UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Power Providers Group v. PJM Interconnection, L.L.C.	)	Docket No. EL11-20-000
PJM Interconnection, L.L.C.	)	Docket No. ER11-2875-000 (not consolidated)

COMMENTS OF THE INDEPENDENT MARKET MONITOR FOR PJM

Pursuant to Rule 211 of the Commission's Rules and Regulations, 18 CFR § 385.211 (2010), Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor for PJM[1] ("Market Monitor"), submits these comments responding to the complaint filed by the PJM Power Providers ("Power Providers") on February 1, 2011, and the filing of PJM Interconnection, L.L.C. ("PJM") on February 11, 2011 in response to the complaint ("MOPR Filing"). The MOPR Filing proposes revisions to the Minimum Offer Price Rule ("MOPR"), a provision of the Reliability Pricing Model ("RPM") intended to protect PJM's capacity market from the monopsony exercise of market power.

The actions of New Jersey and Maryland have highlighted issues with the PJM RPM construct that need to be addressed. The states have legitimate concerns about long term reliability and the potential for the new entry necessary to provide that reliability.

1 Capitalized terms herein are not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT").

Addressing the potential for new entry means addressing barriers to new entry in the capacity market. Competitive entry is essential for long term reliability and for the functioning of the capacity market. It is also appropriate to be concerned about the actions of incumbent generators who benefit from prices that are high but not high enough to incent new entry and who understand the price impact of new entry.

The states' concerns with the price of capacity are legitimate, but the assertion that the price of capacity is too high is not supported. In fact, there are a number of capacity market design elements that result in suppressing rather than increasing capacity market prices. Price is clearly related to entry. Entry will occur when the expected price for capacity over the life of the asset is adequate to provide for the return on and of capital invested in the project. When capacity is needed for reliability, it can reasonably be expected that the price will have to be equal to the nominal levelized cost of entry and that the price will remain at that level for a significant period of time. Entry under any other conditions would be irrational.

The New Jersey legislation would, if implemented, suppress the price of capacity in New Jersey and elsewhere in PJM. Whether intentional or not, this exercise of monopsony market power on behalf of New Jersey customers is short sighted, unlikely to reduce capacity payments by New Jersey customers in the long run and constitutes an intervention into the PJM capacity markets that is not consistent with a competitive outcome. The New Jersey approach, if implemented, puts the entire capacity market at risk.

Power Providers and PJM propose revisions to MOPR that would significantly improve the existing rule, but do not address all of the concerns associated with the MOPR and the broader capacity market issues implicated. Even as PJM proposes to revise it, the MOPR would unnecessarily and unreasonably permit exercise of monopsony market power. The Market Monitor is concerned that other aspects of the proposed MOPR may not offer an enduring solution to the issues raised. Accordingly, the Market Monitor recommends specific design elements for inclusion in a revised MOPR.

The Commission should take whatever emergency measures are needed to ensure a just and reasonable result in the Base Residual Auction which will be run in May, but additional steps are also necessary to address longer term issues. The proposed modifications to MOPR are only part of the solution. The others are equally important.

This proceeding also presents an opportunity to strengthen the consensus about the role of mitigation in PJM's market design. An essential first step is recognition that effective mitigation is an essential and permanent feature of regulation through competition. The capacity market is structurally non competitive. Without mitigation, market power and not competition will set prices. The Market Monitor agrees with Power Providers (at 25) that when the market screens identify uncompetitive offers, "the proper course is to reset offers to 100% of the applicable benchmark." This applies to offers that are too high as well as offers that are too low. The goal of mitigation is the complete elimination of market power rather than permitting some arbitrary, acceptable amount.

Power Providers are also correct in seeking to design rules that apply ex ante rather rely than on post facto enforcement. Mitigation cannot be efficiently achieved through enforcement actions after the fact. Regulation through competition requires the application of rules ex ante that accurately enforce competitive offers and permit competitive market outcomes.

I. BACKGROUND

A. Current MOPR Provisions

1. The PJM Capacity Market

The PJM Capacity Market exists to provide a market mechanism for the provision and pricing of reliability.

Power Providers repeat (at 6) the misconception that the mitigation of energy offers to competitive levels explains the need for a capacity market. Market power mitigation in the energy market applies only where there is local market power and simply requires sellers to offer supply at competitive levels, which economists recognize as short run marginal costs. Competitive behavior is always appropriate and, in a well designed market, does not produce faulty market outcomes. No sound market design relies on uncompetitive behavior for any purpose, nor is such reliance lawful under the Federal Power Act.

Market participants, including both suppliers and buyers, are deprived of the benefits of competition if suppliers are permitted to exercise market power and raise prices above the competitive level or if buyers are permitted to exercise market power and reduce prices below competitive levels.

2. The Minimum Offer Price Rule (MOPR)

The Minimum Offer Price Rule for Certain Planned Generation Capacity Resources ("MOPR") is a product of the confidential RPM settlement discussions that culminated in PJM's filing of September 29, 2006.[2] The MOPR includes conduct, impact and incentives tests for Sell Offers to determine whether mitigation will be applied. The conduct test is

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[2] *See* PJM filing in Docket No. ER05-1410-000; OATT Attachment DD § 5.14(h).

failed if an offer is less than 80 percent of the real levelized net cost of new entry determined according to the asset class. If no asset class applies, the rule refers to the net cost of new entry for a combustion turbine ("CT") and lowers the threshold to 70 percent.[3]

The impact test is failed if the Sell Offer moves prices $25/MW-day or 20 percent lower in a large Locational Deliverability Area ("LDA"), defined as having a LDA Reliability Requirement greater than 15,000 MW. [4] The alternative percentage threshold rises to 30 percent in a small LDA, having a less than 15,000 MW requirement.[5]

The MOPR's incentive test is failed if the Capacity Market Seller and Affiliates have a "net short position," and that net short position is equal to or greater than ten percent of the total Reliability Requirement of a smaller LDA, defined as having an LDA Reliability Requirement less than 10,000 MW, or five percent of the requirement of a larger LDA, defined as greater than 10,000 MW.[6]

If any Sell Offer fails the three tests above, then the results of the Base Residual Auction are discarded and a replacement clearing price is determined. In the first step, PJM

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3 OATT Attachment DD § 5.14(h)(3).

4 OATT Attachment DD § 5.14(h)(1).

5 OATT Attachment DD § 5.14(h)(1).

6 OATT Attachment DD § 5.14(h)(1). The tariff defines "net short position:" "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." *Id*.

discards all Sell Offers that fail the MOPR test.[7] The rule affords no opportunity to revise an offer or to replace a failed Sell Offer with a competitive offer, as in the case of mitigation of excessive offers.[8] PJM clears the market using only the remaining eligible Sell Offers, according priority to self supply.[9] The Market Monitor does not agree with any interpretation of the MOPR that would somehow include back into the reclearing of the market any Self Supply offer that was excluded because it failed the MOPR.[10]

The MOPR applies only to a Sell Offer in a Base Residual Auction for the first Delivery Year in which the resource qualifies as Planned Generation Capacity Resource. [11]

The MOPR exempts coal and nuclear base load resources.[12]

The MOPR also exempts units built "in response to a state regulatory or legislative mandate to resolve a projected capacity shortfall in the Delivery Year affecting that state, as

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7 The tariff defines "Self-Supply" as a type of Sell Offer: "'Self-Supply' shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be committed regardless of clearing price. An LSE may submit a Sell Offer with a price bid for an owned or contracted Capacity Resource, but such Sell Offer shall not be deemed 'Self-Supply,' solely as such term is used in this Attachment." OATT Attachment DD § 2.65.

