December 22, 2006. To the extent necessary, waiver of the Commission's notice requirements is requested.

V. Service and Request for Waiver of Posting Requirements

Pursuant to Rules 602(d) and 2010 (18 C.F.R. §§ 385.602(d) & 2010), PJM has served, either by paper or electronic service, the settlement documents listed in section II above, on all the parties listed on the official service list compiled by the Secretary in this proceeding, all PJM members, and all state commissions in the PJM Region.

With regard to service on the PJM members and the state commissions, PJM requests waiver of the posting requirements, so as to permit electronic service rather than paper service. Waiver of paper service is consistent with the Commission's decision to establish electronic service as the default method of service on service lists maintained by the Commission Secretary for Commission proceedings.[1] While Order No. 653 did not amend the posting requirements, application of its rules to tariff filings would be consistent with the Commission's "efforts to reduce the use of paper in compliance with the Government Paperwork Elimination Act."[2] Applying amended section 385.2010(f) to

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1 See Electronic Notification of Commission Issuances, Order No. 653, 110 FERC ¶ 61,110 (2005).

2 Id. at P 2, citing 44 U.S.C. § 3504.

this filing, PJM will post this filing today to the FERC filings section of its internet site, http://www.pjm.com/documents/ferc.html, and send an e-mail to all PJM members and all state utility regulatory commissions in the PJM Region[3] alerting them that this filing has been made by PJM today and is available by following such link. Within one business day, PJM will send a second e-mail to the same list, containing a link that takes the recipient directly to the filed document.[4]

Respectfully submitted,

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Encl.
cc: Service List

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3 PJM already maintains, updates, and regularly uses e-mail lists for all Members and affected commissions.

4 PJM anticipates that in unusual circumstances, it may not be possible to post the document to its website on the day of filing, or to distribute an active link to the document within one business day. Consistent with §385.2010(i)(3), if a link to the document does not become available within two business days after filing, PJM will arrange for immediate service by other means.

PJM Interconnection, L.L.C.
Docket Nos. EL05-148 and
ER05-1410
September 29, 2006

Attachment B
Supplemental Affidavit of
Joseph E. Bowring

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM INTERCONNECTION, L.L.C.	)	**Docket Nos. ER05-1410-000 and EL05-148-000**

SUPPLEMENTAL AFFIDAVIT OF JOSEPH E. BOWRING
ON BEHALF OF PJM INTERCONNECTION, L.L.C.
ON SETTLEMENT AGREEMENT

My name is Joseph E. Bowring and I am the PJM Market Monitor. My business address is 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19403. Since March 1999, I have been responsible for the market monitoring activities of PJM, as defined by the PJM Market Monitoring Plan, Attachment M to the PJM Open Access Transmission Tariff. I am a Ph.D. economist and have substantial experience in applied energy and regulatory economics. I have taught economics as a member of the faculty at Bucknell University and at Villanova University. I have served as a senior staff economist for the New Jersey Board of Public Utilities and as Chief Economist for the New Jersey Department of the Public Advocate's Division of Rate Counsel. I have also worked as an independent consulting economist.

I previously submitted an affidavit in this proceeding to explain and support several aspects of PJM's August 31, 2005 initial filing on its proposed Reliability Pricing Model ("RPM"). I am submitting this Supplemental Affidavit to explain and support several changes to PJM's initial filing effected by the September 29, 2006 Settlement Agreement ("Settlement") in this proceeding. In particular, in this affidavit, I will:

- explain that the revised methodology used in RPM to calculate the net energy and ancillary services revenue offset is consistent with the objectives I described in my prior affidavit both for the calculation of Net CONE and the calculation of offer caps for specific units; and

- explain why identified, revised portions of the market power mitigation rules included in the settlement are consistent with the objectives I described in my prior affidavit.

I. Net Energy and Ancillary Services Revenue Offset Against the Cost of New Entry

RPM uses a variable resource requirement curve ("VRR Curve") to represent the demand side in each RPM auction market. The cost of new entry ("CONE") for a combustion turbine ("CT"), net of the revenues such a unit would receive in the energy and ancillary services markets ("Net CONE"), is a key parameter of the VRR Curve and therefore of the maximum price that will be paid for capacity under various supply conditions.

If a new unit is to recover all of its costs from the PJM markets in equilibrium, the unit needs to recover from the capacity market only those costs not recovered in the other PJM markets. A competitive offer price in the RPM market for a new CT for its first year of operation equals the total annual fixed costs of the CT, less expected net revenues from all other sources. This is the incremental cost of new capacity. Accordingly, the CONE value must be reduced by an amount equal to the revenue a new CT can expect to receive from the PJM energy and ancillary services markets, less the variable expenses incurred to obtain those revenues ("revenue offset").

Net revenue, as applied in the RPM context, is the contribution to fixed costs received by generators from PJM energy and ancillary services markets.[1] Gross energy market revenue is the product of the energy market price paid for the output and the generation output. Gross revenues are also received from ancillary services markets. Net revenue equals total gross revenue less variable operating costs.

The RPM proposal relies on a formula to determine this revenue offset amount for the Reference Resource. The revenue offset is based on the operating parameters of the same resource on which the CONE is based. The CONE is based on the GE Frame 7FA combustion turbine and the net capacity and net heat rate of this Reference Resource are used to calculate revenue offset values based on historical data from defined time periods.

The Settlement modifies the initial RPM filing and uses the following to define the historical time period used to calculate the net revenue offset for CONE: "For each of the first three Delivery Years of the Transition Period, such determination shall be based on the six consecutive calendar years preceding the relevant BRA. For any subsequent Delivery Year, such determination shall be based on the three consecutive calendar years preceding the relevant BRA." The change is that the initial RPM filing included the use of a six year period for all auctions.

The revenue offset calculation is used in RPM auctions that will determine capacity prices for Delivery Years three years in the future. The objective in the revenue offset calculation is to get the incentives right both for investors in generation and for load that will purchase capacity. Given that net revenue is calculated based on historical data, the choice is among possible numbers of years and annual weights. Investors are making decisions about constructing capacity based on expectations of energy revenues for the economic life of the facility. Thus investors are unlikely to build a unit based on

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1 The net revenues calculated in the Market Monitoring Unit's PJM State of the Market Report include capacity market revenues. Such revenues are not included here as the goal is to determine a competitive offer price in the capacity market for new entry after accounting for net revenues from all the markets except the capacity market.

the expectation that the last one or two years of net revenues represents future net revenues, *especially in light of actual historical net revenue fluctuations.*

I conclude that the use of a rolling three-year simple average of net revenues for the Reference Resource for the revenue offset calculation beginning after the third Delivery Year will reasonably meet the stated objective.

Nonetheless, neither PJM nor investors can perfectly predict net revenues for the operating year. One goal in calculating both the CONE and the revenue offset is to define a reasonable measure of the competitive cost of new entry while leaving room for competitive forces to actually determine the clearing price in the capacity auctions, subject to the constraint of the VRR Curve. If actual competitive participant offers are less than the estimated Net CONE, the clearing price will be lower than the Net CONE and if actual competitive participant offers are greater than the estimated Net CONE, the clearing price will be higher than the Net CONE.

Another goal of calculating the revenue offset is to provide a mechanism for equilibrating the results of the energy markets and the capacity market. If the revenue offset is high, the competitive offer price for new entry will decline correspondingly as will the Net CONE. The reverse is also true. In the absence of such an equilibrating mechanism, there is a risk that total payments from all markets could exceed or fall short of the incentives consistent with resource adequacy. In addition, such an equilibrating mechanism provides a disincentive to the exercise of market power in the energy market. If market power is exercised in the energy market so as to increase prices and net revenues, this mechanism would reduce the capacity market price correspondingly but the impact would be attenuated by the inevitable differences between the historical average revenue offset and actual delivery year results.

The revenue offset formula in the filing calculated energy market revenues using a "perfect dispatch" approach. The perfect dispatch approach assumes that a unit will operate whenever the LMP is greater than the marginal costs of the unit (fuel plus variable operation and maintenance expense). This is the simplest approach and does not take account of operating constraints like minimum run times and other similar constraints. The Settlement uses the "peak-hour" approach, also presented in my prior Affidavit, which explicitly accounts for such operating constraints for the Reference Resource. This approach produces a more refined estimate but also requires a number of detailed assumptions about how the unit would run. The relevant assumptions, as presented in my prior Affidavit, are included in the Settlement.

I conclude that the peak-hour approach, as adopted, will provide a more accurate measure of net revenues than the perfect dispatch approach and thus provide a more accurate VRR.

The same time periods identified for the revenue offset formula will be used in the determination of offer caps for individual units. However, actual net revenues for specific units will include all relevant sources of revenue depending on the unit. The actual net revenues will include, as appropriate, revenues from energy markets, ancillary services markets and operating reserves credits as well as from bilateral contracts.

I conclude that it is reasonable to apply the defined time periods from the Settlement to the calculation of actual net revenues for actual units to be used in the calculation of unit-specific offer caps. This will ensure consistency between the determination of the VRR, resultant market prices and the projected revenues for individual units.

II. Market Power Mitigation Rules

RPM includes explicit rules governing market power mitigation in the capacity market. This is an important benefit of the RPM proposal, as PJM's existing capacity market does not include explicit market power mitigation rules. As I have concluded in the 2005 and prior State of the Market Reports, market power is endemic to the current capacity market design, yet there are no explicit rules limiting the exercise of market power in the capacity market. Given that, all else equal, RPM will increase market power, e.g through the creation of smaller, regional or LDA-based (Locational Deliverability Area) capacity markets, this explicit set of market power mitigation rules is central to the RPM construct. The RPM mitigation rules are required to make the RPM construct produce competitive outcomes. At the same time, the RPM market power mitigation rules are designed to minimize intervention in the capacity markets and to explicitly permit scarcity pricing as described in my prior Affidavit.

I will address the following changes to Section 6 of the RPM rules in proposed Attachment DD to the PJM Tariff, which contains the proposed market power mitigation rules for RPM:

- Detailed application of the three pivotal supplier test;
- Definition of the competitiveness of new entry;
- Revised data submission requirements;
- CRF table modifications.

A. Three Pivotal Supplier Test

Consistent with the Commission approved test currently applied to the energy market, the market structure test uses the three pivotal supplier test. The exact method of defining the three pivotal supplier has been modified to conform with that currently applied by PJM in the energy market, consistent with PJM's statement in the RPM filing. Two changes to the filed RPM are the removal of references to net supply and the use of a market definition based on 150 percent of the clearing price.

I conclude that this is the appropriate way to apply the three pivotal supplier test and the three pivotal test is the appropriate test to apply in the RPM.

B. Definition of the Competitiveness of New Entry

The market power mitigation rules in the RPM filing assumed that new entry would be competitive. The Settlement modifies this assumption at section 6.5(a)(ii) where certain criteria and procedures for evaluating the competitiveness of new entry are specified.

I conclude that these provisions appropriately strengthen the market power mitigation provisions of the RPM while maintaining the incentives for new entry and the ability of competitive new entry to set the clearing price when appropriate.

C. Revised Data Submission Requirements

The Settlement modifies the data submission requirements at section 6.7(c) of Attachment DD. The RPM filing provided that potential participants in any RPM auction in any LDA that failed the Preliminary Market Structure Screen would have to submit specified data to permit calculation of an offer cap if required by the auction clearing results. The Settlement provides that if a unit is in an Unconstrained LDA Group and unlikely to be in a resource class that will set the clearing price, such unit will not have to submit data in the first instance. In addition, if the owner of a unit commits to offer such unit at or less than the defined proxy price for the relevant resource class, such unit will not have to submit data in the first instance. The MMU could require such data submission if the data is required for a complete evaluation of the market. The rationale for such revised data submission requirements is to reduce the data reporting requirements where the resultant data would not change the ability of the MMU to evaluate the competitiveness of the market.

I conclude that the revised data submission requirements do not affect the ability of the MMU to evaluate the competitiveness of any affected auction, especially as the MMU has the ability to obtain such data if it is subsequently determined to be necessary in a particular case.

D. Modified CRF Table in Offer Caps

The Settlement modifies an element of the offer caps in section 6.8 (a) of Attachment DD. In particular the CRF (capital recovery factor) table is modified to include additional options.

The definition of avoidable costs included in the RPM filing provided for the potential that an owner may need to make an incremental investment in a unit in order to maintain it as a capacity resource for the delivery year and for future years. The definition of avoidable costs provides for inclusion of the annual carrying costs of making such an investment (the capital recovery factors). These carrying costs include the return on and of capital including a rate of return and depreciation. The underlying financial model assumptions are identical to those used in PJM's definition of the CONE, with one important exception. The definition of avoidable costs explicitly recognizes that the useful life of a capacity investment in an existing unit is directly related to the age of the existing unit. It can reasonably be expected that an investment in a unit that is 20 years old will have a shorter useful life than an investment in a unit that is 5 years old. The capital recovery factors included in the definition of avoidable costs are therefore calculated on the basis of the age of the unit and therefore the expected remaining useful life. This provides an appropriate incentive to maintain and invest in existing capacity resources.

The Settlement modifies the CRF table by adding two new categories, i.e., the "40 Plus Alternative" category and the "Mandatory Capital Expenditures" Category.

The 40 Plus Alternative category provides for 100 percent recovery of all incremental capital costs in one year, using a CRF of 1.100. This accelerated recovery is provided for units that are either gas or oil-fired and that began commercial operation no less than 40 years prior to the conduct of the relevant BRA (excluding units that are receiving payments under the generation deacitivation provisions of the PJM OATT). Resources electing the 40 Year Plus Option will be modeled in the RTEP process as "at-risk" at the end of the one-year amortization period. The Settlement provides that PJM shall give market participants reasonable notice of such election. Finally, the Settlement caps such offers at the Net CONE.

The Mandatory Capital Expenditures category provides for accelerated recovery of all incremental capital costs. This accelerated recovery is provided for units that must make an incremental investment to comply with a governmental requirement that would otherwise materially impact operating levels during the Delivery Year. In order to qualify a unit must be a coal, oil or gas-fired resource that began commercial operation no fewer than fifteen years prior to the start of the first Delivery Year for which such recovery is sought and the required incremental investment is equal to or exceeds \$200/kW of capitalized project cost. A unit could also qualify if it is a coal-fired unit located in a constrained LDA, began commercial operation at least 50 years prior to the date of the RPM Settlement, and the seller signed the Settlement. Finally, the Settlement caps such offers at .90 times Net CONE.

I conclude that these modifications to the CRF table component of the RPM offer caps are generally consistent with a competitive outcome.

III. Conclusions

It is my overall conclusion that these modifications made to the market power mitigation provisions of the RPM will not materially affect the ability of the MMU to ensure that market outcomes are competitive. The market power mitigation rules do not and cannot guarantee a competitive outcome, but they do provide a critical, tariff-based set of rules that will substantially increase the probability of a competitive outcome. I also conclude that the rules do not inhibit the MMU from monitoring the RPM market, from proposing modifications to the mitigation rules if necessary to prevent the exercise of market power, or from seeking specific mitigating actions from the Commission should the MMU identify a market power issue.

This completes my affidavit.

SS:) Commonwealth of Pennsylvania
)
) County of Montgomery

AFFIDAVIT OF JOSEPH E. BOWRING

Joseph E. Bowring, being first duly sworn, deposes and says that he has read the foregoing "Supplemental Affidavit of Joseph E. Bowring," that he is familiar with the contents thereof, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

/s/ Joseph E. Bowring
Joseph E. Bowring

Subscribed and sworn to before me this 29th day of September, 2006.

/s/ Renee L. Dogariei
Notary Public

My Commission expires: August 25, 2007

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Renee L. Dogariei, Notary Public
Lower Providence Twp., Montgomery County
My Commission Expires Aug. 25, 2007
Member, Pennsylvania Association Of Notaries

PJM Interconnection, L.L.C.
Docket Nos. EL05-148 and
ER05-1410
September 29, 2006

Attachment C
Supplemental Affidavit of
Benjamin F. Hobbs

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C. Docket No. ER05-1410-000 and
and EL05-148-000

SUPPLEMENTAL AFFIDAVIT OF BENJAMIN F. HOBBS
ON BEHALF OF PJM INTERCONNECTION, L.L.C.
ON THE SEPTEMBER 29, 2006 SETTLEMENT CAPACITY DEMAND CURVE

I, Benjamin F. Hobbs, being duly sworn, depose and state as follows:

My name is Benjamin F. Hobbs and I am a Professor of Geography and Environmental Engineering, and of Applied Mathematics and Statistics (Joint Appointment) at the Johns Hopkins University. I previously submitted an affidavit in this proceeding ("August 31 Affidavit") in connection with the August 31, 2005 filing by PJM Interconnection, L.L.C. ("PJM") to establish the Reliability Pricing Model ("RPM"). I also submitted a supplement affidavit on May 30, 2006 in response to the Commission's April 20, 2006 order on the RPM proposal ("April 20 Order"), addressing certain issues concerning the definition and analysis of alternative demand curves for capacity.

The purpose of this supplemental affidavit is to present an analysis of the demand curve agreed upon by the parties in the settlement filed on Sept. 29, 2006 (the "Settlement Curve"), and to discuss the adjustment of the assumed CONE in response to experienced capacity prices.

1. Analysis of the Settlement Curve

Assumptions. The Settlement Curve has been defined for the purposes of this simulation as connecting the following points:

- IRM-3%: 1.5*(72,000 –E/AS offset)/0.93 (in $/unforced MW/yr)
- IRM+1%: 1*(72,000 –E/AS offset)/0.93 (in $/unforced MW/yr)
- IRM+5%: 0.2*(72,000 – E/AS offset)/0.93 (in $/unforced MW/yr)

"IRM" is the installed capacity target of 115%. The "E/AS offset" is the amount that the curve is adjusted for energy and ancillary services gross margins that the benchmark turbine is assumed to be able to earn.[1] The curve to the left of IRM-3% is flat at the indicated price; the price is zero to the right of IRM+5%. All percentages are expressed in terms of the ratio of installed capacity to peak load. The capacity prices are expressed in terms of $/unforced MW/yr; to express these in $/installed MW, the denominator of 0.93—the expected unforced availability of turbines—is removed.

The analysis is based on the same approximating assumption as in the analyses in my August 31, 2005 and May 30, 2006 affidavits concerning the E/AS offset used to define the demand curve: that the offset is the same in every year. As explained on pages 25-26 of my August 31, 2005 affidavit, the average E/AS gross margin earned by the benchmark turbine during the 1999-2004 would have been $21,000/installed MW/yr under the "peak-hour dispatch" assumption.[2] This $21,000 value is the offset used to define the Settlement Curve in these simulations, according to the above definition of the curve. As an approximation, this value is treated as being the same in every year, rather than a rolling average of previous years as in the actual curve definition.

An assumption also needs to be made about what E/AS gross margins are actually earned in each year, as a function of system scarcity conditions. Reduced reserve margins will increase these gross margins, according to the 1999-2004 experience summarized in my August 31, 2005 affidavit. In this supplemental affidavit, the simulations assume that E/AS gross margins are

[1]The energy and ancillary service (E/AS) gross margin is defined as revenues net of variable operating cost. Thus, it can be viewed as the contribution of revenue to covering fixed costs.

[2] Under this assumption, the benchmark turbine (that is the basis of the CONE calculation) is assumed to be operated only during peak periods. In particular, turbines are assumed to be dispatched in four distinct blocks of four hours of continuous output for each block from the peak-hour period (between 8 a.m. and 11 p.m.) for any day when the average real-time locational marginal price is at least equal to the cost of generation (including start-up and shutdown costs) for at least two hours during each four-hour block. The blocks are assumed to be dispatched independently. This is a more realistic characterization of the dispatch, and therefore of the revenues, of the benchmark turbine for the purpose of calculating net CONE.

earned by the benchmark turbine according to the peak-hour dispatch assumption.[3] Therefore, consistent with this assumption, the benchmark turbine is assumed to earn E/AS gross margins in each year according to the lower of the two curves in Figure 3 of the August 31, 2005 affidavit, which is based on a peak-hour dispatch assumption for the benchmark turbine. That curve is \$7600/installed MW/yr lower than the curve used in the base case simulations in my August 31, 2005 affidavit, where instead I assumed that the benchmark turbine would be operated in any hour in which the price exceeded the marginal operating cost.

