UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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PJM Interconnection, L.L.C.	)	Docket No. ER09-1063-004
	)	

PROTEST AND COMPLIANCE PROPOSAL 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 ("Market Monitor" or "MMU"),[1] submits this protest to the compliance filing submitted by PJM Interconnection, L.L.C. ("PJM") in the above captioned proceeding on June 18, 2010 ("June 18th Proposal"), and submits for the Commission's consideration the Market Monitor's proposed amendments to the June 18th Proposal ("Amended Proposal") that corrects certain serious flaws included in the June 18th Proposal. This filing also complies with the Commission's directive in Order No. 719 that the Independent Market Monitor "provide us with its view on any

1 Capitalized terms used herein and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT") or the PJM Operating Agreement ("OA").

proposed reforms" to market rules governing price formation during periods of operating reserve shortage.[2]

The Market Monitor supports the core conceptual approach to scarcity pricing included in the June 18th Proposal, and believes this proposal, if corrected, could meet the Commission's objective in Order No. 719 and significantly enhance and complete the overall PJM market design. However, the June 18th Proposal contains serious flaws that flow from a fundamental misunderstanding of the nature of the problem with PJM's scarcity pricing rules. The approach adopted in the June 18th Proposal is predicated on the implied false assumption that prices are too low in PJM and that the level of reserves available to PJM threatens system reliability. This undue and unsubstantiated alarm leads to a proposed radical alteration of the PJM market design in a manner that would raise the overall price of wholesale electric service in PJM with no corresponding benefit to its wholesale customers.

The key specific flaws include in summary the following:

- Unnecessarily forcing fixed reserve constraint penalty factors into energy prices, introducing administrative margins of $850 to $1,700 to marginal

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2 *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶31,281 at P 235 (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).

offers, causing real-time energy prices to artificially exceed real-time energy offer caps and price caps and thereby causing:

- The scarcity pricing mechanism to work at cross purposes with the PJM Day-Ahead and Real-Time Market designs;
- The need to increase offer caps in the day ahead market so that they do not match the real time offer caps;
- The creation of new mechanisms for the exercise of market power not addressed in the PJM proposal; and
- The scarcity pricing mechanism to work at cross purposes with existing local and aggregate market power mitigation rules in both the Day-Ahead and Real-Time Energy Markets.

- Creating double recovery of scarcity rents by capacity resources in a given delivery year by failing to include a scarcity pricing revenue true up mechanism, thereby causing:

  - The mechanism to work at cross purposes with the basis for the Day-Ahead and Real-Time Energy Market interactions;
  - The scarcity pricing mechanism to work at cross purposes with the RPM capacity market by distorting long term price signals for capacity resources; and
  - Causing unnecessary and counterproductive wealth transfers between load and capacity resources.

- Creating and failing to address market power issues created by its proposed design for the Synchronized Reserve Market by:

    - Failing to provide a must offer requirement for synchronized reserves; and
    - Allowing separate Tier 2 reserve parameter's from its energy offer parameters.

- Failing to address the issue of false positive scarcity events, thereby increasing the likelihood of inefficient pricing signals and wealth transfer in the Real-Time Market.
- Eliminating full Tier 2 hour ahead assignment of reserves, thereby:
    - Reducing the ability of load response to participate as Tier 2 reserves;
    - Reducing the amount of Tier 2 reserves available from on line resources; and
    - Reducing overall available reserves relative to an hour ahead construct, thereby increasing the possibility of unnecessary and avoidable shortage events.

- Adding an unnecessary and superfluous primary reserve requirement as a constraint on optimization and a trigger for scarcity and proposing to create an unnecessary market for non-synchronized primary reserves, thereby:
    - Introducing additional measurement error issues;
    - Introducing a substantial additional risk of unnecessary and avoidable false scarcity events; and
    - Increasing the costs of system operation without demonstrated operational need or a demonstrated means to measure primary reserve levels.

- Allowing demand-side resources and emergency purchases to set prices, thereby:
    - Exposing the market to the exercise of market power; and
    - Undermining the improvements to dispatch that could be achieved through implementation of the scarcity pricing rules.

- Failing to address the issues of the recallability of RPM capacity resources during an emergency, thereby:
    - Failing to ensure that a key obligation of capacity resources is enforced when it is most critical to the operation of the market.

- Failing to address the issues in the Regulation market caused by continuing (i) to calculate opportunity costs on the basis of the lower of cost based or price based offers rather than the actual dispatch schedule and (ii) to fail to net regulation revenues from make whole balancing operating reserve payments, thereby:
    - Resulting in a non-competitive market outcome;
    - Resulting in inconsistent treatment of the opportunity costs of regulation resources relative resources in other PJM markets; and
    - Resulting in inconsistent treatment of offsets to operating reserves across all markets.

The Commission should reject these aspects of the June 18th Proposal because they are unjust and unreasonable, particularly in light of the Commission's explicit requirement in Order No. 719 that any scarcity pricing proposal not work at "cross purposes" to PJM's existing market design.[3] If these flaws are not corrected, the result will be unnecessary and unjustified price increases for PJM customers, an incoherent and inefficient market design, inefficient pricing and, overall, a serious disruption in the heretofore primarily beneficial evolution of PJM's market design.

The Amended Proposal corrects each of the flawed components in the June 18th Proposal so that the Amended Proposal works in harmony with the existing PJM market design and improves price formation during periods when operating reserves are scarce consistent with the objectives of Order No. 719. The objective here is not simply to increase the overall cost of wholesale energy to consumers. Because PJM has established a robust capacity market in the form of RPM, the PJM market design does not require in the form of new scarcity pricing rules a mechanism to facilitate a further transfer of wealth from consumers to producers. Likewise, there is no indication that PJM confronts a reliability crisis concerning the level of reserves in the short or long term. What can be improved is the incorporation of the payment for reserves into the market so that pricing signals are more granular and efficient when supply on the

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[3] Order No. 719 at P 204.

system is tight. This may change to whom and how compensation for reserves flows, but would not be expected to significantly alter the overall amounts transferred. One improvement, for example, would be relatively greater compensation to load actively participating and responding to price.

Following the order of the flaws identified above, corrections that amend the proposal consistent with the true objectives for the reform of the scarcity pricing rules in PJM include:

- Maintaining and enforcing the penalty factor associated with going short reserves for purposes of dispatch while limiting the price effect of going short reserves to a level that is consistent with the physical resource price caps that exist in the Day-Ahead and Real-Time Energy Markets, thereby:
  - Providing all of the advantages of a security constrained dispatch approach to scarcity pricing, while providing market results that are consistent with overall market design and market efficiency goals;
  - Eliminating the need to increase offer caps in the Day-Ahead Market or for selected participant groups;
  - Eliminating market power issue introduced by the PJM proposal; and
  - Maintaining the effectiveness of existing local and aggregate market power mitigation rules in both the Day-Ahead and Real-Time Energy Markets.
- A scarcity pricing revenue true up that explicitly eliminates double recovery of scarcity rent by capacity resources in a given delivery year, thereby:

    - Preserving the basis for the Day-Ahead and Real-Time Energy Market interactions;
    - Preserving the long term signals to capacity resources; and
    - Preventing unnecessary and counterproductive wealth transfers between load and capacity resources and among loads and capacity resources.

- Corrections for the market power issues created in the Synchronized Reserve Market by:

    - Introducing a must offer requirement for synchronized reserves; and
    - Requiring that within hour Tier 2 reserve offer parameters match energy offer parameters.

- A duration component to the determination of a reserve shortage, thereby:

    - Addressing the problem of false positives; and
    - Decreasing the likelihood of inefficient pricing signals and unnecessary wealth transfer in PJM's Real-Time Energy Market.

- A mechanism to assign Tier 2 reserves prior to the operational hour thereby:

    - Preserving the ability of demand-side resources to participate as Tier 2 reserves;
    - Preserving the current availability of Tier 2 reserves from on line resources; and
    - Preserving the overall level of available reserves, thereby reducing the number of unnecessary shortage events.

- Modeling only synchronized reserve requirements as a constraint in the security constrained optimization approach to scarcity pricing, thereby:
  - Internalizing an actual and current operational goal in the automatic dispatch; and
  - Providing a clear improvement in current practice.

- Retention of current rules that do not permit emergency demand-side resources and emergency purchases to set prices, thereby:
  - Providing continued protection of the markets from market power; and
  - Preserving the benefits of improved dispatch promised by this scarcity pricing reform.

- Requiring the development of clear rules governing the emergency recall of RPM capacity to ensure that such capacity meets its obligations to provide system resources during an emergency, thereby:
  - Limiting the possibility of false scarcity events; and
  - Ensuring that customers receive the benefits of their purchase of capacity resources.

- Resolving the issues in the Regulation Market design by using the actual dispatch schedule as the reference for opportunity cost calculations and netting regulation revenues from make whole balancing operating reserve payments, thereby:
  - Resulting in a competitive market outcome

- Resulting in consistent treatment of the opportunity costs across all markets
- Resulting in consistent treatment of offsets to operating reserves across all markets.

The Market Monitor includes as an attachment to this pleading a Supporting Statement that explains in detail the defects included in the June 18th Proposal and includes and supports the Amended Proposal (*infra* section III) that corrects these defects and meets the Commission's directives and requirements in Order No. 719 and the standards of the Federal Power Act.[4] The Market Monitor respectfully requests that the Commission reject those portions of the June 18th Proposal that have not been shown by PJM to meet these directives, requirements and standards and require that PJM develop and file revisions to its Operating Agreement and other tariffs, as necessary, for PJM to implement the Amended Proposal.

I. BACKGROUND

A. The Scarcity Pricing Compliance Requirement of Order No. 719

Among the series of reforms included in Order No. 719 related to the development of demand-side response in the organized wholesale markets, is the requirement to address existing market rules to the extent that they do not "produce

[4] *See* Federal Power Act § 205, 16 U.S.C. § 824d (2000).

prices that accurately reflect the value of energy and, by failing to do so, may harm reliability, inhibit demand response, deter entry of demand response and generation resources, and thwart innovation."[5] This requirement seeks removal of barriers to demand response "by requiring price formation during periods of operating shortage to more accurately reflect the value of such energy during such shortage periods."[6] The Commission determined (at P 246) "to require each RTO or ISO to support its proposed reform in shortage pricing or its demonstration of the adequacy of its existing rules with adequate factual support." The Commission explained (*Id*.) that "[t]his factual record will allow the Commission to discharge its duty to ensure that any reform is necessary and narrowly tailored to address the circumstances in that region, and that it is designed to protect consumers against the exercise of market power."

The Commission's consideration of this issue in the context of demand-side participation is significant because it indicates that the fundamental emphasis of this aspect of compliance is to increase the ability of and incentives to demand-side resources to participate in meeting short-term reliability needs on the system. The focus is on integrating such resources into improved markets for operating reserves, and treating reserve options comparably, not creating an additional revenue stream for

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5 Order No. 719 at P 192.

6 *Id*. at P 194.

incumbent generation resources or reforming current approaches to achieving resource adequacy over the long term. This is also significant because PJM has large and growing participation in its demand-side response programs,[7] and reform of the scarcity pricing rules may have limited additional impact. Demand-side resources currently have the ability to participate in PJM's Energy, Capacity, Synchronized Reserves and Regulation Markets.

In order to evaluate scarcity pricing rule proposals or justifications, the Commission adopted six criteria (at P 247), explaining that it "will use these six criteria to consider whether the factual record compiled by the RTO or ISO meets the requirements adopted in this Final Rule." The Commission determined:

> … The RTO or ISO must describe how its proposal would:
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> - Improve reliability by reducing demand and increasing generation during periods of operating reserve shortage;
> - Make it more worthwhile for customers to invest in demand response technologies;
> - Encourage existing generation and demand resources to continue to be relied upon during an operating reserve shortage;
> - Encourage entry of new generation and demand resources;

[7] *See, e.g.*, 2009 State of the Market Report for PJM at 111–124.

- Ensure that the principle of comparability in treatment of and compensation to all resources is not discarded during periods of operating reserve shortage; and
- Ensure market power is mitigated and gaming behavior is deterred during periods of operating reserve shortages including, but not limited to, showing how demand resources discipline bidding behavior to competitive levels. [8]

None of the criteria above mandate general price increases for reserves, subsidies for preferred resource classes or new investment based on inefficient pricing. However, these criteria do encourage greater diversity of participation in the supply of reserves, particularly from demand-side resources, because the costs for securing reserves can become more appropriately and narrowly targeted to specific users, and every user, in that case, would have an incentive to invest in capabilities that would allow it to take advantage of the opportunity to access a new revenue source and to defend against the possibility of such investment by others that could increase its share of the costs of reserves.

Order No. 719 indicates a range of acceptable approaches to compliance primarily in order to accommodate difference in the market designs of the affected RTOs and ISOs:

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[8] *Id.*; *see also*, *Id*. at PP 208–237.

> Under the revised criteria, we expect an RTO or ISO to explain how its market rules will reduce or avoid periods of operating reserve shortages as well as how its market rules will reliably reduce demand and increase generation during periods of operating reserve shortage. Nothing in this Final Rule dictates the particular market rules or mechanisms an RTO or ISO must adopt. For example, we do not require regions that have not adopted a capacity market to develop such markets. We are intentionally providing latitude to the RTOs and ISOs to work with their stakeholders to determine the appropriate mechanisms for their regions and then explain how those mechanisms meet the revised criteria.[9]

Although this requirement directs RTOs to either implement a significant reform or demonstrate the adequacy of the existing rules, the scope of the directive remains focused. Each of the above six criteria specify rules that address actions taken during operating reserve shortages and the need for comparable incentives and compensation for demand-side and generation resources. The Commission expressly considered and rejected criteria other than the six adopted,[10] and took care to further define certain of its six criteria with some precision.[11] To the extent that a proposal does not address the

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[9] Order No. 719 at PP 247–48.

[10] *See* Order No. 719 at 249–50.

[11] *See* Order No. 719 at P 248 n.342 ("For example, the third criterion in the NOPR sought an explanation of how the market rules encourage existing generation and demand resources needed during an operating reserve shortage to "remain in business." Upon review, the Commission is concerned that this could have been read to require shortage pricing provisions that would

six criteria or is unrelated to the six criteria, it is not a requirement for compliance and should be rejected as not within the scope of compliance in this proceeding.[12] For example, the Commission clarifies that it does not require an RTO to include a capacity market in its proposal if it does not already have one, provided that it can show that its rules and/or its proposal meet the six criteria.[13] Indeed, the Commission does not require that an RTO submit any reform proposal to the extent that it can demonstrate the adequacy of its existing rules.[14] The Commission has approved two compliance filings on the basis of the RTO's existing rules.[15] The Commission has also made clear that it will accept a measured approach to compliance that meets its criteria, but does not insist that RTOs attempt to implement an end state for which neither the RTO nor its stakeholders are prepared.[16]

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subsidize or give preferences to resources to ensure they "remain in business." Instead, our intention is for the RTO or ISO to explain how its shortage pricing proposal, together with existing market rules, encourages existing generation and demand resources to be available in an emergency. Similarly, the fifth criterion in the NOPR could have been read to limit comparable treatment and compensation for all resources to periods of operating reserve shortage. Because neither of these implications was our intention, we clarify the wording of these criteria.").

12 *See*, *e.g.*, *PJM Interconnection, L.L.C.*, 117 FERC ¶61,331 (2006).

13 *Id*. at P 248.

14 *Id*. at P 246.

15 See New York Independent System Operator, Inc., 129 FERC ¶61,164 at PP 50–51(2009); ISO New England Inc. and New England Power Pool, 130 FERC¶61,054 at PP 87–89 (2010).

16 *See NYISO*, 129 FERC ¶61,164 at P 51 (The Commission clarified, "[W]e do not want to foreclose on any fruitful stakeholder discussions underway currently or future discussions that may revise and improve scarcity pricing.").

The Commission also emphasized (at P 204) that scarcity rules should not disrupt the existing market design, noting that "[a]dding any element to a market design can have effects on the other elements." To avoid this result, the Commission affirmed its requirement in Order No. 719 that "each RTO or ISO address in its compliance filing how its selected method of shortage pricing interacts with its existing market design."[17] Order No. 719 does not require an RTO to modify other components of the RTO's existing market design; it instead expressly directs RTOs not to include in their compliance filing proposed reforms that disrupt the coherency of the existing market construct. For example, in response to concerns raised by some that "demand response resources would be negatively affected by the shift of revenues from capacity markets to energy markets," the Commission further required (at P 204), particularly with respect to the relationship between the scarcity pricing rules and the capacity market rules, that the RTO affirmatively demonstrate their coherence:

> In general, giving resource suppliers and customers more choices for how they participate in markets is beneficial. Shortage pricing in an emergency and capacity markets for long-term resource adequacy assurance serve largely distinct purposes, but we agree that they should not work at cross purposes. Adding any new element to a market design

[17] *PJM Interconnection, L.L.C.*, 129 FERC ¶61,250 (2009), citing Order No. 719 at P 204.

> can have effects on the other elements. We require that each RTO and ISO address in its compliance filing how its selected method of shortage pricing interacts with its existing market design.

The Commission rightly recognizes that scarcity pricing reform is a significant reform with the potential to impact each RTO's existing market design in ways that are difficult to predict. The existing rules of each RTO are unique, and all have complicated interactions. Each RTO must affirmatively demonstrate that its proposal makes changes needed for compliance with Order No. 719's six criteria and that any proposed changes do not work at "cross purposes" with the existing elements of its particular design.

B. PJM Stakeholders Did Not Agree to a Common Proposal

PJM filed the June 18th Proposal in order to comply with the directive in Order No. 719, but PJM does not have any authorization from its Members to take any action that exceeds what is necessary to achieve compliance. No proposal, including the June 18th Proposal, achieved the supermajority in the PJM stakeholder process required to effect changes to the PJM Operating Agreement, including the rules for the PJM Interchange Energy Market included as Schedule 1 to the Operating Agreement.[18] Consequently, no aspect of this filing comes at PJM's initiative under section 205 of the Federal Power Act. Moreover, PJM must meet section 205's burden of proof as applied

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[18] PJM Operating Agreement §§ 8.4, 18.6.

to compliance filings,[19] and every element of the June 18th Filing must fall within the scope of compliance.[20] In order for PJM to change any element of PJM market design other than those elements within the scope of Order No. 719's directives, it must either obtain the support of a supermajority of PJM Members or PJM must show that the existing element of its market design is unjust, unreasonable or unduly discriminatory under section 206 of the Federal Power Act.[21] Although PJM points out the shortcomings of its existing rules in light of Order No. 719's criteria,[22] it does not demonstrate that the existing rules are unjust and unreasonable.

In evaluating the June 18th Proposal in comparison to the Amended Proposal, or any other proposal, the Commission should recognize that PJM has no mandate from its Members, and its authorization in this proceeding is limited to those steps necessary for compliance. The Commission's objectives in Order No. 719 can be fully realized with an approach consistent with the existing market rules, PJM's existing capabilities and reasonable caution about how these important rule changes will operate in practice.

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19 *See* 16 U.S.C. § 824d; *see also*, *e.g.*, *New York Independent System Operator, Inc.*, 117 FERC ¶61,266 at P 22 (2006) ("[T]he Commission rejects the claim that it shifted the burden of proof to EPIC when it found that "EPIC has not made a convincing case" that NYISO's compliance filings were inadequate… The burden of proof in this proceeding was on NYISO.").

20 See, e.g., PJM Interconnection, L.L.C., 117 FERC ¶61,331 (2006).

21 *See* 16 U.S.C. § 824e. PJM took this approach when it filed to reform its capacity market rules and implement the Reliability Pricing Model ("RPM") despite having failed to obtain the required supermajority. *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 at PP 21–36 (2006).

22 June 18th Proposal at 8–17.

There is no consensus among PJM Members to implement a risky and unpredictable proposal for scarcity pricing that could disrupt other elements of PJM's market design or subject consumers to market power, gaming or price shocks in the energy market. On the contrary, the Commission has preferred rate design and transitional rule implementation mechanisms that avoid inflicting "rate shocks" on electric customers.[23] There is no emergency in PJM concerning resource adequacy, operating reserves adequacy or barriers to entry to demand-side resources that justifies imposing radical and potentially disruptive changes.

In its review of the six criteria and in light of its circumstances, the Market Monitor believes that PJM could have taken a conservative approach and chosen to submit a filing demonstrating with sufficient factual evidence that its existing market

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23 *See PJM Interconnection, L.L.C.*, 117 FERC ¶61,331 at PP 65, 68 (2006) ("The Commission also finds that the use of a transition period is just and reasonable as it provides for regional pricing prior to implementation of the full division of PJM into 23 Locational Delivery Areas, and allows the participants in the market a period of time to understand and get used to the dynamics of the new capacity market prior to its full implementation."); *see also*, *e.g.*, *S. Cal. Edison Co.*, 121 FERC ¶61,168 at P 59 (2007); *American Electric Power Service Corporation*, 118 FERC ¶61,041 at 61,214–15 (2007), citing *Construction Work in Progress for Public Utilities; Inclusion of Costs in Rate Base,* Order No. 298, 48 Fed. Reg. 24,323 (June 1, 1983), FERC Stats. & Regs. ¶30,455, *order on reh'g*, Order No. 298-A, 48 Fed. Reg. 46,012 (Oct. 11, 1983), FERC Stats. & Regs. ¶30,500 (1983), *order on reh'g*, Order No. 298-B, 48 Fed. Reg. 55,281 (Dec. 12, 1983), FERC Stats. & Regs. ¶30,524 (1983).

rules meet the six criteria set forth in Order No. 719. The last of the four approaches sanctioned by the Commission in Order No. 719 describes PJM's existing rules.[24]

The Market Monitor has not requested that the Commission reject PJM's compliance filing because it believes that Order No. 719 anticipates a variety of possible approaches to meeting its requirement for scarcity pricing reform and, even more importantly, as the Market Monitor explains in its Supporting Statement and has long observed in its annual state of the market reports that it considers PJM's current scarcity pricing rules inadequate.[25] This proceeding affords an opportunity to reform PJM's scarcity pricing rules in a manner that could enhance PJM's overall market design in the short term and position it well for continued refinement over the long term. The Market Monitor believes that PJM stakeholders have made significant progress toward developing such a proposal that is consistent with the third approach sanctioned by the Commission, an approach potentially becoming the industry standard.[26] This

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24 Order No. 719 at 208 ("(4) RTOs and ISOs would set the market-clearing price during an emergency for all supply and demand response resources dispatched equal to the payment made to participants in an emergency demand response program").

25 *See*, *e.g.*, 2008 State of the Market Report for PJM at 6.

26 Order No. 719 at 208 ("(3) RTOs and ISOs would establish a demand curve for operating reserves, which has the effect of raising prices in a previously agreed-upon way as operating reserves grow short"). The Commission approved the scarcity pricing rules of the New York Independent System Operator and ISO New England indicated as consistent with the third approach. *See NYISO*, 129 FERC 61,164 at PP 47, 50; *ISO-NE*, 130 FERC ¶61,054 at P 87.

achievement should not be lost, and would be preserved if the Commission accepted the Amended Proposal.

However, for the reasons explained *infra* Section II, critical features of the June 18th Proposal are seriously flawed. PJM has not and cannot demonstrate that certain key aspects of its proposal are just and reasonable. In some cases PJM has not developed these aspects of its proposal to the point where the Commission can evaluate them. One of the reasons that the June 18th Proposal is incomplete and unsupported is because it attempts, as explained below, to prematurely impose a program that attempts changes that are too far reaching both in terms of the immediate exposure to very high reserve prices and their consistency with PJM's existing market design. Certain aspects of the June 18th Proposal should be rejected because they work at cross purposes to the existing market rules contrary to the specific directive in Order No. 719 that compliance proposals not do so[27] and/or could result in unjust and unreasonable double recovery for the same service.[28]

The Market Monitor has therefore developed in parallel over the course of the stakeholder process an Amended Proposal that incorporates the desirable aspects of the

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27 Order No. 719 at P 204.

28 *See, e.g., Cal. Indep. Sys. Operator Corp.*, 126 FERC ¶61,150 at P 113 (2009) ("The Commission … proposed to limit the possibility of a resource receiving a double recovery by capping the total recovery for non-resource adequacy resources at the ICPM monthly rate."); *Dynegy Midwest Generation*, 121 FERC ¶61,025 at PP 68–69 (2009).

June 18th Proposal while correcting its flaws. Under the circumstances of this compliance proceeding, the Commission should take advantage of its position to choose the optimal approach to scarcity pricing in PJM solely on the basis of merit.

The Market Monitor demonstrates below (*infra* Section III) that this Amended Proposal meets the standard under section 205 of the Federal Power Act and the requirements for compliance with Order No. 719, including the six specific criteria and the overarching requirement that a scarcity pricing proposal constitute a coherent part of the overall market design and not work at cross purposes with that design. Because the Amended Proposal introduces greater risk that individual users in particular circumstances may be exposed to prices as high as $1,000 per MWh, it will become more "worthwhile for customers to invest in demand response technologies" and for all resources to be ready to supply reserves in short term shortage situations (criteria 2, 3 & 4). This may improve reliability without building market power into the rules (criteria 1 & 6). All resources, under the Amended Proposal are dispatched and compensated on a comparable basis (criteria 5). The Amended Proposal is not, however, designed to inefficiently raise the overall cost of wholesale electric service in PJM or to address an as of yet unsubstantiated reliability issue.

C. PJM's Market Design

Scarcity pricing rules can improve PJM's market design only the extent that new rules are compatible with the existing ones. PJM does not have a mandate to overhaul fundamental aspects of its market design in this proceeding. Wherever possible, PJM should conform its proposal to fit into its existing market design. Scarcity pricing has the potential to impact PJM's market design, including, but not limited to the market components discussed below.

1. PJM Capacity Market

In 2004, PJM recognized that its capacity market design was inadequate and implemented arguably the most robust capacity market of the RTOs and ISOs primarily in the form of the Reliability Pricing Model ("RPM"). RPM is not perfect, and some of its worst defects are recent changes, [29] but RPM generally has succeeded in creating a source of scarcity revenues for incumbent generation and with modest but important corrections, has the potential to fulfill its promise of incenting new investment in generating resources. For the purposes of this proceeding, the Commission should determine that long-term resource adequacy is sufficiently addressed in PJM, even though it may not make a similar determination for every other RTO or ISO, and in some cases, may appropriately consider proposals that seek to address resource adequacy over the long as well as the short-term. PJM does not require a scarcity pricing proposal to address long-term resource adequacy issues, and, most importantly,

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29 *See* 2009 State of the Market Report for PJM at 299–310; IMM, "Analysis of the 2013/2014 RPM Base Residual Auction" (July 14, 2010).

to compensate generation capacity resources or other resources that have cleared RPM auctions and serve as capacity resources.

2. System Offer Cap of $1,000 per MWh

Since 1997, the tariff has included as part of the program to mitigate the potential exercise of market power an overall system offer cap of $1,000 per MWh.[30] The Market Monitor has recommended the retention of this important protection to PJM's markets in every state of the market report issued since.[31] The introduction of new scarcity pricing rules brings with it uncertain and potentially significant impact on the price of energy and ancillary services in PJM, and this is a compelling additional reason to ensure that that this protection remains in place.

3. Procurement of Synchronized Reserves

Real-time energy reserves are categorized as either 10 minute primary reserves, or 30 minute secondary reserves. Ten minute primary reserves are defined as the amount of additional output, over current system output levels, that system resources, either synchronized or non-synchronized to the system, could provide in ten minutes. Thirty minute reserves are defined as the amount of additional output, over current system output levels, that system resources could provide in ten to thirty minutes. The

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30 See Pennsylvania-New Jersey-Maryland Interconnection, 81 FERC ¶61,257 (1997).

31 *See*, *e.g.*, 2009 State of the Market Report for PJM at 8.

available reserve from a specific resource is the minimum of its remaining room to move (how much of its maximum output remains unused at a point in time) and ramp rate (the amount of additional output that the unit can produce within a defined period of time).

From an operational perspective, there are two types of 10 minute primary reserves, synchronized and non-synchronized. Synchronized primary reserves are provided by resources operating and synchronized to the system, such as demand response, steam units, hydro units and units in synchronous condensing mode. Non-synchronized primary reserves are provided by resources that, based on their operational characteristics, could start and produce a specified amount of output in 10 minutes or less. Non-synchronized reserves are typically made up of quick start combustion turbine units.