8 OATT Attachment DD § 5.14(h)(3).

9 OATT Attachment DD § 5.14(h)(4).

10 See Power Provider at 53. PJM states (at 20) that it finds the provision "admittedly ambiguous," but clarifies that "PJM has never intended to exempt self-supply offers from application of the MOPR." This interpretation violates both the order of operations described in the rule as well as the canon of construction that rejects interpretations resolving ambiguity in a manner that renders a term meaningless. *See Negonsott v. Samuels*, 507 U.S. 99 (1993); *Mountain States Tel. & Tel. v. Pueblo of Santa Ana*, 472 U.S. 237 (1985).

11 OATT Attachment DD § 5.14(h)(2).

12 OATT Attachment DD § 5.14(h)(1).

determined pursuant to a state evidentiary proceeding that includes due notice, PJM participation, and an opportunity to be heard."[13]

The MOPR provides for its termination and reinstatement under certain conditions.[14]

The Market Monitor has long believed that the MOPR is flawed because its scope is insufficiently broad and its terms are unduly complicated and ambiguous.[15] The Market Monitor supported its proposed replacement in an earlier proceeding with a process that would have relied on specific evaluations of offers.[16]

II. COMMENTS

A. The Framework of New Jersey P.L. 2011 Operates Inconsistent with PJM Capacity Market Design, the Purpose of the MOPR and the Applicable Legal Standards.

The MOPR complements other RPM mitigation rules which prevent the exercise of market power to raise capacity prices. Together these rules help to ensure prices that reflect the competitive outcomes required by law rather than the exercise of market power.

New Jersey Public Law 2011, Chapter 9 ("P.L. 2011") requires New Jersey electric public utilities ("NJ Utilities") to procure capacity when it is not needed for reliability at levels above prevailing capacity prices and requires that this capacity clear the auction. Because resources selected under the P.L. 2011 approach ("P.L. 2011 Resources") receive

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13 OATT Attachment DD § 5.14(h)(1).

14 OATT Attachment DD § 5.14(h)(5).

15 *See PJM Interconnection, L.L.C.*, 126 FERC ¶61,275 at P 186 (2008).

16 *Id.*

out-of-market payments and are indifferent to RPM prices, their only incentive is to offer at a level low enough to clear, i.e. at $0.

The rationality of this arrangement from the state's perspective entirely depends upon a reduction of market prices sufficient to offset the costs to procure the P.L. 2011 Resource. The overall result is one resource receiving above market prices for its capacity while other resources receive below market prices, including capacity provided from non traditional sources such as demand response and alternative technologies. Such price discrimination would prevent the market from establishing just and reasonable prices in the applicable Delivery Year.

Moreover, the result is also unduly discriminatory. The statutory framework essentially renders a selected investment immune to market results in a manner that confiscates a portion of the market value of existing investment not similarly immune. At no point does the market test the need for the resource to enter. At no point is the unit at risk from the market to recover its costs.

1. The Commission Can Expect that Implementation of the P.L. 2011 Framework Would Have a Large and Immediate Impact on RPM Prices.

If the Commission permits implementation of the P.L. 2011 framework, our analysis, which we include together with as an Attachment, indicates that its impact is expected to be immediate and large. Adding 2,000 MW of capacity in New Jersey, paying for it through an out of market subsidy, and requiring it to offer at zero would result in a reduction in capacity market revenues to PJM suppliers of more than two billion dollars per year, including about 1.17 billion dollars in EMAAC and about 0.740 billion dollars in rest of MAAC. The reduction in capacity payments to suppliers in New Jersey would be about 562 million dollars.

This substantial reduction in revenue would affect the investment decisions of current owners of capacity and demand side resources and potential investors in capacity and demand side resources both in New Jersey and in areas outside of New Jersey. The likely result is less investment in capacity and demand side resources. Depressing the price in New Jersey would also mean that the required direct subsidy by New Jersey ratepayers would increase with perhaps significant unintended consequences for the business and residential customers who would have to pay the subsidy.

2. The MOPR Should Be Enforced in Substance Rather Than Form, and, as a Matter of Substance, P.L. 2011 Resource Have a Net Short Position on the Basis of Their Statutory Defined Relationship to Load-Serving Entities.

The MOPR requires that PJM reject and reclear the market without Sell Offers that fail each of the series of tests designed to identify uneconomic conduct, an incentive to exercise monopsony power and an impact on the market outcomes.

Sell Offers from capacity constructed under the framework of P.L. 2011 will almost certainly fail the conduct and will fail the impact tests. Further, the incentive to affect the RPM price is also evident. The question is whether the Capacity Market Seller has a net short position that would fail the MOPR screen. The statute requires New Jersey Electric Utilities ("NJ Utilities") to contract with the owners of resources selected under P.L. 2011 ("P.L. 2011 Resources") for capacity. The statute circumvents the rule by directing P.L. 2011 Resource, which presumably does not itself serve load and is not net short, to submit the Sell Offer into RPM. Nonetheless, this conduct plainly violates the substance of the MOPR because it creates an identical motive to offer below cost into RPM within a framework designed to artificially suppress prices. The question is whether the New Jersey ratepayers who are required to buy the capacity are net short, which they are by any conceivable measure.

B. New Jersey Can Exercise Its Right to Build Capacity Through Alternative Approaches Consistent with RPM.

New Jersey clearly has the right and the obligation to address its own reliability needs if it does not think they are being adequately addressed through the PJM markets. The most direct option would be for New Jersey to require that LSEs opt out of RPM markets entirely via the Fixed Resource Requirement Alternative ("FRR").[17] Under FRR, New Jersey's procurement choices would have much less impact on other participants in RPM markets. New Jersey could make its own decisions about how best to reach required reliability levels. There is no guarantee that the FRR would lower costs relative to participation in RPM markets. New Jersey would not escape the market factors that determine prices in RPM with FRR alone.

New Jersey could also implement a form of capacity procurement, as set forth in the proposed legislation, that complements RPM. A complementary procurement could be designed to permit the BPU to run a competitive auction for New Jersey, designed to procure capacity of specific types and in specific locations most consistent with the evolving needs of New Jersey. The key requirement is that any winning resource would be required to offer and clear in the next Base Residual Auction at its full annualized costs, which would be the competitive offer. Such an offer could not reflect subsidies or out of market payments, and would likely set the capacity market clearing price. A program of this type

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17 *See* PJM Reliability Assurance Agreement ("RAA") Schedule 8.1.

could be effective if selection under this program meant reduced state regulatory barriers to entry.