The E/AS curve used in the below analyses is the sum of two components: (1) a \$2400/installed MW/yr fixed E/AS revenue stream that does not depend on reserve margin and (2) a variable E/AS gross margin (termed "scarcity revenue" in the tables of results, *infra*) that depends on the actual reserve margin in the year. In comparison, the E/AS gross margin curve used in the base cases of the August 31, 2005 affidavit had a higher fixed component of \$10,000/installed MW/yr but the same variable E/AS gross margin, and so yielded \$7600/installed MW/yr more in E/AS revenue at any given reserve margin. Use of the latter curve, which assumes maximally flexible operation of the baseline turbine, including the ability to start any number of times and run for very short times, is less realistic than the peak-hour dispatch assumption with limited number of starts on a day and minimum run time.

To summarize the E/AS assumptions, the base case results I discuss below use the peak-hour dispatch-based E/AS gross margins for determining the average E/AS offset in the curves, while the actual E/AS gross margins earned in each year are simulated using the peak-hour dispatch assumption (the lower curve in Figure 3 of the August 31, 2005 affidavit). Additionally, all demand curves are evaluated under the assumption that the auction takes place three years ahead of the date in which the capacity is made available, rather than the four years assumed in my August 31, 2005 affidavit. All other assumptions are the same as in my August 31, 2005 base case

[3] See Footnote 2, *supra*.

analyses, including the use of twenty five simulations, each 100 years in length.

The sensitivity analyses are based on the same changes in assumptions described in Table 2 (page 50) of my August 31, 2005 affidavit.

Results. I now summarize base case results and sensitivity analyses for the Settlement Curve, as well as selected results for Curves 1, 3, and 4 (as defined in the August 31, 2005 Affidavit) for comparison. Curve 4 is the curve recommended by PJM in its August 31, 2005 filing, while Curve 3 is an alternative curve that is shifted 1% to the left from the recommended curve (measured in terms of installed reserve margin). Curve 1 is the "no demand curve" case, in which the demand curve is effectively a vertical line at the IRM, with the price capped at twice the CONE minus the E/AS offset.[4] Results for these curves allow me to characterize the relative performance of the Settlement Curve. First, Table 1 shows the base case results for the Settlement Curve and Curves 1, 3, and 4. Then Tables 2 and 3 provide results for Curve 4 and the Settlement Curve, respectively, under a number of sensitivity analyses.

[4] Curve 1 is evaluated in Table 1 under the assumption that all new capacity bids in at $25,000/unforced MW/yr, rather than the $0/unforced MW/yr assumed for Curves 3 and 4. The bidding assumption has only a small effect on the performance of Curves 3 and 4, as shown in my August 31, 2005 affidavit as well as in Table 2, *infra*. However, that assumption does impact the performance of Curve 1; in order to provide a conservative estimate of the relative deterioration in performance that results from using no demand curve, I use a bidding assumption for Curve 1 that is more favorable for that curve. If instead bids of new capacity are assumed to be zero, then the performance is instead as follows: 34.6% probability of meeting or exceeding IRM; -0.8% average reserve over IRM; and 145.6 $/peak MW/yr consumer payments for scarcity and ICAP.

Table 1. Summary of Base Case Results for Settlement Curve and Curves 1, 3, and 4: Average Values (Standard Deviations In Parentheses) (All Values in $/installed kW/yr, except Consumer Payments)

Curve	Reserve Indices		Generation Profit, $/installed kW/yr	Components of Generation Revenue ($/installed kW/yr)			Consumer Payments for Scarcity + ICAP $/Peak kW/yr
	% Years Meet or Exceed IRM	Average % Reserve over IRM		Scarcity Revenue	E/AS Fixed Revenue	ICAP Payment	
Curve 1. Vertical Demand Curve at IRM ("No Demand Curve")	52.2	-0.5 (0.9)	52.2 (93.2)	41.9 (72.5)	2.4	68.9 (50.3)	122.9 (99.9)
Curve 3. Alternate Curve with New Entry Net Cost at IRM (Shift Left to CT net cost at IRM)	90.2	1.1 (0.8)	14.0 (50.9)	25.8 (49.8)	2.4	46.8 (5.0)	81.6 (53.3)
Curve 4. Alternate Curve with New Entry Net Cost at IRM+1%	98.4	1.7 (0.9)	11.3 (43.0)	21.2 (41.4)	2.4	48.7 (6.6)	79.2 (44.8)
Settlement Curve	95.2	1.1 (0.7)	14.4 (49.4)	25.1 (48.2)	2.4	47.8 (6.3)	82.1 (51.7)

Table 2. Summary of Results for Curve 4 (August 31, 2005 Proposed Curve), Average Values

Curve	Reserve Indices		Generation Profit, $/installed kW/yr	Components of Generation Revenue ($/installed kW/yr)			Consumer Payments for Scarcity + ICAP $/Peak kW/yr
	% Years Meet or Exceed IRM	Average % Reserve over IRM		Scarcity Revenue	E/AS Fixed Revenue	ICAP Payment	
Base Case	98.4	1.7	11.3	21.2	2.4	48.7	79.2
Max Price = Net Cost multiplied by 1.5	96.8	1.6	11.8	21.9	2.4	48.5	79.7
Max Price = Net Cost multiplied by 1.2	94.0	1.5	12.6	22.9	2.4	48.3	80.4
Price drops to zero at IRM+10%	98.8	1.7	11.1	21.1	2.4	48.6	79.0
Original Curve: No chopoff	98.8	1.7	11.1	21.1	2.4	48.6	79.0
Low Percent CT added when profit is equal to cost	97.4	1.6	12.4	21.7	2.4	49.3	80.4
High Percent CT added when profit is equal to cost	97.6	1.7	11.5	21.5	2.4	48.6	79.3
10,000 bids for new capacity	98.6	1.7	11.2	21.2	2.4	48.6	79.0
25,000 bids for new capacity	98.7	1.7	11.1	21.1	2.4	48.6	79.0
44,000 bids for new capacity	98.8	1.7	11.0	21.0	2.4	48.6	78.9
44,000 bids for new, 20,000 for existing capacity	98.8	1.7	11.0	21.0	2.4	48.6	78.9
Zero risk aversion (0.5)	97.0	2.1	7.5	20.2	2.4	45.9	74.9
High risk aversion	90.6	1.2	23.1	28.0	2.4	53.7	91.7
High rate of decay in weights	100.0	1.6	10.5	21.1	2.4	48.1	78.3
Low decay in weights	87.4	1.6	17.8	24.3	2.4	52.0	86.1

Table 3. Summary of Results under Settlement Curve, Average Values

Curve	Reserve Indices		Generation Profit, \$/installed kW/yr	Components of Generation Revenue (\$/installed kW/yr)			Consumer Payments for Scarcity + ICAP \$/Peak kW/yr
	% Years Meet or Exceed IRM	Average % Reserve over IRM		Scarcity Revenue	E/AS Fixed Revenue	ICAP Payment	
Base Case	95.2	1.1	14.4	25.1	2.4	47.8	82.1
Low Percent CT added when profit is equal to cost	92.2	1.1	15.3	25.7	2.4	48.2	83.1
High Percent CT added when profit is equal to cost	95.5	1.2	14.4	25.4	2.4	47.5	82.1
10,000 bids for new capacity	95.2	1.1	14.4	25.1	2.4	47.8	82.1
25,000 bids for new capacity	95.2	1.1	14.4	25.1	2.4	47.8	82.1
44,000 bids for new capacity	94.2	1.2	13.8	24.8	2.4	47.6	81.5
44,000 bids for new, 20,000 for existing capacity	94.2	1.2	13.8	24.8	2.4	47.6	81.5
Zero risk aversion (0.5)	87.8	1.6	9.5	24.6	2.4	43.5	76.5
High risk aversion	65.7	0.0	38.2	43.6	2.4	53.2	107.2
High rate of decay in weights	99.7	1.2	14.1	24.6	2.4	48.0	81.8
Low decay in weights	84.4	1.0	17.3	27.7	2.4	48.2	85.1

The qualitative conclusions concerning the comparison of Curves 1, 3, and 4 (Table 1) and the effects of alternative assumptions upon the Curve 4 results (Table 2) are the same as in my August 31, 2005 affidavit. Thus, the change from a four year-ahead to three year-ahead auction does not change the general conclusions.[5]

Turning to the comparison of the Settlement Curve results with Curves 1, 3, and 4, I make the

[5] However, it should be noted that the average "Consumer Payments for Scarcity + ICAP" are higher than reported in the August 31, 2005 affidavit for Curves 1, 3, and 4. The reason for this is that the average consumer costs includes only scarcity E/AS costs, and not the fixed component. When the assumption of a peak-hour dispatch-based E/AS curve is used in the simulation, the fixed component of the E/AS gross margin to turbines shrinks from \$10,000/installed MW/yr to \$2400/installed MW/yr; therefore, for a turbine to break even, it must obtain more revenue from other sources, namely capacity payments and variable (scarcity) E/AS revenues. In equilibrium, therefore, the latter increase by approximately \$7600 per installed MW per year. This change also translates into an increase in calculated "Consumer Payments for Scarcity + ICAP" by roughly that much; the increase is not exact, because the equilibrium solutions change slightly and, more importantly, Consumer Payments are expressed on a \$/peak MW load/yr basis, not \$/installed MW/yr. Note that the total cost paid by consumers does not actually increase; this increase in "Consumer Payments for Scarcity + ICAP" is matched by a decrease in nonscarcity-related energy and ancillary services payments.

following conclusions. When the Settlement Curve is defined using a fixed average E/AS offset (rather than a rolling 3 year average, as actually would be used), Table 1 shows that its performance in terms of Consumer Cost is comparable to Curve 3, achieving a value of 82.1 $/Peak kW/yr (as opposed to 81.6 and 79.2 for Curves 3 and 4, respectively, under the base case assumptions). Its performance in terms of "% Years Meeting or Exceeding IRM" is 95.2%, which lies between Curves 3 and 4 (90.2% and 98.4%, respectively).

These differences between the Settlement Curve and Curves 3 or 4 are very small compared to the gulf between their performance and that of Curve 1 ("No Demand Curve"), which performs much worse. In particular, in comparison to the Settlement Curve and Curves 3 and 4, Curve 1 results in 50% higher consumer payments for scarcity and ICAP, and roughly half the probability of meeting or exceeding the IRM. Therefore, I conclude that the differences among Curves 3, 4, and the Settlement Curve are minor compared to the benefits of moving from the vertical curve case (analogous to the present PJM ICAP system) to RPM.

The sensitivity analysis results for the Settlement Curve, in terms of how alternative assumptions affect Consumer Payments, are qualitatively similar to Curve 4. The Settlement Curve is, however, somewhat more sensitive to risk aversion assumptions (because it has a slightly more vertical aspect than Curve 4). But this difference is not large compared to the differences between the vertical curve (Curve 1) results and the sloped demand curves.

Thus, based on this analysis, I conclude that the Settlement Curve's performance would likely be similar to that of Curve 4, which was recommended by PJM in its August 31, 2005 filing, and much better than the vertical demand curve (Curve 1).

2. Updating Procedures for the Settlement Curve: The Empirical CONE

In this section, I address the settlement's "Empirical CONE" procedure. Given that any estimate of CONE is uncertain and that generation technology is evolving, it is desirable to have a predictable and transparent procedure for changing the assumed CONE when bidding behavior and market clearing prices indicate that actual capacity costs may differ significantly from the assumed CONE. Predictability and transparency is helpful in establishing confidence in the market and in facilitating the creation of a forward market for capacity rights. It is also desirable that such a procedure not result in large swings in CONE that reflect short-term market behavior rather than changes in technology. The proposed procedure, in which the demand curve's CONE is changed by no more than the minimum of (1) 10% and (2) 50% of the difference between the assumed CONE assumed and the Empirical CONE (as defined in the settlement), is a reasonable compromise for the following reasons. First, it will yield much less year-to-year variation than the situation where the demand curve's CONE was set equal to the Empirical Cone. Second, the curve's CONE will nevertheless still move over time in the direction of the Empirical CONE if bidding behavior indicates a persistent shift in peaking technology costs.

This concludes my affidavit.

	)	State of Maryland
SS:	)	
	)	City of Baltimore

AFFIDAVIT OF BENJAMIN F. HOBBS

Benjamin F. Hobbs, being first duly sworn, deposes and says that he has read the foregoing "Supplemental Affidavit of Benjamin F. Hobbs," that he is familiar with the contents thereof, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

/s/ ____________________
Benjamin F. Hobbs

Subscribed and sworn to before me this 29 day of September, 2006.

/s/ ____________________
Notary Public

My Commission expires: May 2, 2010

ERIN SIMON
Notary Public Maryland
City of Baltimore
My Commission Expires on
May 2, 2010

PJM Interconnection, L.L.C.
Docket Nos. EL05-148 and
ER05-1410
September 29, 2006

Attachment D
Supplemental Affidavit of
Paul R. Williams

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM INTERCONNECTION, L.L.C.) **Docket Nos. ER05-1410-000 and EL05-148-000**

AFFIDAVIT OF PAUL R. WILLIAMS ON BEHALF OF THE PORTLAND CEMENT ASSOCIATION ON SETTLEMENT AGREEMENT

Q. **Please state your name and business address.**

A. My name is Paul R. Williams, and my business address is 150 Green Valley Circle, Dresher, Pennsylvania, 19025-1515. My business telephone number is (215) 499-6940.

Q. **What is your current position and background?**

A. I am the President of Liberty Energy Group, Inc ("LEG"). LEG provides strategic and tactical management services for energy and related products to heavy industrial and utility clients. LEG clients include the Portland Cement Association and its members; Mittal Steel; Eastman Chemical; Air Liquide Group; and Sterling Energy Management, LLC, a global power plant project development and operations company providing services to utility companies and independent power producers. Prior to LEG, I was Director - Energy Management for Air Liquide America, Inc., for approximately 6 months after their purchase of Messer Griesheim Industries, Inc., and was employed in the same role by Messer for approximately 4 years. Prior to Messer, I worked for Bethlehem Steel, Air Products and Chemicals, and Exelon Corporation in various energy management, risk management, project development, asset optimization, pricing and rates, and regulatory roles. I have a Bachelor of Science Degree in Electrical Engineering from Drexel University in Philadelphia, PA, with a concentration on electric power systems and electrical machines. I hold a Master of Science Degree in Engineering Management from Drexel University, which was concentrated on utility management and specifically the economic operation of bulk power systems.

Q. **What is the purpose of your statement?**

A. I am addressing the benefits of the proposed use of an Empirical Cost Of New Entry ("E-CONE") in the Reliability Pricing Model ("RPM") capacity mechanism proposed by the Supporting Parties and PJM Interconnection, LLC ("PJM") in the settlement filed in Docket Nos. ER05-1410 and EL05-148.

Q. **How would E-CONE be used within RPM, as proposed in the settlement?**

A. RPM includes a downward-sloping demand curve based on an administratively determined Cost Of New Entry ("CONE"), which is essentially an estimate of the capital carrying charges of new electric generation capacity. The value of CONE is important to the RPM mechanism because it essentially drives capacity revenues for generation suppliers and costs for consumers. Therefore, CONE needs to provide adequate compensation for generation suppliers to build adequate electric generation capacity to supply system loads, while not over-compensating generation suppliers and causing consumer prices to exceed "just and reasonable" levels.

Q. **What is the benefit of the proposed E-CONE process?**

A. PJM's RPM filing relied on an administrative determination of CONE in order to create the demand curve. This value was the subject of much debate for many valid reasons. In order for PJM to develop a CONE value, PJM Staff made a series of assumptions regarding the size and configuration of the expected marginal electric generation capacity that a competitive market would produce. The myriad assumptions were the subject of debate between generation suppliers, which would necessarily want the CONE value to be as high as reasonably possible, and consumers, which would pay less under a more conservative set of assumptions. Ultimately, the administrative wrangling over CONE values would be expected to lead to periodic over- and under-pricing within the RPM capacity construct. This outcome would be sub-optimal for both generation suppliers and consumers, as revenues to generation would alternately be inadequate to provide the necessary levels of investment for system reliability or excessive relative to the reasonable actual costs of new generation. E-CONE uses market-like dynamics, rather than an administrative process, to determine the appropriate value of CONE. The use of E-CONE avoids the need for PJM Staff to make numerous assumptions regarding the size and configuration of likely new generation capacity investments and, instead, uses actual clearing prices in the Base Residual Auction, ostensibly driven by rational bids of successful developers in PJM's footprint, to set CONE.

Q. How does E-CONE work within RPM and why is that better than the administratively determined CONE value?

A. Starting with Base Residual Auction ("BRA") number 5, which will be held in 2009 for a subsequent Delivery Year, the value of gross CONE (i.e., CONE prior to a Net Energy and Ancillary Services Revenue Offset) may be adjusted if there has been cumulative net demand for new resources in the defined "Adjustment Areas." This approach is superior to the administratively determined CONE in that it evaluates the accuracy of the CONE value only after there has been a need for actual "New Entry." Requiring this demonstration of actual need as a trigger for E-CONE calculations provides better assurances that the BRA clearing prices upon which E-CONE is calculated are being driven by the offer prices of actual, new generation investment in that Adjustment Area. Because the process provides for dynamic interaction between real-world outcomes and the CONE value used in the VRR Curve, it should provide a more realistic estimate of the actual CONE than any administratively determined CONE.

Q. How does E-CONE develop a new CONE value for use within RPM?

A. If the evaluation of CONE demonstrates that the actual offers within an Adjustment Area are within a reasonable band of the current value of CONE, then no change to the current CONE estimate is made. This bandwidth helps to avoid excessive modification to CONE, providing a more stable capacity price curve for both suppliers and consumers. However, if there is excess generation and the excess grows, or if there is less than the desired amount of generation and the shortfall grows, then the value of CONE is either decreased or increased, respectively, to adjust for the imbalance in the model.

Changes, when necessary, to the CONE value used in the price curve would be based on a three-year rolling average of the Gross Clearing CONE (i.e., the actual clearing value of capacity for that year, grossed up to reflect a back-out of the Net Energy and Ancillary Services Revenue Offsets for that year). Essentially, the new CONE value is adjusted based upon the actual projects that successfully clear the market. This is a more robust CONE determination than an administrative mechanism with all of its inherent assumptions. By using actual cleared offers that have undergone the appropriate checks for market power and any necessary mitigation, consumers' ever-present concerns about market power in PJM's footprint are reduced with respect to the key pricing point on the VRR Curve (i.e., the value at IRM + 1).

Q. Does this complete your statement?

A. Yes.

Attested By,

/ Paul R. Williams /

September 29th, 2006

PJM Interconnection, L.L.C.
Docket Nos. EL05-148 and
ER05-1410
September 29, 2006

Attachment E
Supplemental Affidavit of
Robert B. Stoddard

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	Docket No. EL05-148-000 Docket No. ER05-1410-000

AFFIDAVIT OF ROBERT B. STODDARD IN SUPPORT OF SETTLEMENT AGREEMENT

Commonwealth of Massachusetts **County of Suffolk**	ss.

CONTENTS

I, Robert B. Stoddard, being duly sworn, depose and say:

I. INTRODUCTION AND SUMMARY

1. My name is Robert B. Stoddard. I am a Vice President of CRA International ("CRA") in its offices at 200 Clarendon Street, T-33, Boston, Massachusetts 02116. On October 19, 2005, I submitted an affidavit in these dockets on behalf of Mirant Americas Energy Marketing, LP, Mirant Chalk Point, LLC, Mirant Mid-Atlantic, LLC, Mirant Peaker, LLC and Mirant Potomac River, LLC ("Mirant")[1] commenting on the Reliability Pricing Model ("RPM") filings by PJM Interconnection, LLC ("PJM"). That affidavit presented my professional and educational credentials. On November 23, 2005, I filed a supplemental affidavit on behalf of the [Mirant Parties], Williams Power Company, Inc. ("Williams"), and NRG Power Marketing, Inc., Conemaugh Power LLC, Indian River Power LLC, Keystone Power LLC, NRG Energy Center Dover LLC, NRG Rockford LLC, Rocky Road Power LLC, and Vienna Power LLC ("NRG Companies"), and on February 3, 2006, I spoke on Panel 2 at the Commission's Technical Conference. Subsequently, on February 23, 2006, I filed an answering affidavit on behalf of Mirant and the NRG Companies, and on June 1, 2006, prefiled testimony on paper hearing issues on behalf of Mirant.