Synchronized primary reserves include Tier 1 and Tier 2 synchronized reserves. The term, Synchronized Reserve Market, refers only to supply of and demand for Tier 2 synchronized reserves. Tier 1 synchronized reserves are provided by resources that are online, following economic dispatch, and able to respond to a spinning event by ramping up from their present output. All resources operating on the PJM system are considered potential Tier 1 resources, except for those explicitly assigned to Tier 2 synchronized reserve. Tier 2 resources include units that are backed down to provide synchronized reserve capability, condensing units synchronized to the system and available to increase output, and demand side resources.

The market demand for Tier 2 synchronized reserve is determined by subtracting the amount of forecast Tier 1 synchronized reserve available from each synchronized reserve zone's synchronized reserve requirement for the period. The Synchronized Reserve Market is thus a residual market, designed to procure additional Tier 2 10 minute synchronized reserves when there is in sufficient Tier 1 to meet the 10 minute synchronized reserve requirement.

From a market standpoint, Tier 1 reserves are provided by units following economic dispatch and receiving market prices for their energy. Providers of Tier 1 are not foregoing any potential energy profits because such units are free to operate at their profit maximizing output. Such units have no incentive to produce any more or any less than their current output level. The reserves that they provide at their dispatch point are based on their remaining room to move and their ramp rate. If the system needs additional output that these resources have available and unsold, such units would continue to follow dispatch as prices increased. There is no incremental cost associated with the provision of Tier 1 primary reserves.

Tier 2 primary reserves are different. The provision of Tier 2 reserves imposes an economic cost on the owner. The owner of a unit following economic dispatch that provides Tier 2 primary reserves must back down the unit from its profit maximizing operating point in order to provide those reserves. A synchronous condensor must start up and spin, an action also imposing costs. Consequently, a market is required for Tier 2 reserves in order to coordinate prices, marginal incentives, output levels and operations requirements between the energy market and reserve requirements.

For these reasons, PJM has had such a market, specifically to procure synchronized primary reserves, since December 2002. This market satisfies the need to have resources ready for emergency, 10 minute dispatch, consistent with predefined operational reliability standards. The amount PJM needs is predetermined, and PJM has a reasonable method to determine how much synchronized reserve it has and how much it needs. Energy market prices enable accurate pricing of the value of synchronized reserves, because LMP for each unit accurately measures the opportunity cost of forgone output to provide reserves. The Synchronized Reserve Market also can and does compensate demand-side resources for a comparable product of dispatchable forgone consumption that can be made reliably available on an emergency basis.

Historically, non-synchronized primary reserve levels have been handled very differently by PJM. Primary Reserves are made up of total available synchronized reserves and the available pool of non-synchronized reserves. This means that at any point in time, total 10 minute synchronized reserves count towards meeting PJM's 10 minute primary reserve requirement, but Tier 2 demand is not affected by the level of primary reserves or by the supply-demand balance for primary reserves. Following the parallel with the synchronized reserve market, one might expect a residual market for non-synchronized reserves to exist. PJM does not, however, have a residual market for non-synchronized 10 minute primary reserves, despite the existence of a primary reserve requirement. There appear to be several reasons for this. First, these reserves are provided by resources that are not required to take any economic action; they are merely required to exist. PJM relies on revenues from the energy market and the capacity market to ensure that these units remain in service and remain available to provide either energy or reserves. The capacity market is designed to ensure that sufficient resources are in service to meet system needs, including forecast peak system needs. The capacity market includes by direct reference in its demand parameters combustion turbine units, precisely the type of unit likely to be capable of providing quick start Tier 2 reserves. Second, PJM has historically not taken actions to meet the primary reserves requirement. PJM provides no evidence that it accurately measures or actively dispatches to control for primary reserves requirements, undermining its claims that it needs a residual non-synchronized reserve market to maintain primary reserve levels.

While there may be reasons to examine the role of primary reserves in the PJM market, the inclusion of a very specific approach to primary reserves within the limited context of compliance with Order No. 719 is wholly unjustified, particularly given the very substantial impacts that this introduction would have on PJM markets. Further, PJM has not done the basic analytical work to justify such a dramatic change in its market design, regardless of the proceeding. It is also unjustified to propose a market for a type of resource prior to having the demonstrated capability to measure the amount of available primary reserves. Compliance with Order No. 719 should not interfere with the current and appropriate focus of PJM reserves markets on procuring synchronized reserves.

4. Emergency Demand Response Setting Price

A significant and growing portion of RPM capacity is made up of Emergency Demand Response (DR) resources. Under RPM, each load serving entity (LSE) in PJM must meet its capacity obligations, determined by its proportional contribution to peak load and the amount of capacity cleared in the auction, by acquiring capacity resources through the PJM Capacity Market. LSEs are required to purchase enough capacity to meet their portion of forecast peak load. Emergency DR is sold by participants who are willing to reduce their load when called on by PJM in real-time because the capacity serving them is needed by load that has paid for capacity.

The importance of Emergency DR in terms of both participation MW and revenues is growing rapidly. Under RPM, demand-side resources in the Capacity Market increased by 3,206.9 MW from 4,167.5 MW on June 1, 2008 to 7,374.4 MW on June 1, 2009. Since the implementation of the RPM design on June 1, 2007, capacity revenue has become the primary source of revenue to Emergency DR.

Under current market rules Emergency DR cannot set price when called. In part, this is due to the fact that the portion of a customer's load represented in the offers is already required to curtail, based on its sale of capacity, during an emergency. In other words, Emergency DR represents non-firm load that does not have a right to the capacity that it has not paid for and is, in the case of an emergency, required to be curtailed by the participant. In addition, Emergency DR customers currently cannot set price because Emergency DR participation does not require that the Emergency DR capacity have any of the characteristics of resources that could be made eligible to set price in a least cost security constrained dispatch model: discrete and measurable dispatchability in the form of telemetry, metering and a specific bus location. This is not based on a prohibition on demand response resources setting price in PJM. Demand response resources with discrete and measurable dispatchability in the form of telemetry, metering and a specific bus location are eligible, under PJM tariff, to set price. Demand Response resources with discrete and measurable dispatchability in the form of telemetry, metering and a specific bus location are eligible to set price outside of emergency situations, as part of normal dispatch. This is because resources with these characteristics can be dispatched as part of security constrained solution. Emergency DR with these characteristics could qualify to be marginal, if acting as economic demand (not emergency) demand response, but these characteristics are not a required for participation in the Emergency DR program.

Compliance with Order 719 does not require that Emergency DR set price. Emergency is adequately compensated and PJM has not suggested otherwise. The ability to set price is unrelated to compensation. Emergency DR should not set price until it meets the fundamental technical requirements of an LMP market.

II. PROTEST

A. Components of the June 18th Proposal Fail to the Meet the Commission's Requirements and Work at Cross Purposes with PJM's Market Design.

As explained in the Supporting Statement and in summary below, the Market Monitor supports the approach to scarcity pricing adopted in the June 18th Proposal but opposes those features that amount to an extreme solution to unsubstantiated problems. The Amended Proposal modifies the June 18th Proposal so that it is consistent with a reasonable assessment of the objectives of scarcity pricing reform.

B. The June 18th Proposal Includes A Combination of Excessive and Arbitrary Penalty Factors and Rigid Treatment of Constraints in the Clearing Optimization That Will Escalate Prices Without Any Economic Basis or Benefit and Undermine the Protection from Unjust and Unreasonable Prices Afforded by the Existing Mitigation Rules

Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM.

The market design must provide adequate revenues to support a level of capacity resources to cover forecasted peak load plus a reserve margin that provides reliability. The price signal function of scarcity pricing is directly related to the operational reliability aspect of reliability. The market design must provide for price signals during scarcity conditions that contribute to reliable operations.

While reliability is referenced by PJM as a reason for scarcity pricing, PJM does not clearly state which aspect of reliability it means. Some of PJM's arguments address the resource adequacy aspect of reliability and some of PJM's arguments address the operational reliability aspect of reliability.

While the scarcity pricing mechanism should not provide additional compensation to capacity resources, it should provide compensation to resources that were not compensated through the RPM construct, including energy only demand-side response, capacity which did not clear in RPM and imports.

PJM's decision to have the penalty factors directly affect marginal unit bus LMPs during reserve shortages introduces a number of market design issues. PJM's proposal undermines PJM's existing market power mitigation rules, introduces new avenues for market manipulation that are not addressed in the June 18th Proposal, requires the lifting of offer caps in the day-ahead market so that they do not match real-time offer caps, and introduces efficiency issues in the interaction of the Day-Ahead and Real-Time Energy Market. Further, PJM's defense of the $2,700 price cap is based on erroneous interpretations of value of lost load studies and the unsubstantiated and unclear claim that prices in excess of a $1,000 are needed in PJM markets to maintain reliability.[32]

There is no reason to increase the maximum price in PJM markets in order to implement scarcity pricing. PJM has not provided evidence that, given an RPM construct that procures capacity well in excess of what is needed to meet system reliability requirements, prices in excess of the $1,000 offer cap are needed to make PJM's system reliable. PJM has not made the case that its system is currently, or will become, unreliable at current price caps. PJM has not provided evidence that prices in excess of $1,000 are needed to incent economic demand response. PJM has not provided evidence that any additional theoretically available demand response, available only at prices in excess of $1,000, will make the difference between a reliable or unreliable system.

Given the significant changes to the PJM markets that are required in order to implement any significant change to scarcity pricing, a gradual approach is warranted.

A simpler solution to the scarcity pricing issues, in terms of market efficiency and consistency with overall market design, is to limit the price effect of going short reserves to a level that is consistent with the physical resource price caps that exist in

32 *See* Supporting Statement at 24–26.

the Day-Ahead and Real-Time Energy Markets. In the optimization problem this can be implemented by relaxing the reserve constraint to prevent the constraint from binding and setting the marginal unit bus prices to predefined price targets when the constraint is relaxed. As in the application of this approach with other reliability constraints in the optimization, this approach maintains and enforces the penalty factor associated with going short reserves for purposes of dispatch. The difference is that when the constraint is relaxed the approach in the Amended Proposal imposes a flexible price effect on the marginal unit buses so long as reserves fall short of the reserve requirements. The flexible price effect is the dollar amount needed to get the marginal unit bus price to the shortage price target. So long as the marginal incentives to produce energy (energy margin) or provide reserves (opportunity cost of foregone energy production) are maintained, this approach provides all the advantages of a security constrained dispatch approach to scarcity pricing, while providing market results that are consistent with overall market design and market efficiency goals.

The $1,000 per MWh offer cap is a longstanding feature of PJM market design and constitutes a key part of its mitigation program.[33] The June 18th Proposal recognizes these facts when it purports (at 11, 30–31) that the June 18th Proposal continues this

[33] See Pennsylvania-New Jersey-Maryland Interconnection, 81 FERC ¶61,257 (1997); see also supra Section I.C.2.

protection because it allows prices to rise to $2,700 per MWh on the basis of an $1,700 per MWh adder to an offer of $1,000 per MWh rather as part of an offer totaling $2,700. Implementation of Order No. 719 requirements for scarcity pricing rules does not require changing the $1,000 per MWh offer cap. On the contrary, Order No. 719 requires that any such proposal work with PJM's existing market rules, particularly those pertaining to mitigation.[34] Accordingly, the Commission should reject this component of the June 18th Proposal.

C. The June 18th Proposal Is Unjust and Unreasonable Because It Allows Double Recovery of Scarcity Revenues and Works at Cross Purposes with PJM's Existing Market Design.

Scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The RPM design reflects the recognition that the energy markets, by themselves, will not result in adequate revenues. The RPM design provides an alternate method for collecting scarcity revenues. The revenues in the capacity market are scarcity revenues.

PJM proposes that revenues generated by the scarcity mechanism during scarcity events be passed through RPM's three-year average energy and ancillary net revenue

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[34] Order No. 719 at P 195 ("[T]he Commission is not taking any action to remove market mitigation in regional markets. Each of the Commission's proposed reforms includes some form of mitigation, either bid caps, administratively-determined prices, or prices tied to payments made in emergency demand response programs administered by RTOs or ISOs (and thus approved by the Commission). RTOs and ISOs are free to propose other pricing reforms and associated mitigation that meet the criteria herein."); *Id*. at PP 198–99, 204.

offset in the same way as all other energy and ancillary service revenues and not affect RPM revenues in the year in which a scarcity event occurs. The June 18th Proposal would allow capacity resources to keep scarcity revenues in the delivery year along with the RPM revenues for that delivery year.

PJM's approach results in a significant mismatch between the timing of the scarcity event and associated revenues, and the impact on the RPM clearing prices. As a result, there is substantial uncertainty introduced into the RPM auction process about the likely impact on future auction results. The result will be to distort the prices of RPM in the future. Future RPM prices, set in an auction the year after the scarcity event, will be lower despite the fact that the scarcity event signaled that not enough capacity has been purchased. This is exactly the wrong price signal to send through the RPM market.

PJM's approach means that the net revenue offset would increase for three subsequent auctions, which would occur one, two and three years in the future after the scarcity event. The net revenue offset reduces the net CONE used to derive the demand curve in the RPM market. The net revenue offset also reduces net ACR based offers of capacity resources. The result of PJM's approach would be to reduce the RPM clearing price for capacity delivery years that are five, six and seven years after the scarcity event.

PJM argues that its approach ensures comparable treatment between RPM and non-RPM resources. But the June 18th Proposal does not ensure comparable treatment of RPM and non-RPM resources because the June 18th Proposal ignores the fact that capacity resources have already been compensated for availability during scarcity (and non-scarcity) periods while non-RPM resources have not.

There is additional and significant uncertainty under the PJM approach about whether the offset would ever occur. Some participants have already argued that the CONE unit should be assumed to clear in the Day-Ahead Energy Market and therefore not receive any scarcity revenue. In that case, there would be no offset under the PJM approach.

In addition, for the period from its proposed effective date until May 31, 2015, the RPM demand curves could not account for any scarcity revenues that may accrue during those years. Any scarcity revenues that accrue during those years will not offset the price of capacity procured through RPM. The June 18th Proposal fails to address this issue.

The real issue is that PJM has not made it clear whether it believes that scarcity pricing in the energy market should increase the total revenues received by capacity resources. To make such an argument would be to concede that RPM is not working as designed. This lack of clarity of purpose has led to PJM's poorly designed offset proposal that creates timing mismatches, uncertainty and pricing distortions in the

RPM auctions. This lack of clarity has also confused the already complex discussion about an appropriate offset mechanism.

If PJM believes that scarcity pricing should increase the revenues to capacity resources, PJM should state this clearly. This could lead to a payment mechanism that explicitly increased revenues to capacity owners in a defined way.

If PJM believes that scarcity pricing should not increase the revenues to capacity resources, PJM should state this clearly. This could lead to a scarcity pricing true up mechanism designed explicitly to ensure that such increase does not occur.

The June 18th Proposal's failure to include an explicit scarcity pricing revenue true up mechanism will result in a significant mismatch between capacity resources that receive scarcity pricing revenues and those that face lower RPM prices as a result. Similarly, PJM's scarcity pricing revenue true up proposal will result in a significant mismatch between loads that pay scarcity pricing revenues and those that face lower RPM prices as a result. The only result is pointless transfers of wealth.

A subset of capacity resource MW and units will receive real-time scarcity pricing revenues during a scarcity event. Similarly, a subset of load MW and customers will pay these real-time scarcity pricing revenues to the capacity resources during a scarcity event.

This means that under PJM's proposal the over collection and over payment of scarcity pricing revenues will occur for individual participants, but any offset would occur through adjustments to RPM Locational Delivery Area (LDA) clearing prices, not participant specific adjustments. This means that the individual participants that overpaid or were overcompensated will not have participant specific adjustments to what they were paid or were charged for capacity in the delivery year. Instead, any adjustment would occur through a change in the RPM price and will be spread across all participants, five to seven years after the event, whether or not they were overcharged or over paid in the delivery year. The result is a significant mismatch between the capacity resources that receive scarcity revenues and those capacity resources with reduced capacity payments. There is a comparable mismatch between load that pays scarcity prices and load that receives reduced RPM prices. This is equivalent to a tax payer discovering that she paid $1,000 too much tax in a given year and being assured that her overpayment would be corrected five, six and seven years from now by a cumulative reduction of the aggregate tax burden of her neighbors by $1,000 over the three year period. While the aggregate tax burden would go down, the grateful tax payer can count on only, at best, a very small reduction in her own personal tax obligations over the subsequent three year period.

PJM's approach, where it would affect RPM prices, would result in wealth transfers not only between capacity resources and load in the delivery year, but between capacity resources that received double payment in the delivery year and capacity resources that did not receive double payment in the delivery year. Capacity that received double payment in the delivery year would see a net increase in their scarcity related revenues, when combining RPM payments and energy scarcity revenues. The reduction in RPM payments would be less than the revenues gained through the scarcity event. At the same time capacity that did not receive double payment in the delivery year, including potential new entrants, would see a relative reduction in their potential RPM payments. Such participants would be worse off under the June 18th Proposal than under the Amended Proposal. Similarly, load that overpaid in the delivery year would receive less than its overpayment through the adjustments in the RPM price, as the net effect of the offset would be spread across the prices paid by all load in subsequent years.

PJM's proposed approach does not, and cannot, correct for overcharging and overcompensating scarcity pricing revenues to specific participants, whether capacity resources or load. PJM's approach will tend to increase payments to capacity resources. It thereby increases the cost of reliability from a specific set of resources, RPM assigned resources, without increasing the reliability they provide. Any increase in reliability, if any, will come from non-RPM resources, if any, that are attracted by the scarcity price.

The June 18th Proposal allows capacity resources to keep scarcity revenues in the delivery year along with the RPM related scarcity rents for that delivery year. This will increase the three year average net revenues of actual and potential capacity resources in the delivery year and reduce net ACR based offers of those resources in three subsequent RPM auctions for capacity. This will reduce the RPM clearing price of capacity in three subsequent auctions for capacity to be delivered five, six and seven years after the event. This pass through would also affect the CONE unit used to derive the demand curve in the RPM market for three subsequent auctions, which would also reduce the RPM clearing price for capacity that will be delivered five, six and seven years after the event.

This means that under the June 18th Proposal, rather than providing a true up of the administratively determined scarcity pricing revenues in the same delivery year, the scarcity pricing revenues are paid back through marginal impacts in subsequent RPM auctions, five, six and seven years after the event, through potential reductions in RPM prices caused by the effect of reduced CONE on the RPM demand curve (VRR curve) and the reduced ACR offer curves offered by capacity resources.

PJM's approach will cause the energy market scarcity mechanism to distort the longer-term price signal provide by the RPM market. Simulation analysis shows that under the June 18th Proposal scarcity events will tend to cause the price for forward capacity in the RPM auction to fall five, six and seven years after the scarcity event. In other words, under the PJM proposed approach, after a scarcity event, the price for capacity, and the marginal investment signal for new capacity sources, will be reduced relative to the case where the scarcity pricing revenue true up mechanism include in the Amended Proposal is used. The June 18th Proposal will therefore work to deter new entry, via its effect on the RPM price signal, and protect incumbents that receive real-time scarcity rents. Lowering the RPM price signal for capacity five, six and seven years into the future after a scarcity event is not only counter intuitive, it is counterproductive to forward price signals needed to incent new entry after a scarcity event.

PJM's approach would produce a price signal in RPM that has exactly the opposite of the desired impact. A scarcity event means that PJM is short of capacity compared to actual requirements. The result should be that the price of capacity increases to reflect that condition. The PJM approach will result in a decrease in the capacity price.

If accepted uncorrected by the Commission, the June 18th Proposal would allow a program intended to address to improve the pricing of short term operating reserve shortages to obstruct the long term approach to securing resource adequacy. This result is unjust and unreasonable and violates Order No. 719's directive (at P 204) that the scarcity pricing rules not work at "cross purposes" with the existing market design, including the capacity market design in particular. Accordingly, the Commission should reject this component of the June 18th Proposal.

D. The June 18th Proposal Includes Provisions that Would Restructure PJM's Basic Treatment of Reserves That Are Outside the Scope of this Proceeding and Fails to Offer Any Support for Such Provisions, That, If Adopted, Could Result in More Frequent and False Identification of Scarcity Events, Higher Overall Prices in PJM, and Introduce Needless Risk of Price Shocks to the Wholesale Market.

1. The Proper Objective for Compliance with Order No. 719 Is Improvement to Shortage Pricing in an Emergency, Not Additional Measures for Assurance of Long-Term Resource Adequacy That Have Been Fully Addressed by RPM and Are Therefore Outside The Scope of Compliance.

Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM.

Order No. 719 recognizes these two functions and draws an important distinction between "shortage pricing in an emergency and capacity markets for long-term resource adequacy assurance." Not every RTO has a well developed capacity market, but those that do, such as PJM, have fully addressed long-term resource adequacy assurance. What remains for PJM to address is limited to "shortage pricing in an emergency."

Any scarcity pricing application based on a reserve constraint requirement must use clearly defined reserve targets and accurate measurement of the resources that are available to meet those requirements. The reserve targets must match defined reserve requirements to which system operators actually operate. The objective should be to create a system that recognizes scarcity in needed reserves; a system that redispatches to maintain needed reserves; a system that provides market signals that are consistent with this redispatch; and a system that provides market signals consistent with any failure to maintain needed reserves. The definition of scarcity and its reflection in price should be based directly on the level of available 10 minute synchronized reserves relative to the relevant reserve requirement and the progressive use of emergency measures. It is the Market Monitor's position that this definition meets the defined objective. However, if PJM can demonstrate that PJM actually operates to a different definition of reserves and a different operational definition of scarcity, the MMU approach can be modified to be consistent with such a different definition.

PJM addresses short term emergencies that may result from system contingencies or inaccurate forecasts with synchronized reserves, and the market design should properly focused on Tier 2 synchronized reserves because those are the resources that it must procure on an emergency basis. An improved market design for Tier 2 synchronized reserves also offers an improved environment for demand response resources which actively participate in the PJM Synchronized Reserve Market.

PJM has no authorization from its Members to take action beyond what is appropriate to comply with Order No. 719, and no authorization to include an overreaching attempt to restructure the reserves markets. Moreover, the June 18th

Proposal fails to include critical features of its proposed restructuring, such as how it will measure the primary reserves it has and the level of primary reserves it would use as a trigger for scarcity pricing. The Commission cannot evaluate and approve restructuring the reserve markets when it is unable to review such critical components.

The Commission should stand by its determination in Order No. 719 (at P 204) to ensure that new scarcity pricing rules should not work at cross purposes with the existing market design. This limited proceeding is not the appropriate forum for restructuring the reserves markets. Such a proposal should be made separately so that PJM members could consider the interactions between such changes and the existing market design.

2. The June 18th Proposal Provides False Assurance About the Frequency and Duration of Scarcity Events When It Proposes Significant Conceptual Changes to How Events Are Triggered and Fails to Provide Details Sufficient to Support an Analysis of How These Conceptual Trigger Would Operates

The June 18th Proposal downplays the risks and defends its $2,700 scarcity price on the basis of claims that scarcity events will be rare.[35] PJM's states it is "necessary to provide the right signal to the market when shortage conditions are about to or have already begun to occur, and that since scarcity/shortage events occur so infrequently,

[35] *See* Supporting Statement at 36–39.

there should be no real concern about a significant or measurable transfer of wealth from suppliers to load."[36] On the contrary, the Commission should be very concerned.

PJM does not currently have accurate real time measurements of available primary reserves that are a critical and indispensable part of the June 18th Proposal's approach to scarcity pricing. An implicit assertion that better measurement will be forthcoming in time for implementation does not satisfy PJM's burden of proof in this proceeding.[37] In the absence of accurate real time measurements of available primary reserves, it is not possible to know how many times PJM has been in scarcity conditions, as the June 18th Proposal defines scarcity, in the last ten years or even how many times PJM was close to being in scarcity conditions. As a result, it is not possible to predict how frequently PJM can be expected to experience scarcity conditions in the future. It is also impossible to predict the likely dollar levels of wealth transfers that might occur under the June 18th Proposal or the likely impact on future RPM prices.

One of the measurement error issues that will exist even if PJM could accurately determine the level of primary reserves available is the issue of false positive scarcity events. An event that may look like a scarcity event if viewed myopically, but fits

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36 June 18th Proposal, Affidavit of Paul M. Sotkiewicz, Ph.D. on Behalf of PJM Interconnection, L.L.C. at 26–27 ("PJM Affidavit").

37 The June 18th Proposal ignores PJM's current inability to accurately measure the product it would proceed to establish a market to procure. For discussion of this issue, see the Supporting Statement at 36–38 & n.16.

within normal operations and expectations, involves no shortage of resources, and may occur routinely, is a "false positive." Triggering scarcity pricing for false positives is wasteful and counterproductive, and arbitrarily raises the cost of electricity to PJM consumers. When the Market Monitor and other stakeholders raised this issue in the Scarcity Pricing Working Group (SPWG), PJM recognized the problem and suggested that operations could, in the face of a transient event, relax the reserve constraint for some period to prevent the penalty factors from affecting the marginal unit bus prices. The Market Monitor believes that this approach would work, and it is the same approach that the Market Monitor recommends *infra* Section III.D.

The June 18th Proposal assures the Commission that, "If some combination of extreme realizations of actual peak weather more severe than expected, economic conditions more robust than expected, and supply resource performance worse than expected, then reserve shortage conditions may occur."[38] However, elsewhere the June 18th Proposal indicates that reserve shortages are not that rare an event by its measure. PJM identifies seven separate occasions over the last five years on which it has suffered what it considers to be extreme system conditions.[39] This may be evidence of faulty system planning, dispatch issues, or RPM market design issues. However, it is even

[38] PJM Affidavit at 6.
[39] *Id*. at 10.

more likely that this is an indication that PJM cannot accurately measure its reserve levels, particularly Primary Reserves, and that PJM did not actively dispatch based on the asserted seven events and does not actively dispatch to maintain the Primary reserves requirement. PJM does not present any evidence that it accurately measured Primary Reserve levels or actively dispatched to control for Primary Reserves requirements during these events. PJM cites only Primary Reserve Warnings, not related actions or market effects, as evidence that PJM was short primary reserves. All activity and price effects cited were based on the maintenance of synchronized reserve requirements.

The Commission should not ignore or discount serious questions regarding the proposed scarcity price levels and how frequently they will occur upon implementation of the June 18th Proposal. The financial impacts could be severe, and such impacts would be further compounded by PJM's inadequate scarcity pricing revenue true up mechanism. The evidence suggests that a more gradual approach is appropriate, which would permit the reasoned determination of the appropriate triggers for scarcity pricing and the appropriate measurement of those reserve triggers. The reasonable objectives of Order No. 719 to improve scarcity pricing and remove barriers to the participation of demand-side resources do not require risking price shocks to PJM consumers. There is no market or reliability crisis in PJM; no barriers in the current market design prevent the steady growth of demand-side participation in PJM markets.[40] There is ample time for a gradual and orderly approach to implementing scarcity pricing that would allow PJM and its stakeholders to learn from each step and use that information to inform the appropriate next steps. Prescheduled transitions with predefined steps, of the type proposed by PJM, do not permit such a gradual and orderly approach.

3. The June 18th Proposal Creates a New and Undefined Market for Primary Reserves That Confuses the Long and Short-Term Procurement of Operating Reserves in a Manner Inconsistent with the Objectives of Order No. 719 and with the Potential to Significantly Increase, without Economic or Reliability Justification, the Number of Scarcity Events in PJM

The June 18th Proposal would implement both primary and synchronized reserve requirements as constraints in the security constrained optimization approach to scarcity pricing. PJM currently dispatches, manually within the hour and via a Tier 2 synchronized Reserve Market prior to the operational hour, to maintain synchronized reserves. PJM avoids going short synchronized reserves as current operational practice. Inclusion of the synchronized reserve target as a constraint would internalize this current operational goal into the automatic dispatch.

The primary reserves target is 150 percent of the largest contingency in a given reserve region. Primary reserves consist of synchronized (Tier 1 and Tier 2) and non-synchronized 10 minute reserves. While primary reserves are defined, PJM does not

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[40] *See supra* footnote no. 7.

currently actively dispatch to maintain primary reserves. The implementation of a primary reserve requirement as a constraint would introduce a primary reserve target as a constraint in the dispatch solution, and would, according to June 18th Proposal, require the creation of an active market for non-synchronized primary reserves which does not exist today. The June 18th Proposal provides that scarcity pricing occurs due to a shortage of either synchronized or primary reserves and that the shortage of each would result in a separate $850 penalty factor.