This would produce outcomes consistent with the PJM and RPM market design. The point of this approach would be to ensure that new capacity is built without undermining competitive market outcomes.

C. New Jersey Highlights the Need to Correct Flaws in the RPM Market Design

The MOPR, like many PJM Market Rules that emerge from settlements, is not a model of clarity. Whether or not the Commission looks past its flawed form to apply the substance of MOPR in the Base Residual Auction for the 2014/2015 Delivery Year, the current MOPR is unjustly and unreasonably narrow and requires reform. Power Providers and PJM both have proposed changes to the MOPR. The Market Monitor below provides recommended elements for an effective MOPR and comments on the relative merits of the Power Providers' and PJM's proposals.

1. Summary of Essential Components and Positions on MOPR Reform

The MOPR should include the following essential components:

- Minimum offer price should be 100 percent of net CONE
  - Nominal levelized
  - Exception process through MMU
  - By technology
  - DA or RT net revenues as appropriate
- Subsidies or out of market revenues cannot be reflected in the offer price
- All technologies are included
- Long lead time units have a separate test
  - If demonstrated need, no minimum price
- MOPR applies to:
  - new self supply

- until an unsubsidized offer clears once
- to LDAs, whether constrained or not
- all RPM Auctions

The Market Monitor discusses each element of its proposed replacement rule against the current MOPR below. The MOPR revised as the Market Monitor recommends is simple and straightforward. Overall, the revised MOPR requires a new resource to clear at least one RPM Auction on the basis of its cost of entry without considering any out of market payments. A Seller can quickly demonstrate compliance with the rule by offering above default cost of new entry levels. If an entrant cannot do this, it can ask the Market Monitor, PJM and ultimately the Commission to examine its unit specific costs. This approach is simple, consistent with economics, consistent with other PJM mitigation rules, minimally burdensome on new entrants and fully protects the market from monopsonistic exercise of market power.

The current rule is needlessly complex because and lacks flexibility to address unanticipated circumstances. PJM's and P3's proposal are significant improvements, but PJM's proposal retains restrictions on its scope that serve only to reduce its accuracy and effectiveness and increase the likelihood that the Commission will need to take future emergency action to address scenarios that differ from the assumed paradigm. P3's proposal in some cases raises the risks for new entrants beyond what is necessary. On many significant areas, however, the Market Monitor, PJM and P3 agree. The Market Monitor provides the following table to show the similarities and differences among the three proposals:

Comparisons of Proposals for MOPR Reform			
Design Element	**IMM**	**Power Providers**	**PJM**
Default Level	Net Asset Class	Net Asset Class	90% Net Asset

	CONE without adjustment	CONE, without adjustment	Class CONE, or 70% Net CONE
Unit Specific Level	IMM initial review, then PJM, then FERC	IMM initial review, then PJM, then FERC	FERC only
Impact Test	None	None	None
Term	Must clear one auction	Must clears two auctions	Must clear three auctions
Exempt Types of Units	None	None	Nuke, coal, IGCC, hydro, wind solar
Net Short Test	None	None	None
Accounting Approach	Nominal Levelized	Nominal Levelized	Nominal Levelized
Out of market payments	Not permitted	Not permitted	Permitted in some cases
LDAs	All LDAs	All LDAs	Constrained LDAs
RPM Auctions	All Auctions	All Auctions	BRA only

2. Adjusted Default CONE Values Allow Exercise of Monopsony Market Power; Market Sellers Should Have an Opportunity to Establish Unit Specific Costs Under the Commission-Approved Process for Evaluating Inputs to Mitigation

The benchmark for a competitive offer should be 100 percent of the appropriate nominal levelized costs of new entry of that technology type. No amount of market power exercise should be permitted as a matter of sound economic market design and as a matter of compliance with the standards of the Federal Power Act.

In addition, there should be an exception process under which a market participant could submit its proposed offer with full documentation to the MMU for review and discussion. If the MMU agreed that the offer reflects costs and does not reflect out of market payments, and PJM did not disagree and no party appealed to FERC, the offer could be used. Such a process would reduce administrative costs and the duration of the review compared to requiring a filing at FERC for each exception. The ultimate recourse would be to FERC.

PJM cites (at 13) to pre-Order No. 719 decisions requiring change to the provisions for according too much discretion to the Market Monitor to determine whether offers from new units were too high or low.[18] The Commission objected to the Market Monitor using "its sole judgment to determine inputs that can ultimately set the market clearing price" as the originally filed MOPR provided.[19] In Order No. 719, the Commission determined that the Market Monitor could participate in a process reviewing Sell Offers submitted by Capacity Market Participants, except that PJM would have ultimate responsibility for administering its tariff.[20] If a Capacity Market Seller or the Market Monitor disagreed with PJM's decision whether or not to accept the offer, either party could take the issue to the Commission for final resolution.

Under PJM's MOPR proposal a Capacity Market Seller could take a matter to the Commission if it wanted to obtain an approval of a cost more than ten percent below the default. No process of any kind would apply to an offer up to 10 ten percent below the

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18 *PJM Interconnection, L.L.C.*, 126 FERC ¶61,275 at P 190 (2009); *PJM Interconnection, L.L.C.*, 117 FERC ¶61,331 at PP 114–115 (2009); *PJM Interconnection, L.L.C.*, 119 FERC ¶61,318 at P 180 (2009).

19 119 FERC ¶61,318 at P 180.

20 *See Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶31,281 at PP 370–79 (2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶31,292 (2009), *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009); *see also*, *PJM Interconnection, L.L.C.*, 129 FERC ¶61,250 (2008).

default. This invites a routine exercise of market power up to 10 ten percent below the competitive price in PJM markets.

The formula established in Order No. 719 can readily apply to a reformed MOPR. The process proposed by Power Providers (at 13–14) also is consistent with the Order No. 719 formula. PJM need not presume that the Commission would reject an approach to administering the MOPR consistent with Order No. 719 on the basis of precedent prior to the order. If the alternative to including such a process is building into the rules a substantial opportunity to exercise monopsony market power, then the Commission should require this process.

PJM proposes (at 10–12) a ten percent reduction to the calculation of costs, replacing the current 80 percent reduction. PJM explains: "A screen of 90% sets a reasonable balance between legitimate competing interest: on the one hand, recognizing the imprecision of 'one-size fits all' administrative estimates, balanced against, on the other hand, preserving protections against unreasonable exercise of market power."

The compromise that PJM proposes is unnecessary and is based primarily on a false analogy to the calculation of unit-specific avoided cost rates. Section 6.7(c) of Attachment DD sets forth default values for Sell Offers. These default values include no ten percent adjustment. Only avoided cost rates calculated on unit specific basis receive a ten percent adjustment to establish a maximum value.