2. *I have also been active through the settlement process on behalf of Mirant. In this* capacity, I participated fully in nearly all settlement meetings and conference calls, and I had extensive personal involvement in the development and negotiation of several key aspects of the proposed market design that would be created by the proposed settlement. I have carefully reviewed the Settlement Agreement and the accompanying tariff sheets and Reliability Assurance Agreement.

3. I render this affidavit in support of the overall settlement and, in particular, two elements of the settlement: the New Entry Price Adjustment Rule and the Minimum Offer Price Rule. These two rules, although not included as part of the RPM design filed by PJM last year, make

[1] At the time that I submitted my Affidavit on October 19, 2005, the Mirant Parties were: Mirant Americas Energy Marketing, LP ("MAEM"), Mirant Chalk Point, LLC, Mirant Mid-Atlantic, LLC, Mirant Peaker, LLC ("Mirant Peaker"), and Mirant Potomac River, LLC. Since that time, MAEM has ceased to conduct any active business, and has transferred its assets to Mirant Energy Trading, LLC ("MET"), which is also an intervenor in these proceedings. Likewise, Mirant Peaker has merged into Mirant Chalk Point. As a result, the Mirant Parties, as referred to herein, included MET, instead of MAEM, and do not include Mirant Peaker.

good economic sense either in that market design or in the design as modified by the Settlement Agreement, inasmuch as they will create market prices for capacity that are less susceptible to swings created either by the inherent "lumpiness" of investment or by attempts to depress wholesale prices by needlessly overbuilding capacity. With these two rules, therefore, capacity market prices will more closely reflect the actual marginal cost of meeting system resource adequacy.

4. As with all settlements, the proposed Reliability Pricing Model (the "RPM") market design reflects a number of compromises necessary to resolve this case without litigation. With this background in mind, it is my professional opinion that it is a reasonable market design. It is not necessarily the only market design that could work to accomplish these goals, but it is a workable design that reflects a widely-supported compromise of suppliers, buyers and regulators. Given the settlement posture of this case, however, my opinion should not be construed out of context as my support or the support of my client for specific individual components, or for any aspect of the market design as it might be implicated in other proceedings.

II. New Entry Price Adjustment

5. In its May 19, 2006 brief on paper hearing issues, PJM proposed the addition of a pricing rule to allow new units to set the clearing price for several years in small, import-constrained areas.[2] The nub of the issue is this: the size of a single, efficient generating plant may be several times larger than the annual load growth in a locational delivery area ("LDA"). Building such a unit would sharply lower the capacity clearing price in that LDA until the surplus created by the investment can be absorbed by load growth. As I have described in earlier testimony, this effect would lead to a saw-tooth pattern of prices and may undermine investment in capacity. The New Entry Price Adjustment Rule in the Settlement Agreement provides that a large, new unit selected in the Base Residual Auction ("BRA") in an import-constrained LDA may be offered in the next two BRAs at the lower of its first-year bid or 90 percent of Net CONE. If it does so and is selected in the BRA, the unit is paid no less than its first-year offer price, while other capacity resources would receive the (potentially lower) capacity clearing price.

[2] Brief of PJM Interconnection, L.L.C. on Paper Hearing Issues (May 19, 2006) at 36-37.

6. Furthermore, during this three year period, PJM will model the LDA with its own VRR curve. This is a necessary design element of the rule. If the import constraint was modeled only in the first year, then the unit that was needed in that year to meet the LDA's reliability requirement would *appear* not to be needed in subsequent years. Without this unit, however, the LDA would not meet its locational reliability requirement. Therefore, to give meaning to the ability to bid at a meaningful level in the second and third years as a new resource, PJM must continue to model the LDA as a potentially constrained region.

7. The Settlement Agreement's New Entry Price Adjustment rule strikes a reasonable balance between two competing views of how capacity clearing price should be set when load growth is met entirely with surplus capacity built in an earlier year. One view is that, the price should remain equal to the first-year offer price of the resource, reflecting the price paid to that resource and the fact that the overbuild resulted from a technological limitation. An alternative view is that it should fall to the VRR curve value, regarding the surplus capacity as a free good. If the first view prevailed, the price could remain at or above Net CONE for several years even when no new capacity was required, potentially causing yet more new capacity being built in response to the high price. If the second view prevailed, we would have left unaddressed the inefficiencies created by the saw-tooth prices. The proposed New Entry Price Adjustment rule finds a middle path that damps harmful price volatility while avoiding sending a false "build" signal to the market.

III. Minimum Offer Price Rule

8. The Minimum Offer Price Rule ("MOPR") is a mechanism to limit the effect on wholesale capacity prices that could occur if buyers with a net short position purchase or build new capacity in excess of market needs, thereby artificially suppressing the price of existing resources it obtains through the RPM. This rule should, in my profession opinion, reduce the incentive of buyers to undertake such wasteful over-investment in new capacity without restricting their ability to engage in, and realize the full value of, commercially reasonable bilateral contracts to provide for loads' future reliability needs.

9. The MOPR is important to the proper functioning of the RPM. Without it, a two-tiered pricing system will likely develop, where new resources are paid a competitive New CONE through bilateral contracts, while existing resources (providing exactly the same reliability

services) are paid an RPM clearing price that has been suppressed through overbuilding that serves little purpose except to suppress capacity prices.[3] If the RPM price were consistently lower than the price being paid to new entrants paid through contracts, this will weaken the market. Only resources qualifying for, willing, and able to enter into such contracts would enter, since spot RPM prices would be artificially low. Furthermore, it would suppress the development of demand-side resources, because customers would not see the to the full cost of maintaining resource adequacy in the capacity price.

10. The need for a MOPR is perhaps best illustrated by example. Consider this hypothetical: an import-constrained LDA has a locational requirement of 15,000 MW, currently met by internal resources and imports totaling 15,300 MW. No new resources are needed, and if no new resources come on line, the fact that supply is 102% of requirements will lead to a market price of 80 percent of Net CONE.[4] If Net CONE is $120/MW-day, the RPM price would be $96/MW-day and total payments by load in the LDA will be $536,112,000, as shown in Exhibit RS-2.

11. Suppose one LSE in that LDA has a net short position of 1,500 MW, 10 percent of the locational requirement. To cover that net short position in the RPM auction, its cost will be $53,611,200.[5] Seeking to reduce its costs, the LSE considers another option: buying capacity bilaterally. It has two options:

a. It can solicit bids for capacity resources generally. Existing resources may consider responding to the RFP and offering a price near the expected spot-market price of $96/MW-day (80 percent of Net CONE). New resources, however, would not be expected to win the solicitation, since their likely offer

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[3] My concern on this point is not merely hypothetical, but is borne out by a recent Request for Proposals issued by the Connecticut Department of Public Utility Control, seeking "new or incremental capacity" (and explicitly noting that "[e]xisting resources will not be considered eligible under this procurement process."), and such new capacity will be required to submit bids into the New England Forward Capacity Market ("FCM") in a way narrowly tailored to be as low as possible without triggering the rule analogous to the MOPR, regardless of actual costs. Connecticut will pay the difference between the bid cost and the revenue requirements of the new suppliers through supplemental contract payments. But for the existence of the MOPR-like rule in the FCM, the opportunity to suppress prices and distort market outcomes would be even greater.

[4] I assume throughout that the offer prices from existing supply are low enough to clear all existing supply.

[5] This figure is not the same as the net short position times the clearing price because the LSE also has responsibility to buy 10% of the cleared resources above the IRM, 30 MW.

would be closer to Net CONE. While a bilateral contract with existing resources may provide benefits such as greater long-term price certainty, it would not necessarily lead to a discount from the RPM prices.

b. It can solicit bids for *new* capacity resources, but only for a portion of its net short position. Although the cost *per MW* of new capacity will be higher than the cost of existing resources in this hypothetical, the *total* cost of meeting the LSE's capacity needs may be lower depending on how that new resource is bid into RPM. Adding new resources into the market lowers the RPM clearing price formulaically. Thus the higher per-MW cost of a relatively small quantity of new MWs can be offset by the reduction in the market-clearing price the LSE pays to cover its remaining short position.

12. Suppose in particular that the LSE in question decides to build (either on its own balance sheet or by contract) a new 300 MW resource. The extra resources, equal to 2 percent of the LDA's requirement, drives the reserve margin up to 104% and the price down to 40 percent of Net CONE, or $48/MW-day—half of the price that would otherwise occurred, thereby roughly halving the cost of covering its remaining 1,200 MW of net short position.[6] If the LSE paid the full gross Cost of New Entry ("CONE") for the new resources it built, its one-year savings would be $18,396,000, about one-third of the total cost without this new-build strategy. Even if it paid *twice* CONE for the new capacity, the LSE would still save $5,256,000 in the first year.

13. I have prepared a chart, Exhibit RS-3, that shows how capacity payments are sharply reduced by this overbuilding. Unlike most graphs of the VRR, this one plots the entire range of the VRR, from 0 MW to IRM+5, demonstrating just how steep the VRR is. The market outcome is at 80 percent of CONE, and payments are the shaded green rectangle. By buying 300 MW at a price of 100 percent of CONE, the 15,300 MW of existing capacity resources are repriced to 40 percent of CONE, and total consumer payments is the area below the red line.

14. The example shows two important parts of the issue:

a. First, in order to benefit from this behavior, the LSE needs to have a net short position in the market *after* considering its bilateral purchases and owned

[6] The cost is not exactly halved, because the LSE also must by an additional 30 MW of capacity resulting from the overbuild.

assets. The key to the overbuild strategy is to offset above-market bilateral costs paid to cover part of a net short position with depressed market prices to cover the remaining, unhedged position.

b. Second, the quantity of new resources has to be large enough to lower market prices materially. Otherwise, the savings on the unhedged position would not be large enough to offset the above-market costs paid for the new resources.

15. The MOPR, as proposed, therefore includes a net-short test and impact tests, which provide reasonable assurance that the MOPR will not change the market price unless warranted to restore the price to a competitive level:

16. **Net Short Test**. Resources offered by (or under contract to) parties that do not have a significant net short position in the LDA are presumed to be offered in competitively. For example, if an independent power producer is willing and able to build a generation resource with *no* capacity payment, its bid of zero would not be repriced by the MOPR since the developer is not net short of capacity. Likewise, if a buyer wants to purchase or self-provide its entire capacity obligation, leaving itself without a net short position in the BRA, the MOPR will not apply to its bilateral purchases.

17. **Impact Tests**. The MOPR includes two impact tests that are designed to limit the application of the rule to situations where the oversupply is unlikely to have a legitimate purpose:

a. *Offer price threshold*. PJM should not reprice legitimate offers of new supply that reflect the resources' actual economics but are simply less costly than expected. Therefore, offers that are within 20% of the class-specific Net CONE estimate, or (if there is no class-specific Net CONE estimate for the resource) 30% of the generic Net CONE value will not be repriced, since these offers (a) are likely to be consistent with a competitive offer level and (b) can at worst suppress prices by 20 to 30 percent.

b. *Price impact threshold*. If some capacity offers were repriced, but the effect of repricing those offers is not large, then the RPM will clear with the offers as submitted. If each LSE simply covered its net short position through ownership or contracts, the total quantity of resources would be approximately what was needed, IRM+1, plus or minus some amount reflecting differing views on load growth, lumpy project investment, etc. Even if all these resources were offered in at $0, the RPM would clear near the IRM+1 target quantity and a corresponding price near Net CONE. The MOPR's price impact threshold allows natural fluctuations around Net CONE, only restoring a price nearer Net CONE if a large price effect was induced by the actions of a party that stood to profit from the excursion.

18. The MOPR also includes a "sunset" provision that triggers when new resources are required in the Rest of Market area. At such time, the price differential between historically constrained zones and the rest of market will be small, with the pool-wide clearing price at or near Net CONE in most years. When that occurs, the benefit to suppressing the price inside the LDA is also small. The Settlement Agreement does provide, however, that if the Net CONE in some LDA exceeds the Net CONE in surrounding areas by 50 percent or more, that the MOPR would apply to that high-cost LDA. This provision ensures that differences in prices driven by underlying cost differences are not erased.

19. To the greatest extent possible, the MOPR was designed to be a symmetric check on the bids from new entry. Although, as a general matter, bids from new entry should be competitive, the Settlement Agreement identifies possible situations where bids that, if left in the market, would unduly shift (up or down) the capacity clearing price from its competitive level. Bids that are above a competitive level and not checked by sufficient competition from other new entry bids can be rejected, avoiding market price distortions. The MOPR provides a parallel check on bids that are below a competitive level. The MOPR strikes an equitable balance of leaving these offers in the market, thereby giving the contracting parties the benefit of the particular contract, while neutralizing large price distortions created by purchases well in excess of forecast reliability needs.

20. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	Docket No. EL05-148-000 Docket No. ER05-1410-000

AFFIDAVIT OF ROBERT B. STODDARD

Commonwealth of Massachusetts **Suffolk County**	ss.

I, Robert B. Stoddard, being duly sworn, depose and state that the contents of the foregoing Affidavit dated September 28, 2006, is correct, accurate and complete to the best of my knowledge, information, and belief:

Robert B. Stoddard

SUBSCRIBED AND SWORN to
before me this 28th day of September, 2006

Suzanne M. Walsh
Notary Public
My commission expires: 2/26/2011

SUZANNE M. WALSH
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
February 26, 2011

PJM Interconnection, L.L.C.
Docket Nos. EL05-148 and
ER05-1410
September 29, 2006

Attachment F
RPM Timeline

RPM Timetable

Date	Item
4 months before BRA	Data Submittal to MMU for Preliminary Market Structure Screen (MSS)

3 months before BRA	• *Post results of Preliminary MSS*
	• Post Parameters for Delivery Year (DY)
	  o Preliminary PJM Region/Zonal Peak Load Forecasts and ILR Forecasts by LDA
	  o IRM, Pool-wide Average EFORd, and FPR
	  o Demand Resource Factor
	  o PJM Region Reliability Requirement and VRR Curve for PJM Region
	  o LDA Reliability Requirements and VRR Curves *for the LDAs to be modeled in BRA (including* the CETO and CETL information)
	  o Transmission Upgrades expected to be in service for DY
	  o CONE and Net E&AS values used in VRR Curves

2 months before BRA	• Data Submittal to MMU if submitting non-zero sell offer price for a resource in an LDA or Unconstrained LDA Group that fails Preliminary MSS • Election of FRR Alternative starting with DY
1 month before DY BRA	• MMU to notify Capacity Market Sellers of Market Seller Offer Caps • Submittal of Initial FRR Capacity Plan for Delivery Year
DY – 3 years (May)	DY Base Residual Auction (BRA)
DY – 23 months (June)	DY First Incremental Auction
DY – 12 months (Feb 28)	Post Final PJM Region/Zonal Peak Load Forecasts for DY
DY – 13 months (April)	DY Second Incremental Auction
DY – 6 months (Nov 30)	Final EFORd fixed for DY
DY – 4 months (January)	DY Third Incremental Auction
DY – 3 months (March 1)	ILR Nomination
June 1, DY	Start of Delivery Year (DY)

RPM Timetable

RPM Timetable Example for 2011/2012 Delivery Year

Date	Item
January 2008	Data Submittal to MMU for Preliminary Market Structure Screen (MSS)

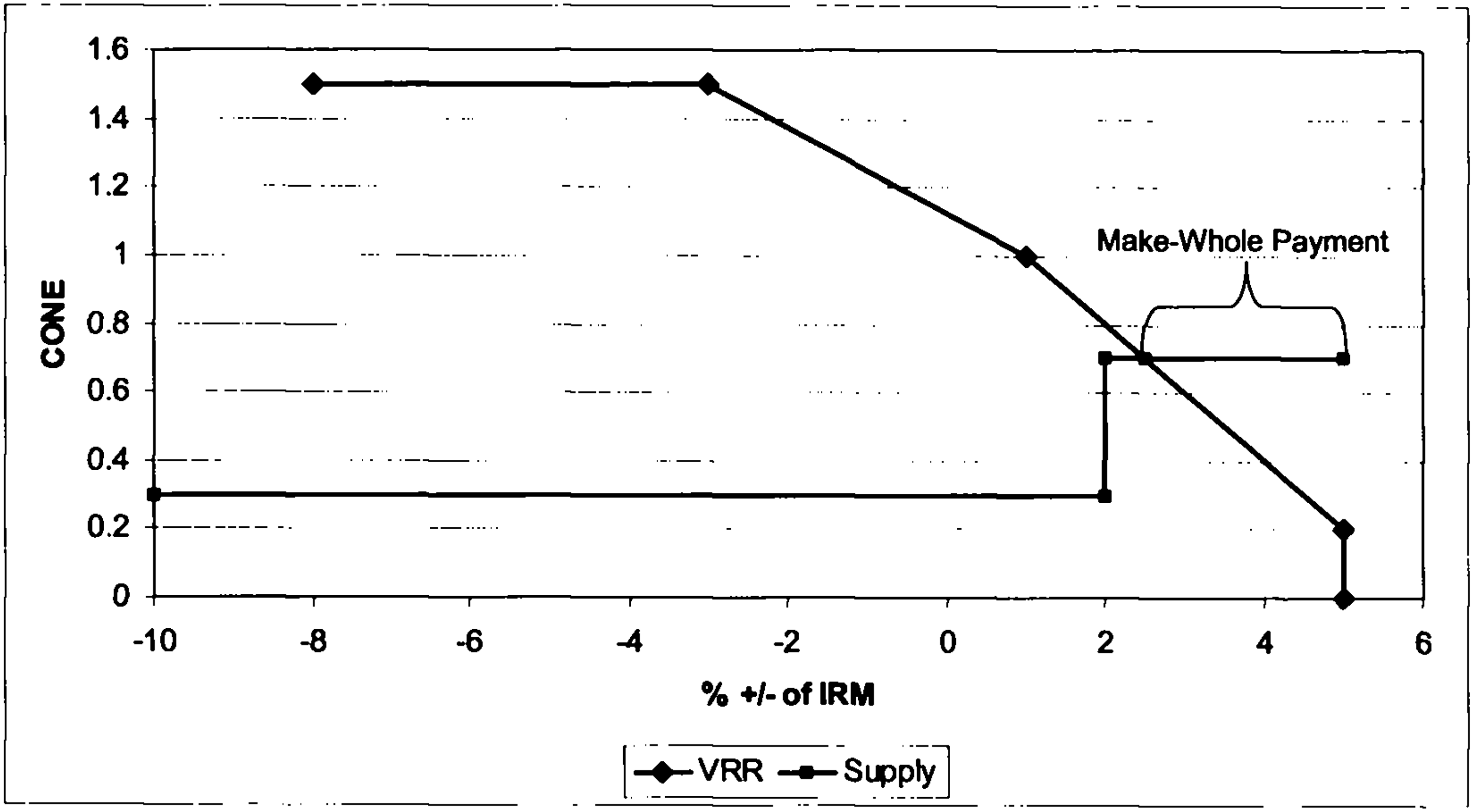
February 1, 2008	• Post results of Preliminary MSS
	• Post Parameters for 2011/2012 Delivery Year (DY)
	  o Preliminary PJM Region/Zonal Peak Load Forecasts and ILR Forecasts by LDA
	  o IRM, Pool-wide Average EFORd, and FPR
	  o Demand Resource Factor
	  o PJM Region Reliability Requirement and VRR Curve for PJM Region
	  o LDA Reliability Requirements and VRR Curves for the LDAs to be modeled in BRA (including the CETO and CETL information)
	  o Transmission Upgrades expected to be in service for 2011/2012 DY
	  o CONE and Net E&AS values used in VRR Curves

March 2008	• Data Submittal to MMU if submitting non-zero sell offer price for a resource in an LDA or Unconstrained LDA Group that fails Preliminary MSS • Election of FRR Alternative starting with 2011/2012 DY
April 2008	• MMU to notify Capacity Market Sellers of Market Seller Offer Caps • Submittal of Initial FRR Capacity Plan for 2011/2012 Delivery Year
May 2008	2011/2012 DY Base Residual Auction
June 2009	2011/2012 DY First Incremental Auction
February 28, 2010	Post Final PJM Region/Zonal Peak Load Forecasts for 2011/2012 DY
April 2010	2011/2012 DY Second Incremental Auction
November 30, 2011	Final EFORd fixed for 2011/2012 DY
January 2011	2011/2012 DY Third Incremental Auction
March 1, 2011	ILR Nomination
June 1, 2011	Start of 2011/2012 Delivery Year