This is a significant, unwarranted and unsupported change in the structure of PJM markets.[41] The structure of the proposed primary reserve market is not well defined. The expected market design, market structure, prices and revenues are unclear. No market power mitigation provisions have been included. Because neither Order No. 719 nor effective scarcity pricing rules require the introduction of a primary reserve market, the Commission should reject this approach as outside the scope of this proceeding.[42] Given that PJM cannot currently and accurately measure the level of primary non-synchronized reserves, the consequences of adding this market are unknown. However, it is a safe assumption that the addition of this constraint will significantly increase the incidence of scarcity pricing. The record simply lacks a basis

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41 *See* Supporting Statement at 39–40.

42 *See infra* footnote no. 12.

upon which the Commission could find this aspect of the June 18th Proposal just and reasonable in the face of significant concerns.

E. The Hybrid Approach to Clearing Tier 2 Synchronized Reserves Included in the June 18th Proposal's Lacks Support for the Claimed Efficiencies, and Will Unnecessarily Tighten Supply, Impose Additional Operational Risks on Suppliers and Introduce Concerns About Market Power.

The June 18th Proposal partially replaces the synchronized reserve market with a hybrid structure that assigns only a subset of Tier 2 synchronized resources deemed inflexible prior to the operational hour, with the remainder of any Tier 2 assignments made on a 5 minute basis by the optimization software. For the reasons discussed in detail in the Supporting Statement (at 42–45), this mixed assignment structure converts the current hour ahead market construct into a mechanism to estimate the level of tier 2 reserve requirements and assigns unpriced obligations to these inflexible resources. These residual resources would then become price takers in the residual 5 minute market for Tier 2 reserves.

Both the MMU and the PJM approach will result in a clearing price for reserves that would fully reflect the energy market scarcity price, determined after the close of the hour. While there are similarities in the MMU and PJM approach to the Tier 2 synchronized reserve market, there are also substantive differences between the approaches in terms of the potential efficiency of the dispatch, the risks of economic withholding of reserves and the amount of Tier 2 reserves that will be available. The

MMU and PJM approaches differ in that under the MMU approach more resources would be committed prior to the operational hour, when there is more time to arrange generation set points to provide for Tier 2 reserves and regulation. This would take advantage of the fact that reserve offer related ramp rates for generation tend to exceed energy offer schedule ramp rates. Further, units operating at a fixed set point, rather than facing five minute variations in set points based on fluctuations in LMP, have more available ramp in any five minute period. In combination, these features of the MMU approach would tend to increase the amount of available synchronized reserves on the system in hours where Tier 2 assignments are needed for PJM to meet its synchronized reserve requirement and increase the pool of potential participants relative to the June 18th Proposal. Based on these factors, the MMU recommends that a full hour ahead commitment process, rather than a partial commitment process, be put in place, in combination with a within hour 5 minute optimization, to maximize the transparency and potential participation in the Tier 2 Synchronized Reserves Market.

The Market Monitor also recommends that within-hour five minute Tier 2 assignments be made on the basis of energy offer parameters, rather than Tier 2 hour ahead synchronized reserve offers. Allowing for separate energy and within hour reserve offers would force an inefficient allocation of the unit's capability between reserves and energy since this would artificially create inconsistent parameters sets, one for energy and one for reserves, which distort the direct substitutability of unit capacity deployed as either reserves or energy within the hour. Allowing separate offers would create opportunities to withhold reserves and will distort within-hour valuation of reserves. These distortions do not exist at this time, but would exist under the June 18th Proposal. Further, the Market Monitor recommends that units operating at PJM's discretion in real-time, and not otherwise assigned in the hour-ahead Tier 2 assignment mechanism, be unable to deselect Tier 2 availability within the hour. This would help prevent within hour withholding of reserves. In effect this would create a must offer requirement for within hour assignment for Tier 2 reserves.

The June 18th Proposal has not demonstrated that PJM's proposed redesign of the Synchronized Reserve Market for procuring Tier 2 synchronized reserve is just and reasonable or that it is necessary to meet any of the six criteria in Order No. 719. On the contrary, it violates those criteria by introducing inefficiencies into the existing rules and creating new and substantial market power issues. Accordingly, the Commission should reject this component of the June 18th Proposal.

F. The June 18th Proposal Fails to Correct Faulty Calculations of Opportunity Costs and Balancing Operating Reserve Payments for Units Providing Reserves and Regulation.

The Market Monitor agrees with PJM that an after the fact, rather than prior to the hour, determination of regulation pricing would provide a more accurate and transparent price signal for the Regulation Market. However, the June 18th Proposal would continue the faulty calculation of opportunity costs on the basis of the lower of cost based or price based offers rather than the actual dispatch schedule as the reference and would continue the failure to properly account for regulation revenues when providing for make whole balancing operating reserve payments.[43] If the Commission does not take this opportunity to correct these market design flaws here, it should refrain from any action that would complicate their correction in Docket No. ER09-13-000 or another future proceeding.

G. The June 18th Proposal Does Not Explain How PJM Intends to Recognize the Use of Emergency Action When Applying Its Penalty Factors.

A well designed MW offset mechanism will prevent prices from falling as a result of emergency actions taken during a period of scarcity. It is the Market Monitor's position that its approach, involving discrete shifts in the reserve requirements to control for emergency actions, is a more transparent way to account for emergency actions in the application of the operating reserve penalty factor approach.

The June 18th Proposal does not clearly define how PJM intends to recognize the use of emergency actions in applying its reserve penalty factor curve methodology.[44] The proposal only states that, in the event that PJM operations determines the need for

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43 *See* Supporting Statement at 44–47; *see also*, Market Monitor, "PJM Regulation Market: Impact of December 1, 2008 Changes in Market Design December 1, 2008–October 31, 2009 (November 30, 2009), filed in Docket No. ER09-13-000 (November 30, 2009); 2009 State of the Market Report for PJM at 373–79.

44 *See* Supporting Statement at 48–49.

emergency actions, PJM will enforce the use of the reserve shortage penalty factors on marginal unit bus prices.[45] The June 18th Proposal does not define the level of reserve shortage that would trigger voltage reductions or manual load dumps, or how it will determine when they are no longer needed. The Commission should require that PJM adopts the approach included in the Amended Proposal, explained *infra* Section III.

H. The June 18th Proposal's Provision to Permit Emergency Demand Response to Set Price Is Not Required by Order No. 719, Fails to Account for the Nature of Emergency Demand Response, Undermines Mitigation and Is Outside of the Scope of this Proceeding.

Despite a lack of discrete and measurable dispatchability in the form of telemetry, metering and a specific bus location, the June 18th Proposal would modify existing PJM rules to make Emergency Demand Resources eligible to set price if they are determined to be marginal for energy.[46] The June 18th Proposal does not include a plan to address the lack of telemetry, metering and a specific bus location for these resources before allowing them to act as marginal resources in the security constrained dispatch solution. The June 18th Proposal does not explain how such a resource could be marginal for energy in the absence of this basic information, which is required for all generating units. Instead, the June 18th Proposal provides for only incremental improvement to the inadequate data it already receives from Emergency Demand

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45 PJM Affidavit at 30.

46 *Id*. at 49–56.

Response providers. PJM indicates that Emergency Demand Response providers will be required to submit operational data regarding the availability and status of their collective resources. PJM will still, under the June 18th Proposal, dispatch Emergency Demand Resources by zone, rather than by discrete resource or provider within the zones. Because of this, and the absence of discrete real time information regarding the exact location and level of response from the Emergency Demand Resources, the June 18th Proposal provides that Emergency Demand Resources will set price at the load center of the zone, rather than at the resource-specific bus. This is a radical and unsupported modification of locational marginal pricing and represents another example of the June 18th Proposal working at "cross purposes" with the PJM market design.

Allowing emergency DR set price also raises market power concerns. Allowing Emergency DR to set price could effectively allow the exercise of market power, as under emergency conditions it is likely that most participants are pivotal.

There is no reason why a participant desiring the ability to set price cannot avoid this restriction by reconstituting itself as an Economic rather than an Emergency Demand Resource and meeting the more stringent technical requirements. PJM's existing rules take appropriate account of these the differences, and Order No. 719 nowhere requires otherwise. Order No. 719 does direct RTOs to avoid undermining the mitigation rules and to ensure that the scarcity pricing proposal comports to the existing rules. It is necessary for PJM to change the demand response rules and standards in order to adapt to the June 18th Proposal. Because the June 18th Proposal does not enjoy adequate support from stakeholders, PJM is not authorized to proposed changes the existing rules more aggressive than reasonably necessary to comply with Order No. 719.

I. The June 18th Proposal's Provision to Permit Emergency Purchases to Set Price Is Not Required by Order No. 719, Undermines Mitigation and Is Outside of the Scope of this Proceeding.

PJM has not provided evidence that allowing Emergency Purchases to set price during an operating reserve shortage will improve security constrained system dispatch. PJM does not explain how the rules that disallow emergency purchases from setting price have misaligned energy and reserve prices with system conditions and dispatch instructions, thereby requiring the manual dispatch of the system to maintain reliable system operation since 1998.

Further, the June 18th Proposal would introduce issues of potential market power abuse by sellers of emergency power during a reserve shortage event. As emergency suppliers are not otherwise subject to PJM's market power mitigation rules, PJM's current rules prevent emergency purchases from setting price and thereby prevent sellers of emergency power from abusing market power during a system emergency. Removing this provision would create opportunities for PJM market participants, through third parties or affiliates outside the footprint, to affect the PJM price through the sale of emergency power. Further, since PJM is proposing a cap of $2,700 for the effect of these purchases, this would effectively undermine both PJM's $1,000 offer cap and the three pivotal supplier test as a means of mitigation in the PJM market.

The current rules prohibiting emergency purchases from setting price should be retained to prevent the effective undermining of PJM's market power mitigation rules. Without material benefit in terms of operational integrity, the June 18th Proposal would introduce issues of potential market power abuse by sellers of emergency power during a reserve shortage event. As emergency suppliers are otherwise subject to PJM's market power mitigation rules, PJM's current rules prevent emergency purchases from setting price and prevent sellers of emergency power from abusing market power during a system emergency. Removing this provision would create opportunities for PJM market participants, through third parties or affiliates outside the footprint, to affect the PJM price. This opportunity does not currently exist due to the current market rules preventing emergency purchases from setting price. Further, since PJM is proposing a cap of $2,700 for the effect of these purchases, this would effectively undermine both PJM's $1,000 offer cap and the three pivotal supplier test as a means of mitigation in the PJM market.

Accordingly, the Commission should reject these components of the June 18th Proposal and preserve intact the existing market rules concerning the ability of Emergency Purchases to set price.

III. AMENDED PROPOSAL

A. The Amended Proposal, If Accepted by the Commission, Would Result in a Scarcity Proposal that Fully Meets the Commission's Requirements, Would Preserve a Coherent Market Design in PJM and Would Improve PJM's Market Design.

The Amended Proposal would correct the flaws identified in the June 18th Proposal. In each case the changes are consistent with an approach that allows flexible market mechanisms to determine scarcity payments in preference to an administrative mechanism. The Amended Proposal, consistent with the Commission's requirements, adopts a targeted approach focused on ensuring that the scarcity pricing signal reflects market conditions during periods of scarcity and facilitates reliable operations during scarcity events. The Amended Proposal recognizes that the revenue adequacy aspect of reliability is fully addressed by RPM.

B. The Amended Proposal Retains a Uniform $1,000 per MWh System Offer Cap.

The approach in the June 18th Proposal is one way to structure the mechanics of a reserve constraint in an optimization problem. However, it is not the only way and it is not the preferred way for scarcity pricing. Instead of adding a fixed penalty factor to the marginal cost of energy, the constraint can be relaxed to allow a market solution and to set the price to the target level. This approach allows the continuation of security constrained dispatch but allows the market to provide pricing results that are consistent with offer caps and predefined price caps. This approach is used by PJM in modeling other reliability constraints. This approach is also used to model security constraints or limitations in many organized markets, including PJM, ISO New England and New York ISO. For example, transmission limits, minimum generation events and ramp limits are all modeled as constraints that can be relaxed in the optimization engines of PJM, New York ISO, and ISO New England. The constraint relaxation approach also has the advantage of avoiding a number of inconsistencies that PJM's binding constraint approach creates with other aspects of PJM's market design.

Under the Amended Proposal if the reserve requirements could not be met, the reserve constraint would be relaxed and energy prices at the marginal unit buses would be set to a predefined price target.[47] The Market Monitor is recommending a predefined energy price target that is consistent with PJM's current $1,000 per MWh offer cap in both the Day-Ahead and Real-Time Energy Markets. A price target set at $1,000 at the marginal unit buses in the area with a reserve shortage would provide a clear scarcity signal that is consistent with scarcity, consistent with economic dispatch, consistent with locational pricing, consistent with competitive market outcomes and consistent with PJM's current market design. A $1,000 price target is consistent with the price signal function of scarcity pricing and therefore the operational reliability aspect of reliability.

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[47] *Id.* at 16–17.

Under the existing market rules, PJM has been able to procure the reserves it needs. PJM has no reliability crisis, and no such crisis is anticipated to occur as long as a well designed capacity market remains in place.[48] The market mechanism for procuring reserves included in the Amended Proposal can, therefore, be expected to acquire similar levels of reserves at similar prices as has occurred to date. The essential improvement over the current rules in the Amended Proposal is that the procurement of reserves occurs through a market based mechanism that ensures appropriate energy market price signals. In contrast, the June 18th Proposal immediately forces very high prices, meaning that customers simply pay more for the same quantity of reserves.

C. The Amended Proposal Prevents Double Recovery of Scarcity Revenues.

Scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The RPM design reflects the recognition that the energy markets, by themselves, will not result in adequate revenues. The RPM design provides an alternate method for collecting scarcity revenues. The revenues in the capacity market are scarcity revenues.

The approach to energy market based scarcity must reflect the fact that revenues in the capacity market are scarcity revenues. With PJM's RPM design, there is no need

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48 *Id*. at 21–22.

for a scarcity pricing mechanism in the energy market to ensure revenue adequacy. Nonetheless, it would be preferable to include a scarcity pricing mechanism in the energy market as a complement to a capacity construct because it provides additional direct, market-based incentives to load and generation at the margin, as long as the market rules are designed to ensure that there is a scarcity pricing revenue true up mechanism to prevent double collection of scarcity revenues.

The energy market scarcity pricing mechanism should be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent and verifiable triggers and prices and that there are strong incentives for competitive behavior, strong incentives for performance and strong disincentives to exercise market power and rules to ensure that market power is not exercised. The energy market scarcity mechanism should also be designed to have no net impact on revenues to capacity resources, which are already fully compensated under RPM. The scarcity pricing mechanism should provide performance incentives and increased revenues for any responding resources not already compensated in the capacity market, including non-capacity price sensitive load response, uncleared capacity and imports.

Scarcity revenues represent a double payment to capacity resources, and scarcity pricing revenues should not be paid to capacity resources unless scarcity pricing revenues exceed the capacity price for the year.[49] The purpose of the true up mechanism is to prevent double recovery of scarcity revenues. Accordingly, the Commission should direct PJM to amend the June 18th Proposal to provide for an accurate true up of scarcity pricing revenues paid to capacity resources.

D. The Amended Proposal Triggers Scarcity Based on Measurable Shortages of Synchronized Reserves.

The Amended Proposal preserves a reserve target for synchronized reserves, consistent with current practice, but removes the broader target for primary reserves as a constraint in the optimization.[50] This approach is consistent with the Market Monitor's objective to internalize the cost of maintaining reserve levels needed to maintain reliability, and then sending a clear energy price signal when actual reserve requirements cannot be met. The difference between the June 18th Proposal and the Amended Proposal is not the mechanism, but the fact that the June 18th Proposal includes a second constraint related to Primary Reserves that it has not supported. Adding a reserve requirement in addition to what is needed to maintain reliability would be superfluous and wasteful.

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49 *Id.* at 30–31.

50 *Id*. at 40–41.

E. The Amended Proposal Preserves and Enhances an Efficient Approach to Assign and Price Synchronized Reserves and Associated Protections from the Exercise of Market Power.

Both the MMU and the PJM approach will result in clearing price for reserves that would fully reflect the energy market price, including any periods with a scarcity price, determined after the close of the hour. While there are significant similarities in the MMU and PJM approach to the Tier 2 synchronized reserve market, there are also substantive differences between the approaches including the potential efficiency of the dispatch, the operational risks imposed on synchronized reserve units, the explicit approach to market power, and the amount of Tier 2 reserves that will be available.

The MMU and PJM approaches differ in that under the MMU approach more resources would be committed prior to the operational hour, when there is more time to arrange generation set point to provide for Tier 2 reserves and regulation. This would take advantage of the fact that reserve offer related ramp rates for generation tends to exceed energy offer schedule ramp rates. Further, units operating at a fixed set point, rather than facing five minute variations in set points based on fluctuations in LMP, have more available ramp in any five minute period. In combination, these features of the MMU approach would tend to increase the amount of available synchronized reserves on the system in hours where Tier 2 assignments are needed for PJM to meet its synchronized reserve requirement.

The Market Monitor recommends in the Amended Proposal a must offer requirement for synchronized reserves, given its critical role as a trigger for scarcity pricing.[51]

F. The Amended Proposal Properly Coordinates the Assignment and Pricing of the Regulation Market with the Energy Market.

The Amended Proposal provides that the regulation market would continue to assign regulation prior to the operational hour.[52] The Amended Proposal makes use of the current hour ahead regulation market construct to estimate the level of regulation needed, along with the estimated LMP in the coming hour, to assign regulation resource obligations that would have cleared under the existing market structure. This assignment mechanism would not result in a clearing price for these regulation resources, only an obligation to provide regulation in the coming hour. Five minute prices would be determined by the point of intersection between the assigned regulation supply and the regulation requirement, where the regulation offer price submitted for a unit would be no greater than the unit's incremental operating and maintenance cost plus a $12.00 per MWh margin plus opportunity cost.[53, 54]

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51 *Id*. at 42–45.

52 *Id*. at 46–47.

53 *See* PJM Manual 11 (Scheduling Operations) Rev. 43 at 50 (September 24, 2009).

54 *See* PJM Manual 15 (Cost Development Guidelines) Rev. 10 at 41 (June 1, 2009).

In each five minute interval, the market clearing price for regulation would be comprised of the marginal unit's regulation offer price, the cost of energy use, and the unit's opportunity cost. The opportunity cost would be calculated by PJM based on actual unit specific LMPs and the actual current dispatch schedule as the reference. The hourly price for regulation would be determined after the close of the hour, as the average of the 5 minute (hourly integrated) Tier 2 reserves prices in the hour. All units cleared in the regulation markets would be paid the higher of the hourly integrated 5 minute regulation market-clearing prices or the unit's regulation offer plus $12 plus the unit specific opportunity cost and the cost of energy use incurred. Any unit specific revenue shortfall created by over procurement or hourly integrated prices that were less than the unit specific costs of providing regulation would be made up via uplift. Regulation revenues would not be netted from make whole balancing operating reserve payments.

The Market Monitor agrees with PJM that an after the fact, rather than prior to the hour, determination of regulation pricing would provide a more accurate and transparent price signal for the Regulation Market. However, the Market Monitor disagrees with PJM's proposal to continue to calculate opportunity costs on the basis of the lower of cost based or price based offers rather than the actual dispatch schedule as the reference and to continue to fail to appropriately net regulation revenues from make whole balancing operating reserve payments.

The Commission should adopt this just and reasonable approach to the design of the Regulation Market and the coordination of the Regulation Market and the Energy Market and because it is consistent with PJM's existing overall market design.

G. The Amended Proposal Appropriately Accounts for Emergency Actions.

The reserve penalty factor curve methodology, regardless of price target, also needs an explicit mechanism to offset the effect of non-market administrative measures used during scarcity situations. The Amended Proposal includes an offset that would increase the reserve requirement by the amount of effective energy provided by these emergency steps so as to maintain a market signal consistent with the actual level of scarcity, which is the level of scarcity that would have occurred in the absence of the administrative action.[55] So long as the voltage reduction or manual load dump action was maintained, scarcity pricing would result. This approach is similar to the approach included in the current scarcity rules, and the Commission should approve find this aspect of the Amended Proposal just and reasonable.

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55 *Id*. at 48–49.

H. The Amended Response Protects PJM Markets by Preserving the Existing Rules Concerning the Eligibility of Emergency Demand Response and Emergency Purchases to Set Price.

The Amended Proposal preserves the current rules determining the eligibility of Emergency Demand Resources and Emergency Purchases to set price in the security constrained optimization.[56]

Such rules ensure that the marginal dispatch signals are consistent with marginal resources used to solve the least cost security constrained dispatch optimization problem. Marginal prices correspond to the marginal resource prices at specific buses on the system needed to meet power balance and system security constraints. This is an important feature of security constrained dispatch signals during normal operation and of critical importance during emergency conditions. Demand response resources with discrete and measurable dispatchability in the form of telemetry, metering and a specific bus location are eligible under PJM tariff to be marginal. Only Economic Demand Response resources with such characteristics should be eligible to set price.

An Emergency Demand Resource should not be eligible to set price when called due to the fact that the non-firm portion of a customer's load represented in this capacity has an obligation to curtail, based on its sale of capacity, during an emergency.

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56 *Id*. at 53–58.

In other words, Emergency Demand Resources represent non-firm load that does not have a right to the capacity that it has chosen not to pay for and is, in the case of an emergency, under an obligation to be cut by the participant.

In addition, as discussed *infra* Section I.C.4, preserving the current rules concerning the eligibility of Emergency Demand Response and Emergency Purchases to set price avoids unnecessarily creating avenues for the exercise market power and preserves the existing mitigation program.

IV. CONCLUSION

The Market Monitor respectfully requests that the Commission consider this protest and the Amended Proposal as it resolves the issues raised in this proceeding.

Respectfully submitted,

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Dated: July 19, 2010

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 19th day of July, 2010.

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Attachment

Supporting Statement
Docket No. ER09-1063-004
Scarcity Pricing

The Independent Market Monitor for PJM

July 18, 2010

Contents

This Supporting Statement consists of Part I, which is an Introduction and Summary, includes an abbreviated version of the longer analysis presented in Part II, which presents the arguments in more detail and the Appendices, which present some of the technical background to the arguments. Appendix A presents a technical discussion of the mechanics of scarcity pricing. Appendix B addresses issues related to the scarcity pricing true up mechanism and the impacts of PJM's proposed offset approach on RPM forward prices. Appendix C provides background information on the Synchronized Reserve Market. Appendix D provides background information on the Regulation Market.

I. Introduction and Summary

Price Levels Under Scarcity Pricing

In electricity markets, scarcity means that demand, plus reserve requirements, is nearing the limits of the available capacity of the system. Under the current PJM rules, high prices, or scarcity pricing, result from high offers by individual generation owners for specific units when the system is close to its available capacity.

A wholesale energy market will not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity revenues. Scarcity revenues can be incorporated through capacity markets, through scarcity pricing in energy only markets or through a combination of capacity markets and scarcity pricing. The need for such mechanisms is not the result of the $1,000 per MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market-clearing prices.

Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards that require wholesale power markets to carry excess capacity means that scarcity conditions in the Energy Market occur with reduced frequency. The mandated reserve margin requires units that are called on only under relatively unusual load conditions, if at all. Resources that do not run for energy, but are needed for reliability, are not supported through an energy only market. Thus, an administrative mechanism, whether a capacity market or scarcity pricing or both, is required to provide revenue adequacy consistent with adequate generation capacity for reliability.

In PJM, the Capacity Market provides revenue adequacy consistent with adequate generation capacity for reliability. Scarcity pricing is not required in PJM in order to provide revenue adequacy.

Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM.

The relationship between scarcity pricing and reliability must be clearly defined before a scarcity pricing mechanism is designed. The two functions of scarcity pricing are directly related to two aspects of reliability: resource adequacy and operational reliability. The revenue adequacy function of scarcity pricing is directly related to the resource adequacy aspect of reliability. The market design must provide adequate revenues to support a level of capacity resources to cover forecasted peak load plus a reserve margin that provides reliability. The price signal function of scarcity pricing is directly related to the operational reliability aspect of reliability. The market design must provide for price signals during scarcity conditions that contribute to reliable operations.

While reliability is referenced by PJM as a reason for scarcity pricing, PJM does not clearly state which aspect of reliability it means. Some of PJM's arguments address the resource adequacy aspect of reliability and some of PJM's arguments address the operational reliability aspect of reliability.

The resource adequacy aspect of reliability is fully addressed by RPM. PJM asserts regularly that its market is reliable and that adequate resources are procured through RPM to ensure such reliability. The MMU agrees. For example, in the 2013/2014 BRA, PJM procured capacity that resulted in a 20.2 percent reserve margin, well in excess of the required 15.3 percent reserve margin. PJM procured, over all LDAs, about 6,500 MW in excess of the capacity required to meet its reserve margin which resulted in customers paying about $1.7 billion more than they would have paid to meet the required reserve margin.

The resource adequacy aspect of reliability incorporates demand side resources. DR participates in the Capacity Market. For example, DR offers increased from 9,847.6 MW in the 2012/2013 BRA to 12,952.7 MW in the 2013/2014 BRA, an increase of 3,105.1 or 31.5 percent. In 2009, almost 100 percent of all demand side resource compensation was from the capacity market. Thus, short scarcity prices are not required in order to incent demand side participation. It can be expected that the capacity market will continue to provide more reliable and consistent incentives to demand side resources than will episodic scarcity pricing events.

While the scarcity pricing mechanism should not provide additional compensation to capacity resources, it should provide compensation to resources that were not compensated through the RPM construct, including energy only demand side response, capacity which did not clear in RPM and imports.

The operational reliability aspect of scarcity pricing must be addressed in any changes to the current scarcity pricing mechanism.

When available capacity is not sufficient to maintain reserves, system operators have to turn to non-market solutions to maintain reliable service, including voltage reductions, load dumps and emergency energy purchases. All of these administrative control actions are designed to preserve the level of reserves needed to maintain system reliability. But these administrative emergency actions also produce counter intuitive price effects; they reduce prices during scarcity conditions.

Scarcity pricing is required to address these price signal issues and to provide operational reliability. Scarcity pricing is required to ensure that the market price signals are consistent with actual market conditions during periods of scarcity even when the system operator has to take emergency steps to maintain reliability.

The two functions of scarcity pricing can be coordinated through a well designed scarcity pricing revenue true up mechanism. Energy market scarcity pricing is part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design and the market rules must ensure that there is a well designed scarcity pricing revenue true up mechanism to prevent double collection of scarcity revenues. The absence of such a mechanism will result in an over collection of scarcity revenues in a given delivery year and a counterproductive distortion in the forward prices for capacity. The most straightforward way to ensure that such over collection does not occur, and that the forward markets for capacity provide meaningful investment signals, is to ensure that capacity resources do not receive scarcity revenues from the energy market unless total scarcity revenues for a delivery year exceed the price of capacity for that year.

Both the MMU and PJM propose approaches designed to address these shortcomings in the current scarcity pricing mechanism.[1] Both propose that real-time reserve requirements be clearly defined and that they be modeled as constraints in the security constrained dispatch. Both approaches call for more flexible and locational scarcity

1 *See* PJM compliance filing regarding scarcity pricing rules in FERC Docket No. ER09-1063-004 (June 18, 2010) ("PJM"), including an attached Affidavit of Paul M. Sotkiewicz, Ph.D on Behalf of PJM Interconnection, L.L.C. ("PJM Affidavit").

signals to be implemented via reserve requirements modeled as constraints for defined regions, with administrative reserve scarcity penalty factors, in the security constrained dispatch. Conceptually, incorporating reserve penalty factor curves into the security constrained dispatch internalizes the value of maintaining resources needed for reliability in the centralized dispatch market solution.

Under the MMU's proposal if the reserve requirements could not be met, the reserve constraint would be relaxed and energy prices at the marginal unit buses would be set to a predefined price target. The MMU is recommending a predefined energy price target that is consistent with PJM's current $1,000 per MWh offer cap in both the Day-Ahead and Real-Time Energy Markets. A price target set at $1,000 at the marginal unit buses in the area with a reserve shortage would provide a clear scarcity signal that is consistent with scarcity, consistent with economic dispatch, consistent with locational pricing, consistent with competitive market outcomes and consistent with PJM's current market design. A $1,000 price target is consistent with the price signal function of scarcity pricing and therefore the operational reliability aspect of reliability.