The best analogy to MOPR default values are the ACR default values. These values serve to screen out situations where additional scrutiny is not needed. If such values must err, it is better, respectively, that they are too high or too low. In the case of ACR, the rules afford an option for a unit specific calculation. PJM has failed to propose a similar process for inclusion in the MOPR. The primary purpose of such a review would be to confirm that an offer lower than the default includes a reasonably complete accounting of costs and includes no offset from an out-of-market funding mechanism.[21] An arbitrary ten percent reduction is not a just and reasonable substitute for appropriate ex ante scrutiny of the specific circumstances that could reasonably justify submittal of a lower offer.

The Commission has determined that planned generation and project investment (APIR), a component of ACR, should be treated comparably.[22] The ACR formula specifically excludes APIR from application of the ten percent Adjustment Factor.[23]

The analogy upon which PJM relies is misplaced whether the comparison is to ACR defaults or APIR, the relevant component of ACR. Application of a ten percent discount to default MOPR levels is unsupported. Application of a ten percent discount to unit-specific MOPR values fails the relevant test by analogy as well. It is not just and reasonable to permit a ten percent reduction from the best available cost estimates. This builds the potential exercise of market power into the rules and interferes with the ability of RPM to produce just and reasonable results. Accordingly, the ten percent adjustment should be rejected.

PJM also proposes (at 12) to retain a default value equal to 70 percent of Net CONE for situations where the technology does not fit any of those specified. PJM explains (*Id.*) that this value is a "placeholder that is unlikely to be invoked." When PJM completely

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21 Power Providers (at 34) propose "simply to terminate the mitigation process for any resource that can establish that it will not receive any form of subsidy."

22 *See PJM Interconnection, L.L.C.*, 134 FERC ¶61,065 at P 31 (2011).

23 OATT Attachment DD § 6.8(a) ("Adjustment Factor * (AOML + AAE + AME + AVE + ATFI + ACC + ACLE) + ARPIR + APIR").

overhauls the design of a rule such the MOPR, elements should not carry over without specific support. No placeholder is needed. If a new technology emerges, PJM can develop a specified default cost of new entry value and revise the tariff accordingly.

3. PJM Proposes an Improved Approach for Calculating the MOPR

The Market Monitor agrees that the net CONE values proposed by PJM are more current and accurate than those currently in the tariff. Such values should not be in the tariff without an annual review process that ensures that they will not be allowed to become out of date. The CONE values should continue to be refined as necessary.

The Market Monitor's analysis indicates that for approximately 94 percent of the totals hour during which the CC technology is assumed to be dispatched in the real-time economic dispatch model, the CC technology would be dispatched in the day-ahead market. It is possible that there could be additional real-time revenue if the CC chooses to expand output in real time with duct firing.

4. The Net Short Test Should Be Eliminated

The net short test is intended to limit the scope of the MOPR to those entities with motive to exercise buyer market power. However, the P.L. 2011 shows that an identical motivation can be manufactured by statute. That legislation creates an arrangement motivating resource owners to offer at $0 and to suppress prices even though the market seller may not have a net short position. The Commission can enforce the rule based on its substance for the upcoming BRA, but a MOPR that better matches form to substance will work better over the long term. The net short test undermines the MOPR's effectiveness.

This test lacks an offsetting benefit, as it does not prevent application of the MOPR in any context where it would be inappropriate.[24] This test should therefore be eliminated.

Power Providers claim (at 41), "The Minimum Offer Price Rule is fatally flawed because it permits mitigation of offers only by sellers that are considered net short (because their obligations to purchase capacity substantially exceed their capacity sales)." PJM proposes to eliminate the net short test, explaining (at 16), "this precondition on application of the MOPR opens considerable opportunities for a seller/buyer with exactly that incentive to structure the new entry transaction in [sic] way that achieves the desired price-lowering effects without triggering the MOPR's protective provisions." The Market Monitor agrees.

5. The Impact Test Should Be Eliminated

As in the case of the actual net CONE value, there is no reason to permit any level of market power to be exercised. The impact test would define an acceptable level of market power and should be eliminated for that reason.

Power Providers state (at 36) that "there is no justification for any impact threshold, no matter how moderate." PJM also proposes (at 17) to remove the impact threshold, explaining: "If the current rule's impact test is not met, then a new entry sell offer is allowed to go forward, just as if there was no MOPR provision in the PJM Tariff, even if the offer is well below the MOPR screen level and the seller has provided no justification for a below-cost offer." The Market Monitor agrees.

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24 *See New York Independent System Operator*, 124 FERC ¶61,301 at P 28 (2008) ("We find that all uneconomic entry has the effect of depressing prices below the competitive level...").

6. Term of Mitigation

The goal of the MOPR is to ensure that new entry does not occur at below competitive levels by those with an incentive to suppress the price. The goal of the MOPR is also to not interfere with incentives for new entry. The competitive offer of a new resource in its second BRA, after clearing in its first BRA, is ACR and not net CONE. The MOPR should not create barriers to entry by creating risks for new entrants. Requiring a unit to clear in its second BRA if it has already cleared would create such a barrier by requiring an offer greater than the competitive level.

The MOPR should require that a unit clear one BRA based on an offer of net CONE, or its demonstrated individual net CONE, and to demonstrate that it is not receiving any subsidies, defined to be any revenues from outside the organized PJM markets, and has not contracted to receive any subsidies. In year two, any offer below the existing offer caps would be acceptable, subject to the ongoing requirement to demonstrate that it is not receiving any subsidies and has not contracted to receive any subsidies.

The MOPR applies only to Planned Generation Capacity Resources, a status typically effective for only one Delivery Year.[25] Power Providers propose (at 38) to apply the MOPR indefinitely, excepting any portion of capacity that clears two RPM auctions. PJM proposes (at 19–20) to apply the MOPR in the first BRA in which the planned resource clears and the following two years, but thereafter to except the resource from the MOPR like any other existing Generation Capacity Resource. PJM explains (at 20), that "the three-year period matches the time during which the costs of the new resource are not fully sunk,

[25] *See* OATT Attachment DD § 5.14(h)(2); PJM Reliability Assurance Agreement § 1.70.

giving practical recognition to the seller's ability to affect the clearing prices during that period."

Power Providers approach adopts an unnecessary market hurdle requiring a resource's costs to match the relevant market signal for at least one additional year. PJM's approach goes further, requiring MOPR for three years regardless of the circumstances. These proposals place an unnecessary burden on the potential entrant after making a substantive investment to meet obligations created by their clearing in a BRA auction on the basis of their pre-approved competitive offer. Given the risk of transmission project changes, the risk of unexpected changes in PJM's planning forecast, the risk that developments will change the fundamentals of CONE from year to year, such a requirement would act as a deterrent to competitive entry at current valuations of CONE. Further, it would put the new entrant at risk of its investment being forced out of the market via predatorily priced capacity additions to an incumbent's existing generation designed to defeat and deter new entry after it cleared in a BRA. The restrictions proposed by the Power Providers and PJM would prevent the new entrant from responding to its change in status from a successful new entrant in a BRA to an incumbent generator with sunk investments in subsequent BRAs. It is imperative that a successful entrant be allowed to compete on even terms with other incumbents in subsequent auctions in response to changing conditions in the RPM market.