PJM Interconnection, L.L.C.
Docket Nos. EL05-148 and
ER05-1410
September 29, 2006

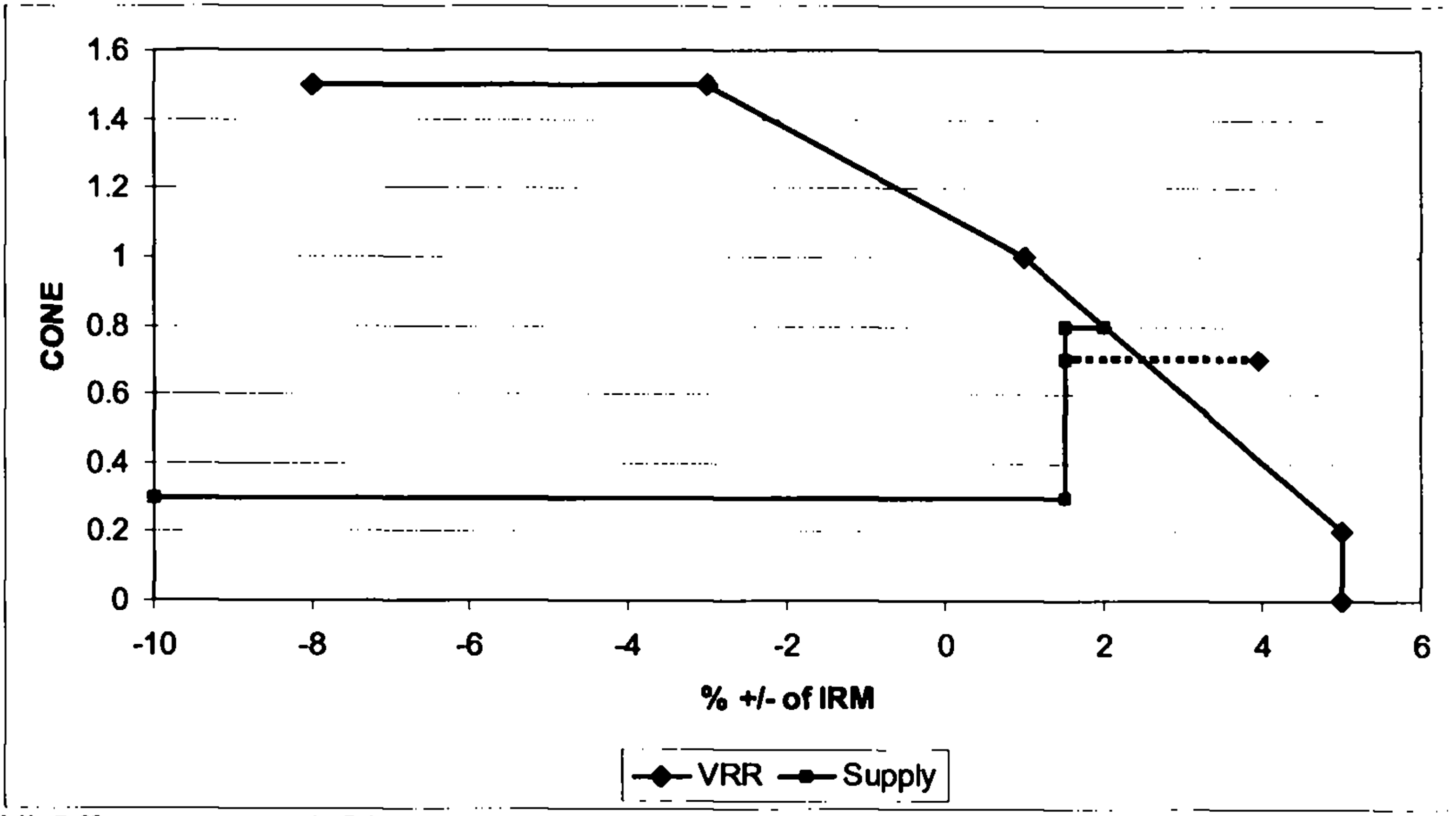
Attachment G
Illustration of
Auction Clearing Scenarios

Make-Whole Example



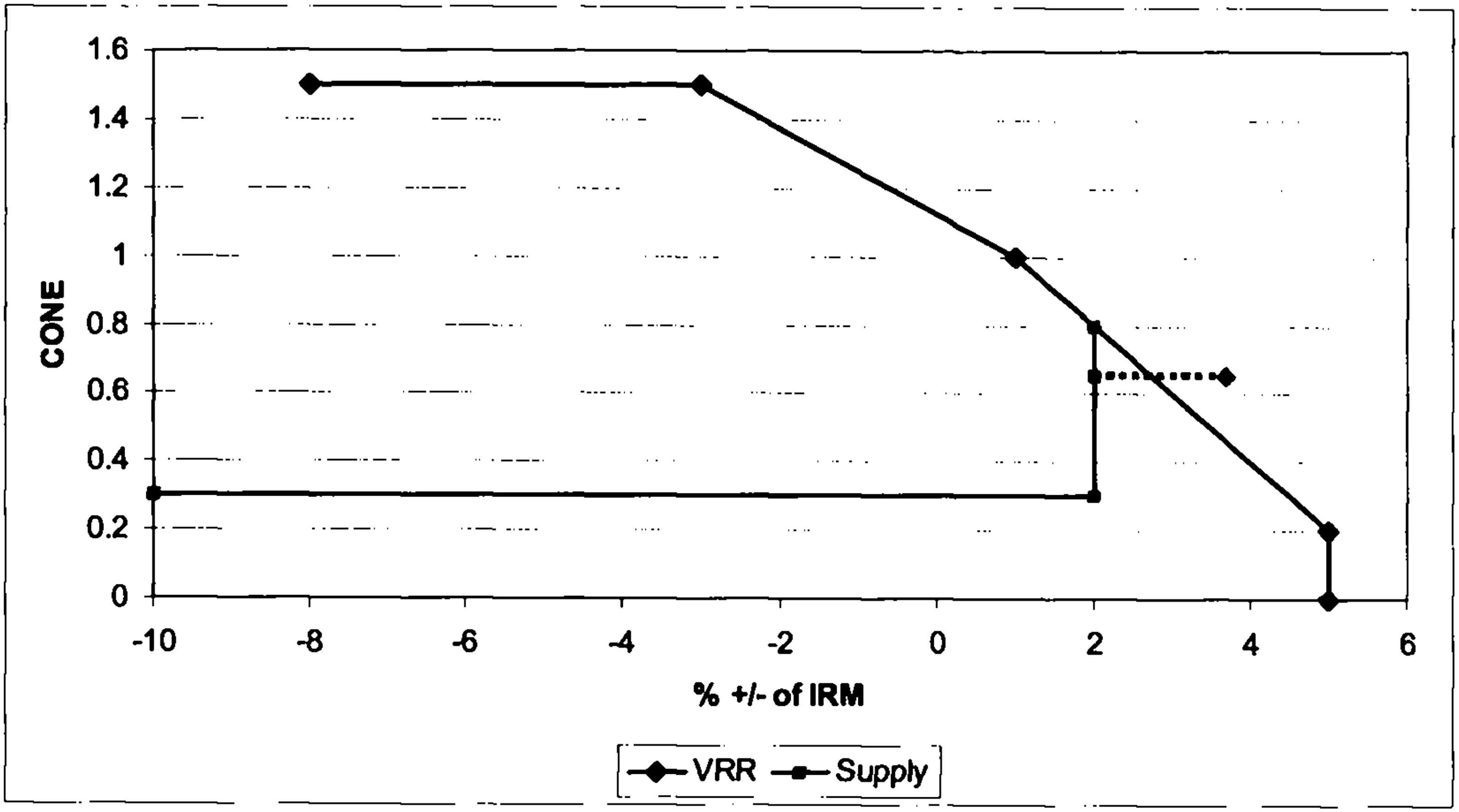
- All Offers are Block Bid
- Since Optimization only needs to clear portion of last offer, VRR sets clearing price
- Clearing Price is 0.7 CONE at IRM+2.5%
- Make Whole payments are for the MW portion of block bid beyond VRR curve

Substitution Example



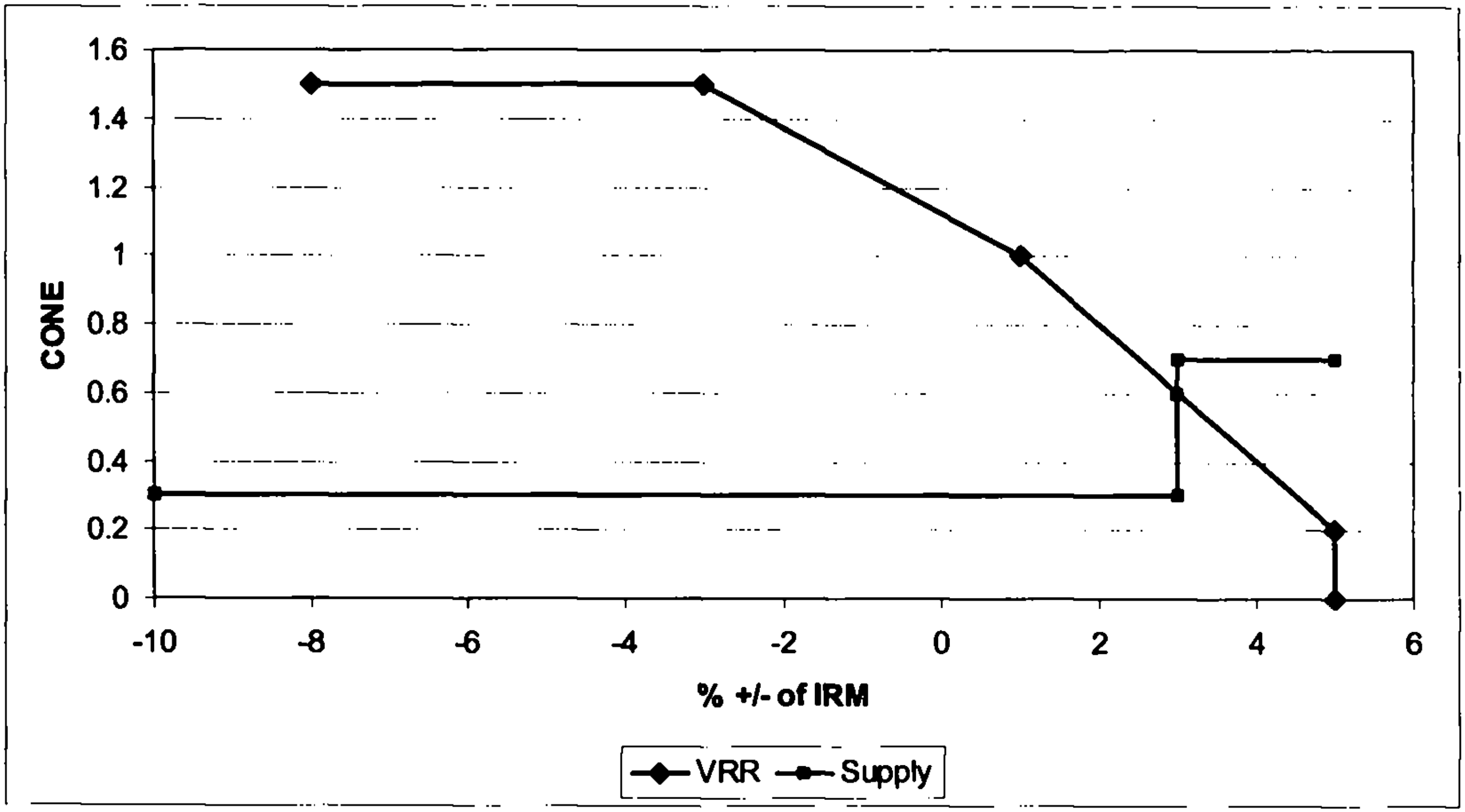
- All Offers are Block Bid
- Optimization will clear the lowest overall cost to LDA
- Substitutes the higher priced offer in for the lower priced offer with no flexibility
- Clearing Price is 0.8 CONE at IRM+2%
- Offer with dotted line does not clear because of lack of flexibility
- No Make Whole payments

Supply Curve Extension Example



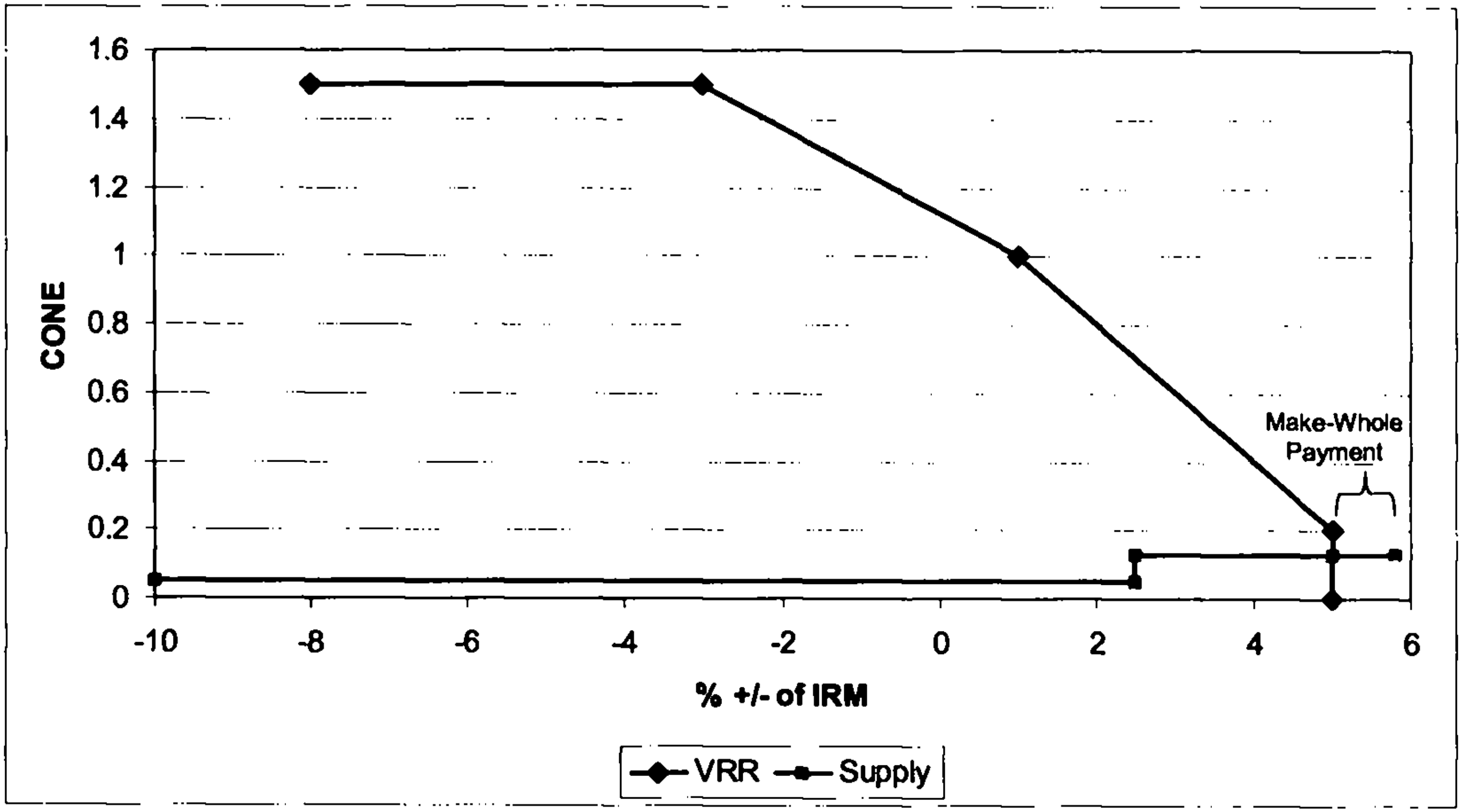
- All Offers are Block Bid
- Continuing vertical portion of supply curve to intersection of VRR Curve results in lower overall cost to LDA
- Since intersection occurs at vertical portion of **Supply** curve, VRR sets clearing price
- Clearing Price is 0.8 CONE at IRM+2%
- Offer with dotted line does not clear because of lack of flexibility
- No Make Whole payments

No Make-Whole Example



- All Offers are Block Bid
- Since intersection occurs at vertical portion of **Supply** curve, VRR sets clearing price
- Clearing Price is 0.6 CONE at IRM+3%
- No Make Whole payments

Vertical VRR Example



- All Offers are Block Bid
- Since intersection occurs at vertical portion of **VRR** curve, Supply sets clearing price
- Clearing Price is 0.13 CONE at IRM+5%
- Make Whole payments are for the MW portion of block bid beyond VRR curve

PJM Interconnection, L.L.C.
Docket Nos. EL05-148 and
ER05-1410
September 29, 2006

Tab 2
Settlement Agreement
And
Attachments

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	Docket Nos.	ER05-1410-000 and -001
	)		EL05-148-000 and -001

SETTLEMENT AGREEMENT
AND OFFER OF SETTLEMENT

TABLE OF CONTENTS

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	Docket Nos.	ER05-1410-000 and -001
	)		EL05-148-000 and -001

SETTLEMENT AGREEMENT
AND OFFER OF SETTLEMENT

Pursuant to Rule 602 of the Federal Energy Regulatory Commission's ("Commission" or "FERC") Rules of Practice and Procedure, this Settlement Agreement and Offer of Settlement (collectively "Settlement Agreement") is submitted by the following parties (and certain of their members or affiliates, as listed in the Settlement Agreement) in this proceeding: Allegheny Electric Cooperative, Inc., Allegheny Energy Companies, American Electric Power, American Forest and Paper Association, Blue Ridge Power Agency, Con Edison Energy, Constellation Energy Group Inc., Dayton Power & Light Co., Dominion Resources Services, Inc., Duke Energy North America, LLC, Edison Mission Energy, Exelon Corporation, FirstEnergy Service Co., FPL Energy Generators, Indiana Office of Utility Consumer Counsel, Indiana Utility Regulatory Commission, Kentucky Public Service Commission, Liberty Electric Power, LLC, LS Power Associates, LP, Michigan Public Service Commission, Mirant Energy Trading, L.L.C., North Carolina Electric Membership Corporation, Old Dominion Electric Cooperative, Pennsylvania Office of Consumer Advocate, PEPCO Holdings, Inc., PJM Industrial Customer Coalition, PJM Interconnection, L.L.C., Portland Cement Association, Reliant Energy Inc., Southern Maryland Electric Cooperative, Inc., Virginia

Municipal Electric Association, and Williams Power Company, Inc. (collectively "Settling Parties").

This Settlement Agreement resolves all issues in Docket Nos. ER05-1410-000 and -001, and EL05-148-000 and -001.

I. BACKGROUND

On August 31, 2005, PJM Interconnection, L.L.C. filed under sections 205 and 206 of the Federal Power Act ('FPA") a proposal for a reliability pricing model ("RPM") to replace its existing capacity obligation rules ("August 31st Filing"). In the August 31st Filing, PJM asked the Commission to find that its existing capacity construct is unjust and unreasonable and that its RPM proposal was a just and reasonable replacement.[1]

On April 20, 2006, the Commission issued an Initial Order on RPM.[2] In its order, the Commission found that PJM's existing capacity construct is unjust and unreasonable.[3] In addition, the Commission made a number of findings as to various aspects of the RPM proposal.[4] In addition to these findings, the Commission instituted a paper hearing and scheduled a technical conference to address a number of issues for which the Commission sought additional information.[5]

Pursuant to the April 20 Order, on May 19, 2006, PJM filed a brief on the paper hearing issues. Parties to the proceeding filed comments on PJM's brief on June 2, 2006, and reply comments on June 16, 2006. The technical conference required by the April 20

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1 *August 31st Filing* at 3.

2 *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 (2006) ("April 20 Order").

3 *Id.* at P 1.

4 *Id.* at P 6.

5 *Id.* at P 173.

Order was held on June 7-8, 2006. Comments on the technical conference were filed on June 22, 2006.