The MMU approach is flexible. The mechanics of this approach allow the price target to match the offer cap, or to be set up in stages based on the level of reserve shortage. For example if offer caps were to increase to $1,500, it would be a simple matter to raise the scarcity price target to keep the mechanism in line with market design parameters.

PJM's decision to have the penalty factors directly affect marginal unit bus LMPs during reserve shortages introduces a number of market design issues. PJM's proposal undermines PJM's existing market power mitigation rules, introduces new avenues for market manipulation that are not addressed in the PJM proposal, requires the lifting of offer caps in the Day-Ahead Market so that they do not match real-time offer caps, and introduces efficiency issues in the interaction of the Day-Ahead and Real-Time Energy Market. Further, PJM's defense of the $2,700 price cap is based on erroneous interpretations of value of lost load studies and the unsubstantiated and unclear claim that prices in excess of a $1,000 are needed in the PJM market to maintain reliability.

In PJM's market design, administratively setting prices over the price cap will, in the absence of an effective scarcity pricing revenue true up mechanism, serve only to generate wealth transfers. Other complications exist in the synergies between markets.

There is no reason to increase the maximum price in PJM markets in order to implement scarcity pricing. PJM has not provided evidence that, given an RPM construct that procures capacity well in excess of what is needed to meet system reliability requirements, prices in excess of the $1,000 offer cap are needed to make PJM's system reliable. PJM has not made the case that its system is currently, or will become, unreliable at current price caps. PJM has not provided evidence that prices in excess of $1,000 are needed to incent economic demand response. PJM has not provided evidence that any additional theoretically available demand response, available only at prices in excess of $1,000, will make the difference between a reliable or unreliable system.

Given the significant changes to the PJM markets that are required in order to implement any significant change to scarcity pricing, a gradual approach is warranted.

A simpler solution to the scarcity pricing issues, in terms of market efficiency and consistency with overall market design, is to limit the price effect of going short reserves to a level that is consistent with the physical resource price caps that exist in the Day-Ahead and Real-Time Energy Markets. In the optimization problem this can be implemented by relaxing the reserve constraint to prevent the constraint from binding and setting the marginal unit bus prices to predefined price targets when the constraint is relaxed. As in the application of this approach with other reliability constraints in the optimization, this approach maintains and enforces the penalty factor associated with going short reserves for purposes of dispatch. The difference is that when the constraint is relaxed the MMU approach imposes a flexible price effect on the marginal unit buses so long as reserves fall short of the reserve requirements. The flexible price effect is the dollar amount needed to get the marginal unit bus price to the shortage price target. So long as the marginal incentives to produce energy (energy margin) or provide reserves (opportunity cost of foregone energy production) are maintained, this approach provides all the advantages of a security constrained dispatch approach to scarcity pricing, while providing market results that are consistent with overall market design and market efficiency goals.

The Scarcity Pricing Revenue True Up Mechanism

The wholesale power markets, in order to be viable, must be competitive and they must provide adequate revenues to ensure an incentive to invest in new capacity. A wholesale energy market will not consistently produce competitive results in the absence of local market power mitigation rules. This is the result, not of a fundamental flaw in the market design, but of the fact that transmission constraints in a network create local markets where there is structural market power. A wholesale energy market will not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity pricing. This is a result, not of offer capping, but of the fundamentals of wholesale power markets which must carry excess capacity in order to meet externally imposed reliability rules.

Scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The RPM design reflects the recognition that the energy markets, by themselves, will not result in adequate revenues. The RPM design provides an alternate method for collecting scarcity revenues. The revenues in the capacity market are scarcity revenues.

The approach to energy market based scarcity must reflect the fact that revenues in the capacity market are scarcity revenues. With the PJM RPM design, there is no need for a scarcity pricing mechanism in the energy market to ensure revenue adequacy. Nonetheless, it would be preferable to include a scarcity pricing mechanism in the energy market as a complement to a capacity construct because it provides additional direct, market-based incentives to load and generation at the margin.

The energy market scarcity mechanism should be designed to have no net impact on revenues to capacity resources, which are already fully compensated under RPM. The scarcity pricing mechanism should provide performance incentives and increased revenues for any responding resources not already compensated in the capacity market, including non-capacity price sensitive load response, uncleared capacity and imports.

PJM does not have a clear position on whether capacity resources require additional payments over and above those received through RPM. This lack of clarity of purpose has led to PJM's poorly designed offset proposal that creates timing mismatches, uncertainty and pricing distortions in the RPM auctions. This lack of clarity has also confused the already complex discussion about an appropriate true up mechanism.

PJM proposes that revenues generated by the scarcity mechanism during scarcity events be passed through RPM's three-year average energy and ancillary net revenue offset in the same way as all other energy and ancillary service revenues and not affect RPM revenues in the year in which a scarcity event occurs. PJM's proposal would allow capacity resources to keep scarcity revenues in the delivery year along with the RPM revenues for that delivery year.

PJM's approach results in a significant mismatch between the timing of the scarcity event and associated revenues, and the impact on the RPM clearing prices. As a result, there is substantial uncertainty introduced into the RPM auction process about the likely impact on future auction results. The result will be to distort the prices of RPM in the future. Future RPM prices, set in an auction the year after the scarcity event, will be lower despite the fact that the scarcity event signaled that not enough capacity has been purchased. This is exactly the wrong price signal to send through the RPM market.

PJM's approach means that the net revenue offset would increase for three subsequent auctions, which would occur one, two and three years in the future after the scarcity event. The net revenue offset reduces the net Cost of New Entry ("CONE") used to derive the demand curve in the RPM market. The net revenue offset also reduces net Avoidable Cost Requirements ("ACR") based offers of capacity resources. The result of PJM's proposal would be to reduce the RPM clearing price for capacity delivery years that are five, six and seven years after the scarcity event.

Transparent and Appropriate Scarcity Pricing Triggers: Reserve Targets and Reserve Target Measurement Requirements

Any scarcity pricing application based on a reserve constraint requirement must use clearly defined reserve targets and accurate measurement of the resources that are available to meet those requirements. The reserve targets must match defined reserve requirements to which system operators actually operate. The objective should be to create a system that recognizes scarcity in needed reserves; a system that redispatches to maintain needed reserves; a system that provides market signals that are consistent with this redispatch; and a system that provides market signals consistent with any failure to maintain needed reserves. The definition of scarcity and its reflection in price should be based directly on the level of available 10 minute synchronized reserves relative to the relevant reserve requirement and the progressive use of emergency measures.

PJM's 10 minute reserve requirement targets are based on engineering requirements and system studies that have defined minimum requirements to maintain system integrity. Explicitly modeling these requirements as constraints in the dispatch will permit the system to optimize the dispatch to maintain appropriate and efficient levels of energy and reserves, and to reflect this optimization in the marginal prices on the system.

Accurate measurement of available resources is an essential element of a reserve requirement based scarcity pricing mechanism. Any mechanism that attempts to internalize the dispatch of reserves will only be as good as the measurement of those reserves. Without accurate measurement of available reserves, any mechanism designed to dispatch the system to maintain reserves will be compromised in both efficiency and effectiveness. PJM does not currently have accurate real-time measurements of available operating reserves that are required for an improved approach to scarcity pricing.[2] PJM needs to develop better measurements of available primary reserves prior to implementing a resource constraint based scarcity pricing mechanism.

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[2] UPDATED: PJM Proposal for Price Formation during Operating Reserve Shortages, December 4, 2009 SPWG, pp. 7–8. <*http://www.pjm.com/~/media/committees-groups/working-groups/spwg/20091204/20091204-item-04-updated-pjm-sp-proposal.ashx*>.

In the absence of accurate real-time measurements of available reserves, it is not possible to know how many times PJM has been in scarcity conditions in the last ten years or even how many times PJM was close to being in scarcity conditions. As a result, it is not possible to predict how frequently PJM can be expected to experience scarcity conditions in the future. As a further result, it is not possible to predict the likely dollar levels of wealth transfers that might occur under PJM's proposal or the likely impact on future RPM prices.

Based on its own determination, PJM appears to have suffered what it considers to be extreme system conditions on seven separate occasions over the last five years. This is an indication that PJM cannot accurately measure its reserve levels and did not actually dispatch based on the asserted seven events, and therefore has no basis for making claims regarding the frequency of reserve shortages going forward.

PJM's filing raises serious questions regarding the operational trigger for its proposed scarcity price levels and how frequently they will occur and what the financial impact would be under PJM's inadequate offset mechanism. It also suggests that a more measured approach is called for in going forward with a scarcity pricing mechanisms, defining the exact approach to measurement of scarcity and in defining the scarcity price level.

Synchronized and Primary Reserve Targets

PJM has proposed to implement both primary and synchronized reserve requirements as constraints in the security constrained optimization approach to scarcity pricing. PJM currently dispatches, manually within the hour and via a Tier 2 synchronized reserve market prior to the operational hour, to maintain synchronized reserves. PJM avoids going short synchronized reserves as current operational practice. Inclusion of the synchronized reserve target as a constraint would internalize this current operational goal into the automatic dispatch.

The primary reserves target is 150 percent of the largest contingency in a given reserve region. Primary reserves consist of synchronized (Tier 1 and Tier 2) and non-synchronized 10 minute reserves. While primary reserves are defined, PJM does not currently actively dispatch to maintain primary reserves. The implementation of a primary reserve requirement as a constraint would introduce an active reserve requirement in the dispatch solution, in the form of primary reserves, and would, according to PJM's proposal, require the creation of an active market for non-synchronized primary reserves which does not exist today. PJM is proposing a separate $850 penalty factor for the synchronized and primary reserves requirements and for scarcity pricing to occur due to a shortage of either one or both reserve products.

This is a significant, unwarranted and unsupported change in the structure of PJM markets. The structure of the primary reserve market is not well defined. The expected market design, market structure, prices and revenues are unclear. There is nothing in Order No. 719 that requires the introduction of this market and nothing in scarcity pricing that requires the introduction of this market. Given than PJM cannot currently accurately measure the level of primary non-synchronized reserves, the consequences of adding this market are unknown. It can be expected that the addition of this constraint will significantly increase the incidence of scarcity pricing but the exact increase cannot be known currently. This is an example of an area where PJM should take incremental steps. It is premature to introduce a new market as part of the proposed modification of the scarcity pricing method.

The MMU is proposing that PJM model synchronized reserve requirements as a constraint in the security constrained optimization approach to scarcity pricing. PJM currently avoids going short synchronized reserves as operational practice, but the practice is not incorporated in the 5 minute security constrained dispatch optimization. Including the synchronized reserves requirement as a constraint would constitute a clear improvement in current practice for a reserve product that PJM actively tries to maintain today.

Consistent with an appropriately gradual approach to scarcity pricing, the MMU is proposing a $1,000 penalty factor be used only for the synchronized reserves requirements and that scarcity pricing only occur when there is a shortage of 10 minute synchronized reserves.

Regulation Assignment and Pricing

The MMU and PJM are aligned in the idea that an after the fact, rather than prior to the hour, determination of regulation pricing would provide a more accurate and transparent price signal for the regulation market. However, the MMU disagrees with PJM's proposal to continue to calculate opportunity costs on the basis of the lower of cost based or price based offers rather than the actual dispatch schedule as the reference and the continued failure to net regulation revenues from make whole balancing operating reserve payments. The MMU recommends the modification to the definition of opportunity cost be reversed and that the elimination of the offset against operating reserve credits be reversed based on the MMU conclusion that these features result in a non-competitive market outcome, and because they are inconsistent with the treatment of the same issues in other PJM markets and inconsistent with basic economic logic.

Accounting for Emergency Actions

A well designed reserve MW offset mechanism will prevent prices from falling as a result of non-market emergency actions taken during a period of scarcity. It is the MMU's position that its approach, involving discrete shifts in the reserve requirements to control for emergency actions, is a more transparent way to account for emergency actions in the application of the operating reserve penalty factor approach.

The MMU's emergency action MW offset makes direct and transparent use of the reserve constraints themselves and will require a transparent measurement of actual reserves levels, along with an accurate and transparent measurement of any MW being contributed from the emergency actions. In contrast, PJM's approach is not transparent and it is not defined within its reserve requirement mechanism. Participants will not be in a position to know, even after the fact, how the emergency actions affected the operation of the system, how dependent the system was on the emergency actions and how this may have affected prices.

The reserve MW offset mechanism should be used to maintain consistent pricing only for non-market emergency actions. It is the MMU's position that this approach should not be applied to emergency capacity resources that have cleared RPM and have a recognized value, namely maximum emergency generation and emergency load response. Maximum emergency generation and emergency load resources need to be counted towards energy when deployed, not against the reserve requirements, as these resources have recognized value in the capacity market and provide their energy, or reduction in demand, at a specified price under emergency conditions.

Emergency Demand Response Setting Price

PJM has not provided evidence that allowing Emergency DR to set price during an operating reserve shortage will improve security constrained system dispatch. PJM does not explain how dispatching an unquantifiable block of MW from a set of resources of unknown location, and allowing this resource set to set price at a load center of a zone, will provide discrete marginal dispatch signals needed to maintain system security in the context of numerous transmission constraints within, across and between zones. PJM does not explain why this artifice will improve operational reliability during a reserve shortage, when the system is in a precarious position, when they would not allow these same resources to set price outside of reserve shortage conditions.

In short, what PJM is proposing would directly undermine the point of using an operating reserve demand curve approach to scarcity pricing. The objective of operating reserve demand curve approach to scarcity pricing is to try to improve the dispatch fidelity in and out of scarcity conditions. This requires a mechanism that provides and sustains prices consistent with scarcity and, more importantly, consistent with the overall market design, both in and out of scarcity. Having Emergency DR, as it is currently formulated, set price would run directly counter to this objective and would make the system less, rather than more, reliable during a scarcity event.

Allowing Emergency DR to set price could effectively allow the exercise of market power, as under emergency conditions it is likely that most participants are pivotal.

More generally, emergency DR should not be eligible to set price when called due to the fact that the non-firm portion of a customer's load represented in this capacity already has an obligation to curtail, based on its sale of capacity, during an emergency.

The MMU recommends that the current rules determining the eligibility of resources to be marginal in the security constrained optimization be retained. Such rules ensure that the marginal dispatch signals are consistent with marginal resources used to solve the least cost security constrained dispatch optimization problem. Marginal prices correspond to the marginal resource prices at discrete buses on the system needed to meet power balance and system security constraints. This is important feature of security constrained dispatch signals during normal operation and of critical importance during emergency conditions. Demand response resources with discrete and measurable dispatchability in the form of telemetry, metering and a specific bus location are eligible, under PJM tariff, to be marginal. It is the MMU position that only economic demand response resources with discrete and measurable dispatchability in the form of telemetry, metering and a specific bus location are, and should be, eligible to be marginal, and only in the context of the security constrained dispatch solution.

Emergency Purchases

PJM has proposed that Emergency Purchases be eligible to set price up to $2,700.

PJM has not provided evidence that allowing Emergency Purchases to set price during an operating reserve shortage will improve security constrained system dispatch. PJM does not explain how the rules that disallow emergency purchases from setting price have misaligned energy and reserve prices with system conditions and dispatch instructions, thereby requiring the manual dispatch of the system to maintain reliable system operation since 1998. PJM has successfully purchased emergency power without having its own prices increase beyond $1,000.

If the Eastern Interconnection were one market, offer caps and market power rules would apply throughout and apply in circumstances of scarcity, perhaps even including on overall scarcity pricing mechanism that determined prices. However, that is not the case. There are clearly seams issues that remain between PJM and its neighbors. The market designs differ in fundamental ways and some neighbors do not have organized markets. In addition, there are market power issues when PJM finds itself in an emergency, for which there are no rules or protections in the tariff. The purchase of emergency power on a bilateral basis that does not affect the market price permits PJM to maintain the integrity of its own market design, given the seams issues. It can also be thought of as a circuit breaker that applies in emergency conditions to protect the PJM market and to ensure that market power is not exercised in ways that could have massive and irreversible consequences for PJM market participants.

PJM's neighboring ISOs do not have capacity constructs comparable to PJM and will be more dependent on their energy market to sustain and attract the capacity they need to meet peak demand. Their energy pricing models reflect this difference in market design. Further, the PJM proposal would introduce issues related to the potential exercise of market power by sellers of emergency power during a reserve shortage event.

II. Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, plus reserve requirements, is nearing the limits of the available capacity of the system. Under the current PJM rules, high prices, or scarcity pricing, result from high offers by individual generation owners for specific units when the system is close to its available capacity. These offers give the aggregate energy supply curve its steep upward sloping tail.[3] As demand increases and units with higher markups and higher offers are required to meet demand, prices increase.

Scarcity Revenues: The Need for Administrative Mechanisms

While higher prices are expected during scarcity without a specific market mechanism, a wholesale energy market will not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity revenues. Scarcity revenues can be incorporated through capacity markets, through scarcity pricing in energy only markets or through a combination of capacity markets and scarcity pricing. The need for such mechanisms is not the result of the $1,000 per MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market-clearing prices.

Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards that require wholesale power markets to carry excess capacity means that scarcity conditions in the Energy Market occur with reduced frequency. The mandated reserve margin requires units that are called on only under relatively unusual load conditions, if at all. Resources that do not run for energy, but are needed for reliability, are not supported through an energy only market. Thus, an administrative mechanism, whether a capacity market, scarcity pricing or both, is required to provide revenue adequacy consistent with adequate generation capacity for reliability.

In PJM, the capacity market provides revenue adequacy consistent with adequate generation capacity for reliability. Scarcity pricing is not required in PJM in order to provide revenue adequacy.

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3 See *2009 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part I," at Figure 2-1, "Average PJM aggregate supply curves: Summers 2008 and 2009."

Scarcity Pricing Logic

Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not required in PJM. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM.

The relationship between scarcity pricing and reliability must be clearly defined before a scarcity pricing mechanism is designed. The two functions of scarcity pricing are directly related to two aspects of reliability: resource adequacy and operational reliability. The revenue adequacy function of scarcity pricing is directly related to the resource adequacy aspect of reliability. The market design must provide adequate revenues to support a level of capacity resources to cover forecasted peak load plus a reserve margin that provides reliability. The price signal function of scarcity pricing is directly related to the operational reliability aspect of reliability. The market design must provide for price signals during scarcity conditions that contribute to reliable operations.

While reliability is referenced by PJM as a reason for scarcity pricing, PJM does not clearly state which aspect of reliability it means. Some of PJM's arguments address the resource adequacy aspect of reliability and some of PJM's arguments address the operational reliability aspect of reliability.

The resource adequacy aspect of reliability is fully addressed by RPM. PJM asserts regularly that its market is reliable and that adequate resources are procured through RPM to ensure such reliability. The MMU agrees. For example, in the 2013/2014 BRA, PJM procured capacity that resulted in a 20.2 percent reserve margin, well in excess of the required 15.3 percent reserve margin. PJM procured, over all LDAs, about 6,500 MW in excess of the capacity required to meet its reserve margin which resulted in customers paying about $1.7 billion more than was needed to meet the required reserve margin.

The resource adequacy aspect of reliability incorporates demand side resources. DR participates in the capacity market. For example, DR offers increased from 9,847.6 MW in the 2012/2013 BRA to 12,952.7 MW in the 2013/2014 BRA, an increase of 3,105.1 or 31.5 percent. In 2009, almost 100 percent of all demand side resource compensation was from the capacity market. Thus, short term scarcity prices are not required and have not been required in order to incent demand side participation. It can be expected that the capacity market will continue to provide more reliable and consistent incentives to demand side resources than will episodic scarcity pricing events.

While the scarcity pricing mechanism should not provide additional compensation to capacity resources, it should provide compensation to resources that were not compensated through the RPM construct, including energy only demand side response, capacity which did not clear in RPM and imports.

The operational reliability aspect of scarcity pricing must be addressed in any changes to the current scarcity pricing mechanism.

When available capacity is not sufficient to maintain reserves, system operators have to turn to non-market solutions to maintain reliable service, including voltage reductions, load dumps and emergency energy purchases. All of these administrative control actions are designed to preserve the level of reserves needed to maintain system reliability. But these administrative emergency actions also produce counter intuitive price effects; they reduce prices during scarcity conditions.

Scarcity pricing is required to address these price signal issues and to provide operational reliability. Scarcity pricing is required to ensure that the market price signals are consistent with actual market conditions during periods of scarcity even when the system operator has to take emergency steps to maintain reliability.

The two functions of scarcity pricing can be coordinated through a well designed scarcity pricing revenue true up mechanism. Energy market scarcity pricing is part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design and the market rules must ensure that there is a well designed scarcity pricing revenue true up mechanism to prevent double collection of scarcity revenues. The absence of such a mechanism will result in an over collection of scarcity revenues in a given delivery year and a counterproductive distortion in the forward prices for capacity. The most straightforward way to ensure that such over collection does not occur, and that the forward markets for capacity provide meaningful investment signals, is to ensure that capacity resources do not receive scarcity revenues from the energy market unless total scarcity revenues for a delivery year exceed the price of capacity for that year.

PJM's Current Scarcity Pricing Mechanism

PJM's current administrative scarcity pricing mechanism is designed to recognize real-time scarcity in the energy market and to increase prices to reflect the scarcity conditions. Under the current PJM rules, administrative scarcity pricing results when PJM takes identified emergency actions and is based on the highest offer of an operating unit. These emergency actions include: emergency energy purchase request events, maximum emergency generation events, manual load dump events and voltage reduction events. When PJM implements any of the identified emergency procedures, any offer capping of units in the affected area is lifted and the LMP of the entire affected area is set equal to the highest-priced offer of a unit dispatched at the time.

PJM's current administrative scarcity pricing mechanism is designed to recognize real-time scarcity in the energy market and increase prices to reflect the scarcity conditions. Under the current PJM rules, administrative scarcity pricing results when PJM takes identified emergency actions and is based on the highest offer of an operating unit. These emergency actions include emergency energy purchase request events, maximum emergency generation events, manual load dump events and voltage reduction events.[4] The use of any of these measures to maintain system integrity in predefined scarcity pricing regions is an indication that the affected area of the system is in a state of scarcity. When PJM implements any of the identified emergency procedures, any offer capping of units in the affected area is lifted and the LMP of the entire affected area is set equal to the highest-priced offer of a unit dispatched at the time.

While an energy market scarcity pricing mechanism is needed, and PJM's use of specific emergency procedures is a reasonable indicator of scarcity conditions, the MMU's review of market results leads to our recommendation that PJM's energy market scarcity pricing mechanism be reviewed and modified. The current mechanism lacks a clear definition and trigger for scarcity. Further, since the scarcity prices under the current scarcity mechanism are not the result of a security constrained dispatch designed to maintain 10-minute reserves and security constrained power balance requirements, the current mechanism does not provide locational pricing that is consistent with security constrained dispatch under conditions of scarcity. Instead, the current mechanism raises prices to the most expensive unit operating under PJM direction, ignoring local constraints. This leads to price based dispatch incentives that are inconsistent with local dispatch requirements. This requires that control of local constraints be done through manual dispatch instructions just as the system is under its greatest stress.

Proposed Scarcity Pricing Approach

Both the MMU and PJM propose approaches designed to address these shortcomings in the current scarcity pricing mechanism. Both propose that real-time reserve requirements be clearly defined and that they be modeled as constraints in the security constrained dispatch. Both approaches call for more flexible and locational scarcity signals to be implemented via reserve requirements modeled as constraints for defined regions, with administrative reserve scarcity penalty factors, in the security constrained dispatch. Conceptually, incorporating reserve penalty factor curves into the security

4 See PJM Open Access Transmission Tariff (OATT), Sixth Revised Volume No. 1, Third Revised Sheet No. 402A.01 (Effective May 17, 2008).

constrained dispatch internalizes the value of maintaining resources needed for reliability in the centralized dispatch market solution.

Under both the PJM and the MMU reserve penalty factor curve approach, local market power mitigation in the energy market would remain in force regardless of scarcity conditions. Rather than depending on market power to increase prices during scarcity, the administrative scarcity pricing mechanism results in defined prices during a scarcity event. Under both the PJM and MMU reserve penalty factor curve approach, reserves scarcity conditions result in administrative scarcity adders being applied to marginal unit bus prices within the affected reserve region. These adders increase the price of energy, forcing a scarcity margin within the locational market price (LMP) at every bus in the affected reserve region.

PJM Proposed Approach: $2,700 Max Prices and Binding the Reserves Constraints during Shortage

In the PJM proposed approach to reserve requirements as part of the security constrained optimization, when the reserve constraint(s) are binding the penalty factors associated with the constraints are directly reflected as a component of the marginal cost of energy from marginal energy resources. This recognizes that marginal energy resources are converting their reserves to energy, therefore the incremental cost to produce an additional unit of energy is the marginal cost of energy plus the incremental cost of giving up an additional MW of reserves, which is the penalty factor associated with the reserve target. Where penalty factors are sufficient to dispatch all available reserves, the direct reflection of fixed penalty factors on the marginal cost of energy will lead to energy prices well in excess of the price offer caps in a market. It is important to note that while this approach has been taken in ISO New England, Midwest ISO and New York ISO, these markets do not have forward capacity markets comparable to PJM's RPM construct. These markets are arguably, particularly in the case of Midwest ISO, more dependent on prices in the energy market to maintain capacity reserves needed to meet reliability requirements. Despite these fundamental design differences, this is the approach being proposed by PJM.

Under PJM's proposal, using $850 penalty factors for its two reserves constraints means that up $1,700 could be added to marginal unit bus prices for purposes of determining LMP. This means LMPs at marginal unit buses could be as high as $2,700 during a reserve shortage.

MMU Proposed Approach: $1,000 Max Prices and Relaxing the Reserves Constraints during Shortage

PJM's approach is one way to structure the mechanics of a reserve constraint in an optimization problem. However, it is not the only way and it is not the preferred way for scarcity pricing. Instead of adding a fixed penalty factor to the marginal cost of energy, the constraint can be relaxed to allow a market solution and to set the price to the target level. This approach allows the continuation of security constrained dispatch but allows the market to provide pricing results that are consistent with offer caps and predefined price caps. This approach is used by PJM in modeling other reliability constraints. This approach is also used to model security constraints or limitations in many organized markets, including PJM, ISO New England and New York ISO. For example, transmission limits, minimum generation events and ramp limits are all modeled as constraints that can be relaxed in the optimization engines of PJM, New York ISO, and ISO New England. The constraint relaxation approach also has the advantage of avoiding a number of inconsistencies that PJM's binding constraint approach creates with other aspects of PJM's market design.

Under the MMU's proposal if the reserve requirements could not be met, the reserve constraint would be relaxed and energy prices at the marginal unit buses would be set to a predefined price target. The MMU is recommending a predefined energy price target that is consistent with PJM's current $1,000 per MWh offer cap in both the Day-Ahead and Real-Time energy markets. A price target set at $1,000 at the marginal unit buses in the area with a reserve shortage would provide a clear scarcity signal that is consistent with scarcity, consistent with economic dispatch, consistent with locational pricing, consistent with competitive market outcomes and consistent with PJM's current market design. A $1,000 price target is consistent with the price signal function of scarcity pricing and therefore the operational reliability aspect of reliability.

The MMU approach is flexible. The mechanics of this approach allow the price target to match the offer cap, or to be set up in stages based on the level of reserve shortage. For example if offer caps were to increase to $1,500, it would be a simple matter to raise the scarcity price target to keep the mechanism in line with market design parameters. Similarly, if a more gradual implementation of scarcity pricing were desired, a series of price targets could be used to reflect a worsening reserve shortage. For example, going one to ten percent short of reserves could result in setting a price target of the greater of $700 or the most expensive resource running at PJM direction, going short eleven to fifty percent could result in price targets of the greater of $850 or the most expensive resource running at PJM direction, and going short fifty-one percent or more could result in price targets of $1,000.