The Market Monitor recommends that the MOPR require that (i) a unit clear one BRA based on either an offer of net CONE or its demonstrated individual net CONE, and (ii) that its sponsor demonstrate that the unit is not receiving any subsidies, defined to be any revenues from outside the organized PJM markets, and has not contracted to receive any subsidies. In year two, any offer would be acceptable subject to ACR based caps. To do otherwise would place an unnecessary burden on the potential entrant after making a substantive investment to meet obligations created by their clearing a BRA on the basis of their competitive offer.

7. Application of the MOPR Should Not Turn on Technology Type.

Monopsony power is not acceptable, regardless of the technology on which entry is based. The MOPR rules should be robust enough and based on the appropriate economics so that any legitimate offer will pass and any non-legitimate offer will not pass. Exempting particular technologies suggests that the rule does not meet these basic tests.

Power Providers take the position (at 39–40) that, "the full buyer mitigation regime should apply to all resources," except that, due the "the compressed time frame," mitigation for the next auction would be limited to combustion turbines and combined cycle resources. PJM proposes (at 19) to exempt from the MOPR (by explicitly permitting $0 offers) new capacity based nuclear, coal and Integrated Gasification Combined Cycle (IGCC), hydroelectric, wind and solar technology. This means that under the MOPR, PJM would accept non-competitive offers on the basis of any of these technologies. Market power is unacceptable regardless of the technology type. That the MOPR may less likely to apply to some of these technologies is no reason to exempt any of these technologies.

8. The MOPR's Sunsetting Provision Can Only Prevent an Appropriate Application of the Rule and Should Be Eliminated.

Power Providers state (at 39) that there is "no justification" for the MOPR provision that "eliminates mitigation in certain circumstances if there is a positive net demand for new resources in two consecutive years" and also provides for reinstatement under certain conditions. PJM proposes (at 21) to delete this provision, explaining, "the objectives of the MOPR are not time-limited." The Market Monitor agrees. The only effect of this rule would be to prevent application of the MOPR under possible future circumstances when the rule should apply. Accordingly, the provision should be eliminated.

9. Long Lead Time Units Should Have a Separate Test

Units that require more than the three year lead time implied by the RPM auction structure should be permitted to request PJM to determine whether the unit is needed in a designated delivery year. If needed, the unit could be constructed and offered into the auction at any price less than the offer cap with the explicit condition that the unit receives no out of market revenues.

D. Other Reforms to RPM are Needed to Complement MOPR Reform.

MOPR reform is needed, but it is not enough to fix the problem with RPM design. The concerns of New Jersey and Maryland about whether the RPM market design is adequate to ensure effective competitive from new entry are valid and should be addressed without delay. If the Commission acts to prevent states from subsidizing new entry in a manner that undercuts the wholesale market design, then it should also exercise its authority to rectify some of the critical problems in that wholesale market design.

Because these reforms relate to new entry, the Commission should not entrust resolution of these issues to the PJM stakeholder process. That process is necessarily dominated by incumbent interests and lacking in representation from new entry. Over many years of stakeholder discussion of RPM issues, only a small number of current PJM stakeholders have consistently represented the interests of potential new entrants in the capacity market. A true new entrant worries about its future investment, not preserving the value of its current investments. New entry only occurs when such investors conclude that total future returns will exceed the total costs of new investment. The market works over the long run only if prices and costs can converge at the point where new entry is attracted.

Incumbents are not merely indifferent to new entry, new entry could damage their market position. It is unreasonable to expect them to behave otherwise. Rules that relate to new entry are an area where the stakeholder process cannot be relied upon to produce a result consistent with the public interest. For the same reasons, reliance on or significant deference to a settlement in this proceeding, particularly without strong and unmistakable guidance from the Commission, would be misguided.

The Market Monitor has long standing concerns about market design elements that suppress prices in the PJM capacity market. These include the failure of the MOPR to fully address monopsony, which could impact prices in EMAAC by about 1.17 billion dollars;[26] the artificial 2.5 percent reduction of demand in the Base Residual Auctions, which has impacted the recent BRA in New Jersey by an artificial reduction of about $.72 billion dollars;[27] and the misdefinition of Demand Resources which leads to excess supply at artificially low prices and thus lower clearing prices.[28]

Investment will not occur until investors reasonably expect to receive a return on and of investment. New Jersey recognizes this as draft versions of the legislation included prices that would cover the actual cost of entry of new generation. The true cost will be a combination of readily quantifiable costs, such as construction and fuel contracts, and

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26 See Attachment at 8.

27 Market Monitor, "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated" at 19–20 (September 20, 2010), which can be accessed at: <*http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf*>.

28 The Market Monitor explained how the misdefinition of Demand Resources distorts the market in its Protest of the Independent Market Monitor for PJM filed in Docket No. ER11-2288-000 (December 20, 2011), which can be accessed at: <*http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Comments_and_Protest_ER11-2288-000_20101220.pdf*>.

difficult to quantify costs, including risks of future adverse changes in conditions affecting the profitability of the investment. If prices are high enough to pose a political problem, and no new entry is occurring despite prices levels, then serious attention also must be paid to the costs and risks inhibiting investment.

1. A Longer NEPA is Needed to Offset Regulatory Barriers to New Entry

P.L. 2011 cites the lack of a sufficiently long New Entry Pricing Adjustment in the RPM market design as its principle justification. Section 1(b) of P.L. 2011 explains:

> The PJM reliability pricing model sought to create enhancements to the previously ineffective capacity procurement mechanism which had resulted in projected capacity deficiencies in New Jersey and other areas of the regional power grid. While the reliability pricing model has resulted in significant capacity additions in the form of new demand response resources, new energy efficiency resources, reversals of generation unit retirements, upgrades of existing generating units and certain new peaking facilities available to the region and the State, the reliability pricing model has not resulted in large additions of peaking facilities or any additions of intermediate or base load resources available to the region and the State;
>
> …The PJM reliability pricing model could, through structural changes, provide necessary incentives, such as the expansion of the "New Entry Price Adjustment" mechanism for the construction of new capacity, including new intermediate and base load plants, by allowing new resources to qualify and receive a guaranteed capacity price for a longer period of time. However, the implementation of similar structural changes was previously denied by FERC and any future implementation is uncertain at this time…

As P.L. 2011 explains, the Commission did reject a proposal by PJM, which the Market Monitor supported, to extend the NEPA term for the new entrant only.[29] The Commission did not accept the change, explaining:

> The proposed relaxation of the pre-conditions and the extension of the lock-in period go beyond the intent of the original provision, intended only to address the issue of lumpy investments in a small LDA. PJM's proposal would further bifurcate capacity markets by giving new suppliers longer payments and assurances unavailable to existing suppliers providing the same service. Thus, it would result in further price discrimination between existing resources, including demand response, and new generation suppliers. . . .
>
> We also recognize that a longer commitment period may aid the developer in financing a project. However, as PJM notes, RPM was designed to provide long-term forward price signals and not necessarily long-term revenue assurance for developers, and we must therefore balance the benefits of the longer commitment period (to the extent it fosters new entry by making project financing easier or cheaper) against the possible uplift payments in excess of auction clearing prices that loads may have to bear due an extension of the NEPA term. In our view, no party has made the case that extending the NEPA term to five or seven years strikes a superior balance to the existing provisions.[30]

The Commission raises important concerns about the need to avoid bifurcation of the market as a matter of economic coherence and price discrimination as a matter of law.