On May 8, 2006, the American Forest and Paper Association ("AFPA") filed a motion to establish settlement judge proceedings, and requested that Administrative Law Judge Lawrence Brenner conduct those proceedings.[6] AFPA also requested that the Commission suspend the technical conference and paper hearing procedures established in the April 20 Order pending the outcome of the proposed settlement judge proceedings.[7] On May 17, 2006, the Commission issued an Order Granting Motion for Appointment of Settlement Judge and Denying Request to Suspend Scheduled Proceedings.[8] In that order, the Commission established settlement judge procedures, but denied AFPA's request to suspend the procedural schedule during the course of the settlement judge proceedings.[9] In addition, the Commission granted AFPA's request that the scope of the settlement discussions would not be limited to the issues that the Commission ordered to be the subject of the paper hearing and technical conference.[10]

Beginning on June 5, 2006, and continuing through the end of July, the parties to this proceeding engaged in lengthy and intense settlement discussions. As noted in the August 3, 2006 Report By Settlement Judge On Agreement In Principle issued in this proceeding, over 150 individuals representing more than 65 parties engaged in more than

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[6] A number of parties either supported or did not oppose the motion to establish settlement judge proceedings.

[7] *See* AFPA Motion at 1.

[8] 115 FERC ¶ 61,186 (2006).

[9] *Id.* at P 1.

[10] *Id.* at P 5.

25 days of settlement discussions with direct Settlement Judge involvement and with the assistance of Mr. Steven Shapiro of the Dispute Resolution Service, and numerous other meetings among the negotiating parties during the settlement period. On August 2, the parties voted on an agreement in principle embodied in a settlement term sheet. All of the parties to this Settlement Agreement either voted to support or not oppose the settlement term sheet. Six parties to the proceeding voted to oppose the settlement term sheet.[11]

Throughout the months of August and September, the parties either supporting or not opposing settlement engaged in further negotiations to resolve the open issues and specifics necessary to reach final settlement on all issues in the term sheet. In addition, the parties drafted and finalized this Settlement Agreement, the accompanying PJM Tariff sheets, and necessary changes to the Reliability Assurance Agreement ("RAA").

II. SETTLEMENT AGREEMENT

A. Implementation Date

The RPM construct described herein shall replace PJM's current capacity construct beginning on June 1, 2007.

B. Variable Resource Requirement Curve

11 The parties that opposed the settlement term sheet were: Catoctin Power, LLC, Coral Power LLC, Maryland Office of the People's Counsel, New Jersey Board of Public Utilities, PPL Parties, and the PSEG Companies, consisting of Public Service Electric and Gas Company, PSEG Energy Resources & Trade LLC and PSEG Power LLC.

The RPM capacity auctions shall be cleared using a Variable Resource Requirement Curve[12] ("VRR Curve") as outlined in the August 31st Filing, at section 5.10 of the proposed attachment to the PJM Tariff setting forth the RPM terms and conditions.[13] The Settling Parties have agreed to modify the parameters of the VRR Curve as described below, and depicted in the accompanying graph. All Cost of New Entry ("CONE") values described and depicted in this section are computed on an unforced equivalent basis as defined in Section 5.10 of Attachment DD.

1. The price is 1.5 times the difference between the CONE and the Net Energy and Ancillary Services Revenue Offset ("Net CONE"), when the quantity is less than or equal to three percentage points less than the approved PJM Region Installed Reserve Margin ("IRM");
2. The VRR Curve then follows a straight line to a price equal to Net CONE, when the quantity is one percentage point greater than the approved PJM Region IRM;
3. The VRR Curve then follows a straight line to a price equal to 0.2 times Net CONE, when the quantity is five percentage points greater than the approved PJM Region IRM; and

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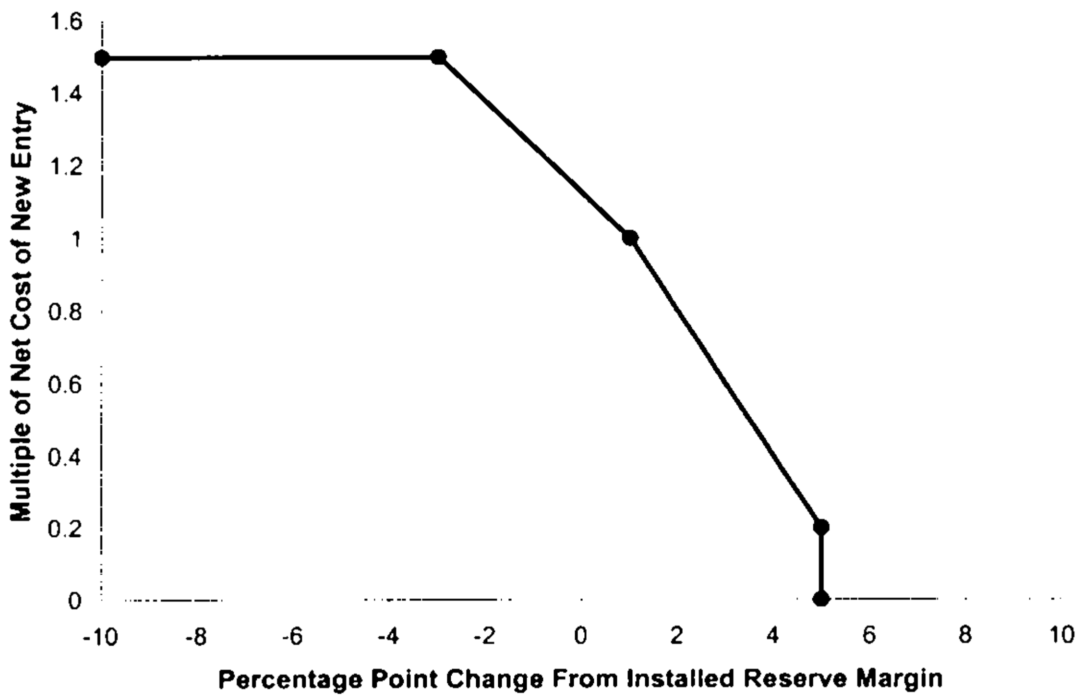
12 Capitalized terms used in this Settlement Agreement that are not otherwise defined in this Settlement Agreement have the meaning given in the PJM Tariff or Reliability Assurance Agreement.

13 That PJM Tariff attachment was designated as "Attachment Y" in the August 31st Filing ("Original Attachment Y"). The attachment is now designated as "Attachment DD" to the PJM Tariff.

4. The VRR Curve then falls vertically to a price of zero at a reserve level, which is five percentage points greater than the approved PJM Region IRM.



C. Base Residual Auction

PJM will conduct a Base Residual Auction ("BRA") as outlined in Section 5.4 of Original Attachment Y, except that, after the Transition Period, the forward commitment shall be three years, not four years, before the Delivery Year. For example, the BRA for the Delivery Year beginning June 2011 will be held in May 2008.

D. Incremental Auctions

Subsequent to the BRA and prior to the Delivery Year, PJM will conduct three Incremental Auctions, as proposed in Original Attachment Y § 5.4, to provide a mechanism for market participants to commit additional resources that may be needed for the Delivery Year either to replace previously committed resources that have become unavailable or to accommodate an increase in the forecasted load.

E. Commitment Period

As proposed in the August 31st Filing, as modified herein, the commitment period for the capacity being offered in the BRA is one year, beginning on June 1 and continuing through May 31 of the following calendar year ("Delivery Year").

F. Reliability Backstop

The Settlement retains Section 16 of Original Attachment Y, except that Section 16.3(a)(i) shall provide that, rather than being triggered after four consecutive years, the Reliability Backstop will be triggered "if the total Unforced Capacity of all Capacity Resources committed through Self-Supply or the Base Residual Auctions for <u>three</u> consecutive Delivery Years...." (emphasis added).

G. Auction Clearing

1. Annual Pricing

This Settlement Agreement eliminates the seasonal aspect to capacity pricing proposed in the August 31st Filing. Therefore, the optimization algorithm utilized in the BRA shall minimize the cost of committing Capacity Resources for the entire Delivery Year.

2. Optimization to Minimize LDA Cost

This Settlement clarifies Section 5.12 of Original Attachment Y to ensure that PJM minimizes total PJM Region capacity costs, regardless of whether the quantity clearing the BRA is above or below the applicable target quantity, by providing that the optimization algorithm will select from among multiple possible alternative clearing results that satisfy applicable constraints and requirements. Such alternatives include, for example, accepting a lower-priced Sell Offer that intersects the VRR Curve and that specifies a minimum capacity block, accepting a higher-priced Sell Offer that intersects the VRR Curve and that contains no minimum-block limitations, or rejecting both of the above alternatives and clearing the auction at the higher-priced point on the VRR Curve that corresponds to the Unforced Capacity provided by all Sell Offers located entirely below the VRR Curve. Section 5.12 shall also be modified to add Section 5.12(e), entitled Equal-Priced Sell Offers, to address the situation where two or more Sell Offers would result in the same total costs to the market under the algorithm.

H. System Constraints

1. Phase-in of LDAs for RPM Pricing Purposes

This Settlement Agreement retains a transition to the full number of Locational Deliverability Areas ("LDAs"), but modifies the phase-in approach.[14] Specifically, under this Settlement Agreement, the LDA transition shall be as follows:

- For Delivery Year 2007/2008: 4 LDAs- SW MAAC (PEPCO and BG&E), Eastern MAAC (PSE&G, JCP&L, PECO, AE, DPL, RECO), MAAC Region plus APS (SW MAAC, Eastern MAAC, Penelec, Met Ed, PPL, and APS), and Rest of Market ("ROM") (ComEd, AEP, Dayton, Dominion, and Duquesne);
- For Delivery Year 2008/2009: same 4 LDAs;
- For Delivery Year 2009/2010: same 4 LDAs; and
- For Delivery Year 2010/2011 and forward: 23 LDAs proposed by PJM in the August 31st Filing.

During this Transition Period, PJM shall post, for informational purposes only, prices for each of the 23 LDAs (i.e., assuming no LDA phase-in) for each BRA.

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[14] The LDA phase-in described herein is intended to apply for RPM pricing purposes and is not intended to apply for purposes of the Regional Transmission Expansion Plan ("RTEP").

2. Identification of Transmission Constraints for Pricing Purposes

As part of the process to determine pricing for each LDA, PJM will determine and post the Capacity Emergency Transfer Objective ("CETO") and Capacity Emergency Transfer Limit ("CETL") values for all LDAs. If an LDA potentially would be constrained, PJM shall determine and post the separate VRR Curve and separate VRR Curve data (e.g., LDA Reliability Requirement, projected ILR, applicable CONE, and applicable Net CONE) for the LDA. Thus, there will be a potential for price separation for that LDA. To be clear, because the BRA shall clear using the actual resource offers in each of the LDAs, some of the LDAs may not bind in terms of a price separation.

Consistent with the phase-in of LDAs as discussed above, PJM will establish a separate VRR Curve for an LDA whenever the CETL is less than 105% of the CETO of the LDA, unless PJM determines that an acceptable level of reliability, consistent with the Reliability Principles and Standards, requires establishment of a separate VRR Curve for an LDA with a margin greater than 5%. In such a case, PJM will post on its web site before February 1, the LDA for which the VRR Curve is being established and the margin or other information that is being used rather than the 5% margin.

3. Integration with Regional Transmission Expansion Planning Process

The manner in which the Capacity Resources will be integrated with the Regional Transmission Expansion Planning ("RTEP") process shall be clarified. First, Generation Capacity Resources that do not clear in the BRAs, and are not sold elsewhere ("At Risk Generation"), shall be considered the minimum amount of at risk generation in the market efficiency analysis of the RTEP process and be considered at risk in the sensitivity cases in the RTEP market efficiency analysis. If necessary, PJM shall file to amend Schedule 6 of the PJM Operating Agreement to ensure such treatment of "at risk" generation. Second, the PJM planning market efficiency analysis shall take into account energy congestion and locational capacity prices, differentials in the initial cost-benefit determination of proposed transmission solutions, and later cost-benefit analyses.

4. LDAs for Pricing Purposes - Definitions and Process

a. Creation of New LDAs for RPM Pricing Purposes

If a new LDA is included in the PJM RTEP planning process, PJM will make a filing to create under RPM, a new LDA (including a new aggregate LDA) if such new region is projected to have a CETL less than 105% of CETO or to address other reliability concerns discussed above. In addition, market participants may propose, and PJM will evaluate, new LDAs (including new aggregate LDAs) for inclusion in the RTEP planning process and RPM.

b. Posting Unconstrained LDAs

In order to ensure that market participants have relevant information prior to the conduct of a BRA, PJM will identify on its website prior to the BRA the LDAs that do not have the potential to bind because they are not constrained LDAs.

c. Process to Change LDAs for RPM Pricing Purposes

The Settling Parties agree that in order for PJM to change any of the LDAs, either during the transition or in the end state, PJM shall make a filing under Section 205 of the FPA to effectuate such a change.

5. Transfer of Obligations to Pay Locational Reliability Charges

Original Attachment Y shall be modified to provide that for purposes of PJM settlements and billing processes, obligations to pay Locational Reliability Charges can be transferred between and among LSEs and other Market Participants as follows: PJM shall facilitate a process, similar to eSchedules, whereby before or after any BRA, an LSE or other Market Participant can provide PJM with a schedule that specifies the buyer, seller, volume of capacity to be transferred, location where capacity prices are calculated, and start and end date of that transfer. This PJM-facilitated process shall not alter the physical supply and demand balance in the BRA, and such transfers shall not establish any obligations that are incompatible with the BRA or any other auction.

I. Market Power Mitigation

All mitigation shall be as proposed by PJM in the August 31st Filing and PJM's May 19, 2006 Brief on Paper Hearing Issues (at pages 25-38), except as follows:

1. Market Power Mitigation Rules for Planned Generation Capacity Resources

Section 6.5(a)(ii) of Original Attachment Y shall be amended to provide that offers based on Planned Generation Capacity Resources shall be presumed competitive in the auctions for the first Delivery Year for which such resource qualifies as a Planned Generation Capacity Resource, but may be rejected if found by the PJM Market Monitoring Unit not to be competitive in accordance with certain specified criteria and procedures.

Planned Generation Capacity Resources that clear the BRA shall be treated as Existing Generation Capacity Resources in the auctions for any subsequent Delivery Year; provided, however, that such resources may receive certain price assurances for the two Delivery Years immediately following the first Delivery Year of service under the conditions specified in Section II.K of this Agreement.

Section 6.5(a)(ii) further shall provide that Sell Offers based on Planned Generation Capacity Resources submitted for the first year in which such resources qualify as Planned Generation Capacity Resources shall be deemed competitive and not be subject to mitigation if: (1) collectively all such Sell Offers provide Unforced Capacity in an amount equal to or greater than two times the incremental quantity of new entry required to meet the LDA Reliability Requirement; and (2) at least two unaffiliated suppliers have submitted Sell Offers for Planned Generation Capacity Resources in such LDA. Notwithstanding the foregoing, any Capacity Market Seller, together with Affiliates, whose Sell Offers based on Planned Generation Capacity Resources in that LDA are pivotal is subject to mitigation.

Where these first two conditions are not met or the Sell Offer is pivotal, the Market Monitoring Unit shall: (1) compare each such Sell Offer to Sell Offers submitted in other LDAs (with due recognition for locational differences) and to the Cost of New Entry for the LDA in which the offer otherwise would clear and other LDAs (with due recognition for locational differences); (2) evaluate potential barriers to new entry on the basis of interviews with potential suppliers and other market participants; and (3) determine, based on that analysis, whether to reject such Sell Offer as non-competitive. Following the conduct of the applicable auction and before the final determination of clearing prices, in accordance with the same timeframe for possible cost-capping of offers based on existing resources, the Market Monitoring Unit shall notify a seller whose Sell Offer is deemed non-competitive and allow such Capacity Market Seller an opportunity to submit a revised Sell Offer. PJM then shall clear the auction with such revised Sell Offer in place if the Market Monitoring Unit determines that such revised offer is competitive in accordance with the above criteria. If the revised Sell Offer is not deemed competitive, it will be rejected.

2. Modifications and Clarifications to Avoidable Cost Formula

The Avoidable Cost Rate contained in Section 6.8(a) of Original Attachment Y shall be modified and clarified as follows:

- **APIR (Avoidable Project Recovery Rate) = PI * CRF**

Where:

- **PI** is the amount of project investment reasonably required to enable a Generation Capacity Resource that is the subject of a Sell Offer to continue operating or improve availability during Peak-Hour Periods during the Delivery Year.

- **CRF** is the annual capital recovery factor from the following table applied in accordance with the terms specified below.

Age of Existing Unit (in Years)	Remaining Life of Plant (Years)	Levelized CRF
1 to 5	20	0.125
6 to 10	15	0.146
11 to 15	10	0.198
16 Plus	5	0.363
Mandatory Capital Expenditures ("CapEx")	4	0.450
40 Plus Alternative	1	1.100

Unless otherwise stated, Age of Existing Unit shall be equal to the number of years since the Unit commenced commercial operation, up to and through the relevant Delivery Year.

Remaining Life of Plant defines the amortization schedule (*i.e.*, the maximum number of years over which the Project Investment may be included in the Avoidable Cost Rate.)

Capital Expenditures and Project Investment

For any given Project Investment, a Capacity Market Seller may make a one-time election to recover such investment using: (i) the highest CRF and associated recovery schedule to which it is entitled; or (ii) the next highest CRF and associated recovery schedule. For these purposes, the CRF and recovery schedule for the "16 Plus" category is the next highest CRF and recovery schedule for both the "Mandatory CapEx" and the "40 Plus Alternative" categories. The Capacity Market Seller using the above table must provide the PJM Market Monitoring Unit with information, identifying and supporting such election, including but not limited to the age of the unit, the amount of the Project Investment, the purpose of the investment, evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment), and detailed information concerning the governmental requirement (if applicable). Absent other written notification, such election shall be deemed based on the CRF such Seller employs for the first Sell Offer reflecting recovery of any portion of such Project Investment. A Sell Offer submitted in the BRA for either or both of the 2007-2008 and 2008-2009 Delivery Years for which the "16 Plus" CRF and recovery schedule is selected may not exceed an offer price equal to the then-current Net CONE (on an unforced-equivalent basis).

For any resource using the CRF and associated recovery schedule from the CRF table that set the Capacity Resource Clearing Price in any Delivery Year, such Capacity Market Seller must also provide to the PJM Market Monitoring Unit, for informational purposes only, evidence of the actual expenditure of the Project Investment, when such information becomes available.

If the project associated with a Project Investment that was included in a Sell Offer using a CRF and associated recovery schedule from the above table has not entered into commercial operation prior to the end of the relevant Delivery Year, and the resource's Sell Offer sets the clearing price for the relevant LDA, the Capacity Market Seller shall be required to elect to either (i) pay a charge that is equal to the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR component of the Avoidable Cost Rate, this difference to be multiplied by the cleared MW volume from such Resource ("rebate payment"); (ii) hold such rebate payment in escrow, to be released to the Capacity Market Seller in the event that the project enters into commercial operation during the subsequent Delivery Year or rebated to LSEs in the relevant LDA if the project has not entered into commercial operation during the subsequent Delivery Year; or (iii) make a reasonable investment in the amount of the PI in other existing Generation Capacity Resources owned or controlled by the Capacity Market Seller or its Affiliates in the relevant LDA. The revenue from such rebate payments shall be allocated pro rata to LSEs in the relevant LDA(s) that were charged a Locational Reliability Charge for such Delivery Year, based on their Daily Unforced Capacity Obligation in the relevant LDA(s). If the Sell Offer from the Generation Capacity Resource did not set the Capacity Resource Clearing Price in the relevant LDA, no alternative investment or rebate payment is required. If the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR amount does not exceed the greater of $10 per MW-day or a 10% increase in the clearing price, no alternative investment or rebate payment is required.

Mandatory CapEx Option

The Mandatory CapEx CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), to a resource that must make a Project Investment to comply with a governmental requirement that would otherwise materially impact operating levels during the Delivery Year, where: (i) such resource is a coal, oil or gas-fired resource that began commercial operation no fewer than fifteen years prior to the start of the first Delivery Year for which such recovery is sought, and such Project Investment is equal to or exceeds $200/kW of capitalized project cost; or (ii) such resource is a coal-fired resource located in an LDA for which a separate VRR Curve has been established for the relevant Delivery Years, began commercial operation at least 50 years prior to the effective date of that certain September 29, 2006 Settlement Agreement in FERC Docket Nos. ER05-1410 and EL05-148, and the Capacity Market Seller submitting the sell offer for such resource was a signatory or an Affiliate of a signatory to such Settlement Agreement.