Market Design Issues with PJM's Proposal

PJM's decision to have the penalty factors directly affect marginal unit bus LMPs during reserve shortages introduces a number of market design issues. PJM's proposal undermines PJM's existing market power mitigation rules, introduces new avenues for market manipulation that are not addressed in the PJM proposal, requires the lifting of offer caps in the day-ahead market so that they do not match real-time offer caps, and introduces efficiency issues in the interaction of the Day-Ahead and Real-Time Energy Market. Further, PJM defense of the $2,700 price cap is based on erroneous interpretations of value of lost load studies and the unsubstantiated and unclear claim that prices in excess of a $1,000 are needed in the PJM market to maintain reliability.

$2,700 Price Cap Undermines PJM Market Power Mitigation Rules

PJM suggests that it is maintaining mitigation of market power under its proposed rules, in that it is going to maintain the $1,000 offer cap and it is going to maintain offer capping for local market power via the Three Pivotal Supplier test. In practice, however, PJM's proposal would undermine market power mitigation as it exists in PJM's markets today. PJM's proposal effectively eliminates market power mitigation provided by the $1,000 offer cap, introduces incentives to exercise market power and new mechanisms that can be used to exercise market power. PJM does not address the market power problems that result from its approach.

PJM's proposal to allow prices to exceed the price cap at marginal unit buses by as much as $1,700 effectively eliminates the $1,000 offer cap as a protection against market power. The $1,000 offer cap in the Day-Ahead and Real-Time Energy Market is, and has been, an important component of market power mitigation in PJM markets. Having marginal bus prices capped at $1,000 has limited the potential gains from non-competitive behavior in PJM's Day-Ahead and Real-Time Energy Markets. The $1,000 offer cap has been the only mechanism constraining the exercise of market power in the overall energy market. PJM has specific mechanisms for constraining the exercise of local market power. Increasing the potential energy price to $2,700 provides increased incentives to engage in activity to force prices up during conditions of potential shortage. These incentives are particularly pronounced among participants with portfolios of generation in highly concentrated markets.

The exercise of market power under PJM's proposed scarcity pricing mechanisms is of particular concern because of the highly concentrated nature of the existing reserves markets, and the dramatic affect that the level of reserves can have on energy prices under the proposed mechanism.

As reported in the 2009 State of the Market Report, the average load weighted Synchronized Reserve Market HHI for the Mid Atlantic Subzone of the RFC Synchronized Reserve Zone for all of 2009 was 2619 which is classified as "highly concentrated." For purchased synchronized reserves (cleared plus added within the hour) the HHI was 3070. In 36 percent of hours, the maximum market share was greater than 40 percent. In 2009, 95 percent of hours in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market failed the three pivotal supplier test. One company was pivotal in 57 percent of all pivotal hours, a second company was pivotal in 53 percent of all pivotal hours, and a third company was pivotal in 51 percent of all pivotal hours. Based on these results like these, the MMU has consistently concluded that the PJM synchronized reserve markets are not structurally competitive.

PJM's current Synchronized Reserve Market rules are designed to address this structural issue by capping all participants at cost plus $7.50. The use of cost based offers does not, however, eliminate all market power as the current market rules do not include a must offer requirement for the provision of reserves. Participants can choose, on a day to day basis, to have individual units offer reserves for the day. Once offered, participants can choose to not participate in any given hour's Synchronized Reserve Market. Under current market rules this has been a concern, but a concern that has been limited to the performance of the Synchronized Reserve Market and that has not impacted the market results. However, with PJM's proposed price cap of $2,700, and the role that reserve shortages will have in attaining prices of that magnitude under PJM's proposal, the ability of participants to withhold reserves in a highly concentrated market is a major concern. Given that a shortage of synchronized reserves can trigger scarcity pricing, regardless of system conditions, the ability and incentives to exercise market power in the synchronized reserve market must be addressed under any scarcity pricing proposal that includes such a trigger.

PJM does not address this issue, despite introducing a market mechanism that increases the significance of the market power issue. The MMU recommends a must offer requirement for synchronized reserves to address this issue.

PJM's Proposed $2,700 Effective Price Cap Introduces Market Design Issues Between the Day-Ahead and Real-Time Energy Markets

PJM's proposal to allow prices to exceed the energy price cap at marginal unit buses by as much as $1,700 introduces a number of market design issues related to the interaction between the Day-Ahead and Real-Time Energy Markets.

$2,700 Prices: Incentives to Withhold from Day-Ahead

The potential $1,700 difference in prices between the Day-Ahead and Real-Time Energy Markets under the PJM proposal will, together with PJM's offset mechanism, provide capacity owners an incentive to withhold from the Day-Ahead Energy Market so they can receive scarcity prices in the Real-Time Energy Market. PJM's proposed offset mechanism would permit capacity owners to receive the scarcity price revenues. The MMU proposal would not.

PJM's market design depends on incenting participants to schedule and participate in the Day-Ahead Energy Market. The current arbitrage incentives between Day-Ahead and Real-Time are designed to align Day-Ahead and Real-Time prices so that the use of day-ahead scheduling is consistent with real-time requirements. PJM's offset proposal is inconsistent with this key element of PJM market design.

PJM's $2,700 price cap in the Real-Time Energy Market, in combination with its offset proposal, results in a scarcity pricing mechanism that is inconsistent with PJM's market design, which requires capacity resources to offer in the Day-Ahead Energy Market. PJM has attempted to address this problem by increasing the offer cap in the Day-Ahead Energy Market to $2,700 only for virtual offers and bids (INCS and DEC) and for price sensitive demand. Physical generation resources would continue to have offer caps of $1,000.

$2,700 Prices: Arbitrage above $1,000 Causes Wealth Transfers Not Efficiency Improvement

The current PJM market design results in arbitrage incentives between Day-Ahead and Real-Time Energy Markets that produce price convergence on average and day-ahead generation scheduling that is consistent with real-time requirements. PJM's proposal to increase offer caps will serve only to facilitate wealth transfers from load to generation and not to improve efficiency or reliability.

The current PJM market design facilitates efficiency improving arbitrage between the Day-Ahead and Real-Time Energy Market. If the Real-Time price is higher than Day-Ahead prices, there is an incentive for virtual players to buy power Day-Ahead and sell it in Real-Time until the price difference is arbitraged away. With the effective price cap equal to the physical offer cap, arbitrage between Day-Ahead and the Real-Time Energy Market results in more resources being committed in the Day-Ahead Energy Market until the Day-Ahead and Real-Time Energy Markets are in balance and the day-ahead dispatch of physical resources is more consistent with real-time dispatch requirements. The overall effect is an improvement in dispatch efficiency and lower marginal and overall production costs.

PJM's scarcity pricing proposal would create a market where capacity resource offers are capped at $1,000, virtual bids and price sensitive demand offers are capped at $2,700 Day-Ahead and the scarcity pricing mechanism can result in prices of $2,700 in real-time. This approach is inconsistent with PJM market design fundamentals. It is also discriminatory. At prices approaching $1,000 in real-time, the entire supply of capacity resources would be available in PJM. The availability of PJM generation resources will not increase with day-ahead prices over $1,000. Prices over $1,000 in Day-Ahead will only increase the prices paid for energy in Day-Ahead, not improve the dispatch efficiency of physical resources visible to the PJM marketplace. Prices in excess of $1,000 constitute only a wealth transfer from load to the owners of capacity.

$2,700 Prices: Lifting Offer Caps Day-Ahead Undermines PJM Day-Ahead Energy Market Power Mitigation

PJM has suggested that it is maintaining mitigation of market power under its proposed rules because it is going to maintain the $1,000 overall market offer cap and it is going to maintain offer capping for local market power in the energy market via the Three Pivotal Supplier test.[5] However, PJM's proposal does not maintain the $1,000 offer cap for non-generation resources. PJM has proposed to change Demand and virtual bid offer caps in the Day-Ahead Energy Market from the current cap of $1,000 to a cap of $2,700. PJM's proposal would eliminate market power mitigation, in the form of the $1,000 offer cap, as it exists in PJM's Day-Ahead Energy Market today.

PJM's proposal to increase offer caps for virtual bids and offers in the Day-Ahead Energy Market is not limited to scarcity conditions but would apply at all times. This creates more general market power issues that are not limited to scarcity conditions.

The $1,000 offer cap in the Day-Ahead Energy Market is, and has been, an important component of market power mitigation in PJM markets. Having marginal bus prices effectively capped at $1,000 has limited the potential gains from non-competitive behavior in PJM's Day-Ahead Energy Market. Increasing the potential energy price to $2,700 provides increased incentives to engage in activity, via virtual bids and offers, to force prices up during conditions of potential shortage. These incentives are particularly pronounced among participants with portfolios of generation in highly concentrated transmission constrained markets.

PJM's proposal would create a dichotomy between the real-time and day-ahead offer caps, which would increase gaming opportunities between the Day-Ahead and Real-

5 PJM Affidavit, p. 33

Time Energy Market. With offers capped at $1,000 in real-time, the only way for real-time prices to exceed $1,000 is PJM's scarcity mechanism. That would not be the case in the Day-Ahead Energy Market, where virtual bids from market participant bids could drive prices, even in the absence of real-time scarcity, above $1,000. PJM's proposed fix thereby increases the magnitude of the potential upside to games that can be played with virtual offers and bids, including the circumvention of day-ahead mitigation for local market power, providing incentives for additional gaming behavior.

Prices in the Day-Ahead Energy Market should reflect competitive outcomes and should reflect scarcity conditions only when scarcity conditions actually exist in the Day-Ahead Energy Market. There should be no offer cap exemption in the Day-Ahead Energy Market for any resources.

PJM has proposed inconsistent approaches to market design in the Real-Time and Day-Ahead- Markets and then proposed ad hoc fixes to resolve the issues. The appropriate approach would be to make modifications to the PJM market design that are consistent with the current design fundamentals and that are internally consistent. If offer caps were to be raised, they should be raised for all resources and for both the Day-Ahead and Real -Time markets.

$1,000 or $2,700: No Evidence That $2,700 is Needed to Maintain Reliability

There is no reason to increase the maximum price in PJM markets in order to implement scarcity pricing. PJM has provided no evidence that increasing the maximum price is required for either the resource adequacy or operational aspects of reliability. PJM has not provided evidence that, given an RPM construct that purchases a surplus of capacity well in excess of what is needed to meet system planning requirements, prices in excess of the $1,000 offer cap are needed to make PJM's system reliable. PJM has not made the case that its system is currently, or will become, unreliable at current price caps. PJM has not provided evidence that prices in excess of $1,000 are needed to incent economic demand response. PJM has not provided evidence that any additional theoretically available demand response, available only at prices in excess of $1,000, will make the difference between a reliable or unreliable system.

As an example, in the 2013/2014 BRA, PJM procured capacity that resulted in a 20.2 percent reserve margin, well in excess of the required 15.3 percent reserve margin. PJM procured, over all LDAs, about 6,500 MW in excess of the capacity required to meet its reserve margin which resulted in customers paying about $1.7 billion more than they would have paid to meet the required reserve margin.

Emergency Purchases

In defense of its $2,700 price levels, PJM claims that "PJM paid prices ranging from $1500/MWh to $4500/MWh for emergency power from neighboring systems."[6] PJM argues that "[t]his evidence suggests that potential maximum energy prices associated with extreme shortage conditions must be closely aligned in neighboring RTOs, otherwise there will be incentives for resources in one RTO to export power into another RTO that has a higher price."[7] PJM does not state the source of its information or what its cited information on prices for emergency power is intended to represent, and the cited data does not include the full range of historical prices offered and paid for emergency power, including prices less than $1,000 per MWh. PJM then argues in cases where reserve shortages may be concurrent between neighboring RTOS, that PJM's reliability will be dependent on having prices competitive with its neighbors. PJM states, "if both the exporting and importing regions are in shortage conditions, then reliability in the importing region may be enhanced at the expense of the exporting region."[8] PJM goes on to state:

> PJM believes the $2700/MWh maximum price that results from its proposed Reserve Penalty Factors is in line with the current maximum price in the NYISO of $2750/MWh and that of the Midwest ISO at $3500/MWh. PJM further believes that such a maximum price will protect system reliability in the event that all three regions are in shortage conditions simultaneously and competing for resources to maintain reliable operations.[9]

PJM's argument is incorrect. If PJM needs to purchase emergency power, it can and has done so successfully without having its own prices increase beyond $1,000. PJM makes bilateral purchases directly from those suppliers who respond to PJM's request. That tariff provision should remain in place.

If the Eastern Interconnection were one market, offer caps and market power rules would apply throughout and apply in circumstances of scarcity, perhaps even including on overall scarcity pricing mechanism that determined prices. However, that is not the

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6 PJM Affidavit, p. 27

7 *Id*.

8 *Id*.

9 *Id*.

case. There are clearly seams issues that remain between PJM and its neighbors. The market designs differ in fundamental ways and some neighbors do not have organized markets. In addition, there are market power issues when PJM finds itself in an emergency, for which there are no rules or protections in the tariff. The purchase of emergency power on a bilateral basis that does not affect the market price permits PJM to maintain the integrity of its own market design, given the seams issues. It can also be thought of as a circuit breaker that applies in emergency conditions to protect the PJM market and to ensure that market power is not exercised in ways that could have massive and irreversible consequences for PJM market participants.

If PJM believed that it must compete on a price basis to maintain reliability then the $2,700 price point is too low. Both MISO ($3,500) and New York ISO ($2,750) have higher reserve scarcity price caps than PJM's proposed $2,700. PJM has not asserted that its current operation reliability is threatened by its current $1,000 cap, despite the much higher effective price caps of its neighbors.

PJM, unlike its neighbors, has RPM. RPM is designed to procure capacity needed to meet reliability requirements three years into the future. Capacity resources must offer into the Day-Ahead Energy Market and under emergency conditions PJM has the right under tariff to recall RPM resources that are exporting in real-time. PJM's neighboring ISOs, do not have comparable capacity constructs and will be more dependent on their energy market to sustain and attract the capacity they need to meet peak demand. Their energy pricing models reflect this difference in market design.

Recall Rights to Energy From Capacity Resources

Given PJM's discussion of emergency purchases, it is surprising that PJM does not address PJM's recall rights to the energy from capacity resources. This recall right is an essential part of the PJM market design and much more critical than emergency purchases.

The sale of capacity is also the sale of recall rights to the energy from capacity resources during an emergency at the market price. The PJM capacity market requires that the energy output of all capacity resources is recallable by PJM during an emergency. The recallability of energy from capacity resources is a fundamental part of the definition of a capacity resource. The recallability of energy is an essential part of why customers pay for capacity and how capacity resources provide reliability. If capacity resources could export their energy output during an emergency, then customers' purchase of capacity would not have contributed to reliability.

Regardless of where, or under what conditions, the energy from a unit is sold, it is recallable by PJM when PJM is in an emergency condition at the market price. PJM does not have clear protocols for recalling the energy output of capacity resources and has not recalled such energy since 1999, despite the fact that PJM has experienced emergency conditions since that time.

Any scarcity pricing mechanism should include an explicit, transparent set of rules governing the recall of energy produced by capacity resources and the defined conditions under which such recalls will occur. The recall rules should provide that the energy from capacity resources is recalled to PJM as part of implementing emergency procedures prior to implementing scarcity pricing and that such recalls occur at the market price. The recall of the energy from capacity resources is a market response and such recalls are price takers and such recalls should be permitted to affect market prices through their impact on the balance of supply and demand. The impact of such recalls on the price of energy, if any, is an appropriate reflection of the contribution of capacity resources to reliability.

The Value of Lost Load

PJM has also defended its $2,700 price level as being consistent with the "value of lost load" study results from a number of sources.[10] PJM argues that this indicates that prices in excess of $1,000 are needed to incent demand response in energy markets, and has been used as the basis of scarcity pricing in other RTO's. PJM cites a number of studies to substantiate its claims regarding its price levels. However, PJM has ignored the fact that the cited studies state explicitly that the referenced calculated values of lost load refer to total service interruptions, not partial interruptions, and the referenced calculated values of lost load are not relevant to determining the appropriate price to incent demand response.

PJM states:

> The maximum energy prices proposed by PJM fall into the dollar range of consumers' willingness to pay for energy or the value of lost load as determined by the Midwest Independent System Operator (Midwest ISO), and approved by the Commission, just two years ago. In that regard, the Midwest ISO conducted a meta-analysis of 24 studies of the cost of un-served energy in the Midwest. Applying a weight of 85 percent to the value of un-served energy for residential customers and 15 percent to small commercial and industrial customers, Midwest ISO determined

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10 PJM Affidavit, pp. 26–27.

> the value of lost load at $3500/MWh as the maximum energy price during reserve shortage conditions.[11]

PJM also cites a Lawrence Berkley National Laboratories study:

> Additionally, a 2009 meta-analysis of 28 studies of the cost of un-served energy from Lawrence Berkeley National Laboratories finds that residential customers have a value of un-served energy of $2600/MWh and large and medium commercial and industrial customers have a value of $25,000/MWh.[12]

While value of load studies do indicate that customers are adverse to complete service interruption, they do not address or indicate the prices that are needed to incent partial reductions of load, i.e. demand response.

PJM assertions about the reasonableness of its price proposals are based on a confusion regarding the theoretical concept of the value of lost load and the price that would be needed for customers to make partial load reductions. In other words, PJM's assertion that the value of lost load is consistent with prices needed to incent demand response is incorrect. They are two completely separate values and two completely separate concepts. As noted in the same Lawrence Berkley National Laboratories study cited by PJM:

> Virtually all interruption cost studies to date have developed interruption costs for full interruptions. While this information is v[e]ry useful for valuing reliability improvements obtainable from system reliability reinforcements, they are of limited use for evaluating the costs and benefits of demand response. Demand response typically involves partial, rather than full interruptions. Most demand response programs do not involve full interruptions. Instead, customers reduce their demand partially in response to control or price signals coming from the system operators. The value of demand response to the system is the cost of the full interruption that might have been experienced by all parties on the system absent the demand response. The costs experienced by demand response participants are not the cost of a full interruption, but instead are the value of the part of the load they curtail at the time of the demand

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[11] PJM Affidavit, p. 26.

[12] PJM Affidavit, p. 27.

> response request. For purposes of evaluating the cost effectiveness of demand response programs, it is not appropriate to consider the value of the partial interruption to be zero – although in some cases it undoubtedly is. The question is: what is the value of the partial interruption for customers participating in these programs if it is not zero. The current meta-database (focused on the value of full interruptions) cannot address this issue.[13]

In setting effective price caps at $2,700, a price that is consistent with the value of lost load, PJM is asserting that the price required to incent partial reductions in demand is equivalent to the consumer surplus associated with consuming electricity. This is an incorrect assertion and one explicitly contradicted by the studies on which PJM relies. As the Lawrence Berkley National Laboratories indicates, the price customers are willing to pay to avoid a black out for three days is likely very different that the price that may incent a customer to reduce its load by 10 percent for an hour. At the value of lost load price customers are just at the point where they are not willing to buy any electricity, not some reduced amount of electricity. It is the value people attribute to having any access to power. Given the necessity of electricity to everyday life, it is not unexpected that the value of the loss of all power is high. This is the price people might be willing to pay to avoid a three day black out during a heat wave. It is not, however, a price level that is needed to incent partial reductions, for customers to cycle air-conditioning units, dim their lights, are post pone the laundry cycle for an hour.

Further, it is worth noting that the electricity market is a unique market. Supply must always equal demand. Where system conditions become critical and rationing, either economic or administrative, does not occur, the system will collapse and the market along with it. When that happens generators also lose the benefit of the market, as there is no way to delivery their product. Local black outs reduce sales. Total system collapse is very bad for business. Both sides of the market have an interest in avoiding loss of load and maintaining reliability. The price that does this should be determined at the point of intersection of the marginal valuation of power for both generators and customers, not the price at which customers are indifferent between consuming electricity or suffering a black out. The current market paradigm in PJM sets the highest point of intersection in the neighborhood of $1,000, at the highest acceptable offer. Not at PJM's purported value of lost load at $2,700.

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13 See Michael J. Sullivan, Ph.D., Matthew Mercurio, Ph.D., Josh Schellenberg, M.A, "Estimated Value of Service Reliability for Electric Utility Customers in the United States," Prepared for the Office of Electric Deliverability and Energy Reliability, United States Department of Energy, June 2009, P. 78. <*http://certs.lbl.gov/pdf/lbnl-2132e.pdf*>.

Scarcity Pricing Mechanism: Conclusion

Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent and verifiable triggers and prices and that there are strong incentives for competitive behavior, strong incentives for performance and strong disincentives to exercise market power.

With a settlement process that incorporates an appropriate scarcity pricing revenue true up mechanism, scarcity pricing can be a mechanism to appropriately structure energy market prices in a competitive market without reliance on the exercise of market power. If these design elements are incorporated, administrative scarcity pricing in the energy market can be a key component in the overall market design.

While prices reflective of scarcity are the goal of any administrative scarcity pricing mechanism, it is important that prices set by the mechanism be consistent with both market efficiency and overall market design goals. In the presence of a capacity market designed to procure resources, including demand side resources, that are greater than required to maintain reserve margins, there is no reliability reason to set prices above the current offer price cap. PJM has not supported its argument that energy prices must exceed $1,000 during scarcity conditions to safeguard system reliability.[14]

In PJM's market design, administratively setting prices over the price cap will, in the absence of an effective scarcity pricing revenue true up mechanism, serve only to generate wealth transfers. Other complications exist in the synergies between markets. For example, where penalty factors drive prices over the price cap in the Real-Time Energy Market, the absence of a similar mechanism in the Day-Ahead Energy Market will ensure inconsistency between the Day-Ahead and Real-Time Energy Market results, creating opportunities for market power. This problem is not easily resolved. Simply increasing the offer cap in the Day-Ahead Energy Market for virtual products to equal the maximum price attainable in the Real-Time Energy Market, for example, would allow arbitrage in prices, but in the absence of physical resources priced in excess of the real-time offer caps, the arbitrage will not improve unit commitment and dispatch instructions, but will only cause wealth transfers among participants as well as additional gaming opportunities.

There is no reason to increase the maximum price in PJM markets in order to implement scarcity pricing. PJM has not provided evidence that, given an RPM construct that procures capacity well in excess of what is needed to meet system reliability

[14] PJM Affidavit, p. 27.

requirements, prices in excess of the $1,000 offer cap are needed to make PJM's system reliable. PJM has not made the case that its system is currently, or will become, unreliable at current price caps. PJM has not provided evidence that prices in excess of $1,000 are needed to incent economic demand response. PJM has not provided evidence that any additional theoretically available demand response, available only at prices in excess of $1,000, will make the difference between a reliable or unreliable system.

Given the significant changes to the PJM markets that are required in order to implement any significant change to scarcity pricing, a gradual approach is warranted. If scarcity pricing is implemented successfully and the markets gain experience with it, higher offer caps could be considered. However, the assertion that much higher prices are required now in order to incent the participation of additional resources is unsupported.

A simpler solution to the scarcity pricing issues, in terms of market efficiency and consistency with overall market design, is to limit the price effect of going short reserves to a level that is consistent with the physical resource price caps that exist in the Day-Ahead and Real-Time Energy Markets. In the optimization problem this can be implemented by relaxing the reserve constraint to prevent the constraint from binding and setting the marginal unit bus prices to predefined price targets when the constraint is relaxed. As in the application of this approach with other reliability constraints in the optimization, this approach maintains and enforces the penalty factor associated with going short reserves for purposes of dispatch. The difference is that when the constraint is relaxed the MMU approach imposes a flexible price effect on the marginal unit buses so long as reserves fall short of the reserve requirements. The flexible price effect is the dollar amount needed to get the marginal unit bus price to the shortage price target. So long as the marginal incentives to produce energy (energy margin) or provide reserves (opportunity cost of foregone energy production) are maintained, this approach provides all the advantages of a security constrained dispatch approach to scarcity pricing, while providing market results that are consistent with overall market design and market efficiency goals.

Scarcity Pricing Revenue True Up Mechanism

The wholesale power markets, in order to be viable, must be competitive and they must provide adequate revenues to ensure an incentive to invest in new capacity. A wholesale energy market will not consistently produce competitive results in the absence of local market power mitigation rules. This is the result, not of a fundamental flaw in the market design, but of the fact that transmission constraints in a network create local markets where there is structural market power. A wholesale energy market will not consistently result in adequate revenues in the absence of a carefully designed and comprehensive approach to scarcity pricing. This is a result, not of offer capping, but of the fundamentals of wholesale power markets which must carry excess capacity in order to meet externally imposed reliability rules.

Scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The RPM design reflects the recognition that the energy markets, by themselves, will not result in adequate revenues. The RPM design provides an alternate method for collecting scarcity revenues. The revenues in the capacity market are scarcity revenues.

The approach to energy market based scarcity must reflect the fact that revenues in the capacity market are scarcity revenues. With the PJM RPM design, there is no need for a scarcity pricing mechanism in the energy market to ensure revenue adequacy. Nonetheless, it would be preferable to include a scarcity pricing mechanism in the energy market as a complement to a capacity construct because it provides additional direct, market-based incentives to load and generation at the margin, as long as the market rules are designed to ensure that there is a scarcity pricing revenue true up mechanism to prevent double collection of scarcity revenues. In other words, scarcity pricing can provide appropriate price signals for operational reliability.

The energy market scarcity pricing mechanism should be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent and verifiable triggers and prices and that there are strong incentives for competitive behavior, strong incentives for performance and strong disincentives to exercise market power and rules to ensure that market power is not exercised. The energy market scarcity mechanism should also be designed to have no net impact on revenues to capacity resources, which are already fully compensated under RPM. The scarcity pricing mechanism should provide performance incentives and increased revenues for any responding resources not already compensated in the capacity market, including non-capacity price sensitive load response, uncleared capacity and imports.

The MMU position is that scarcity revenues represent a double payment to capacity resources and that scarcity pricing revenues should not be paid to capacity resources unless scarcity pricing revenues exceed the capacity price for the year. The purpose of the true up mechanism is to prevent double recovery of scarcity revenues. PJM does not appear to recognize that scarcity pricing revenues will result in a double recovery. PJM does not have a clear position on whether capacity resources require additional payments over and above those received through RPM. This lack of clarity of purpose has led to PJM's poorly designed offset proposal that creates timing mismatches, uncertainty and pricing distortions in the RPM auctions. This lack of clarity has also confused the already complex discussion about an appropriate true up mechanism.

Scarcity Pricing Revenue True Up: PJM Approach

PJM proposes that revenues generated by the scarcity mechanism during scarcity events be passed through RPM's three-year average energy and ancillary net revenue offset in the same way as all other energy and ancillary service revenues and not affect RPM revenues in the year in which a scarcity event occurs. PJM's proposal would allow capacity resources to keep scarcity revenues in the delivery year along with the RPM revenues for that delivery year.

PJM's approach results in a significant mismatch between the timing of the scarcity event and associated revenues, and the impact on the RPM clearing prices. As a result, there is substantial uncertainty introduced into the RPM auction process about the likely impact on future auction results. The result will be to distort the prices of RPM in the future. Future RPM prices, set in an auction the year after the scarcity event, will be lower despite the fact that the scarcity event signaled that not enough capacity has been purchased. This is exactly the wrong price signal to send through the RPM market.

PJM's approach means that the net revenue offset would increase for three subsequent auctions, which would occur one, two and three years in the future after the scarcity event. The net revenue offset reduces the net CONE used to derive the demand curve in the RPM market. The net revenue offset also reduces net ACR based offers of capacity resources. The result of PJM's proposal would be to reduce the RPM clearing price for capacity delivery years that are five, six and seven years after the scarcity event.

PJM argues that its approach ensures comparable treatment between RPM and non-RPM resources. But PJM's proposal does not ensure comparable treatment of RPM and non-RPM resources because PJM's proposal ignores the fact that capacity resources have already been compensated for availability during scarcity (and non-scarcity) periods while non-RPM resources have not.

There is additional and significant uncertainty under the PJM approach about whether the offset would ever occur. Some participants have already argued that the CONE unit should be assumed to clear in the Day-Ahead Energy Market and therefore not receive any scarcity revenue. In that case, there would be no offset under the PJM approach.

The real issue is that PJM has not made it clear whether it believes that scarcity pricing in the energy market should increase the total revenues received by capacity resources. To make such an argument would be to concede that RPM is not working as designed. This lack of clarity of purpose has led to PJM's poorly designed offset proposal that creates timing mismatches, uncertainty and pricing distortions in the RPM auctions. This lack of clarity has also confused the already complex discussion about an appropriate offset mechanism.