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29 *PJM Interconnection, L.L.C.*, 126 FERC ¶61,275 (2009), *order on reh'g*, 128 FERC ¶61,157 (2009) ("Rehearing Order").

30 *Id*. at PP 149–50; *see also* Rehearing Order at P 102 ("The new entrants are guaranteed higher prices and assurances that are not available to existing suppliers. Moreover, while the new entrant is guaranteed its price, the extra capacity it introduces into the market will reduce the prices to existing suppliers. In order to assure reliability, PJM needs to attract new entry when needed, but also to assure that prices are sufficient to retain existing efficient capacity. Both new entry and retention of existing efficient capacity are necessary to ensure reliability and both should receive the same price so that the price signals are not skewed in favor of new entry.").

The Commission is also right to require supporting evidence that the correct balance has been struck. NEPA should not confer a windfall for the exercise of market power but it must be adequate to finance an investment. If NEPA cannot serve as a basis to finance an investment over a fixed multi-year period, then the price in the BRA will need to rise to place high enough to serve as such a basis in one Delivery Year. If there is no financial basis for new investment, then investment cannot be expected.

NEPA can be reformed to provide for an elevated price in an LDA for a multi-year period, probably 5–7 years. This approach avoids the Commission's concerns about bifurcation and discrimination. This approach also avoids concentrating an incentive price in a single year and instead spreads it out over a more manageable period. This preserves one of RPM's advantages over alternative approaches that administratively incorporate capacity prices into energy prices: smoother, predictable and more fairly allocated pricing.

Approval of PJM's MOPR rule should be subject to the condition that the PJM and its stakeholders address this issue. In order to ensure a proper focus on new entry in a process where it is not sufficiently represented, the Commission should provide additional guidance as to how stakeholders can develop and support a proposal designed to attract new entry on an effective and competitive basis. Constructive guidance could include, for example, requiring that PJM's filing include testimony from objective sources of project financing explaining why NEPA and other aspects of the RPM market design would constitute an adequate basis for project finance.

2. Renewed Effort Is Needed to Address Barriers to Grid Access.

The Market Monitor believes another potential source of barriers is the rules for interconnecting new resources and the associated transmission planning rules. Any entity (developer or applicant) that requests interconnection of a generating facility, including increases to the capacity of an existing generating unit, or requests interconnection of a merchant transmission facility, must follow the PJM interconnection process. The process is complex and time consuming as a result of the nature of the required analyses. Nonetheless, this process potentially creates barriers to entry by creating uncertainty for potential entrants about the cost and time associated with interconnecting to the grid. A renewed effort is needed to find ways to modify the generation and transmission interconnection process to minimize the uncertainty for potential market entrants.

This proceeding provides ample reason for the Commission to direct PJM to reexamine its rules. Indeed, such action is necessary on account of the Commission's uniform interconnection rules for all markets set forth in Order No. 2003.[31] PJM has a uniquely designed forward looking capacity market, and it would be appropriate for the Commission to relax Commission requirements to the extent that this would promote more efficient and open coordination of the PJM Interconnection process, the transmission planning process and the capacity market.

PJM should reexamine the CETL/CETO analytical approach to better improve locational signals and coordinate long-term transmission planning with generation additions and exits from the system. PJM should attempt to ensure that the CETO/CETL analysis is better coordinated with the PJM reliability analyses that determines whether generating units are needed for reliability. The result could be more granular constrained

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31 *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 128 S. Ct. 1468 (2008).

LDAs and price signals more attuned to actual local capacity supply and demand conditions.

PJM should propose modifications to the transmission planning process that would limit significant changes in the status of major transmission projects after they have been approved, and thus limit the uncertainty imposed on markets by the use of evaluation criteria that are very sensitive to changes in forecasts of economic variables. These issues are currently being considered in the PJM stakeholder process. The uncertainty created by unexpected changes in plans to build significant transmission lines creates risk and related costs for new entrants in the RPM market.

III. CONCLUSION

The Market Monitor respectfully requests that the Commission afford due consideration to these comments as it resolves the issues raised in this proceeding.

Respectfully submitted,

Joseph E. Bowring
Independent Market Monitor for PJM
President
Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Valley Forge Corporate Center
Eagleville, Pennsylvania 19403
(610) 271-8051
joseph.bowring@monitoringanalytics.com

Jeffrey W. Mayes

General Counsel
Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Valley Forge Corporate Center
Eagleville, Pennsylvania 19403
(610) 271-8053
jeffrey.mayes@monitoringanalytics.com

Dated: March 4, 2011

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Eagleville, Pennsylvania,
this 4th day of March, 2011.

Jeffrey W. Mayes
General Counsel
Monitoring Analytics, LLC
2621 Van Buren Avenue, Suite 160
Valley Forge Corporate Center
Eagleville, Pennsylvania 19403
(610) 271-8053
jeffrey.mayes@monitoringanalytics.com

ATTACHMENT

Impact of New Jersey Assembly Bill 3442 on the PJM Capacity Market

The Independent Market Monitor for PJM

January 6, 2011

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Introduction

New Jersey Assembly Bill No. 3442 was the subject of a hearing on December 16, 2010. The Bill addresses the construction of new generating capacity in New Jersey. One of the questions raised in the hearing was the impact of the proposed addition of generation capacity on PJM markets.

The Bill would require New Jersey to procure 1,000 MW of new capacity when it is not needed for reliability, require the new capacity to clear in the auction through an offer price below its costs and provide subsidies to the new capacity in the form of additional out of market revenue. These features of the Bill are not consistent with the PJM market design. If implemented, the market results would not be consistent with a competitive outcome.

The result of such a subsidy by New Jersey ratepayers would be to artificially depress the Reliability Pricing Model (RPM) auction prices below the competitive level, with the result that the revenues to generators both inside and outside of New Jersey would be reduced as would the incentives to customers to manage load and to invest in cost effective demand side management technologies.

An analysis of the impact of adding 1,000 MW of capacity in New Jersey, paying it through an out of market subsidy, and requiring it to offer at zero shows that the result would be a reduction in capacity market revenues to PJM suppliers of more than one billion dollars per year, including about 600 million dollars in EMAAC and about 400 million dollars in rest of MAAC. The reduction in capacity payments to suppliers in New Jersey would be about 280 million dollars. These would have been the results in the 2013/2014 RPM Base Residual Auction if an additional 1,000 MW of capacity had been offered at a zero price in PSEG.