A Capacity Market Seller that wishes to elect the Mandatory CapEx option for a Project Investment must do so beginning with the Base Residual Auction for the Delivery Year in which such project is expected to enter commercial operation. A Sell Offer submitted in any Base Residual Auction for which the "Mandatory CapEx" option is selected may not exceed an offer price equivalent to 0.90 times the then-current Net CONE (on an unforced-equivalent basis).

40 Year Plus Alternative Option

The 40 Plus Alternative CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), for a resource that is a gas- or oil-fired resource that began commercial operation no less than 40 years prior to the conduct of the relevant BRA (excluding, however, any resource in any Delivery Year for which the resource is receiving a payment under Part V of the PJM Tariff). Generation Capacity Resources electing this 40 Plus Alternative CRF shall be treated as At Risk Generation for purposes of the sensitivity runs in the RTEP process. Resources electing the 40 Year Plus Option will be modeled in the RTEP process as "at-risk" at the end of the one-year amortization period.

A Capacity Market Seller that wishes to elect the 40 Plus Alternative option for a Project Investment must provide written notice of such election to the Office of the Interconnection no later than six months prior to the Base Residual Auction for which such election is sought; provided however that shorter notice may be provided if unforeseen circumstances give rise to the need to make such election and such seller gives notice as soon as practicable.

The Office of the Interconnection shall give market participants reasonable notice of such election, subject to satisfaction of requirements under the PJM Operating Agreement for protection of confidential and commercially sensitive information. A Sell Offer submitted in any Base Residual Auction for which the "40 Plus

Alternative" option is selected may not exceed an offer price equivalent to the then-current Net CONE (on an unforced-equivalent basis).

Section 6.8(b) of Original Attachment Y is modified as follows:

(b) For the purpose of determining an Avoidable Cost Rate, avoidable expenses are incremental expenses directly required to operate a Generation Capacity Resource that a Generation Capacity Resource Owner would not incur if such Resource did not operate during the Delivery Year or meet Availability criteria during Peak-Hour Periods during the Delivery Year.

In addition, Section 6.7 of the Original Attachment Y is modified to provide, in connection with the Capacity Market Seller's submittal of data and calculations for the Market Seller Offer Cap for each existing generation resource that the Market Monitoring Unit shall "notify the Capacity Market Seller one month prior to the auction whether such submittal will be accepted, and if not, provide to such seller detailed information as to why such submittal was not accepted."

3. Relaxed Information Requirement Conditions

The Settling Parties have agreed to delete 6.7(a)(ii) of Original Attachment Y. In addition, the Settling Parties have agreed to make non-substantive modifications to Section 6.7(b) to conform with the Settlement described herein. The Settlement Agreement also includes a new Section 6.7(c) that provides as follows:

(c) Potential auction participants identified in subsection (b) above need not submit the data specified in that subsection for any Generation Capacity Resource:

i. that is in an Unconstrained LDA Group or, if this is the relevant market, the entire PJM Region, and is in a resource class determined by the Market Monitoring Unit as not likely to include the marginal price-setting resources in such auction; or

ii. for which the potential participant commits that any Sell Offer it submits as to such resource shall not include any price above the level identified for the relevant resource class by the Market Monitoring Unit.

> The Market Monitoring Unit shall determine, in its discretion, following stakeholder consultation, the resource classes and corresponding prices described in this subsection and shall identify such resource classes and prices in the posting required by section 6.2(a). Nothing herein precludes the Market Monitoring Unit from requesting additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource; and compliance with such request shall be a condition of participation in any auction. Any Sell Offer submitted in any auction that is inconsistent with any commitment made pursuant to this subsection shall be rejected, and the Capacity Market Seller shall be required promptly to resubmit a Sell Offer that complies with such commitments. If the Capacity Market Seller does not timely resubmit its Sell Offer, it shall be deemed to have submitted a Sell Offer that complies with the commitments made under this subsection, with a default price equal to the maximum price for the class of resource identified in the Sell Offer, as previously specified by the Market Monitoring Unit in the posting required by section 6.2(a). Notwithstanding the foregoing, if the Capacity Market Seller demonstrates to the satisfaction of the Market Monitoring Unit that a significant change in circumstances warrants submission of a Sell Offer that is inconsistent with a prior commitment under this subsection, then the Market Monitoring Unit shall allow such Sell Offer provided that the Capacity Market Seller promptly notifies the Market Monitoring Unit upon becoming aware of the change in circumstances and provides all information deemed necessary by the Market Monitoring Unit to support such Sell Offer and that the offer is otherwise consistent with the requirements of this section 6. The obligation imposed under section 6.6(a) shall not be satisfied unless and until the Capacity Market Seller submits (or is deemed to have submitted) a Sell Offer that conforms to its commitments made pursuant to this subsection.

Finally, the Settling Parties have agreed to replace Section 6.7(d)(iv) with the following:

> (iv) Projected PJM Market Revenues, as defined by section 6.8(d) for any Generation Capacity Resource to which the Avoidable Cost Rate is applied.

4. Offer Cap Offset

The Settling Parties have agreed to set forth the energy and ancillary services offset to the Offer Cap in a new section to Original Attachment Y. Specifically, the Settling Parties have agreed to a new provision, Section 6.8(d), which provides that:

> (d) Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-

specific bilateral contracts from such Generation Capacity Resource, net of marginal costs for providing such energy (i.e., costs allowed under cost-based offers pursuant to Section 6.4 of Schedule 1 of the Operating Agreement) and ancillary services from such resource.

(i) For the first three BRAs (for Delivery Years 2007-08, 2008-09, 2009-10), the calculation of Projected PJM Market Revenues shall be equal to the simple average of such net revenues as described above for calendar years 2001-2006; and

(ii) For the fourth BRA (delivery year 2010-11) and thereafter, the calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net revenues as described above from the three most recent whole calendar years prior to the year in which the BRA is conducted.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because the Generation Capacity Resource was not integrated into PJM during the full period, then the Projected PJM Market Revenues shall be calculated using only those whole calendar years within the full period in which such Resource received PJM market revenues.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because it was not in commercial operation during the entire period, then the Projected PJM Market Revenues shall be calculated based upon net revenues received over the entire period by comparable units, to be developed by the MMU and the Capacity Market Seller.

5. Market Power Mitigation During the Transition Period

A new section 17.5, entitled "Market Mitigation During Transition Period" will be added to Original Attachment Y. New section 17.5 will provide as follows:

The provisions of Section 6 of this Attachment shall apply to all Reliability Pricing Model Auctions conducted during the Transition Period; provided, however, that during the Transition Period, as to a Capacity Market Seller that was a signatory to that certain Settlement Agreement dated September 29, 2006 in FERC Docket Nos. ER05-1410 and ER05-148, or any Affiliate of such a signatory, and that owns or controls no more than 10,000 megawatts of Unforced Capacity in the PJM Region, the otherwise applicable Market Seller Offer Cap provided in Section 6 shall be increased by up to the following amounts in the following years for any Sell Offer submitted by such a seller in any Unconstrained LDA Group with respect to no more than 3,000 megawatts of such Unforced Capacity:

(a) $10/MW-day for the 2007-2008 Delivery Year;

(b) $10/MW-day for the 2008-2009 Delivery Year; and

(c) $7.50/MW-day for the 2009-2010 Delivery Year;

For purposes of this provision, the 10,000 megawatt maximum shall apply separately to a Capacity Market Seller's resources subject to state rate-based regulation and resources that are not subject to state rate-based regulation.

J. Minimum Offer Price Rule for New Entry in Constrained LDAs

A new Section 5.14(h) shall be added to Original Attachment Y of the PJM Tariff, providing as follows:

(1) Prior to each Base Residual Auction, the Market Monitoring Unit shall develop locational asset-class estimates of competitive, cost-based, real levelized (year one) Cost of New Entry, net of energy and ancillary service revenues ("Net Asset Class Cost of New Entry"). Other than the levelization approach, determination of the Cost of New Entry component of the Net Asset Class Cost of New Entry shall be consistent with the methodology used to determine the Cost of New Entry set forth in Section 5.10(a)(iv)(A) of this Attachment. Notwithstanding the foregoing, the Net Asset Class Cost of New Entry shall be zero for: (i) base load resources, such as nuclear, coal and Integrated Gasification Combined Cycle, that require a period for development greater than three years; (ii) any facility associated with the production of hydroelectric power; (iii) any upgrade or addition to an existing Generation Capacity Resource; or (iv) any Planned Generation Capacity Resource being developed in response to a state regulatory or legislative mandate to resolve a projected capacity shortfall in the Delivery Year affecting that state, as determined pursuant to a state evidentiary proceeding that includes due notice, PJM participation, and an opportunity to be heard.

(2) The Market Monitoring Unit shall evaluate any Sell Offer that is based on a Planned Generation Capacity Resource submitted in a Base Residual Auction for the first Delivery Year in which such resource qualifies as such a resource, in any LDA for which a separate VRR Curve has been established, and shall determine whether such Sell Offer meets each of the following criteria:

i. Sell Offer affects the Clearing Price;

ii. Sell Offer is less than 80 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry, less than 70 percent of the Net Asset Class

Cost of New Entry for the Reference Resource effective in such LDA; and

iii. The Capacity Market Seller and any Affiliates has or have a "net short position" in such Base Residual Auction for such LDA that equals or exceeds (a) ten percent of the LDA Reliability Requirement, if less than 10,000 megawatts, or (b) five percent of the total LDA Reliability Requirement, if equal to or greater than 10,000 megawatts. A "net short position" shall be calculated as the actual retail load obligation minus the portfolio of supply. An "actual retail load obligation" shall mean the LSE's combined load served in the LDA at or around the time of the Base Residual Auction adjusted to account for load growth up to the Delivery Year, using the Forecast Pool Requirement. A "portfolio of supply" shall mean the Generation Capacity Resources (on an unforced capacity basis) owned by the Capacity Market Seller and any Affiliates at the time of the Base Residual Auction plus or minus any generation that is, at the time of the BRA, under contract for the Delivery Year.

(3) If the Market Monitoring Unit determines that all of the criteria of Section 5.14(h)(2) are met, it shall notify the Capacity Market Seller of this determination. Within five business days, or such other period to which the Market Monitoring Unit consents, such Capacity Market Seller may supply the Market Monitoring Unit with specific information about the costs and operational parameters relating to its Sell Offer. If the Capacity Market Seller fails to supply any such information within the specified time, or if the Market Monitoring Unit determines that the information provided, combined with revenues that would be earned in PJM-administered markets as determined by PJM, does not support the offer, the applicable cost-based net Cost of New Entry determined in Section 5.14(h)(1) shall be used to establish an alternative Sell Offer. The alternative Sell Offer employed in place of the actual Sell Offer shall be equal to 90 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry equal to 80 percent of the Net Asset Class Cost of New Entry for the Reference Resource. Upon timely receipt of such information, the Market Monitoring Unit shall determine whether such Sell Offer is consistent with the real levelized(year one) competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets (i.e., were all output from the unit sold in PJM-administered spot markets). The Market Monitoring Unit shall adjust the alternative Sell Offer if appropriate on the basis of the relevant and reliable supporting information available and the application of an objective analysis.

(4) The Market Monitoring Unit shall request that the Office of the Interconnection perform a sensitivity analysis on any Base Residual

Auction that included Sell Offers meeting the criteria of Section 5.14(h)(2), for which an acceptable alternative Sell Offer was not provided consistent with Section 5.14(h)(3). Such analysis shall re-calculate the clearing price for the Base Residual Auction employing in place of each actual Sell Offer meeting the criteria a substitute Sell Offer equal to 90 percent of the applicable estimated cost determined in accordance with Section 5.14(h)(1) above, or, if there is no applicable estimated cost, equal to 80 percent of the then-applicable Net CONE. If the resulting difference in price between the new clearing price and the initial clearing price differs by an amount greater than the greater of 20 percent or 25 dollars per megawatt-day for a total LDA Reliability Requirement greater than 15,000 megawatts; or the greater of 25 percent or 25 dollars per megawatt-day for a total LDA Reliability Requirement greater than 5,000 and less than 15,000 megawatts; or the greater of 30 percent or 25 dollars per megawatt-day for a total LDA Reliability Requirement of less than 5,000 megawatts; then the Market Monitoring Unit shall discard the results of the Base Residual Auction and determine a replacement clearing price and the identity of the accepted Capacity Resources using the procedure set forth in section 5.14(h)(5) below.

(5) Including all of the Sell Offers in a single Base Residual Auction that meet the criteria of 5.14(h)(4) above, PJM shall first calculate the replacement clearing price and the total quantity of Capacity Resources needed for the LDA. PJM shall then accept Sell Offers to provide Capacity Resources in accordance with the following priority and criteria for allocation: (i) first, all Sell Offers in their entirety designated as self-supply; (ii) then, all Sell Offers of zero, prorating to the extent necessary, and (iii) then all remaining Sell Offers in order of the lowest price, subject to the optimization principles set forth in Section 5.14.

(6) Notwithstanding the foregoing, this provision shall terminate when there exists a positive net demand for new resources, as defined in Section 5.10(a)(iv)(B) of this Attachment, calculated over a period of consecutive Delivery Years beginning with the first Delivery Year for which this Attachment is effective and concluding with the last Delivery Year preceding such calculation, in an area comprised of the Unconstrained LDA Group in existence during such first Delivery Year. Notwithstanding the foregoing, the Market Monitoring Unit shall reinstate the provisions of this section, solely under conditions in which a constrained LDA has a gross Cost of New Entry equal to or greater than 150 percent of the greatest prevailing gross Cost of New Entry in any adjacent LDA.

The Settling Parties agree that, in addition to the Article V provision regarding No Admissions or Precedent, contained in this Settlement Agreement, this Section J is not intended to reflect any position of the Settling Parties regarding the appropriate level of offer price for new capacity resources in a residual auction.

K. New Entry Price Adjustment

This Agreement establishes a New Entry Price Adjustment in the PJM Tariff and addresses PJM Market Monitoring Unit review of such New Entry Price Adjustment.

1. New section 5.14(c)

The Settling Parties have added a new Section 5.14(c) to Attachment DD in order to address a New Entry Price Adjustment. The new provision states as follows:

> A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:
>
> i. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource;
>
> ii. Acceptance of such Sell Offer in such BRA increases the total Unforced Capacity in the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement to a megawatt quantity corresponding to a point on the VRR Curve where price is no greater than 0.40 times the applicable Net CONE divided by (one minus the pool-wide average $EFOR_D$); and
>
> iii. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource equal to the lesser of: 1) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource; or 2) 0.90 times the then-current Net CONE, on an Unforced Capacity basis, for such LDA.
>
> If the Sell Offer is submitted consistent with the foregoing conditions, then:
>
> i. in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all resources in the LDA receive the Capacity Resource Clearing Price.

ii. in the subsequent two BRAs, if the Resource clears, it shall receive the higher of the foregoing Sell Offer price and the Capacity Resource Clearing Price for such LDA. If the Sell Offer price exceeds the Capacity Resource Clearing Price, the difference will be paid as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2.

For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

2. Market Monitor Review

The MMU's existing authority and review responsibilities will include the New Entry Price Adjustment. The MMU shall analyze and include New Entry Price Adjustment in the State of the Market Report.

L. Determination of the Cost of New Entry

1. CONE for First Four Delivery Years

Subject to Article III of this Agreement, the CONE used to establish the VRR Curves for the BRA for the first, second, third, and fourth Delivery Years (i.e., the Delivery Years commencing June 1, 2007, June 1, 2008, June 1, 2009, and June 1, 2010) shall be at the levels provided in section 5.10(a)(iii) of Original Attachment Y, offset by the Energy and Ancillary Services Revenue offsets determined in accordance with section II.M of this Agreement. The CONE and the Energy and Ancillary Services Revenue Offset shall continue to be separately calculated for any subsequent Delivery Years, and determined in accordance with the provisions of this Agreement and the PJM Tariff.

2. Procedures for Possible Automatic Adjustment to the Cost of New Entry for the Fifth and Subsequent Delivery Years

The CONE established by Section II.L.1 of this Agreement is subject to automatic adjustment under certain conditions. The procedures, conditions, and standards governing such automatic adjustments shall be set forth in a new subsection to section 5.10 of Attachment DD, providing as follows:

(B) Following the Transition Period, the CONE shall be subject to adjustment in accordance with the following:

(1) The CONE in a CONE Area shall be evaluated for possible adjustment when there is a Net Demand for New Resources in the Base Residual Auctions over a period of three consecutive Delivery Years.

(2) Net Demand for New Resources means that, for any such three-year period evaluated, the following formula yields a positive number:

FPR Adjusted Load Growth in Years 1 to 3 + Generation Retirements in Years 1 to 3 –Surplus Resources in Year 1 + (CETL in Year 3 CETL in Year 1);

where:

FPR Adjusted Load Growth in Years 1 to 3 – (Preliminary Zonal Peak Load Forecast for all Zones in such CONE Area for the third Delivery Year in such evaluation minus the Preliminary Zonal Peak Load Forecast for such Zones for the Delivery Year immediately preceding the three Delivery Years evaluated) times the Forecast Pool Requirement (substituting in such calculation, however, a percentage figure of IRM+1, rather than IRM);

Generation Retirements in Years 1 to 3 = all announced deactivations, pursuant to Part V of the PJM Tariff, of Existing Generation Capacity Resources in such CONE Area with an effective date of any day during the three consecutive Delivery Years evaluated, stated on an Unforced Capacity basis;

Surplus Resources in Year 1 = the total Unforced Capacity of all existing Generation Capacity Resources located in such CONE Area that are subject to the offer requirement in section 6.6 of this Attachment for the first Delivery Year evaluated, less the total Unforced Capacity corresponding to "Point Two" (as defined in section 5.10(a)(i)) on the Variable Resource Requirement Curves for all LDAs in such CONE Area for such Delivery Year.

CETL = Capacity Emergency Transfer Limit to the area for which there is a separate VRR curve.

(3) For each CONE Area for which there is a Net Demand for New Resources over such three-year period, as determined pursuant to subsection (b) above, the CONE shall be adjusted (if at all) as prescribed by subsection (e) to the extent required based on the quantity of Unforced Capacity cleared in the Base Residual Auction, as set forth in subsection (d).

(4) If a CONE Area encompasses areas with separate VRR Curves, then the procedures described in subsections (d) and (e) below will be applied separately for each area with a separate VRR Curve, and the CONE for the CONE Area will be determined as the average of the resulting CONE value for the areas, the average to be weighted by the LDA Reliability Requirement of each area. If, pursuant to subsection (f) below, a CONE Area that had been composed of areas with separate VRR Curves is divided into multiple CONE Areas, then the CONE for each new CONE Area will be reset based on the historical CONE values computed for that area, not the weighted average of the now-defunct CONE Area.

(5) If the quantity of Unforced Capacity cleared in the Base Residual Auction for the third Delivery Year evaluated is:

(i) in the Equilibrium Zone, no change to CONE is required.

(ii) above the Equilibrium Zone, CONE shall be decreased in accordance with subsection (e); provided, however, that no change to CONE is required if the excess of Unforced Capacity relative to the Equilibrium Zone for the third Delivery Year evaluated is less than or equal to the excess of Unforced Capacity relative to the Equilibrium Zone for the first Delivery Year evaluated.

(iii) below the Equilibrium Zone, CONE shall be increased in accordance with subsection (e); provided, however, if CONE was increased as a result of Unforced Capacity clearing below the Equilibrium Zone in a CONE adjustment evaluation hereunder for such CONE Area for the immediately preceding Delivery Year, then CONE shall be increased only if the shortage of Unforced Capacity relative to the Equilibrium Zone for the third Delivery Year evaluated is greater than or equal to the shortage of Unforced Capacity relative to the Equilibrium Zone for the first Delivery Year evaluated.

(6) In any case where an increase or decrease to CONE in a CONE Area is required by the above provisions:

(i) the then-current value of the Cost of New Entry for such CONE Area shall be compared against the Empirical CONE for such area,

where:

Empirical CONE = the weighted average for all LDAs in the CONE Area (weighted by load in such LDAs) of: (i) the average Capacity Resource Clearing Price in each such LDA determined in the Base Residual Auctions for such three Delivery Years; plus (ii) the average of the Net Energy and Ancillary Market Revenue Offsets used in the Variable Resource Requirement Curve for such LDA for such three years.