If PJM believes that scarcity pricing should increase the revenues to capacity resources, PJM should state this clearly. This could lead to a payment mechanism that explicitly increased revenues to capacity owners in a defined way.

If PJM believes that scarcity pricing should not increase the revenues to capacity resources, PJM should state this clearly. This could lead to a scarcity pricing true up mechanism designed explicitly to ensure that such increase does not occur.

Scarcity Pricing Revenue True Up Mechanism: MMU Approach

The MMU proposes a direct approach to the scarcity pricing revenue true up mechanism. The MMU believes that RPM appropriately compensates capacity resources and provides for reliability and that no additional compensation from scarcity pricing is required. Given this goal, the most straightforward way to ensure that such over collection does not occur, and that the forward markets for capacity provide meaningful investment signals, is to ensure that capacity resources do not receive scarcity revenues. The settlements process can remove any scarcity pricing revenues from payments to capacity resources and eliminate the need for a complex, uncertain, after the fact procedure for offsetting scarcity revenues in the capacity market.

In addition, the MMU proposes that capacity resources be paid scarcity revenues when scarcity revenues, for a delivery year, exceed capacity revenues for that delivery year. This approach ensures that, if the capacity market did not procure adequate resources or if the capacity market price was suppressed, that capacity resources receive the appropriate incentives in a year when there is significant scarcity.

Under the MMU's approach generators would retain scarcity revenues from the energy market that exceed, on a cumulative annual, the RPM revenues for the delivery year. For example, if a capacity resource were earning $100 per MW-day from RPM and there were three scarcity event days in the year that generated a cumulative equivalent of $120 per MW-day of scarcity revenues, the capacity resource would collect $20 per MW-day from the cumulative scarcity events over and above its $100 per MW-day capacity market based scarcity payment.

In the case of a scarcity pricing mechanism, scarcity pricing revenues are those revenues directly attributable to the scarcity price adder to the marginal unit LMPs during a reserve shortage. That is, they are the revenues that would not exists in the absence of an administrative scarcity pricing mechanism increasing marginal bus prices above marginal unit offers during a reserve scarcity event.

The scarcity revenues not distributed to capacity resources would be used to true up scarcity charges that would otherwise have been paid by participants for capacity resources. There would be no true up for scarcity payments to non capacity resources. Scarcity pricing revenue would be distributed based on the load ratio shares of balancing load. This would prevent double payment of scarcity charges by participants in a particular delivery year.

Non-RPM resources that respond in real-time during the scarcity event should be paid scarcity pricing revenues. These resources would include potential capacity resources that had not cleared in the RPM auction for the delivery year in question, energy only resources, real-time imports and real-time price responsive demand. These are the resources that have not received a capacity payment in exchange for an obligation to offer into the Day-Ahead Energy Market. These non-RPM resources have only the revenues made available in the energy and ancillary service revenues to maintain their availability, and these are the resources that the energy market scarcity mechanism is designed to compensate.

Comparison of the PJM and MMU Approaches to the Scarcity Pricing Revenue True Up Mechanism

Both PJM and the MMU have agreed that there should be a scarcity pricing revenue true up mechanism but there are significant differences between the approaches. While PJM's design objective remains unclear, the MMU's design goal is clear. The MMU believes that RPM appropriately compensates capacity resources and provides for reliability and that no additional compensation from scarcity pricing is required. Given this goal, the most straightforward way to ensure that such over collection does not occur, and that the forward markets for capacity provide meaningful investment signals, is to ensure that capacity resources do not receive scarcity revenues. The settlements process can remove any scarcity pricing revenues from payments to capacity resources and eliminate the need for a complex, uncertain, after the fact procedure for offsetting scarcity revenues in the capacity market.

PJM's lack of clarity of purpose has led to PJM's poorly designed true up mechanism that creates timing mismatches, uncertainty and pricing distortions in the RPM auctions.

PJM True Up Mechanism Would Create Mismatches for Capacity Resources and Loads

PJM's scarcity pricing revenue true up proposal will result in a significant mismatch between capacity resources that receive scarcity pricing revenues and those that face lower RPM prices as a result. Similarly, PJM's scarcity pricing revenue true up proposal will result in a significant mismatch between loads that pay scarcity pricing revenues and those that face lower RPM prices as a result. The result is wealth transfers provide no positive incentives.

A subset of capacity resource MW and units will receive real-time scarcity pricing revenues during a scarcity event. Similarly, a subset of load MW and customers will pay these real-time scarcity pricing revenues to the capacity resources during a scarcity event.

This means that under PJM's proposal the over collection and over payment of scarcity pricing revenues will occur for individual participants, but any offset would occur through adjustments to RPM LDA clearing prices, not participant specific adjustments. This means that the individual participants that overpaid or were overcompensated will not have participant specific adjustments to what they were paid or were charged for capacity in the delivery year. Instead, any adjustment would occur through a change in the RPM price, will be spread across all participants, five to seven years after the event, whether or not they were overcharged or over paid in the delivery year. The result is a significant mismatch between the capacity resources that receive scarcity revenues and those capacity resources with reduced capacity payments. There is a comparable mismatch between load that pays scarcity prices and load that receives reduced RPM prices. This is equivalent to a tax payer discovering that he paid $1,000 too much tax in a given year and being assured that his overpayment would be corrected five, six and seven years from now by a cumulative reduction of the aggregate tax burden of his neighbors by $1,000 over the three year period. While the aggregate tax burden would go down, the grateful tax payer would see only, at best, a very small reduction in his own personal tax obligations over the subsequent three year period.

PJM's approach, where it would affect RPM prices, would result in wealth transfers not only between capacity resources and load in the delivery year, but between capacity resources that received double payment in the delivery year and capacity resources that did not receive double payment in the delivery year. Capacity that received double payment in the delivery year would see a net increase in their scarcity related revenues, when combining RPM payments and energy scarcity revenues. The reduction in RPM payments would be less than the revenues gained through the scarcity event. At the same time capacity that did not receive double payment in the delivery year, including potential new entrants, would see a relative reduction in their potential RPM payments. Such participants would be worse off under the PJM proposal than under the MMU proposal. Similarly, load that overpaid in the delivery year would receive less than its overpayment through the adjustments in the RPM price, as the net effect of the offset would be spread across the prices paid by all load in subsequent years.

The PJM approach will tend to reduce RPM prices, all else held equal, after a scarcity event. However, the effect on net total payments, on an LDA footprint basis, to generation and by load depends on supply and demand fundamentals. There are circumstances where PJM's proposed approach will cause total payments, including scarcity pricing revenues and RPM payments, to decrease and there are circumstances where total payments would increase. Generally however, simulation analysis shows that it is more likely that PJM's approach will result in a net increase in total payments to generation.

Further, even if the PJM approach were to provide a dollar for dollar reduction between the scarcity event year and the adjustments in RPM clearing prices five, six and seven years after the fact, the PJM proposal would still return less revenue in real dollar terms than was imposed on the load in the delivery year in question due to the time value of money. A dollar paid today is worth less than a dollar paid five years from now.

PJM's proposed approach does not, and cannot, correct for overcharging and overcompensating scarcity pricing revenues to specific participants, whether capacity resources or load. PJM's approach will tend to increase payments to capacity resources. It thereby increases the cost of reliability from a specific set of resources, RPM assigned resources, without increasing the reliability they provide. Any increase in reliability, if any, will come from non-RPM resources, if any, that are attracted by the scarcity price.

PJM True Up Mechanism Would Distort RPM Price Signals

PJM's proposal allows capacity resources to keep scarcity revenues in the delivery year along with the RPM related scarcity rents for that delivery year. This will increase the three year average net revenues of actual and potential capacity resources in the delivery year and reduce net ACR based offers of those resources in three subsequent RPM auctions for capacity. This will reduce the RPM clearing price of capacity in three subsequent auctions for capacity to be delivered five, six and seven years after the event. This pass through would also affect the CONE unit used to derive the demand curve in the RPM market for three subsequent auctions, which would also reduce the RPM clearing price for capacity that will be delivered five, six and seven years after the event.

This means that under PJM's proposal, rather than providing a true up of the administratively determined scarcity pricing revenues in the same delivery year, the scarcity pricing revenues are paid back through marginal impacts in subsequent RPM auctions, five, six and seven years after the event, through potential reductions in RPM prices caused by the effect of reduced CONE on the RPM demand curve (VRR curve) and the reduced ACR offer curves offered by capacity resources.

PJM's approach will cause the energy market scarcity mechanism to distort the longer-term price signal provide by the RPM market. Simulation analysis shows that under the PJM proposal scarcity events will tend to cause the price for forward capacity in the RPM auction to fall five, six and seven years after the scarcity event. In other words, under the PJM proposed approach, after a scarcity event, the price for capacity, and the marginal investment signal for new capacity sources, will be reduced relative to the case where the MMU scarcity pricing revenue true up mechanism is used. The PJM proposal will therefore work to deter new entry, via its effect on the RPM price signal, and protect incumbents that receive real-time scarcity rents. Lowering the RPM price signal for capacity five, six and seven years into the future after a scarcity event is not only counter intuitive, it is counterproductive to forward price signals needed to incent new entry after a scarcity event.

PJM's approach would produce a price signal in RPM that has exactly the opposite of the desired impact. A scarcity event means that PJM is short of capacity compared to actual requirements. The result should be that the price of capacity increases to reflect that condition. The PJM approach will result in a decrease in the capacity price.

MMU and PJM Scarcity Pricing Revenue True Up Mechanisms: Marginal Incentives

One of the areas of dispute between PJM and the MMU's approach is the effect of the proposed scarcity pricing revenue true up mechanisms on the marginal incentives to perform during a scarcity event. PJM argues that its proposal to use the RPM three average energy and ancillary service revenue offset to prevent over collection of scarcity rents by capacity resources in the delivery year is needed to preserve incentives for capacity resource performance during a scarcity event.

PJM implies, incorrectly, that the MMU scarcity pricing revenue true up mechanism would negatively affect the marginal incentives of capacity resources to perform during a scarcity event. PJM also asserts, paradoxically, that an offset five, six and seven years later would not have this effect.

PJM's argument implies both that compensation for capacity resources is inadequate under RPM and that the performance incentives are inadequate under RPM. If capacity resources need double recovery of capacity payments, then the RPM design is fundamentally flawed. If that is the case, RPM should be revisited directly rather than attempting to paper over compensation issues by providing double recovery via scarcity pricing. The RPM design should also not depend on double payment to incent capacity resources to perform when they are most needed. If that is the case, the incentive mechanisms in RPM should be revisited directly rather than attempting to address basic RPM design shortcomings in the scarcity pricing design.

PJM's argument also depends on the flawed idea that total revenue payments are more important than marginal price signals for determining short run marginal output. Fundamental economic theory makes it clear that where price, or marginal revenue, is greater than the marginal cost of production, there is an incentive to produce more output until the marginal cost of production equals price, or marginal revenue.[15] This incentive to produce more is the same, at the margin, whether price (marginal revenue) is one dollar above the marginal cost of production or five hundred dollars above the marginal cost of production. Lump sum payments or charges, whether they occur two weeks, one year or seven years after the fact, will not change the marginal incentives to produce at the time the marginal signals are presented. The same is true of marginal consumption decisions. Lump sum payments, such as after the fact offsets, affect income, not marginal choices.

The MMU proposed scarcity pricing revenue true up mechanism would take the form of a lump sum return of energy based scarcity revenues made through the settlement process, after the scarcity event. The scarcity component of LMP, and scarcity revenues associated with that component, would be calculated, for each participant, after the fact. The MMU true up mechanism would not interfere with incentives to perform at the margin during a scarcity event.

MMU and PJM Scarcity Pricing Revenue True Up Mechanisms: Day-Ahead and Real-Time Incentives

PJM's approach affects the incentive to participate in the Day-Ahead Market. PJM's proposed approach gives capacity owners an incentive to withhold from the Day-Ahead Energy Market so they can receive scarcity pricing revenues in the Real-Time Market. PJM's market design depends on incenting participants to schedule and participate in the Day-Ahead Energy Market. The current arbitrage incentives between Day-Ahead and Real-Time are designed to align Day-Ahead and Real-Time prices so that the use of Day-Ahead scheduling is consistent with Real-Time requirements. PJM's approach is inconsistent with this key element of PJM market design.

The MMU scarcity pricing revenue true up mechanism, in contrast, would provide strong incentives for generation to be scheduled in the Day-Ahead Energy Market since there is no true up for scarcity influenced day-ahead revenues.

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[15] In perfectly competitive markets, the marginal revenue observed by a participant equals the market price.

Transparent and Appropriate Scarcity Pricing Triggers: Reserve Targets and Reserve Target Measurement Requirements

Any scarcity pricing application based on a reserve constraint requirement must use clearly defined reserve targets and accurate measurement of the resources that are available to meet those requirements. The reserve targets must match defined reserve requirements to which system operators actually operate. The objective should be to create a system that recognizes scarcity in needed reserves; a system that redispatches to maintain needed reserves; a system that provides market signals that are consistent with this redispatch; and a system that provides market signals consistent with any failure to maintain needed reserves. The definition of scarcity and its reflection in price should be based directly on the level of available 10 minute synchronized reserves relative to the relevant reserve requirement and the progressive use of emergency measures. It is the MMU's position that this definition meets the defined objective. However, if PJM can demonstrate that PJM actually operates to a different definition of reserves and a different operational definition of scarcity, the MMU approach can be modified to be consistent with such a different definition.

PJM's 10 minute reserve requirement targets are based on engineering requirements and system studies that have defined minimum requirements to maintain system integrity. Explicitly modeling these requirements as constraints in the dispatch will permit the system to optimize the dispatch to maintain appropriate and efficient levels of energy and reserves, and to reflect this optimization in the marginal prices on the system. This approach does not preclude the use of existing forward looking market mechanisms that clear, and commit reserves prior to the operational hour. In fact, the absence of some form of pre-commitment process for reserves, given operational constraints on resources, will cause suboptimal results in market outcomes.

Accurate measurement of available resources is an essential element of a reserve requirement based scarcity pricing mechanism. Any mechanism that attempts to internalize the dispatch of reserves will only be as good as the measurement of those reserves. Without accurate measurement of available reserves, any mechanism designed to dispatch the system to maintain reserves will be compromised in both efficiency and effectiveness. Based on the direction of the error at any given time, the system could be buying too many reserves or too few, the system could be in a state of unrecognized scarcity or unrecognized surplus. To be effective, operators will need accurate data on unit availability and capabilities at any given moment, including better data on ramp rates and ambient temperature adjustments.

PJM does not currently have accurate real-time measurements of available operating reserves that are required for an improved approach to scarcity pricing.[16] PJM needs to develop better measurements of available primary reserves prior to implementing a resource constraint based scarcity pricing mechanism. A scarcity pricing mechanism should not be implemented based on the assertion that better measurement will be forthcoming just in time. There is no reason not to pursue a gradual approach to implementing scarcity pricing, learning from each step and using that information to inform the appropriate next steps.

In the absence of accurate real-time measurements of available reserves, it is not possible to know how many times PJM has been in scarcity conditions in the last ten years or even how many times PJM was close to being in scarcity conditions. As a result, it is not possible to predict how frequently PJM can be expected to experience scarcity conditions in the future. As a further result, it is not possible to predict the likely dollar levels of wealth transfers that might occur under PJM's proposal or the likely impact on future RPM prices.

PJM has down played the risks and defended its $2,700 scarcity price on the basis of claims that scarcity events will be rare. PJM's states it is "necessary to provide the right signal to the market when shortage conditions are about to or have already begun to occur, and that since scarcity/shortage events occur so infrequently, there should be no real concern about a significant or measurable transfer of wealth from suppliers to load."[17]

However, as PJM's filing indicates, there is a great deal of confusion on PJM's part on how often these events will occur with RPM in place, and under what circumstances. PJM assures the Commission that "[i]f some combination of extreme realizations of actual peak weather more severe than expected, economic conditions more robust than expected, and supply resource performance worse than expected, then reserve shortage conditions may occur."[18] However, elsewhere in its filing, PJM indicates that, by its measure, reserve shortages are not that rare an event. PJM indicates that "since May

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16 UPDATED: PJM Proposal for Price Formation during Operating Reserve Shortages, December 4, 2009 SPWG, pp. 7–8. <*http://www.pjm.com/~/media/committees-groups/working-groups/spwg/20091204/20091204-item-04-updated-pjm-sp-proposal.ashx*>.

17 PJM Affidavit, p. 26.

18 PJM Affidavit, p. 7.

2005, there have only been seven events for 28 hours in which some region of PJM has been in a reserve shortage."[19]

Based on its own determination, PJM appears to have suffered what it considers to be extreme system conditions on seven separate occasions over the last five years, all seven of which PJM agrees involved unquantified levels of primary reserve shortages.[20] This may be evidence of faulty system planning, dispatch issues, or RPM market design issues. However, it is even more likely that this is an indication that PJM cannot accurately measure its reserve levels, particularly Primary Reserves, and that PJM did not actively dispatch based on the asserted seven events and does not actively dispatch to maintain the Primary reserves requirement. PJM does not present any evidence that it accurately measured Primary Reserve levels or actively dispatched to control for Primary Reserves requirements during these events. PJM cites only Primary Reserve Warnings, not related actions or market effects, as evidence that PJM was short primary reserves. All activity and price effects cited were based on the maintenance of synchronized reserve requirements.

PJM therefore has no basis for making claims regarding the expected frequency of reserve shortages going forward.

PJM's filing raises serious questions regarding the operational trigger for its proposed scarcity price levels and how frequently they will occur and what the financial impact would be under PJM's inadequate offset mechanism. It also suggests that a more measured approach is called for in going forward with a scarcity pricing mechanisms, defining the exact approach to measurement of scarcity and in defining the scarcity price level.

Measurement Issue: Handling Scarcity False Positives

One of the measurement error issues that will exist even if PJM could accurately determine the level of 10 minute reserves available, is the issue of false positive scarcity events. A false positive scarcity event is a transient shortage of reserves, which does not require scarcity pricing or extraordinary action on the part of the dispatchers to resolve within a reasonable period of time. In other words, a false positive scarcity event is an event that may look like a scarcity event if viewed myopically, but fits within normal operations and expectations. These are events that do not meet the definition of an

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19 PJM Affidavit, p. 10.

20 PJM Affidavit, p. 12-16.

extreme event as there are still considerable resources available to correct for the event. These are events where triggering scarcity pricing would be counterproductive and wasteful. These are events that occur frequently and are handled routinely.

For example, during the morning pick up, load typically ramps up very quickly. During the morning pickup it is not unusual for Tier 1 synchronized reserves to be drawn down as units providing Tier 1 reserves are increasing output as fast as possible (thereby reducing their available reserves) to meet the load change. This pattern of events is seen on a regular basis and is not a cause for alarm, or a reason to call for a rush of unscheduled resources to be dispatched.

Prices rise during these events, often spiking on a five minute basis due to the loading of CTs, but they do not, and should not reach scarcity levels. A scarcity level signal sent out during such an event would be a wasteful marginal signal, as the resources needed to meet load are available and responding, at non-scarcity prices. Incenting all generation to come on line would not be productive. If sufficient resources are available at $150 to handle the morning pickup, a signal of $150+$850=$1,000 due to a transient reserve shortage, and a corresponding response from resources, will not improve the situation. If resources did respond to the transient signal, PJM would soon be faced with too much generation, creating a new set of problems. It would not take resources long to learn to ignore such a signal. In this case the signal is also wasteful as prices are reflecting scarcity when resources are not scarce, thereby resulting only in wealth transfers from load to generation.

When this issue was raised by the MMU and other stakeholders in the Scarcity Pricing Working Group (SPWG), PJM recognized the problem. PJM suggested that operations could, in the face of a transient event, relax the reserve constraint for some period to prevent the penalty factors from affecting the marginal unit bus prices. Where the event lasted beyond some preset time limit, indicating that it was not transient, scarcity pricing would be triggered. The MMU believes that this approach would work. This is the same approach recommended by the MMU.

While recognizing that this was an issue during the SPWG meetings, PJM has not addressed the issue in its current filing. Through omission, PJM's currently proposed scarcity pricing mechanism will result in false positive scarcity events.

PJM Proposal: Synchronized and Primary Reserve Targets

PJM has proposed that both primary and synchronized reserve requirements be implemented as constraints in the security constrained optimization approach to scarcity pricing. PJM currently dispatches, manually within the hour and via a Tier 2 synchronized reserve market prior to the operational hour, to maintain synchronized reserves. PJM avoids going short synchronized reserves as current operational practice. Inclusion of the synchronized reserve target as a constraint would internalize this current operational goal into the automatic dispatch.

The primary reserves target is 150 percent of the largest contingency in a given reserve region. Primary reserves consist of synchronized (Tier 1 and Tier 2) and non-synchronized 10 minute reserves. While primary reserves are defined, PJM does not provide evidence that it currently actively dispatches to maintain primary reserves. The implementation of a primary reserve requirement as a constraint would introduce a primary reserve target as a constraint in the dispatch solution, and would, according to PJM's proposal, require the creation of an active market for non-synchronized primary reserves which does not exist today. PJM proposes that scarcity pricing occur due to a shortage of either synchronized or primary reserves and that the shortage of each would result in a separate $850 penalty factor.

This is a significant, unwarranted and unsupported change in the structure of PJM markets. The structure of the proposed primary reserve market is not well defined. The expected market design, market structure, prices and revenues are unclear. No market power mitigation provisions have been included. There is nothing in Order No. 719 that requires the introduction of this market and nothing in scarcity pricing that requires the introduction of this market. Given than PJM cannot currently accurately measure the level of primary non-synchronized reserves, the consequences of adding this market are unknown. It can be expected that the addition of this constraint will significantly increase the incidence of scarcity pricing but the exact increase cannot be known currently. This is an example of an area where PJM should take incremental steps. It is premature to introduce a new market as part of the proposed modification of the scarcity pricing method.

MMU Proposal: Synchronized Reserve Targets

The MMU is proposing that PJM model synchronized reserve requirements as a constraint in the security constrained optimization approach to scarcity pricing. PJM currently avoids going short synchronized reserves as operational practice, but the practice is not incorporated in the 5 minute security constrained dispatch optimization. Including the synchronized reserves requirement as a constraint would constitute a clear improvement in current practice for a reserve product that PJM actively tries to maintain today.

The MMU recommends that primary reserves be considered as an additional constraint in the optimization only after operational experience is gained with the synchronized reserves constraint, only after PJM demonstrates that it actually dispatches to primary reserve requirements and only after PJM can demonstrate the ability to accurately measure primary reserves on a 5 minute basis. Consistent with an appropriately gradual approach to scarcity pricing, the MMU is proposing a $1,000 penalty factor be used only for the synchronized reserves requirements and that scarcity pricing only occur when there is a shortage of 10 minute synchronized reserves.

Synchronized Reserve Target or Synchronized Reserve and Primary Reserve Targets: Conclusion

Both the PJM and MMU approach can make use of one, two or more reserve targets. It is simply a matter of including the reserve requirements/targets as constraints in the optimization. However, the objective should be to internalize the cost of maintaining reserve levels needed to maintain reliability, and then sending a clear energy price signal when actual reserve requirements cannot be met. Adding a reserve requirement in addition to what is needed to maintain reliability would be superfluous and wasteful.

If primary reserves are not currently actively maintained, then it does not make sense to implement a primary reserve target as a trigger for scarcity. If maintaining sufficient 10 minute synchronized reserves is sufficient to maintain reliable operation, and this reflects current practice, there is no reason to use a more stringent 10 minute operating reserve threshold. PJM currently does not have a market mechanism designed to maintain primary reserve targets, nor does it currently actively control for primary reserve requirements. PJM's proposals to add a primary reserves requirement as part of the optimization, and to add a non-synchronized reserves market to maintain primary reserve levels would be superfluous and wasteful.

Synchronized Reserves Assignment and Pricing

The MMU proposes that PJM model synchronized reserve requirements as a constraint in the security constrained optimization approach to scarcity pricing. Both the PJM and MMU approach can make use of one, two or more reserve targets. It is simply a matter of including the reserve requirements/targets as constraints in the optimization. However, the objective should be to internalize the cost of maintaining reserve levels needed to maintain reliability, and then sending a clear energy price signal when actual reserve requirements cannot be met.

Synchronized Reserves Assignment and Pricing: PJM Proposed Approach

In PJM's scarcity pricing proposal the synchronized reserve market will be partially replaced with a hybrid structure that assigns only a subset of Tier 2 Synchronized resources deemed inflexible prior to the operational hour, with the remainder of any

Tier 2 assignments made on a 5 minute basis by the optimization software. This mixed assignment structure would make use of the current hour ahead construct to estimate the level of Tier 2 reserve requirements needed and the likely LMP in the coming hour to assign "inflexible" Tier 2 synchronized reserves resource obligations that would have cleared under the existing market structure. This assignment mechanism would not result in a clearing price for these inflexible resources, only an obligation to provide Tier 2 reserves in the coming hour. These inflexible assigned resources would then be taken as a fixed amount of Tier 2 supply that would be credited against the amount of Tier 2 reserves needed to meet the Synchronized reserve requirement in any 5 minute dispatch solution. Effectively this would mean that the inflexible assigned resources would be treated as price takers in the residual 5 minute market for Tier 2 reserves. Five minute prices would be determined by the point of intersection between the residual supply and residual Tier 2 demand, where the synchronized reserve offer price submitted for a unit would be no greater than the unit's incremental operating and maintenance cost plus a $7.50 per MWh margin.[21, 22]

In each five minute interval, the market clearing price would be comprised of the marginal unit's synchronized reserve offer price, the cost of energy use, the startup cost (if the unit is not running) and the unit's opportunity cost. Opportunity cost would be calculated by PJM based on actual unit specific LMPs and generation schedules from the unit dispatch system. The hourly price for reserves would be determined after the close of the hour, as the average of the 5 minute (hourly integrated) Tier 2 reserves prices in the hour. All units cleared in the Synchronized Reserve Markets are paid the higher of either the hourly integrated 5 minute market-clearing prices or the unit's synchronized reserve offer plus the unit specific opportunity cost and the cost of energy use incurred. For purposes of compensation, the MW of supply from each resource will be determined on the basis of their hourly integrated (average supplied Tier 2 reserve MW for the hour) cleared MW of supply of Tier 2 reserves. Any unit specific revenue shortfall created by over procurement or hourly integrated prices that were less than the unit specific costs of providing reserves would be made up via uplift.

Synchronized Reserves Assignment and Pricing: MMU Proposed Approach

In the MMU's scarcity pricing proposal the synchronized reserve market would clear as it does today, with the remainder of any Tier 2 assignments made on a 5 minute basis by

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21 See PJM, "Manual 11: Scheduling Operations," Revision 43 (September 24, 2009), p. 50.

22 See PJM, "Manual 15: Cost Development Guidelines," Revision 10 (June 1, 2009), p. 41.

the optimization software. This mixed assignment structure would make use of the current hour ahead construct to estimate the level of Tier 2 reserve requirements needed and the likely LMP in the coming hour to assign all Tier 2 synchronized reserves resource obligations. This assignment mechanism would not result in a clearing price for these resources, only an obligation to provide Tier 2 reserves in the coming hour. These assigned resources would then be taken as fixed portions of the supply curve for Tier 2 sync, with any additional resources that become available appearing in the curve on the basis of their 5 minute unit specific opportunity cost. This total 5 minute Tier 2 supply curve would be used to meet the Synchronized reserve requirement in any 5 minute dispatch solution. Five minute prices would be determined by the point of intersection between the Total Tier 2 supply and Tier 2 demand, where the synchronized reserve offer price submitted for a pre-committed unit would be no greater than the unit's incremental operating and maintenance cost plus a $7.50 per MWh margin. Units available within the hour would be valued at the actual marginal opportunity cost (the difference between their bus specific LMP and their operation point on their active offer).

The hourly price for reserves would be determined after the close of the hour, as the average of the 5 minute (hourly integrated) Tier 2 reserves prices in the hour. All units cleared in the Synchronized Reserve Markets are paid the higher of either the hourly integrated 5 minute market-clearing prices or their effective offer for Tier 2 reserves. For pre-committed units this effective offer is the unit's synchronized reserve offer plus the hourly integrated unit specific opportunity cost and the cost of energy use incurred. For within hour committed units, this effective offer would be the unit specific hourly integrated opportunity cost. For purposes of compensation, the MW of supply from each resource will be determined on the basis of their hourly integrated (average supplied Tier 2 reserve MW for the hour) cleared MW of supply of Tier 2 reserves. Any unit specific revenue shortfall created by over procurement or hourly integrated prices that were less than the unit specific costs of providing reserves would be made up via uplift.