An analysis of the impact of adding 2,000 MW of capacity in New Jersey, paying it through an out of market subsidy, and requiring it to offer at zero shows that the result would be a reduction in capacity market revenues to PJM suppliers of more than two billion dollars per year, including about one billion dollars in EMAAC, about 700 million dollars in rest of MAAC and about 125 million in rest of RTO. The reduction in capacity payments to suppliers in New Jersey would be about 560 million dollars. These would have been the results in the 2013/2014 RPM Base Residual Auction if an additional 2,000 MW of capacity had been offered at a zero price in PSEG.

This substantial reduction in revenue would affect the investment decisions of current owners of capacity and potential investors in capacity both in New Jersey and in areas outside of New Jersey. The likely result is less investment in new and existing capacity, in the form of generation resources and demand response. Depressing the price in New Jersey would also mean that the required direct subsidy by New Jersey ratepayers would increase for the specified procured MW, with perhaps significant unintended consequences for the business and residential customers who would have to pay the mandatory subsidy. The result of depressing RPM prices in New Jersey would also be to increase the probability that additional subsidies by New Jersey ratepayers will be required for any future capacity additions, either in the form of generation or demand side resources, needed to maintain reliability in New Jersey. The result of depressing RPM prices over a broad section of PJM would be to increase the probability that subsidies by ratepayers in other states will be required for any future capacity additions, either in the form of generation or demand side resources, needed to maintain reliability in that area.

The primary purpose of the Minimum Offer Price Rule (MOPR) in the PJM capacity market tariff is to prevent market participants from submitting uneconomic offers based on the receipt of out of market payments which result in artificially depressing RPM auction prices. While it is unclear if the MOPR would apply to the offers that result from the proposed legislation, those offers are not consistent with the intent of the MOPR under current capacity market conditions. The MOPR was designed to apply in this situation.

If the proposed legislation were to pass, the outcome in the short term will be regulatory uncertainty and unintended consequences for New Jersey, for all owners of and investors in capacity in PJM and for all potential investors in capacity in New Jersey, as jurisdictional issues are addressed and the meaning of the market rules is resolved.

Analysis

The analysis starts with all the inputs for the Base Residual Auction (BRA) for the 2013/2014 Delivery Year. The specified MW of capacity are added to the supply curve of capacity at the specified price in the specified location. The market is recleared and the clearing prices and quantities are calculated.

Table 1 shows the RPM market results for PJM if an additional 1,000.0 MW of Unforced Capacity (UCAP) had been offered in the PSEG zone at $0 per MW-day, compared to the actual results in the 2013/2014 BRA. Table 2 shows the difference between actual results for PJM and the results that would have occurred if an additional 1,000.0 MW UCAP had been offered in PSEG at $0 per MW-day. The results for Pepco would have remained the same. The EMAAC Locational Deliverability Area (LDA) would not have been constrained, but would have cleared with MAAC.[1] The EMAAC clearing price would have decreased $53.75 per MW-day (21.9 percent) to $191.25 per MW-day, and

1 PSEG was modeled as a separate LDA in the 2013/2014 BRA, but did not have a binding constraint and cleared with EMAAC.

the EMAAC clearing quantity would have increased 566.6 MW (1.7 percent) to 33,402.0 MW. The rest of MAAC clearing price would have decreased $34.90 per MW-day (15.4 percent) to $191.25 per MW-day, and the rest of MAAC clearing quantity would have decreased 79.4 MW (0.3 percent) to 29,933.4 MW. The rest of RTO clearing price would have decreased $1.67 per MW-day (6.0 percent) to $26.06 per MW-day, and the rest of RTO clearing quantity would have decreased 487.2 MW (0.6 percent) to 84,616.2 MW.

Table 3 shows the RPM market results for New Jersey if an additional 1,000.0 MW UCAP had been offered in PSEG at $0 per MW-day, compared to the actual results in the 2013/2014 BRA. Table 4 shows the difference between actual results for New Jersey and the results that would have occurred if an additional 1,000.0 MW UCAP had been offered in PSEG at $0 per MW-day. The zones in New Jersey include AECO, JCPL, PSEG, and RECO. The EMAAC LDA would not have been constrained, but would have cleared with MAAC. All zones in New Jersey would have received the MAAC clearing price. The resource clearing price in the New Jersey zones would have decreased $53.75 per MW-day (21.9 percent) to $191.25 per MW-day. The AECO clearing quantity would have decreased 1.8 MW (0.1 percent) to 1,885.9 MW, the JCPL clearing quantity would have decreased 4.5 MW (0.1 percent) to 4,071.8 MW, the PSEG clearing quantity would have increased 918.2 MW (8.0 percent) to 12,389.0 MW, and the RECO clearing quantity would have decreased 0.3 MW (0.9 percent) to 32.1 MW.

Table 5 shows the RPM market results for PJM if an additional 2,000.0 MW UCAP had been offered in PSEG at $0 per MW-day, compared to the actual results in the 2013/2014 BRA. Table 6 shows the difference between actual results for PJM and the results that would have occurred if an additional 2,000.0 MW UCAP had been offered in PSEG at $0 per MW-day. The results for Pepco would have remained the same. The EMAAC LDA would not have been constrained, but would have cleared with MAAC. The EMAAC clearing quantity would have increased 1,461.2 MW (4.5 percent) to 34,296.6 MW. The SWMAAC LDA would have had a binding constraint. SWMAAC did not have a binding constraint and cleared with MAAC in the 2013/2014 BRA. The SWMAAC clearing price would have decreased $53.78 per MW-day (23.8 percent) to $172.37 per MW-day, and the rest of SWMAAC clearing quantity would have decreased 122.9 MW (1.9 percent) to 6,327.5 MW. The rest of MAAC clearing price would have decreased $84.78 per MW-day (37.5 percent) to $141.37 per MW-day, and the rest of MAAC clearing quantity would have decreased 154.7 MW (0.7 percent) to 23,407.7 MW. The rest of RTO clearing price would have decreased $3.67 per MW-day (13.2 percent) to $24.06 per MW-day, and the rest of RTO clearing quantity would have decreased 1,183.6 MW (1.4 percent) to 83,919.8 MW.

Table 7 shows the RPM market results for New Jersey if an additional 2,000.0 MW UCAP had been offered in PSEG at $0 per MW-day, compared to the actual results in the 2013/2014 BRA. Table 8 shows the difference between actual results for New Jersey and the results that would have occurred if an additional 2,000.0 MW UCAP had been offered in PSEG at $0 per MW-day. The zones in New Jersey include AECO, JCPL, PSEG, and RECO. The EMAAC LDA would not have been constrained, but would have cleared with MAAC. All zones in New Jersey would have received the MAAC clearing price. The resource clearing price that New Jersey zones would have received would have decreased $103.63 per MW-day (42.3 percent) to $141.37 per MW-day. The AECO clearing quantity would have decreased 2.4 MW (0.1 percent) to 1,885.3 MW, the JCPL clearing quantity would have decreased 6.2 MW (0.2 percent) to 4,070.1 MW, the PSEG clearing quantity would have increased 1,916.0 MW (16.7 percent) to 13,386.8 MW, and the RECO clearing quantity would have decreased 0.4 MW (1.2 percent) to 32.0 MW.