(ii) if an increase is required, CONE shall be increased by the lesser of (a) 0.50 times the positive difference between Empirical CONE and CONE; and (b) 0.10 times CONE.

where a decrease is required, CONE shall be decreased by the lesser of (a) 0.50 times the negative difference between Empirical CONE and CONE; and (b) 0.10 times CONE.

(7) Any LDA for which a separate VRR Curve has been established for the Base Residual Auctions for each of three consecutive Delivery Years shall be evaluated under the provisions of this section. If the result of such evaluation is that the CONE calculated for such LDA would differ by at least 10 percent from the CONE then applicable to such LDA, then such LDA shall be established as a CONE Area, with a Cost of New Entry adjusted based on the Cost of New Entry computed over the prior three Delivery Years for that LDA.

ADDITIONAL DEFINITIONS FOR DEFINITION SECTION

"Equilibrium Zone" shall mean:

(a) for the VRR Curve for the PJM Region, any quantity of Unforced Capacity between (i) [the PJM Region Reliability Requirement multiplied by (100% plus IRM%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation; and (ii) [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 2%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation; and

(b) for the VRR Curve for any Locational Deliverability Area, any quantity of Unforced Capacity between (i) [the LDA Reliability Requirement multiplied by (100% plus IRM%) divided by (100% plus IRM%)] minus the Forecast LDA ILR Obligation; and (ii) [the LDA Reliability Requirement multiplied by (100% plus IRM% plus 2%) divided by (100% plus IRM%)] minus the Forecast LDA ILR Obligation (if not previously accounted for in establishing the CETO for such LDA);

where:

"Forecast LDA ILR Obligation" – the sum of the Forecast Zonal ILR Obligations for all Zones in such LDA.

"CONE Area" shall mean the areas listed in section 5.10(a)(iii) and any LDAs established as CONE Areas pursuant to section 5.10(a).

M. Net Energy and Ancillary Services Revenue Offset to the Cost of New Entry Used to Establish the VRR Curve

The Net Energy and Ancillary Services Revenue Offset used to determine the VRR Curves in the BRA for the first, second, and third Delivery Years (i.e., the Delivery Years beginning on June 1, 2007, June 1, 2008, and June 1, 2009) shall be determined as proposed in section 5.10(a)(iv) to Original Attachment Y. However, the Settlement Agreement amends that subsection to provide that:

- energy revenues will be calculated on the basis of Peak-Hour Dispatch, as described herein, using Real-Time Prices;
- the Reference Resource definition in Attachment DD used as the basis of this calculation shall be revised to state that it is based on the same specific resource used in the August 31st Filing to estimate the CONE;
- the heat rate of such resource shall be 10,500 MMBtu/MWhs;
- the calculation of the Net Energy and Ancillary Services Revenue Offset for sub-regions of the PJM Region pursuant to section 5.10(a) of Attachment DD, shall use a posted fuel pricing point in such sub-region, if available, and if such pricing point is not available, a fuel transmission adder to such sub-region from an appropriate pricing point for the PJM Region; and
- if such sub-region, for which a separate CONE was calculated, was not integrated into the PJM Region for the entire applicable period, then the

offset shall be calculated using only those whole calendar years during which the sub-region was integrated.

For purposes of the Base Residual Auction for any Delivery Year following the first three Delivery Years, the Energy and Ancillary Services Revenue Offset shall be calculated in the same manner as set forth in this section, except that the calculation shall be based on the three consecutive calendar years preceding such calculation.

Peak-Hour Dispatch, for purposes of calculating the Net Energy and Ancillary Services Revenue Offset for the Reference Resource prescribed above, will be defined in Attachment DD as an assumption that the Reference Resource is dispatched in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average real-time LMP for the area for which the Net CONE is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be dispatched independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be dispatched for such block. The details of such calculation will be posted in the PJM Manuals.

N. Deficiency Charges

1. Ability to Cure

The charges and credits proposed in the Sections 7-13 of Original Attachment Y shall apply. Provided, however, that a Capacity Market Seller that fails or is expected to fail a rating test under Section 7 may obtain and commit Unforced Capacity from a replacement Generation Capacity Resource meeting the same locational requirements.

Any such commitment shall be effective upon no less than one day's notice to the Office of the Interconnection. Such Unforced Capacity may include uncommitted/uncleared Sell Offer blocks from Generation Capacity Resources that were otherwise committed. The charge shall be assessed from the first day of the season for which the test was failed through the last day before the effective date of the commitment of such replacement Generation Capacity Resource in an amount equal to the full shortage of Unforced Capacity determined in Section 7.1(b) of Attachment DD. Thereafter, any charges assessed on the Capacity Market Seller that fails such a rating test under Section 7 shall be assessed for such full shortage of Unforced Capacity less any amount from such replacement Generation Capacity Resource.

2. Peak Hour Period Availability

The Settling Parties agree to add a new Section 10 to Attachment DD that provides for peak hour availability charges and credits. The new Section 10 will provide as follows:

(a) To preserve and maintain the reliability of the PJM Region and to encourage Capacity Market Sellers to maintain the availability of Generation Capacity Resources during critical peak hours of the Delivery Year, each Capacity Market Seller that commits a Generation Capacity Resource for a Delivery Year shall be credited or charged to the extent the critical peak-period availability of its committed Generation Capacity Resources exceeds or falls short, respectively, of the expected availability of such resources. Charges and credits hereunder shall not apply to wind or solar resources.

(b) Critical peak periods for purposes of this assessment ("Peak-Hour Periods") shall be the hour ending 1500 EPT through the hour ending 1900 EPT on any day during the calendar months of June through August that is not a Saturday, Sunday, or federal holiday, and the hour ending 800 EPT through the hour ending 900 EPT and the hour ending 1900 EPT through the hour ending 2000 EPT on any day during the calendar months of January and February that is not a Saturday, Sunday or federal holiday.

(c) Peak-Period Equivalent Forced Outage Rate and Peak-Period Capacity Calculations

The Peak-Period Equivalent Forced Outage Rate shall be calculated for Peak-Hour Periods based on the following formula:

$EFOR_P$ (%) = (FOH + EFPOH) / (SH + FOH)

where

FOH = full forced outage hours when the unit was called upon, excluding those outages deemed as OMC (as defined below);

EFPOH = equivalent forced partial outage hours when the unit was called upon, excluding those outages deemed as OMC (as defined below); and

SH = service hours as defined pursuant to NERC GADS standards.

The Peak-Period Capacity of a Generation Capacity Resource shall be calculated as follows:

PCAP = ICAP * (1.0 - $EFOR_P$)

where

ICAP = the installed capacity rating of such Generation Capacity Resource

(d) Determination of Expected $EFOR_P$ and PCAP for Generation Capacity Resources: For each Delivery Year, the expected $EFOR_P$ and PCAP of each Generation Capacity Resource committed to serve load in such Delivery Year shall be the $EFOR_P$ and UCAP, respectively, calculated on a rolling-average basis using such resource's service history during the five consecutive annual periods of twelve consecutive months ending September 30 last preceding such Delivery Year. Such $EFOR_D$ and UCAP shall be determined in accordance with Schedule 5 of the Reliability Assurance Agreement, which excludes (for purposes of Capacity Resource UCAP calculations) outages deemed outside management control in accordance with the standards and guidelines of NERC ("Outside Plant Management Control" or "OMC") as defined in the Generating Availability Data System, Data Reporting Instructions in Attachment K or its successor.

(e) For each Delivery Year, the actual $EFOR_P$ and PCAP of each Generation Capacity Resource shall be calculated during the Peak-Hour Periods of such Delivery Year, provided however, that such calculation shall not include any day such a resource was unavailable if such unavailability resulted in a charge or penalty due to delay, cancellation, retirement, de-rating, or rating test failure. The full or partial forced outage hours when called upon shall be those outage hours during which the cost-based offer for energy from the resource would have been less than the applicable Locational Marginal Price for such resource, or when the Office of the Interconnection would have called upon the resource (absent the outage) for operating reserves, in both cases as determined by the Office of the Interconnection in accordance with the procedures specified in the PJM Manuals (including, without limitation, respecting such unit's current operating constraints). In addition, for single-fueled, natural gas-fired units, a failure to perform during the winter Peak-Hour Period shall be excused for purposes of this section if the Capacity Market Seller can demonstrate to the Office of the Interconnection that such failure was due to non-availability of gas to supply the unit.

(f) If the calculation under subsection (e) for any Generation Capacity Resource for a Delivery Year results in fewer than fifty total Service Hours during Peak Hour Periods, then the actual $EFOR_P$ for purposes of such calculation shall be the resource's $EFOR_D$ and the actual PCAP for purposes of such calculation shall be the resource's UCAP, in both cases considering all hours in the Delivery Year (to the extent required by the $EFOR_D$ and UCAP calculations).

(g) For each Delivery Year, the excess or shortfall in Peak-Hour Period availability for each Generation Capacity Resource shall be determined by comparing such resource's expected and actual PCAP, subject to the limitation under subsection (h) below. The net Peak-Hour Period availability shortfall or excess for each Capacity Market Seller and FRR Entity in each Locational Deliverability Area, shall be the net of the shortfalls and excesses of all Generation Capacity Resources in such Locational Deliverability Area committed by such Capacity Market Seller for such Delivery Year.

(h) As to any Generation Capacity Resource experiencing or expected to experience a full or partial outage during any Peak-Hour Period that would or could result in a shortfall under subsection (g) above, a Capacity Market Seller may obtain and commit Unforced Capacity from a replacement Generation Capacity Resource (not previously committed) meeting the same locational requirements as such resource. Such Unforced Capacity shall be recognized for purposes of this section prospectively from the effective date of commitment of such replacement resource, and to the extent such replacement Unforced Capacity thereafter is available during Peak-Hour Periods, any shortfall that otherwise would have been calculated shall be reduced to that extent. Any such commitment of replacement capacity shall be effective upon no less than one day's notice to the Office of the Interconnection.

(i) The shortfall determined for any Generation Capacity Resource shall not exceed an amount equal to 0.50 times the Unforced Capacity of such resource; provided, however, that if such limitation is triggered as to any

Generation Capacity Resource for a Delivery Year, then the decimal multiplier for this calculation as to such resource in the immediately succeeding Delivery Year shall be increased to 0.75, and if such limitation again is triggered in such succeeding Delivery Year, then the multiplier shall be increased to 1.00. The multiplier shall remain at such elevated level for each succeeding Delivery Year until the shortfall experienced by such resource is less than 0.50 times the Unforced Capacity of such resource for three consecutive Delivery Years.

(j) A Peak-Hour Period Availability Charge shall be assessed on each Capacity Market Seller with a net shortfall in PCAP in an LDA, where such charge is equal to such shortfall times the annual Capacity Clearing Price determined for such Locational Deliverability Area for such Delivery Year (365* the clearing price expressed in $/MW-day).

(k) The revenues from such charges shall be distributed to the Capacity Market Sellers, and FRR Entities that committed Generation Capacity Resources, in such Locational Deliverability Area that have net excess PCAP for such Delivery Year, provided however that any such seller shall be paid no more than the product of such seller's net excess PCAP times the Capacity Resource Clearing Price determined for such Locational Deliverability Area for such Delivery Year. Any excess revenues remaining after such distribution shall be distributed to all LSEs in the Zone that were charged the same Locational Reliability Charge for the Delivery Year for which the Peak Hour Availability Charge was assessed, and to all FRR Entities in the Zone that are LSEs and whose FRR Capacity Plan resources over-performed in the Delivery Year, on a pro-rata basis in accordance with each LSE's Daily Unforced Capacity Obligation.

(l) The Office of the Interconnection shall provide estimated charges and credits based on the summer Peak-Hour Periods within three calendar months after the end of the summer period. Final charges and credits for the Delivery Year shall be billed within three calendar months following the end of the winter period.

By June 1, 2007, PJM will analyze the historical availability of gas supplies in the PJM Region during winter conditions and its impact on the ability of generators to deliver capacity and to otherwise affect their reliability of performance. PJM shall, to the extent that such analysis indicates is necessary, develop adequate performance metrics within the PJM Manuals and propose any necessary changes to Section 10(e) of Attachment DD. Pending the outcome of the above study and acceptance by FERC of the resulting FPA

Section 205 filing by PJM, the following, as set forth in new section 10(e) above, shall apply: For single fueled natural gas-fired units, a failure to perform during the winter $EFOR_P$ period shall be excused for purposes of the $EFOR_P$ performance metric if Seller can demonstrate to the OI that such failure was due to non-availability of gas to supply the unit.

O. Fixed Resource Requirement

The long-term Fixed Resource Requirement Alternative ("FRR Alternative") proposed by PJM in its August 31st Filing shall be revised as provided below. The FRR Alternative discussed herein provides an alternative means to RPM for an eligible LSE to satisfy its Unforced Capacity Obligation for loads in the PJM Region. The FRR Alternative applies only to the ability of an FRR Entity to meet its Unforced Capacity Obligation and does not affect the ability of an FRR Entity to participate in all other voluntary markets administered by PJM. Terms used in this Section II.O are as defined in the PJM RAA.

1. Eligibility

An investor-owned utility ("IOU"), Electric Cooperative, or Public Power Entity, as defined in the RAA, shall be eligible to select the FRR Alternative if it demonstrates the capability to satisfy the entire Unforced Capacity obligation for all load, including load growth, in the applicable FRR Service Area for the term of such entity's participation in the FRR Alternative.

Eligible entities that select the FRR Alternative must designate all load, including load growth, in the PJM Region.

However, an FRR Entity may split its loads between RPM and the FRR Alternative if: (1) the Party elects the FRR Alternative for all load (including expected load growth) in one or more FRR Service Areas; (2) the Party complies with the rules and procedures of the Office of the Interconnection and all relevant Electric Distributors related to the metering and reporting of load data and settlement of accounts for separate FRR Service Areas; and (3) the Party separately allocates its Capacity Resources to and among FRR Service Areas in accordance with rules specified in the PJM Manuals. The Office of the Interconnection shall use sub-accounts for Parties meeting these conditions, to facilitate implementation of these provisions.

In addition to the eligibility requirements of Paragraph 1 above, a Single-Customer LSE may select the FRR Alternative, provided that: (a) the Single-Customer LSE is a signatory to this Settlement Agreement (or is an entity that (i) is a named member of an association or coalition that is a signatory to the Settlement Agreement, and (ii) does not file or join in any comments opposing this Settlement Agreement); (b) the Single-Customer LSE selects the FRR Alternative on or before April 1, 2008; (c) the Single-Customer LSE meets the requirements of Section B.3. of Schedule 8.1 to the PJM RAA; and (d) the aggregate total of such selections does not exceed 1000 MW of Obligation Peak Load in the PJM Region.

2. Election, and Termination of Election, of the FRR Alternative

An entity eligible for the FRR Alternative must make its initial selection of the FRR Alternative option no less than two months before the conduct of the BRA for the first Delivery Year for which such election is to be effective. Such notice must be provided in writing to the Office of the Interconnection and the minimum duration of the FRR Alternative selection is five consecutive Delivery Years.

An FRR Entity may terminate its election of the FRR Alternative effective with the commencement of any Delivery Year following the minimum five Delivery Year commitment by providing written notice of such termination to PJM no later than two months prior to the BRA for such Delivery Year. An FRR Entity that has terminated its election of the FRR Alternative shall not be eligible to re-elect the FRR Alternative for a period of five consecutive Delivery Years following the effective date of such termination.

Notwithstanding Sections B.1. and B.2. above, in the event of a State Regulatory Structural Change, as defined in Section 1.81 of the RAA, the affected FRR Entity may either elect the FRR Alternative or terminate its election of the FRR Alternative effective as to any Delivery Year by providing written notice of such election or termination to PJM as soon as possible but in any event no later than two (2) months prior to the BRA for such Delivery Year.

No later than one month prior to the deadline for entities to select the FRR Alternative, PJM shall post on its website the percentage of Capacity Resources required to be located in each LDA.

3. FRR Capacity Plan and FRR Commitment Insufficiency Charge

No later than one month before the initial BRA after FRR selection, each FRR Entity shall submit its FRR Capacity Plan to PJM demonstrating its commitment of Capacity Resources for the term of such election sufficient to meet the FRR Entity's Daily Unforced Capacity Obligation for the load identified in the FRR Capacity Plan. Each FRR Entity shall extend and update such plan by no later than one month prior to the BRA for each succeeding Delivery Year.

Each FRR Capacity Plan shall indicate the nature and current status of each resource, including the status of each planned Generation or Demand Response resource, the planned deactivation or retirement of any such resource, and the status of commitments for each sale or purchase of capacity included in the FRR Capacity Plan.

The FRR Capacity Plan of any FRR Entity that commits, for any Delivery Year, not to sell surplus Capacity Resources as a Capacity Market Seller in the RPM auctions, either directly or indirectly, shall designate Capacity Resources in an amount (MW) no less than the Forecast Pool Requirement for each applicable Delivery Year times the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast for such Delivery Year. Those FRR Entities that do not commit, for any Delivery Year, to not sell surplus Capacity Resources as a Capacity Market Seller in the RPM auctions, either directly or indirectly, shall designate Capacity Resources at least equal to the Threshold Quantity, as defined in Section 1.82 and Schedule 8.1 to the PJM RAA. The Threshold Quantity cannot be sold into the RPM auctions, but can be used to meet the FRR Entity's load growth or be sold to an entity outside of PJM or to another FRR Entity.

All Capacity Resources committed in an FRR Capacity Plan shall meet the applicable Capacity Resource requirements pursuant to the RAA and the PJM Operating Agreement and must be on a unit-specific basis. Capacity Resources that are subject to bilateral contract(s) for less than a full Delivery Year may be committed in an FRR Capacity Plan if the resources included in such plan in the aggregate satisfy all obligations for all Delivery Years.

All load management programs on which an FRR Entity intends to rely for a Delivery Year must be included in the FRR Capacity Plan and satisfy all requirements applicable to Demand Resources. However, previously uncommitted Unforced Capacity from such load management programs may be used to satisfy an increased capacity obligation of an FRR Entity.

For each LDA for which PJM establishes a separate VRR Curve for any Delivery Year addressed by a Capacity Resource Plan, the plan must include a minimum percentage of Capacity Resources for such Delivery Year located within such LDA ("Percentage Internal Resources Required"). Such Percentage Internal Resources Required shall be calculated as provided in Section D.5. of Schedule 8.1 to the PJM RAA. An FRR Entity may reduce its Percentage Internal Resources Required for an LDA by committing to a Qualified Transmission Upgrade, as set forth in Attachment DD to the PJM Tariff, that increases the CETL for such LDA.

PJM shall assess the adequacy of all FRR Capacity Plans. If PJM determines that an FRR Capacity Plan submitted by an entity seeking to elect the FRR Alternative does not satisfy the Party's capacity obligations, the entity shall not be permitted to elect the FRR Alternative.

If a previously approved FRR Entity submits an FRR Capacity Plan that is not sufficient, the Office of the Interconnection shall notify the FRR Entity, in writing, of the insufficiency within five (5) business days of the submittal of the FRR Capacity Plan. If the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then the FRR Entity shall be assessed an FRR Commitment Insufficiency Charge. The amount of this charge shall be equal to two times the CONE for the relevant location, times the shortfall of Capacity Resources below the FRR Entity's capacity obligation, including any Threshold Quantity requirement, for the remaining term of the plan.

4. Conditions on Purchases and Sales of Capacity Resources by FRR Entities

An FRR Entity may not include in its FRR Capacity Plan for any Delivery Year any Capacity Resource that has cleared in any RPM auction for such Delivery Year. An FRR Entity may include in its FRR Capacity Plan Capacity Resources obtained from another FRR Entity, provided, however, that each FRR Entity is responsible for meeting its own capacity obligations and that the same megawatts of Unforced Capacity shall not be committed to more than one FRR Capacity Plan for any given Delivery Year.

An FRR Entity that designates Capacity Resources in its FRR Capacity Plan for a Delivery Year based upon a Threshold Quantity may offer to sell Capacity Resources in excess of that needed for the Threshold Quantity in an RPM auction, provided, however, that such sales must not exceed an amount equal to the lesser of (a) 25% times the Unforced Capacity equivalent of the IRM for such Delivery Year times the Preliminary Forecast Peak Load for which the FRR Entity is responsible under its plan for such Delivery Year, or (b) 1300 MW.