The MMU also recommends that generators have a must offer requirement for synchronized reserves to address market power concerns.

Synchronized Reserves Assignment and Pricing

Both the MMU and the PJM approach will result in clearing price for reserves that would fully reflect the energy market price, including any periods with a scarcity price, determined after the close of the hour. While there are significant similarities in the MMU and PJM approach to the Tier 2 Synchronized Reserve Market, there are also substantive differences between the approaches including the potential efficiency of the dispatch, the operational risks imposed on synchronized reserve units, the explicit approach to market power, and the amount of Tier 2 reserves that will be available.

The MMU and PJM approaches differ in that under the MMU approach more resources would be committed prior to the operational hour, when there is more time to arrange generation set point to provide for Tier 2 reserves and regulation. This would take advantage of the fact that reserve offer related ramp rates for generation tends to exceed energy offer schedule ramp rates. Further, units operating at a fixed set point, rather than facing five minute variations in set points based on fluctuations in LMP, have more available ramp in any five minute period. In combination, these features of the MMU approach would tend to increase the amount of available Synchronized reserves on the system in hours where Tier 2 assignments are needed for PJM to meet its Synchronized reserve requirement.

Synchronized Reserves: Market Power Concerns Under the PJM Approach to the Tier 2 Market

The MMU approach, by basing the provision of within-hour reserves on unit characteristics included in a participant's energy offers and not on the basis of separate offers to provide reserves, avoids market power issues that would be introduced by the PJM approach to within hour Tier 2 offers and provides more efficient market signals in the 5 minute dispatch. Currently market participants provide within-hour reserves on the basis of their energy offer operating parameters including the start time of the unit, the ramp capability of the unit and the total number of MW available from the unit.[23] These parameters also play a direct role in determining how much energy the unit will sell into the PJM market at any given moment in time. As there are no incremental costs for a resource to provide reserves, rather than energy, at a particular dispatch point, the within hour reserve availability bid (over and above its unit specific opportunity cost) should be zero because the resource is already dispatched and committed to serve energy on the basis of the same set of parameters which determine its reserve capabilities. Allowing for separate energy and within hour reserve offers would force an inefficient allocation of the unit's capability between reserves and energy since this would artificially create inconsistent parameters sets, one for energy and one for reserves, which distort the direct substitutability of unit capacity deployed as either reserves or energy within the hour. Allowing separate offers would create opportunities to withhold reserves. Despite this obvious issue, PJM is proposing to allow generators to

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23 Within hour reserves in this context does not refer to reserves that currently clear in the hour ahead Tier 2 market, which do provide offers to participate.

have separate offers, with non-cost based adders, for the provision of within hour Tier 2 reserves, thereby introducing a distortion to within-hour valuation of reserves that does not exist at this time.

PJM's proposal does not address market power issues. Participants can choose, on a day to day basis, to have individual units offer in reserves for the day. Once offered, participants can choose to withhold participation in any given hour's Synchronized Reserve Market. Under current market rules this has been a concern, but a concern that has been limited to the performance of the Synchronized Reserve Market. However, with PJM's proposed price cap of $2,700, and the fact that a reserve shortage will directly result in scarcity pricing under PJM's proposal, the ability of participants to withhold reserves in a highly concentrated market is a concern that must be addressed.

PJM is not proposing a fix to this issue, despite introducing a market mechanism that increases the incentives to exercise market power. The MMU recommends a must offer requirement on reserves to address this issue and recommends that PJM adopt the same measure.

Synchronized Reserves Assignment and Pricing: Conclusion

Both the MMU and the PJM approach will result in a clearing price for reserves that would fully reflect the energy market scarcity price, determined after the close of the hour. While there are similarities in the MMU and PJM approach to the Tier 2 synchronized reserve market, there are also substantive differences between the approaches in terms of the potential efficiency of the dispatch, the risks of economic withholding of reserves and the amount of Tier 2 reserves that will be available. The MMU and PJM approaches differ in that under the MMU approach more resources would be committed prior to the operational hour, when there is more time to arrange generation set points to provide for Tier 2 reserves and regulation. This would take advantage of the fact that reserve offer related ramp rates for generation tend to exceed energy offer schedule ramp rates. Further, units operating at a fixed set point, rather than facing five minute variations in set points based on fluctuations in LMP, have more available ramp in any five minute period. In combination, these features of the MMU approach would tend to increase the amount of available Synchronized reserves on the system in hours where Tier 2 assignments are needed for PJM to meet its Synchronized reserve requirement and increase the pool of potential participants relative to the PJM proposal. Based on these factors, the MMU recommends that a full hour ahead commitment process, rather than a partial commitment process, be put in place, in combination with a within hour 5 minute optimization, to maximize the transparency and potential participation in the Tier 2 Synchronized Reserves Market.

The MMU also recommends that within-hour five minute Tier 2 assignments be made on the basis of energy offer parameters, rather than Tier 2 hour ahead Synchronized reserve offers. Allowing for separate energy and within hour reserve offers would force an inefficient allocation of the unit's capability between reserves and energy since this would artificially create inconsistent parameters sets, one for energy and one for reserves, which distort the direct substitutability of unit capacity deployed as either reserves or energy within the hour. Allowing separate offers would create opportunities to withhold reserves and will distort within-hour valuation of reserves. These distortions do not exist at this time, but would exist under PJM's proposal. Further, the MMU recommends that units operating at PJM discretion in real-time, and not otherwise assigned in the hour-ahead Tier 2 assignment mechanism, be unable to deselect Tier 2 availability within the hour. This would help prevent within hour withholding of reserves. In effect this would create a must offer requirement for within hour assignment for Tier 2 reserves.

The MMU recommends a must offer requirement for synchronized reserves, given its critical role as a trigger for scarcity pricing.

Regulation Market Assignment and Pricing

Regulation matches generation with very short-term changes in load by moving the output of selected resources up and down via an automatic control signal. Regulation is provided, independent of economic signal, by generators with a short-term response capability (i.e., less than five minutes) or by demand-side response (DSR). Longer-term deviations between system load and generation are met via primary and secondary reserve and generation responses to economic signals. PJM and the MMU are both proposing changes to how the regulation market is priced under scarcity pricing.

Regulation Assignment and Pricing: PJM's Proposed Approach

In PJM's scarcity pricing proposal the Regulation Market would continue to assign regulation prior to the operational hour. PJM would make use of the current hour ahead regulation market construct to estimate the level of regulation needed, along with the estimated LMP in the coming hour, to assign regulation resource obligations that would have cleared under the existing market structure. This assignment mechanism would not result in a clearing price for these regulation resources, only an obligation to provide regulation in the coming hour. Five minute prices would be determined by the point of intersection between the assigned regulation supply and the regulation requirement, where the regulation offer price submitted for a unit would be no greater than the unit's incremental operating and maintenance cost plus a $12.00 per MWh margin and plus opportunity cost.[24, 25]

In each five minute interval, the market clearing price for regulation would be comprised of the marginal unit's regulation offer price, the cost of energy use, and the unit's opportunity cost. The opportunity cost would be calculated by PJM based on actual unit specific LMPs and the lower of cost based or price based offers rather than the current dispatch schedule as the reference. The hourly price for regulation would be determined after the close of the hour, as the average of the 5 minute (hourly integrated) Tier 2 reserves prices in the hour. All units cleared in the regulation markets would be paid the higher of the hourly integrated 5 minute regulation market-clearing prices or the unit's regulation offer plus $12 plus the unit specific opportunity cost and the cost of energy use incurred. Any unit specific revenue shortfall created by over procurement or hourly integrated prices that were less than the unit specific costs of providing regulation would be made up via uplift. PJM would continue to net the regulation revenues from make whole balancing operating reserve payments.

Regulation Assignment and Pricing: the MMU's Proposed Approach

In the MMU's scarcity pricing proposal the regulation market would continue to assign regulation prior to the operational hour. The MMU proposal would make use of the current hour ahead regulation market construct to estimate the level of regulation needed, along with the estimated LMP in the coming hour, to assign regulation resource obligations that would have cleared under the existing market structure. This assignment mechanism would not result in a clearing price for these regulation resources, only an obligation to provide regulation in the coming hour. Five minute prices would be determined by the point of intersection between the assigned regulation supply and the regulation requirement, where the regulation offer price submitted for a unit would be no greater than the unit's incremental operating and maintenance cost plus a $12.00 per MWh margin plus opportunity cost.[26, 27]

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[24] See PJM, "Manual 11: Scheduling Operations," Revision 43 (September 24, 2009), p. 50.

[25] See PJM, "Manual 15: Cost Development Guidelines," Revision 10 (June 1, 2009), p. 41.

[26] See PJM, "Manual 11: Scheduling Operations," Revision 43 (September 24, 2009), p. 50.

[27] See PJM, "Manual 15: Cost Development Guidelines," Revision 10 (June 1, 2009), p. 41.

In each five minute interval, the market clearing price for regulation would be comprised of the marginal unit's regulation offer price, the cost of energy use, and the unit's opportunity cost. The opportunity cost would be calculated by PJM based on actual unit specific LMPs and the actual current dispatch schedule as the reference. The hourly price for regulation would be determined after the close of the hour, as the average of the 5 minute (hourly integrated) Tier 2 reserves prices in the hour. All units cleared in the regulation markets would be paid the higher of the hourly integrated 5 minute regulation market-clearing prices or the unit's regulation offer plus $12 plus the unit specific opportunity cost and the cost of energy use incurred. Any unit specific revenue shortfall created by over procurement or hourly integrated prices that were less than the unit specific costs of providing regulation would be made up via uplift. Under the MMU proposal, the regulation revenues would not be netted from make whole balancing operating reserve payments.

Regulation Assignment and Pricing: Comparing the MMU and PJM's Proposed Approach

The MMU agrees with PJM that an after the fact, rather than prior to the hour, determination of regulation pricing would provide a more accurate and transparent price signal for the Regulation Market. However, the MMU disagrees with PJM's proposal to continue to calculate opportunity costs on the basis of the lower of cost based or price based offers rather than the actual dispatch schedule as the reference and to continue to not net regulation revenues from make whole balancing operating reserve payments. (See Appendix D)

Regulation Assignment and Pricing: Conclusion

The MMU and PJM are aligned in the idea that an after the fact, rather than prior to the hour, determination of regulation pricing would provide a more accurate and transparent price signal for the regulation market. However, the MMU continues to disagree with PJM's proposal to continue to calculate opportunity costs on the basis of the lower of cost based or price based offers rather than the actual dispatch schedule as the reference and to continue to not net regulation revenues from make whole balancing operating reserve payments. The MMU continues to recommend that the modification to the definition of opportunity cost be reversed and that the elimination of the offset against operating reserve credits be reversed based on the MMU conclusion that these features result in a non-competitive market outcome, and because they are inconsistent with the treatment of the same issues in other PJM markets and inconsistent with basic economic logic.

Accounting for Emergency Actions and Emergency Capacity

PJM has designed the RPM capacity market construct to ensure that there is sufficient capacity to meet its reliability requirements. PJM also has emergency procedures that can be employed to maintain the system. PJM has a scarcity mechanism to maintain prices during the use of these procedures to prevent counter intuitive price results during these events. PJM and the MMU are proposing a mechanism to improve the scarcity mechanism. The purpose of the mechanism, in part, is to provide and sustain prices consistent with scarcity when system operators have to turn to non-market solutions to maintain reliable service, including voltage reductions and manual load dump. All of these administrative control actions are designed to preserve the level of reserves needed to maintain system reliability. Absent intervention, these administrative emergency actions produce counter intuitive price effects; they reduce prices during scarcity conditions.

Both the MMU and PJM proposed reserve penalty factor curve methodologies include provisions to offset the effect of non-market administrative measures used during scarcity situations. While the design intentions are similar, there are differences in the approaches being proposed by PJM and the MMU.

Accounting for Emergency Actions: PJM approach

PJM has not clearly defined how it intends to recognize the use of emergency actions in applying its reserve penalty factor curve methodology. PJM has only stated that it, in the event that PJM operations determines the need for emergency actions, PJM will enforce the use of the reserve shortage penalty factors on marginal unit bus prices.

PJM does not define the level of reserve shortage that would trigger voltage reductions or manual load dumps, or how it will determine when they are no longer needed.

Accounting for Emergency Actions: MMU approach

It is the MMU's position that the reserve penalty factor curve methodology, regardless of price target, also needs an explicit mechanism to offset the effect of non-market administrative measures used during scarcity situations. The offset would increase the reserve requirement by the amount of effective energy provided by the emergency step so as to maintain a market signal consistent with the actual level of scarcity, which is the level of scarcity that would have occurred in the absence of the administrative action. So long as the voltage reduction or manual load dump action was maintained, scarcity pricing would result.

Accounting for Emergency Actions: Conclusion

A well designed MW offset mechanism will prevent prices from falling as a result of emergency actions taken during a period of scarcity. It is the MMU's position that its approach, involving discrete shifts in the reserve requirements to control for emergency actions, is a more transparent way to account for emergency actions in the application of the operating reserve penalty factor approach.

The MMU's emergency action MW offset makes direct and transparent use of the reserve constraints themselves and will require a transparent measurement of actual reserves levels, along with an accurate and transparent measurement of any MW being contributed from the emergency actions. In contrast, PJM's approach is not transparent and it is not defined within its reserve requirement mechanism. Participants will not be in a position to know, even after the fact, how the emergency actions affected the operation of the system, how dependent the system was on the emergency actions and how this may have affected prices.

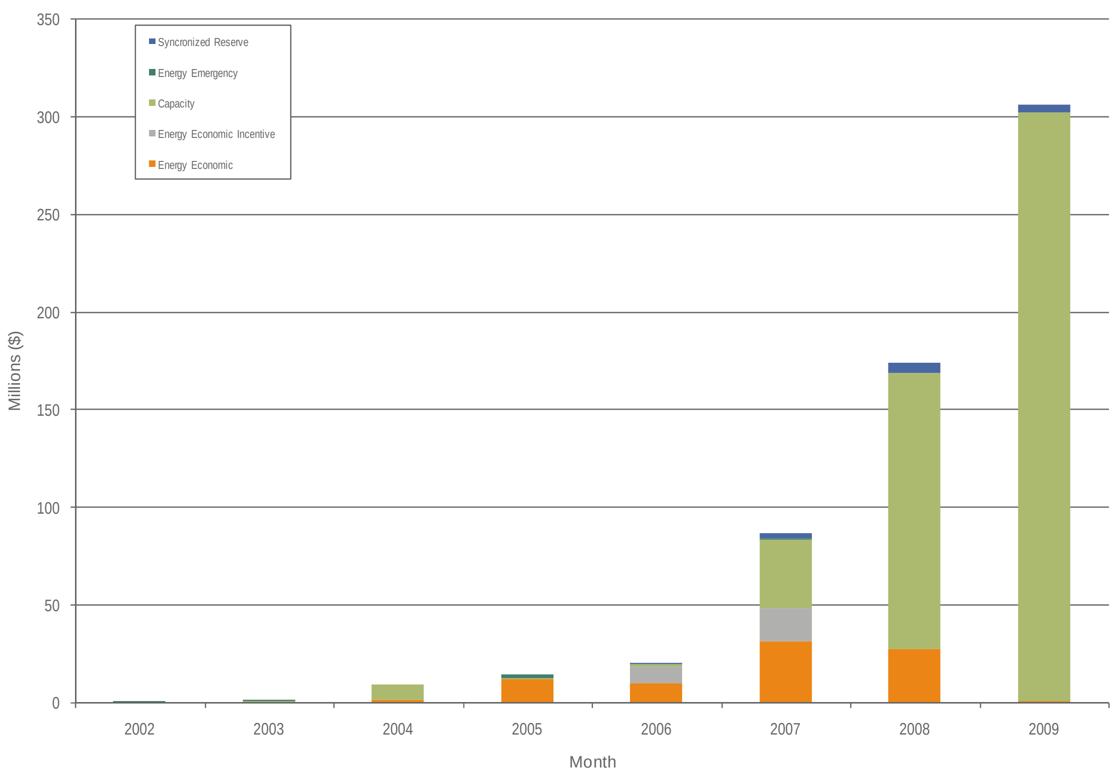
The reserve MW offset mechanism should be used to maintain consistent pricing only for non-market emergency actions. It is the MMU's position that this approach should not be applied to emergency capacity resources that have cleared RPM and have a recognized value, namely maximum emergency generation and emergency load response. Maximum emergency generation and emergency load resources need to be counted towards energy when deployed, not against the reserve requirements, as these resources have recognized value in the capacity market and provide their energy, or reduction in demand, at a specified price under emergency conditions.

Emergency Demand Response Setting Price

A significant and growing portion of RPM capacity is made up of Emergency Demand Response (DR) resources. Under RPM, each load serving entity (LSE) in PJM must meet its capacity obligations, determined by its proportional contribution to peak load and the amount of capacity cleared in the auction, by acquiring capacity resources through the PJM Capacity Market. LSEs are required to purchase enough capacity to meet their portion of forecast peak load. Emergency DR is sold by participants who are willing to reduce their load when called on by PJM in real-time because the capacity serving them is needed by load that has paid for capacity.

The importance of Emergency DR in terms of both participation MW and revenues is growing rapidly. In 2009, in the Economic Program, participation decreased compared to 2008. There were decreases in a range of activity metrics including registrations, settlements submitted, settled MWh and credits. There were many factors contributing to lower levels of participation and lower revenues in the Economic Program, including lower price levels in 2009, lower load levels and improved measurement and verification. Under RPM, demand-side resources in the Capacity Market increased by 3,206.9 MW from 4,167.5 MW on June 1, 2008 to 7,374.4 MW on June 1, 2009. Figure 1 shows all revenue from PJM Demand Side Response Programs by market for the period 2002 through 2009. Since the implementation of the RPM design on June 1, 2007, capacity revenue has become the primary source of revenue to demand side participants. Economic Program revenues declined in 2008 while capacity revenue increased significantly. In 2009, payments from the Economic Program were significantly lower than 2008, decreasing by $26 million or 96 percent, from $27.7 million to $1.2 million, while capacity revenue increased significantly, rising by $161 million or 114 percent, from $141 million to $303 million since 2008. Synchronized Reserve credits decreased by $1.1 million, from approximately $5.1 million to $4.0 million from 2008 to 2009.

Figure 1 Demand Response revenue by market: Calendar years 2002 through 2009 <<dsr_table_2009.xls FIGURE-NEW-INTRO>>last updated **01/19/09**



Emergency DR sales by load to the RPM market represents a commitment by specific customers to reduce load by a pre-specified amount during emergency conditions, thereby reducing the amount of capacity required to serve them in a given delivery year.

In effect, the load customers are identifying that portion of their load that is non-firm, and by selling this non-firm load back into the auction as capacity, they reduce their capacity obligations and their resulting capacity payments, by the amount of non-firm load they clear in the auction.

In return, the providers of Emergency DR capacity can be called up to 10 times a year, for six hours at a time, and are obligated to reduce their load by their committed amount. This is a significantly lower performance requirement than that faced by generation backed capacity that sells into the market. There is no reason to believe that the customers who pay for capacity will need the capacity used by participating LM customers only ten times per year. In fact, it can be expected that the probability of needing that capacity will increase with the amount of MW that participating LM customers clear in the RPM auctions. Further, Emergency DR providers are not required to have any of the telemetry or interval metering required of a generation based capacity resources. Due to the lack of direct telemetry and metering, the actual response of Emergency DR Capacity to a called event can only be determined until well after the fact. In addition, the specific location of the Emergency DR response is not known until well after the fact. In terms of effectiveness, dependability and verifiable performance, Emergency DR is, MW for MW, inferior to generation backed capacity for purposes of contributions to reliability requirements. Despite its shortcomings, Emergency DR MW are treated as equivalent to generation backed capacity MW, on a MW for MW basis, in the RPM auctions.

During an emergency event, Emergency DR participants will be paid the higher of the submitted minimum dispatch price or the zonal real-time LMP for emergency reductions. The minimum dispatch price, which is submitted by the participant, acts as a floor for energy compensation during an emergency event. Given the current program rules, market participants have an incentive to submit a minimum dispatch price at the maximum threshold for energy bids of $1,000/MWh. For the 2009/2010 delivery year, approximately 88 percent of registered sites representing 71 percent of registered MW in the Emergency Full Capacity option submitted a minimum dispatch price of either $999 or $1,000 per MWh. When an emergency demand response event is called by PJM, any Emergency DR called is, subject to after the fact verification, paid the higher of its minimum dispatch price and LMP for every MW of reduction, up to the MW amount they committed in the RPM auction as capacity. This energy payment is only made for mandatory curtailments.

There is no relationship between the minimum dispatch price and the locational price of energy or the participant's costs associated with not consuming energy. The minimum dispatch price is also not a meaningful signal from the participant about its willingness to curtail. In the Emergency Full option, end use participants are already contractually obligated to curtail during an emergency event because they are capacity resources and receive capacity payments. Thus, the ability to submit a minimum dispatch price is a guarantee of an energy payment for resources that are already required to curtail, regardless of their minimum dispatch price. The appropriate energy payment for a load reduction during an emergency event is the hourly LMP less any generation component of their retail rate. For customers on a real-time LMP contract, no energy payment is necessary because the customer saves the hourly LMP by not consuming during an emergency event. Any energy payment in excess of the real-time LMP net of generation costs results in an unnecessary and inappropriate subsidy.[28]

Under current market rules DR cannot set price when called. In part, this is due to the fact that the portion of a customer's load represented in the offers is already required to curtail, based on its sale of capacity, during an emergency. In other words, Emergency DR represents non-firm load that does not have a right to the capacity that it has not paid for and is, in the case of an emergency, required to be curtailed by the participant. In addition, Emergency DR customers currently cannot set price because Emergency DR participation does not require that the Emergency DR capacity have any of the characteristics of resources that could be made eligible to set price in a least cost security constrained dispatch model: discrete and measurable dispatchability in the form of telemetry, metering and a specific bus location. This is not based on a prohibition on demand response resources setting price in PJM. Demand response resources with discrete and measurable dispatchability in the form of telemetry, metering and a specific bus location are eligible, under PJM tariff, to set price. Demand Response resources with discrete and measurable dispatchability in the form of telemetry, metering and a specific bus location are eligible to set price outside of emergency situations, as part of normal dispatch. This is because resources with these characteristics can be dispatched as part of security constrained solution. Emergency DR with these characteristics could qualify to be marginal, if acting as economic demand (not emergency) demand response, but these characteristics are not a required for participation in the Emergency DR program.

Emergency Demand Response Setting Price: PJM's Position

Despite a lack of discrete and measurable dispatchability in the form of telemetry, metering and a specific bus location, PJM has proposed that Emergency DR be eligible to set price if they are determined to be marginal for energy. PJM's proposal does not include a plan to address the lack of telemetry, metering and a specific bus location for

[28] Energy Only participants are also paid the higher of the real-time LMP and the submitted minimum dispatch price. However, there are currently no participants registered under this option.

these resources before allowing them to act as marginal resources in the security constrained dispatch solution. Instead, PJM is proposing only to incrementally improve the inadequate data it already receives from Emergency Demand Response providers. PJM indicates that Emergency Demand Response providers will be required to submit operational data regarding the availability and status of their collective resources. PJM will still, under its proposal, dispatch Emergency DR by zone, rather than by discrete resource or provider within the zones. Because of this, and the absence of discrete real-time information regarding the exact location and level of response from the Emergency DR, PJM is proposing that Emergency DR will set price at the load center of the zone, rather than at the resource-specific bus.

Emergency Demand Response Setting Price: MMU's Position

The MMU proposes that the current rules determining the eligibility of resources to set price in the security constrained optimization be retained. Such rules ensure that the marginal dispatch signals are consistent with marginal resources used to solve the least cost security constrained dispatch optimization problem. Marginal prices correspond to the marginal resource prices at specific buses on the system needed to meet power balance and system security constraints. This is an important feature of security constrained dispatch signals during normal operation and of critical importance during emergency conditions. Demand response resources with discrete and measurable dispatchability in the form of telemetry, metering and a specific bus location are eligible, under PJM tariff, to be marginal. It is the MMU position that only economic demand response resources with such characteristics should be eligible to set price.

Further, Emergency DR should not be eligible to set price when called due to the fact that the non-firm portion of a customer's load represented in this capacity has an obligation to curtail, based on its sale of capacity, during an emergency. In other words, Emergency DR represents non-firm load that does not have a right to the capacity that it has chosen not to pay for and is, in the case of an emergency, under an obligation to be cut by the participant. The MMU recommends that the option to specify a minimum dispatch price under the Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. The MMU also recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program.

Emergency Demand Response Setting Price: Comparison

PJM argues allowing Emergency DR to set price would enhance operational reliability during an emergency event. PJM states:

> Permitting emergency resources to set price in the Real-time Energy Market properly aligns energy and reserve market prices with system conditions and dispatch instructions, thereby enhancing operational reliability during periods of operating reserve shortage.[29]

PJM goes on to argue:

> Under current PJM Tariff provisions, these resources are not permitted to set price and have the effect of misaligning energy and reserve prices with system conditions and dispatch instructions requiring manual dispatch of resources and out of market payments to maintain reliable system operations.[30]

PJM has not provided evidence that allowing Emergency DR to set price during an operating reserve shortage will improve security constrained system dispatch. PJM does not explain how dispatching an unquantifiable block of MW from a set of resources of unknown location, and allowing this resource set to set price at a load center of a zone, will provide discrete marginal dispatch signals needed to maintain system security in the context of numerous transmission constraints within, across and between zones. PJM does not explain why this artifice will improve operational reliability during a reserve shortage, when the system is in a precarious position, when they would not allow these same resources to set price outside of reserve shortage conditions.

Rather than avoid the need to manually dispatch the system under conditions of system stress, the PJM proposal would, where it allowed Emergency DR to set price, have exactly the same shortcoming as PJM's current scarcity pricing mechanism. The PJM proposal would raise zonal prices to the most expensive DR resource called at PJM direction, ignoring local constraints. Just as under the current scarcity pricing mechanism, this will lead to price based dispatch incentives that are inconsistent with local dispatch requirements. This will require that control of local constraints be done through manual dispatch instructions just as the system is under its greatest stress. PJM proposal would ensure that prices, when Emergency DR is marginal, would not be the result of a security constrained dispatch designed to maintain 10-minute reserves and security constrained power balance requirements.

In short, what PJM is proposing would directly undermine the point of using an operating reserve demand curve approach to scarcity pricing. The objective of operating reserve demand curve approach to scarcity pricing is to try to improve the dispatch

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29 PJM Affidavit, p. 29

30 PJM Affidavit, p. 30

fidelity in and out of scarcity conditions. This requires a mechanism that provides and sustains prices consistent with scarcity and, more importantly, consistent with the overall market design, both in and out of scarcity. Having Emergency DR, as it is currently formulated, set price would run directly counter to this objective and would make the system less, rather than more, reliable during a scarcity event.

Further, PJM is not proposing to change the requirements of Emergency DR capacity to make it eligible under security constrained optimization to set price. That would require that Emergency DR have telemetry, metering and a specific bus location. Instead, PJM is actively avoiding setting up such requirements of Emergency DR providers:

> PJM will develop a web-based user interface for the submission of this information so as not to impose the cost burden of real-time metering on discrete demand response resources. PJM also proposes to permit Curtailment Service Providers who may operate a fleet of distributed Emergency Demand Response resources to aggregate the operational data for these resources up to a control zonal level, by notification time, for administrative ease.[31]

Given this level of data, PJM's only option will be to continue to dispatch Emergency DR by zone, rather than by discrete resource or provider within the zones. This data is not sufficient for the use of Emergency DR as a solution to the security constrained dispatch in, or out, of scarcity conditions.

PJM's proposal to have emergency DR set price also raises market power concerns. Emergency DR participants are not required to be real-time LMP customers. As such Emergency DR customers can be on fixed prices, either through regulated rates or through fixed bilateral contracts. Being immune to the price affects their offers would have, if marginal, and being the beneficiaries of the energy payment for any reductions presents perverse incentives, relative to load customers exposed to real-time LMP, to bid in offers in excess of their actual cost to curtail. Allowing Emergency DR to set price could effectively allow the exercise of market power, as under emergency conditions it is likely that most participants are pivotal.