Tables

Table 1 Impact on PJM of increasing supply in PSEG by 1,000.0 MW UCAP at $0 per MW-day: 2013/2014 RPM Base Residual Auction

	Actual Auction Results			New Generation Analysis		
LDA	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Revenue	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Revenue
Pepco	$247.14	4,791.7	$432,240,569	$247.14	4,791.7	$432,240,569
EMAAC	$245.00	32,835.4	$2,936,305,645	$191.25	33,402.0	$2,331,668,363
Rest of MAAC	$226.15	30,012.8	$2,477,399,073	$191.25	29,933.4	$2,089,538,404
Rest of RTO	$27.73	85,103.4	$861,369,808	$26.06	84,616.2	$804,860,833
PJM Total		152,743.3	$6,707,315,095		152,743.3	$5,658,308,168

Table 2 Difference between PJM actual and analysis results of increasing supply in PSEG by 1,000.0 MW UCAP at $0 per MW-day: 2013/2014 RPM Base Residual Auction

	Difference Clearing Prices		Difference Cleared UCAP		Difference Revenue	
LDA	$ per MW-day	Percentage	MW	Percentage	$	Percentage
Pepco	$0.00	0.0%	0.0	0.0%	$0	0.0%
EMAAC	($53.75)	(21.9%)	566.6	1.7%	($604,637,283)	(20.6%)
Rest of MAAC	($34.90)	(15.4%)	(79.4)	(0.3%)	($387,860,669)	(15.7%)
Rest of RTO	($1.67)	(6.0%)	(487.2)	(0.6%)	($56,508,975)	(6.6%)
PJM Total			0.0	0.0%	($1,049,006,927)	(15.6%)

Table 3 Impact on New Jersey of increasing supply in PSEG by 1,000.0 MW UCAP at $0 per MW-day: 2013/2014 RPM Base Residual Auction

	Actual Auction Results			New Generation Analysis		
Area	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Revenue	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Revenue
AECO	$245.00	1,887.7	$168,807,573	$191.25	1,885.9	$131,647,607
JCPL	$245.00	4,076.3	$364,523,128	$191.25	4,071.8	$284,237,089
PSEG	$245.00	11,470.8	$1,025,776,290	$191.25	12,389.0	$864,829,631
RECO	$245.00	32.4	$2,897,370	$191.25	32.1	$2,240,781
NJ Total	$245.00	17,467.2	$1,562,004,360	$191.25	18,378.8	$1,282,955,108

Table 4 Difference between New Jersey actual and analysis results of increasing supply in PSEG by 1,000.0 MW UCAP at $0 per MW-day: 2013/2014 RPM Base Residual Auction

	Difference Clearing Prices		Difference Cleared UCAP		Difference Revenue	
Area	$ per MW-day	Percentage	MW	Percentage	$	Percentage
AECO	($53.75)	(21.9%)	(1.8)	(0.1%)	($37,159,966)	(22.0%)
JCPL	($53.75)	(21.9%)	(4.5)	(0.1%)	($80,286,039)	(22.0%)
PSEG	($53.75)	(21.9%)	918.2	8.0%	($160,946,659)	(15.7%)
RECO	($53.75)	(21.9%)	(0.3)	(0.9%)	($656,589)	(22.7%)
NJ Total	($53.75)	(21.9%)	911.6	5.2%	($279,049,253)	(17.9%)

Table 5 Impact on PJM of increasing supply in PSEG by 2,000.0 MW UCAP at $0 per MW-day: 2013/2014 RPM Base Residual Auction

	Actual Auction Results			New Generation Analysis		
LDA	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Revenue	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Revenue
Pepco	$247.14	4,791.7	$432,240,569	$247.14	4,791.7	$432,240,569
Rest of SWMAAC	$226.15	6,450.4	$532,446,655	$172.37	6,327.5	$398,094,979
EMAAC	$245.00	32,835.4	$2,936,305,645	$141.37	34,296.6	$1,769,706,275
Rest of MAAC	$226.15	23,562.4	$1,944,952,417	$141.37	23,407.7	$1,207,838,490
Rest of RTO	$27.73	85,103.4	$861,369,808	$24.06	83,919.8	$736,975,292
PJM Total		152,743.3	$6,707,315,095		152,743.3	$4,544,855,605

Table 6 Difference between PJM actual and analysis results of increasing supply in PSEG by 2,000.0 MW UCAP at $0 per MW-day: 2013/2014 RPM Base Residual Auction

	Difference Clearing Prices		Difference Cleared UCAP		Difference Revenue	
LDA	$ per MW-day	Percentage	MW	Percentage	$	Percentage
Pepco	$0.00	0.0%	0.0	0.0%	$0	0.0%
Rest of SWMAAC	($53.78)	(23.8%)	(122.9)	(1.9%)	($134,351,677)	(25.2%)
EMAAC	($103.63)	(42.3%)	1,461.2	4.5%	($1,166,599,370)	(39.7%)
Rest of MAAC	($84.78)	(37.5%)	(154.7)	(0.7%)	($737,113,927)	(37.9%)
Rest of RTO	($3.67)	(13.2%)	(1,183.6)	(1.4%)	($124,394,516)	(14.4%)
PJM Total			0.0	0.0%	($2,162,459,490)	(32.2%)

Table 7 Impact on New Jersey of increasing supply in PSEG by 2,000.0 MW UCAP at $0 per MW-day: 2013/2014 RPM Base Residual Auction

	Actual Auction Results			New Generation Analysis		
Area	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Revenue	Clearing Prices ($ per MW-day)	Cleared UCAP (MW)	Revenue
AECO	$245.00	1,887.7	$168,807,573	$141.37	1,885.3	$97,281,574
JCPL	$245.00	4,076.3	$364,523,128	$141.37	4,070.1	$210,017,364
PSEG	$245.00	11,470.8	$1,025,776,290	$141.37	13,386.8	$690,759,549
RECO	$245.00	32.4	$2,897,370	$141.37	32.0	$1,651,202
NJ Total	$245.00	17,467.2	$1,562,004,360	$141.37	19,374.2	$999,709,689

Table 8 Difference between New Jersey actual and analysis results of increasing supply in PSEG by 2,000.0 MW UCAP at $0 per MW-day: 2013/2014 RPM Base Residual Auction

	Difference Clearing Prices		Difference Cleared UCAP		Difference Revenue	
Area	$ per MW-day	Percentage	MW	Percentage	$	Percentage
AECO	($103.63)	(42.3%)	(2.4)	(0.1%)	($71,525,998)	(42.4%)
JCPL	($103.63)	(42.3%)	(6.2)	(0.2%)	($154,505,764)	(42.4%)
PSEG	($103.63)	(42.3%)	1,916.0	16.7%	($335,016,741)	(32.7%)
RECO	($103.63)	(42.3%)	(0.4)	(1.2%)	($1,246,168)	(43.0%)
NJ Total	($103.63)	(42.3%)	1,907.0	10.9%	($562,294,671)	(36.0%)