An FRR Entity that designates Capacity Resources in its FRR Capacity Plan for a Delivery Year based upon a Threshold Quantity may not offer to sell such resources in any RPM auction, but may use such resources to meet any increased capacity obligation due to unanticipated load growth, or may sell such resources outside the PJM region or to another FRR Entity, subject to Section D of Schedule 8.1 of the RAA.

An entity that selects the FRR Alternative for only part of its load in the PJM Region that designates Capacity Resources as Self-Supply in an RPM auction to meet its expected Daily Unforced Capacity Obligation shall not be required, solely due to such designation, to identify Capacity Resources in its FRR Capacity Plan based on the Threshold Quantity. However, such entity may not designate Capacity Resources in excess of the lesser of (a) 25% times the entity's total Unforced Capacity Obligation or

(b) 200 MW. An entity can avoid this limitation by identifying Capacity Resources in its FRR Capacity Plan based on the Threshold Quantity.

5. FRR Daily Unforced Capacity Obligations and Deficiency Charges

For each billing month during a Delivery Year, the Daily Unforced Capacity Obligation of an FRR Entity shall be determined on a daily basis for each Zone as provided in Section F of Schedule 8.1 to the RAA.

An FRR Entity shall be assessed an FRR Capacity Deficiency Charge in each Zone addressed in the Entity's FRR Capacity Plan for each day during a Delivery Year that it fails to satisfy its Daily Unforced Capacity Obligation in each Zone. Such Capacity Deficiency Charge shall be in an amount equal to the deficiency below such FRR Entity's Daily Unforced Capacity Obligation for such Zone times twice the Cost of New Entry applicable to such Zone.

If an FRR Entity acquires load that is not included in the Preliminary Zonal Peak Load Forecast, such acquired load shall be treated in the same manner as provided in Sections H.1 and H.2 of Schedule 8.1 to the RAA.

6. Capacity Resource Performance

Any Capacity Resource committed by an FRR Entity in an FRR Capacity Plan for a Delivery Year shall be subject during such Delivery Year to the following charges as set forth in Attachment DD to the PJM Tariff: (a) Generation Resource Rating Test Failure Charge (Attachment DD, Section 7); (b) Capacity Resource Deficiency Charge (Attachment DD, Section 8); (c) Peak Season Maintenance Compliance Penalty Charge (Attachment DD, Section 9); (d) Peak Hour Period Availability Charges and Credits (Attachment DD, Section 10); (e) Demand Resource and ILR Compliance Penalty

Charge (Attachment DD, Section 11); and (f) Emergency Procedure Charge (Attachment DD, Section 13); provided, however, that the Daily Deficiency Rate under Sections 7, 8, 9 and 13 of Attachment DD to the PJM Tariff, and the charge rates under Sections 10 and 12 of Attachment DD to the PJM Tariff, shall be the applicable Net Cost of New Entry. An FRR Entity shall have the same opportunities to cure deficiencies and avoid or reduce associated charges during the Delivery Year that a Market Seller has under Sections 7 and 10 of Attachment DD to the PJM Tariff. An FRR Entity may cure deficiencies and avoid or reduce associated charges prior to the Delivery Year by procuring replacement Unforced Capacity outside of any RPM auction and committing such capacity in its FRR Capacity Plan.

7. Annexation

In the event a Public Power Entity annexes service territory to include new customers on sites where no load had previously existed, then incremental load on such a site shall be treated as unanticipated load growth with an obligation to have sufficient resources in the Delivery Year.

In the event a Public Power Entity annexes service territory to include load from an entity that has not elected the FRR Alternative, then:

a. For any Delivery Year for which a BRA already has been conducted, such acquiring Public Power Entity shall meet its obligations for the incremental load by paying PJM for incremental obligations (including any additional demand curve obligation) at the Capacity Resource Clearing Price for the relevant location. PJM shall use such revenues to pay capacity resources that cleared in the BRA for that LDA.

b. For any Delivery Year for which a BRA has not been conducted, such acquiring FRR Entity shall include such incremental load in its FRR Capacity Plan.

Annexation whereby a Party that has not elected the FRR Alternative acquires load from an FRR entity:

a. For any Delivery Year for which a BRA already has been conducted, PJM would consider shifted load as unanticipated load growth for purposes of determining whether to hold a Second Incremental Auction, and if a Second Incremental Auction is held, the FRR Entity would have a must offer requirement for sufficient capacity to meet the load obligation of shifted load. If no Second Incremental Auction is held, the FRR Entity may sell associated volumes of capacity into RPM or bilaterally.

b. For any Delivery Year for which a BRA has not been conducted, the FRR Entity that lost such load would no longer include such load in its FRR Capacity Plan, and PJM would include shifted load in future BRAs.

8. Savings Clause for State-Wide FRR Program

Schedule 8.1 of the RAA shall include the following savings clause:

Nothing herein shall obligate or preclude a state, acting either by law or through a regulatory body acting within its authority, from designating the Load Serving Entity or Load Serving Entities that shall be responsible for the capacity obligation for all load in one or more FRR Service Areas within such state according to the terms and conditions of this Settlement Agreement and the PJM Tariff and Reliability Assurance Agreement. Each LSE subject to such state action shall become a Party to the PJM Reliability Assurance Agreement and shall be deemed to have elected the FRR Alternative.

9. FRR Interaction with RTEP

The Settling Parties recognize the following principles concerning interaction of the FRR Alternative with the Regional Transmission Expansion Planning ("RTEP") process:

RPM auctions will be conducted and capacity clearing prices will be established for any LDA that includes loads for which the FRR Alternative has not been elected, and the payments for capacity based on such clearing prices will be considered in PJM's Office of the Interconnection's market efficiency analysis for economic-based transmission upgrades or enhancements.

RPM auctions will not be conducted for any LDA in which the FRR Alternative has been elected as to all load.

The PJM market efficiency analysis for economic-based transmission upgrades or enhancements shall be applied consistently throughout the PJM Region in accordance with applicable provisions of the PJM Tariff; provided however that for any LDA in which the FRR Alternative has been elected as to all load, such market efficiency analysis will not consider payments for capacity within such LDA.

In accordance with the settlement revisions to the RAA included herewith, an FRR Entity may include in its FRR Capacity Plan a transmission upgrade that increases the CETL into the LDA served by such FRR Entity and reduces the LDA's reliance on Capacity Resources located within such LDA.

Any Party's election of the FRR Alternative shall not change PJM's planning analysis for reliability-based transmission upgrades or enhancements.

P. Other Issues

1. Resource Operational Reliability Requirements

The Settling Parties agree that the Resource Operational Reliability Requirements included in the August 31st Filing shall be eliminated. No later than June 2008, PJM shall implement markets and/or market rules for the PJM Region, outside of the RPM markets, to address the "Operational Reliability Requirements" described in the August 31st Filing (i.e., load-following (which includes cycling) and thirty minute reserves). PJM shall make a filing, either through a stakeholder process, or if that fails, unilaterally, in time to implement this subsection by June 2008.

2. Transmission, Generation, and Demand Response Coordination

A forum shall be established for discussion dedicated to increase coordination among PJM, state siting authorities, regulatory commissions, and PJM stakeholders to identify, evaluate, and hopefully rectify, any barriers to entry of investment in generation, transmission, and demand response.

3. Barriers to Infrastructure Development

The Settling Parties agree that the market needs to be made aware of barriers to infrastructure development. To that end, as part of the annual State of the Market Report, the MMU will analyze and identify barriers, if any, to infrastructure development in each LDA.

4. Demand Response and Energy Efficiency

The Settling Parties commit to establish additional process within the PJM region for pursuing and supporting demand response and incorporating energy efficiency applications.

5. Locational Reliability Charge

Section 5.14 of Attachment DD is amended to clarify that the Locational Reliability Charge is assessed for each Zone (rather than an LDA), including Zones composed of multiple LDAs.

6. Fulfillment of Obligations Under EL03-236

This Settlement Agreement fulfills the obligations of Paragraph 10 of the Settlement Agreement filed and approved in PJM Interconnection, LLC, Docket No. EL03-236.

7. Firm Capacity Exports

PJM shall file separately to address appropriate charges and credits as necessary to reflect locational price differences in capacity exported from the PJM region.

8. Long-Term Market Design

Nothing herein shall preclude the development of a long-term market design that does not rely upon an administrative capacity construct at a later time.

9. Tariff Clarifications and Corrections

Attachment DD is modified to clarify and correct errors, omissions, and inconsistencies in the August 31st Filing, including (but not limited to): (a) determinations of the LDAs and increases in import capability associated with a Qualifying Transmission Upgrade (e.g., Sections 5.6.1(g) and 5.14(d)); (b) clarification to ILR payment provisions (e.g., Section 11(b)); (c) rules to ensure that incremental CTRs do not exceed the total CTRs available to loads in any LDA (e.g., Sections 5.15 and 5.16); and (d) rules governing the allocation of CTR credits in nested LDAs (e.g., section 5.15). In addition, the Reliability Assurance Agreement included with the August 31st Filing shall be updated to reflect relevant amendments to the East RAA, West RAA, or South RAA that have become effective since August 31, 2005.

III. FILING RIGHTS

Nothing contained in this Settlement Agreement shall be construed as affecting in any way PJM's right unilaterally to make application to the FERC for a change in rates, terms and conditions under section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder. Nothing contained in the Settlement Agreement shall be construed as restricting any rights of the other parties under the Federal Power Act, including rights under section 206. Prior to PJM's exercise of its 205 rights with respect to changing the Reference Resource or the CONE Areas, PJM shall (i) hold at least one stakeholder meeting to discuss the proposed changes, and (ii) provide stakeholders at least 15 calendar days' notice of any such stakeholder meeting.

IV. APPROVAL AND EFFECTIVE DATE OF SETTLEMENT AGREEMENT

The Parties shall seek and cooperate in securing Commission approval of this Settlement Agreement. This Settlement Agreement shall become effective as of the date on which the Commission approves or accepts the Settlement Agreement in its entirety, including the revised PJM Tariff sheets in Attachments A through F.

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

V. MISCELLANEOUS PROVISIONS

Amendments to the PJM Agreements

The amendments to the PJM Tariff, the Operating Agreement, RAA, West RAA and RAA South set forth in Attachments A through F to this Settlement Agreement implement the terms and conditions of this Settlement Agreement and are incorporated as part of this Settlement Agreement. Unless otherwise provided in this Settlement Agreement, the provisions in the August 31st Filing apply. To the extent there is a conflict between any provisions of this Settlement Agreement and the attached tariff and agreement provisions, the attached tariff and agreement provisions shall govern.

Just and Reasonable Standard. The Commission's review of any proposed modifications to this Settlement Agreement shall be based on the just and reasonable standard and not the public interest standard.

No Admissions or Precedent. This entire Settlement Agreement, and the Parties' performance of their obligations hereunder, are the result of the settlement and compromise of all the claims and actions expressly addressed in this Settlement Agreement, and neither the Settlement Agreement nor the Parties' performance hereunder shall be deemed to be an admission of any fact or of any liability. This Settlement Agreement shall be binding on the Parties only with respect to the subject matter of this Settlement Agreement, and shall not bind the Parties to apply the principles or provisions of this Settlement Agreement to any other agreement, arrangement, or proceeding. The Settlement Agreement establishes no principles and no precedent with respect to any issue in this proceeding. The acceptance of this Settlement Agreement by the Commission shall not in any respect constitute a determination by the Commission as to the merits of any allegation or contention made in this proceeding.

Entire Agreement. This Settlement Agreement, including any attachments, constitutes the entire agreement between and among the Parties, and no other agreement with regard to the matters addressed in this Settlement Agreement shall be binding on the Parties except by written amendment to this Settlement Agreement. Except for the terms and conditions enumerated in this Settlement Agreement and any attachment hereto, the Parties acknowledge and agree that the Parties have not made any other promises, warranties, or representations to each other or any other Party regarding any aspect of the settlement of the matters addressed in this Settlement Agreement. Each Party acknowledges that it has read this Settlement Agreement and executed it without relying upon any other promise, warranty, or representation, written or otherwise, of any other Party. Each Party acknowledges that no other Party has made any promise, warranty, or representation, express or implied, to induce the Parties to execute this Settlement Agreement.

Settlement Discussions. The discussions between the Parties that have produced this Settlement Agreement have been conducted on the explicit understanding, pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602, that all settlement communications and discussions shall be privileged and confidential, shall be without prejudice to the position of any Party or participant making such communications or participating in any such discussions, and are not to be used in any manner in connection with this proceeding, any other proceeding, or otherwise, except to the extent necessary to enforce its terms.

Further Assurances. Following execution of this Settlement Agreement, the Parties shall prepare and execute any further pleadings, documents, or amendments to existing or future PJM agreements reasonably necessary to effectuate the Parties' intent under this Settlement Agreement.

Successors and Assigns. This Settlement Agreement is binding upon and for the benefit of the Parties and their successors and assigns.

Authorizations. Each person executing this Settlement Agreement represents and warrants that he or she is duly authorized and empowered to act on behalf of, and to sign for, the Party for whom he or she has signed.

Counterparts. This Settlement Agreement may be executed in one or more counterparts, each of which shall be deemed to be an original and all of which together shall be deemed to be one and the same instrument.

IN WITNESS WHEREOF, the Parties have caused this Settlement Agreement to be duly executed.

pjm/rpm documents/rpm settlement agreement - stripped

Signature Page for
Settlement Agreement and
Offer of Settlement
Filed on September 29, 2006 in
FERC Docket Nos. ER05-1410 and EL05-148

Robert Weinberg / PMF

Robert Weinberg
Duncan, Weinberg, Genzer & Pembroke, P.C.

On Behalf Of
Allegheny Electric Cooperative, Inc.

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Randall Palmer /RMF

Randall B. Palmer
Senior Attorney
Allegheny Energy, Inc.

On Behalf Of
Monongahela Power Company,
The Potomac Edison Company, and
West Penn Power Company, all doing
business as Allegheny Power, and
Allegheny Generating Company

Craig Galligan /RMF

Craig Galligan
Senior Attorney
Allegheny Energy, Inc.

On Behalf of
Allegheny Energy Supply Company, LLC and is subsidiaries, including
Buchanan Energy Company of Virginia, LLC and
Buchanan Generation, LLC

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J. Craig Baker
Senior Vice President of Regulatory Services
American Electric Power Service Corporation

On Behalf Of:
Appalachian Power Company
Columbus Southern Power Company
Indiana Michigan Power Company
Kentucky Power Company
Kingsport Power Company
Ohio Power Company
Wheeling Power Company

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Donald J. Sipe
Partner
Preti Flaherty Beliveau & Pachios, LLP

On Behalf Of
American Forest and Paper Association
NewPage Corporation

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David Pomper /DMF

David E. Pomper
Spiegel & McDiarmid

Attorney For and On Behalf Of
Blue Ridge Power Agency and its members:
City of Bedford, City of Bristol, City of Danville,
Town of Front Royal, City of Martinsville, City of Radford,
Town of Richlands, and City of Salem, all of Virginia;
Virginia Polytechnic Institute and State University
(including its Education and General and Auxiliaries accounts);
Central Virginia Electric Cooperative; and
Craig-Botetourt Electric Cooperative.

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Steve Wemple / P MF

Stephen B. Wemple
Vice President, Regulatory Affairs
Con Edison Competitive Shared Services

On Behalf Of
Consolidated Edison Energy, Inc.

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Michael Yuffee /PMF

Michael Yuffee, Esq.
McDermott Will & Emery

On Behalf Of
Baltimore Gas and Electric Company
Big Sandy Peaker Plant, LLC
Calvert Cliffs Nuclear Power Plant, Inc.
Constellation Energy Commodities Group, Inc.
Constellation Generation Group, LLC
Constellation NewEnergy, Inc.
Constellation Power Source Generation, Inc.
Handsome Lake Energy, LLC
University Park Energy, LLC
Wolf Hills Energy, LLC

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Gary Stephenson

Gary Stephenson
Vice President, Commercial Operations
DPL Inc.

On Behalf Of
Dayton Power & Light Co.
DPL Energy, LLC

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Fred Wood / PMF

Fred G. Wood
Senior Vice President, Financial Management
Dominion Resources Services, Inc

On Behalf Of
Virginia Electric and Power Company
Dominion Energy Marketing, Inc.
Dominion Retail, Inc.
Armstrong Energy Limited Partnership, LLLP
Elwood Energy, LLC
Fairless Energy, LLC
Pleasants Energy, LLC
Dresden Energy, LLC
Kincaid Generation, LLC
State Line Energy, LLC

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Kenneth Jennings
Director – Market and RTO Services
Duke Energy Americas

On Behalf Of
Duke Energy North America, LLC

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Reem Fahey / PMF

Reem Fahey
Managing Director, Market Policy
Edison Mission Energy

On Behalf Of
Edison Mission Energy
Edison Mission Marketing & Trading, Inc.
Midwest Generation EME, LLC

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Elizabeth A. Moler

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On Behalf Of
Exelon Corporation and its subsidiaries
Exelon Generation
Commonwealth Edison Company
PECO Energy Company

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On Behalf Of
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Doswell Limited Partnership
Backbone Mountain Windpower LLC
Mill Run Windpower LLC
Somerset Windpower LLC
Meyersdale Windpower LLC
Waymart Wind Farm, LP
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On Behalf Of
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Senior Vice President, Mirant Mid-Atlantic, LLC
Senior Vice President, Mirant Potomac River, LLC
Senior Vice President, Mirant Sugar Creek, LLC

On Behalf Of
Mirant Energy Trading, L.L.C.
Mirant Chalk Point, LLC
Mirant Mid-Atlantic, LLC
Mirant Potomac River, LLC
Mirant Sugar Creek, LLC

By: /s/ Denise C. Goulet

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On Behalf Of
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Atlantic City Electric Company
Delmarva Power & Light Company
Potomac Electric Power Company
Conectiv Energy Supply, Inc.
Conectiv Atlantic Generation
Conectiv Delmarva Generation, Inc.
Conectiv Bethlehem, LLC
Pepco Energy Services, Inc.
Potomac Power Resources, LLC
Fauquier Landfill Gas, LLC
Rolling Hills Landfill Gas, LLC

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Bob Weishaar /jl MF
Robert A. Weishaar, Jr.
McNees Wallace & Nurick LLC

On Behalf Of
PJM Industrial Customer Coalition, which for purposes of this proceeding includes:

Air Liquide Industrial U.S. LP;
BOC Gases;
Carpenter Technology Corporation;
Cinram Manufacturing, Inc.;
E.I. DuPont de Nemours & Co. Inc.;
Ellwood National Steel;
Gerdau Ameristeel Corporation;
Jefferson Health System;
Kimberly-Clark Corporation;
Lehigh Cement Company;
Occidental Petroleum;
PPG Industries, Inc.;
Praxair, Inc.;
Procter & Gamble Paper Products Company;
The Timken Company;
and United States Steel Corporation.

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Paul M. Flynn
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On Behalf Of
PJM Interconnection, L.L.C.

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Paul Williams / PMF

Paul Williams
President, Liberty Energy Group, Inc

On Behalf Of
Portland Cement Association
Buzzi Unicem, USA, dba RC Cement Co.
CEMEX S.A. de C.V.
Essroc Cement Corp.
Giant Cement Holding, Inc.
Lafarge North America, Inc.
Lehigh Cement Company
St Lawrence Cement Company

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Jerry J. Langdon
Executive Vice President
Reliant Energy, Inc.

On Behalf Of
Reliant Energy Inc. and its subsidiaries Orion Power Midwest, L.P., Reliant Energy Electric Solutions, LLC, Reliant Energy Services, Inc., Reliant Energy Seward, LLC, Reliant Energy Solutions East, LLC, and Reliant Energy Wholesale Generation, LLC

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Bob Weinberg /PMF

Robert Weinberg
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On Behalf Of
Southern Maryland Electric Cooperative, Inc.

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David Pompen /DMF
David Pomper
Spiegel & McDiarmid

Attorney For and On Behalf Of
Virginia Municipal Electric Association No. 1
and its members, the Town of Blackstone,
Town of Culpeper, Town of Elkton, City of Franklin,
Harrisonburg Electric Commission,
City of Manassas, and Town of Wakefield, all of Virginia.

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Senior Vice President
Williams Power Company, Inc.

Legal

On Behalf Of
Williams Power Company, Inc.
Williams Generation Company-Hazleton