More generally, emergency DR should not be eligible to set price when called due to the fact that the non-firm portion of a customer's load represented in this capacity already has an obligation to curtail, based on its sale of capacity, during an emergency. Emergency DR represents non-firm load that does not have a right to the capacity that it

31 PJM, p. 30

has chosen not to pay for and is, in the case of an emergency, an obligation to be cut by the participant.

Emergency Demand Response Setting Price: Conclusion

The MMU recommends that the current rules determining the eligibility of resources to be marginal in the security constrained optimization be retained. Such rules ensure that the marginal dispatch signals are consistent with marginal resources used to solve the least cost security constrained dispatch optimization problem. Marginal prices correspond to the marginal resource prices at discrete buses on the system needed to meet power balance and system security constraints. This is important feature of security constrained dispatch signals during normal operation and of critical importance during emergency conditions. Demand response resources with discrete and measurable dispatchability in the form of telemetry, metering and a specific bus location are eligible, under PJM tariff, to be marginal. It is the MMU position that only economic demand response resources with discrete and measurable dispatchability in the form of telemetry, metering and a specific bus location are, and should be, eligible to be marginal, and only in the context of the security constrained dispatch solution.

Emergency DR should not be eligible to set price when called due to the fact that the non-firm portion of a customer's load represented in this capacity has an obligation to drop off the system, via its capacity commitments, during an emergency. Emergency DR represents non-firm load that does not have a right to the capacity that it has not paid for and is, in the case of an emergency, an obligation to be cut by the participant. To this end, the MMU recommends that the option to specify a minimum dispatch price under the Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. The MMU also recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program.

Emergency Purchases

Emergency purchases are emergency imports that are arranged and paid for out of normal market channels, and they are not processed through PJM's energy market. When PJM makes a request for emergency offers, energy providers from outside the footprint fax in offers to provide PJM with energy at specified prices. Based on these offers PJM directly purchases power from one or more supplied offers. Under current market rules Emergency Purchases are not eligible to set price, nor are they subject to market power mitigation or screens. Emergency Purchases are considered out of market purchases.

Emergency Purchases Setting Price

PJM has proposed that Emergency Purchases be eligible to set price up to $2,700.

PJM argues allowing Emergency Purchases set price would enhance operational reliability during an emergency event. PJM states:

> Permitting emergency resources to set price in the Real-time Energy Market properly aligns energy and reserve market prices with system conditions and dispatch instructions, thereby enhancing operational reliability during periods of operating reserve shortage.[32]

PJM goes on to argue:

> Under current PJM Tariff provisions, these resources are not permitted to set price and have the effect of misaligning energy and reserve prices with system conditions and dispatch instructions requiring manual dispatch of resources and out of market payments to maintain reliable system operations.[33]

PJM has not provided evidence that allowing Emergency Purchases to set price during an operating reserve shortage will improve security constrained system dispatch. PJM does not explain how the rules that disallow emergency purchases from setting price have misaligned energy and reserve prices with system conditions and dispatch instructions, thereby requiring the manual dispatch of the system to maintain reliable system operation since 1998.

Further, the PJM proposal would introduce issues of the potential exercise of market power by sellers of emergency power during a reserve shortage event. As emergency suppliers are not otherwise subject to PJM market power mitigation rules, PJM's current rules prevent emergency purchases from setting price and thereby prevent sellers of emergency power from abusing market power during a system emergency. Removing this provision would create opportunities for PJM market participants to, through third parties or affiliates outside the footprint, affect the PJM price through the sale of emergency power. Further, since PJM is proposing a cap of $2,700 for the effect of these purchases, this would effectively undermine both PJM's $1,000 offer cap and the three pivotal supplier test as a means of mitigation in the PJM market.

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32 PJM, p. 29

33 PJM Affidavit, p. 28

The current rules prohibiting emergency purchases from setting price should be retained to prevent the effective undermining of PJM's market power mitigation rules. Without material benefit in terms of operational integrity, PJM's proposal would introduce issues of potential exercise of market power by sellers of emergency power during a reserve shortage event. As emergency suppliers are otherwise subject to PJM market power mitigation rules, PJM's current rules preventing emergency purchases from setting price, prevent sellers of emergency power from abusing market power during a system emergency. Removing this provision would create opportunities for PJM market participants to, through third parties or affiliates outside the footprint, affect the PJM price. This opportunity does not currently exist due to the current market rules preventing emergency purchases from setting price. Further, since PJM is proposing a cap of $2,700 for the effect of these purchases, this would effectively undermine both PJM's $1,000 offer cap and the three pivotal supplier test as a means of mitigation in the PJM market.

If the Eastern Interconnection were one market, offer caps and market power rules would apply throughout and apply in circumstances of scarcity, perhaps even including on overall scarcity pricing mechanism that determined prices. However, that is not the case. There are clearly seams issues that remain between PJM and its neighbors. The market designs differ in fundamental ways and some neighbors do not have organized markets. In addition, there are market power issues when PJM finds itself in an emergency, for which there are no rules or protections in the tariff. The purchase of emergency power on a bilateral basis that does not affect the market price permits PJM to maintain the integrity of its own market design, given the seams issues. It can also be thought of as a circuit breaker that applies in emergency conditions to protect the PJM market and to ensure that market power is not exercised in ways that could have massive and irreversible consequences for PJM market participants.

Appendix A: The Mechanics of the MMU Proposed Scarcity Pricing Approach

It is the MMU's position that flexible and locational scarcity signals should be implemented by incorporating reserve requirements as constraints, with administratively set penalty factors, into the security constrained dispatch. Conceptually, incorporating reserve penalty factor curves into the security constrained dispatch internalizes the value of maintaining resources needed for reliability in the centralized dispatch market solution, prior to going into scarcity conditions.

The penalty factors associated with the reserve target constraints force the system to dispatch to maintain energy and reserves with available resources. When reserves become scarce the optimization software will commit increasingly expensive energy resources to maintain reserves, so long as reserves are available and the opportunity cost of dispatching the reserves is less than the penalty factor associated with the reserve constraints. The cost of redispatching to maintain reserves will be implicit in the energy price, as is the cost to redispatch to maintain system transmission constraints.

To avoid running short of reserves for non-economic reasons, the MMU recommends a penalty factor equal to the price cap on offers, currently $1,000 per MWh, be associated with the reserve constraints. A $1,000 penalty on the reserve target constraints means that the system would be willing to pay as much as a $1,000 in opportunity costs to dispatch for reserves. A $1,000 penalty factor would therefore make the entire supply stack available to the dispatch software to meet energy and reserve needs. With a $1,000 penalty factor, the system will only go short of reserves when there are no reserves available at an opportunity cost less than or equal to $1,000. Penalty factors set at levels less than the price offer cap in the market, like PJM's $850 per MWh penalty factor, provide the opportunity for the system to go short reserves while reserves are still available in the dispatch stack.

Under some applications of security constrained optimization, when the reserve constraint(s) are binding the penalty factors associated with the constraints would be directly reflected as a component of the marginal cost of energy from marginal energy resources. This reflects that marginal energy resources are converting their reserves to energy, therefore the incremental cost to produce an additional unit of energy is the marginal cost of energy plus the incremental cost of giving up an additional MW of reserves, which is the penalty factor associated with the reserve target. Where penalty factors are sufficient to dispatch all available reserves, the direct reflection of fixed penalty factors on the marginal cost of energy will lead to energy prices well in excess of the price offer caps in a market.

While having the constraint bind and the penalty factors directly affect the marginal cost of energy is consistent with some applications, it is not the only way to implement this approach, nor is this approach generally used in practical market applications when modeling transmission or ramp limitations in organized markets. For example, transmission and ramp limits are also modeled as constraints in the optimization engines of PJM, NYISO, New England

ISO, and Midwest ISO, these constraints have associated penalty factors to inform the dispatch. Where one or more of these requirements cannot be met in a particular dispatch solution, the result is not the reflection of the associated penalty factors in the marginal cost of energy. Instead, the constraint is relaxed to allow a market solution without forcing the fixed penalty factor into the marginal cost of energy. This approach allows the continuation of security constrained dispatch and allows the market to provide pricing results that are consistent with energy price caps. The constraint relaxation approach also has the advantage of avoiding a number of complications that PJM's binding constraint approach creates with other aspects of PJM's current market design.

A simpler solution to the scarcity pricing issues, in terms of market efficiency and consistency with overall market design, is to limit the price affect of going short reserves to a level that is consistent with the physical resource price caps that exist in the Day-Ahead and Real-Time markets. In the optimization problem this can be implemented by relaxing the reserve constraint to prevent the constraint from binding and setting the marginal unit bus prices to predefined price targets when the constraint is relaxed. In effect, this approach maintains and enforces the penalty factor associated with going short reserves for purposes of dispatch, but imposes a flexible price affect on the marginal unit buses so long as reserves fall short of the reserve requirements. The flexible price effect is the dollar amount needed to get the marginal unit bus price to the shortage price "target" picked by the policy maker. So long as the marginal incentives to produce energy (energy margin) or provide reserves (opportunity cost of foregone energy production) is maintained, this approach provides all the advantages of a security constrained dispatch approach to scarcity pricings, while providing market results that are consistent with overall market design and market efficiency goals.

Under the MMU's proposal if the reserve requirements could not be met, the reserve constraint would be relaxed and energy prices at the marginal unit buses would be set to a predefined price target. The MMU is recommending a predefined energy price target that is consistent with PJM's current offer caps in both the Day-Ahead and Real-Time markets. A price target set at $1,000 at the marginal unit buses in the area with a reserve shortage would provide a clear scarcity signal that is consistent with scarcity, consistent with economic dispatch, consistent with locational pricing, consistent with competitive market outcomes and consistent with PJM's current market design.

The mechanics of this approach allow the price target to match the offer cap, or to be set up in stages based on the level of reserve shortage. For example if offer caps were to increase to $1,500, it would be a simple matter to raise the scarcity price target to match to keep the mechanism in line with market design parameters. Similarly, if a more gradual scarcity price was desired, a series of price targets could be used to reflect a worsening reserve shortage. For example, going one to ten percent short of reserves could result in setting a price target of the greater of $700 or the most expensive resource running at PJM direction, going short eleven to fifty percent could result in price targets of the greater of $850 or the most expensive resource running at PJM direction, and going short fifty-one percent or more could result in price targets of $1,000.

The within hour mechanism discussed in this appendix is only part of the MMU approach to the assignment and dispatch of synchronized reserves to meet reserve requirements. The MMU approach, like the PJM approach, also includes an hour ahead assignment mechanism that arranges the assignment of Tier 2 synchronized reserves going into an hour, based on expectations of available Tier 1 reserves. In the MMU's scarcity pricing proposal the Synchronized Reserve Market would clear as it does today, with the remainder of any Tier 2 assignments made on a 5 minute basis by the optimization software. This mixed assignment structure would make use of the current hour ahead construct to estimate the level of tier 2 reserve requirements needed and the likely LMP in the coming hour to assign all Tier 2 sync reserves resource obligations. This assignment mechanism would not result in a clearing price for these resources, only an obligation to provide Tier 2 reserves in the coming hour. These assigned resources would then be taken as fixed portions of the supply curve for Tier 2 sync, with any additional resources that become available appearing in the curve on the basis of their 5 minute unit specific opportunity cost. This total 5 minute Tier 2 supply curve would be used to meet the synchronized reserve requirement in any 5 minute dispatch solution. Five minute prices would be determined by the point of intersection between the Total Tier 2 supply and Tier 2 demand, where the synchronized reserve offer price submitted for a pre-committed unit would be no greater than the unit's incremental operating and maintenance cost plus a $7.50 per MWh margin.[1, 2] Units available within the hour would be valued at the actual marginal opportunity cost (the difference between their bus specific LMP and their operation point on their active offer).

The hourly price for reserves would be determined after the close of the hour, as the average of the 5 minute (hourly integrated) Tier 2 reserves prices in the hour. All units cleared in the Synchronized Reserve Markets are paid the higher of either the hourly integrated 5 minute market-clearing prices or their effective offer for Tier 2 reserves. For pre-committed units this effective offer is the unit's synchronized reserve offer plus the hourly integrated unit specific opportunity cost and the cost of energy use incurred. For within hour committed units, this effective offer would be the unit specific hourly integrated opportunity cost. For purposes of compensation, the MW of supply from each resource will be determined on the basis of their hourly integrated (average supplied Tier 2 reserve MW for the hour) cleared MW of supply of Tier 2 reserves. Any unit specific revenue shortfall created by over procurement or hourly integrated prices that were less than the unit specific costs of providing reserves would be made up via uplift.

Example

The following example shows how the MA proposal would handle within hour dispatch for energy and reserves in and out of reserve shortage conditions. For ease of exposition, the hour

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1 See PJM. "Manual 11: Scheduling Operations," Revision 43 (September 24, 2009), p. 50.

2 See PJM. "Manual 15: Cost Development Guidelines," Revision 10 (June 1, 2009), p. 41.

ahead commitment process, and associated affect on Tier 2 pricing, is ignored. Table 1 provides an example of how the intra hour optimization would allocate resources between energy and synchronized reserves under varying conditions. The reserve requirement is assumed to be 100 MW of reserves. There are three units, units A, B and C. Unit A is a 400 MW unit with a MC of $20 that can provide a maximum of 50 MW of 10 minute reserves. Unit B is a 400 MW unit with a MC of $60 that can provide 50 MW of 10 minute reserves. Unit C is a quick start 400 MW unit with a MC of $800 that can provide 50 MW of 10 minute reserves.

Table 1 Model Assumptions

Market Prices					Dispatch							
Total Load/Energy	System Reserve	Energy Price (LMP)	Contribution to LMP	"Scarcity Adder"	MU	MU for Purposes of Price	Energy A	Reserves A	Energy B	Reserves B	Energy C	Reserves C
800	100	$800			C	C	400	0	350	50	50	50
1100	100	$800			C	C	400	0	350	50	350	50
1110	90	$1,000	$940	$200	B	C	400	0	360	40	350	50
1170	30	$1,000	$200	$200	C	C	400	0	400	0	370	30

At 800 MW of load, the least cost way to meet the energy and reserve requirements is to load Generator A to 400 MW, Generator B to 350 MW (the reserve requirement requires that Generator B keep 50 MW of its capacity as reserves). The marginal cost of energy is $60. Generator B has 50 MW of capacity left. Since Generator B can provide 50 MW of 10 minute reserves, all 50 MW of Generator B's remaining capacity are attributed to the system's reserve requirement. Paid $60 a MW for energy and zero for the reserves (Tier 1), Generator B is indifferent between providing 1 more MW of energy or 1 more MW of reserves. Generator B does not suffer any opportunity cost for foregone output, since Generator B's margin on energy (the difference between the LMP and generator B's offer) is zero. Generator C is also providing 50 MW of reserves, a quick start unit, can provide 50 MW of energy in ten minutes, if needed. LMP is currently lower than unit C's $400 Marginal Cost, which indicates that there is no opportunity cost associated with holding generator C offline as a source of reserves. There are sufficient reserves to meet the reserve target at a cost of less than the $1,000 penalty factor used in the optimization. This means that the system will not forego any reserves in meetings its energy requirements.

At 1100 MW of load, the least cost solution to meet the load requirement and reserve target is 400 MW from generator A, 350 MW of output from generator B and 350 MW from Generator C. Generator C is the marginal unit for energy, setting LMP at $800. At these output levels, Generator B is providing 50 MW of reserves and Generator C is providing 50 MW of reserves. Figure 1 shows the system supply and demand curves, the output levels of all three generators and remaining supply available from Generator B and C when there is 1100 MW of load. Figure 2 shows the reserve constraint (the operating reserve penalty factor curve) as a kinked demand curve for reserves, with a maximum price set equal to the $1,000 penalty factor. At 1100 MW of load, Generator B is receiving $740 a MW in effective margin over its offer for each MW of energy it produces. At these prices, in order for Generator B to be indifferent between providing energy or reserves, needs to be paid $740 a MW for each MW of reserves it provides. Generator

C, on the other hand, is the marginal unit for energy and is not receiving a margin on its energy output. Generator C therefore does not need to be paid opportunity costs for its reserves to be indifferent between producing energy or reserves. At 1100 MW, there is just enough capacity on the system to meet load and maintain the reserve target of 100 MW. There are sufficient reserves to meet the reserve target at a cost of less than the $1,000 penalty factor used in the optimization.

Figure 1 Energy Supply and Demand, 1100 MW of Load

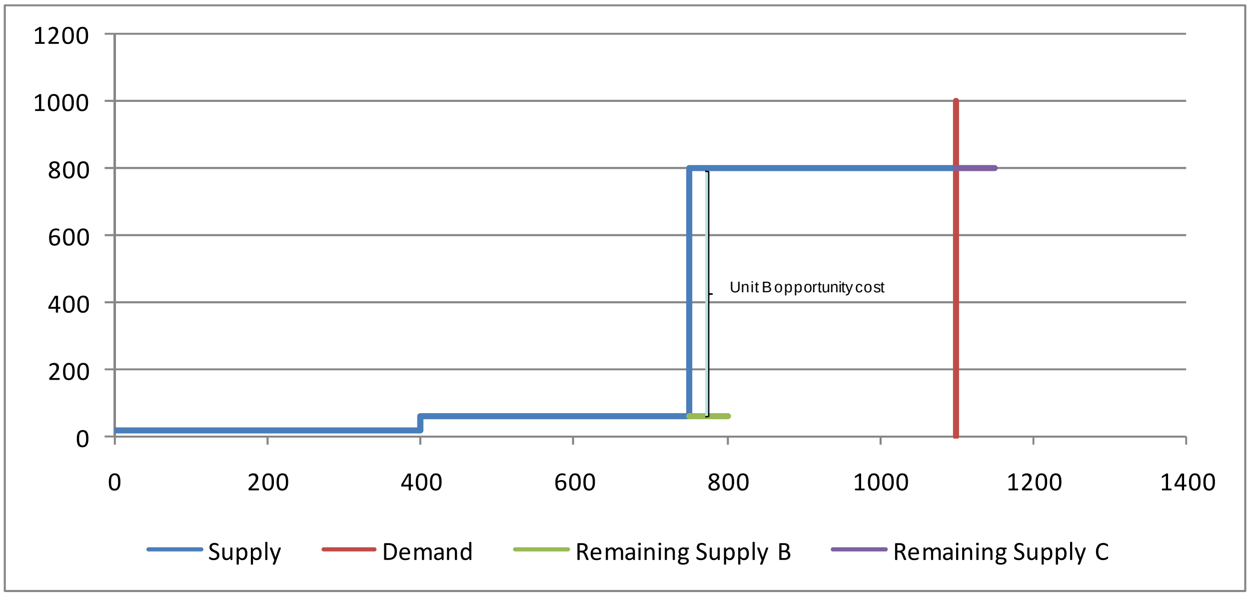
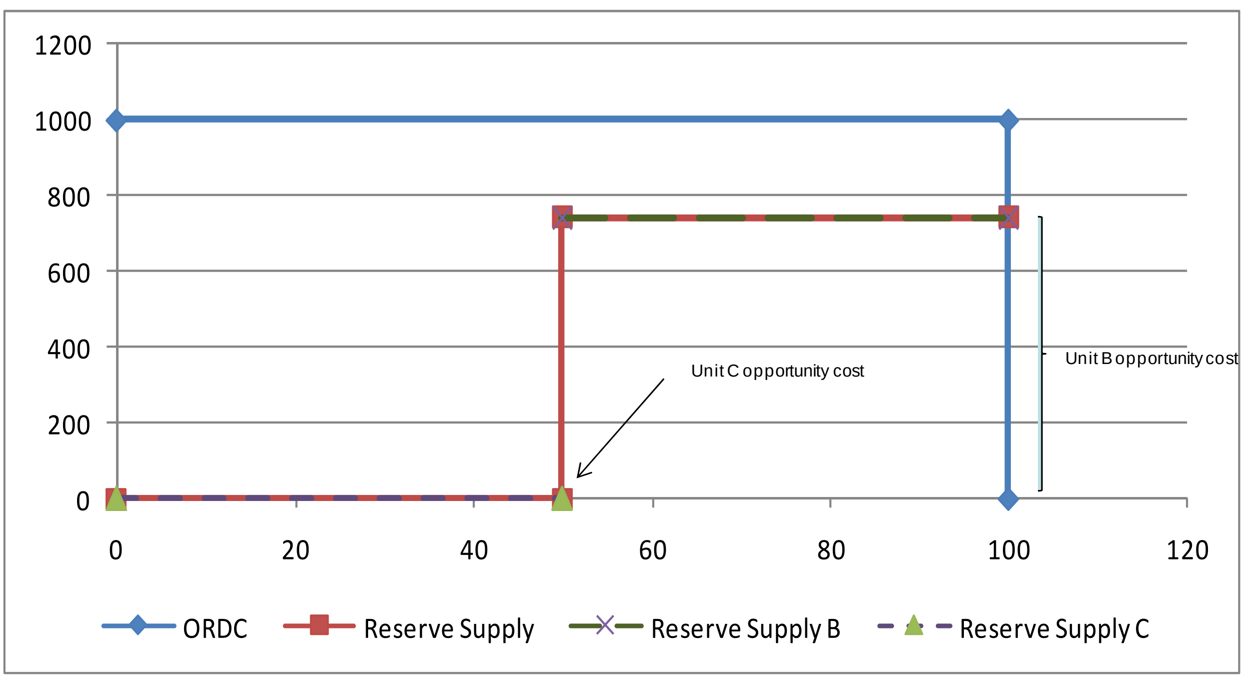


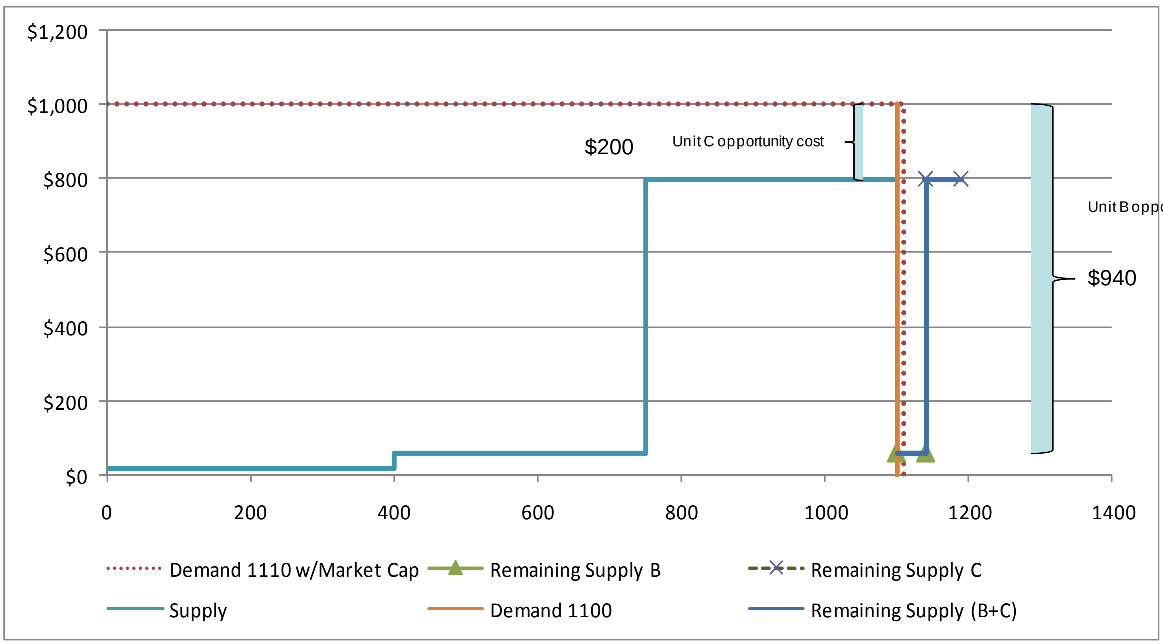
Figure 2 Reserve Supply and ORDC Requirement, 100 MW Reserve Target



If load increases above 1100 MW, the system will need to convert reserve MWs from either Generator B or C into MWs of energy. This would cause the system to fall short of its 100 MW reserve target in favor of producing more energy from either Generator B or C. At this point, under the MA proposal, the reserve constraint is relaxed so that the constraint does not bind, and prices at the marginal unit bus(es) are set equal to $1,000 (or other predetermined price target, based on the severity of the reserve shortage) within the affected reserve region(s).

The effect of this action is shown in Figure 3 and Figure 4, where the effective reserve target, modeled in the optimization, is reduced by 10 MW (the constraint is relaxed) to a reserve target of 90 MW and the price at the marginal unit bus (Unit B) is set equal to $1,000. The price at the marginal unit bus(es) will be maintained at $1,000 (or some other predefined target) so long as the reserve requirement constraint needs to be relaxed to prevent the constraint from binding.

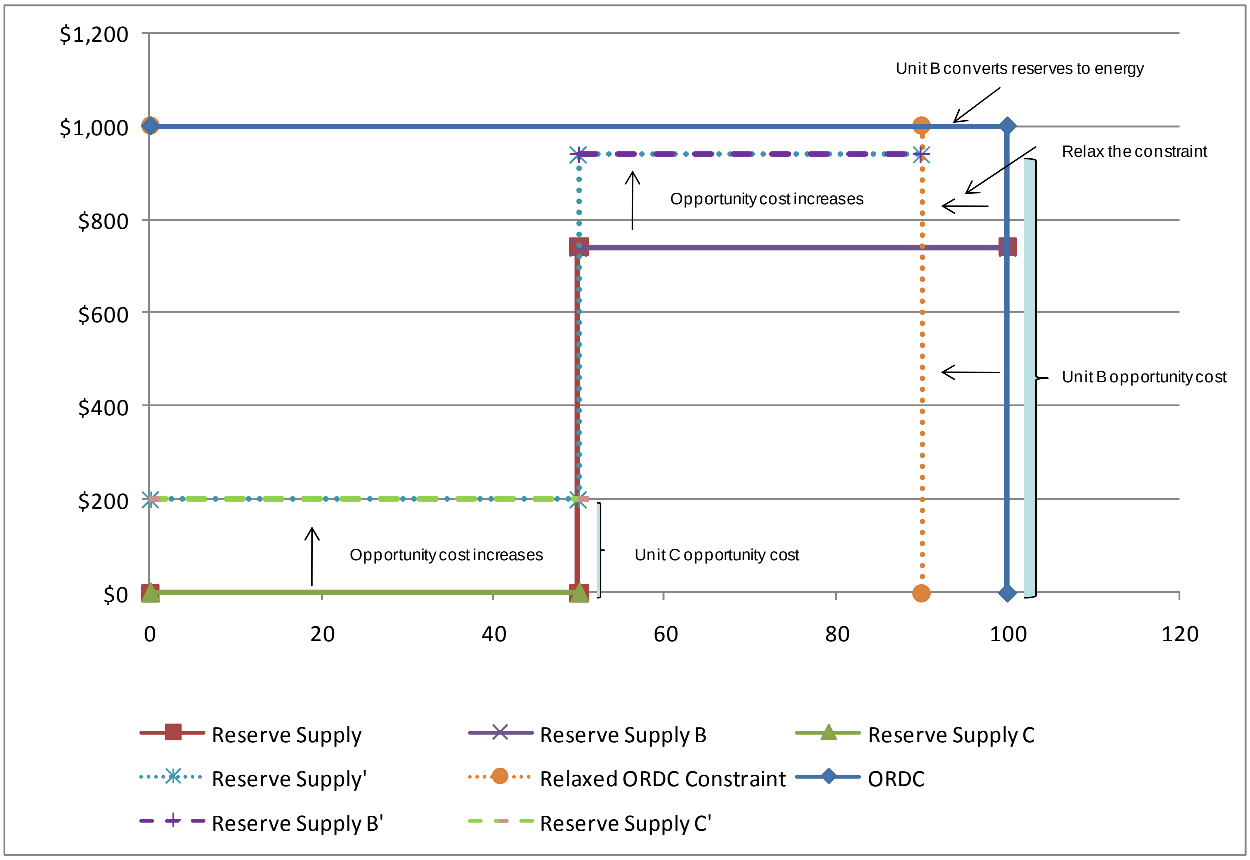
Figure 3: Energy Supply and Demand, 1110 MW of Load



As shown in Figure 3, under the MMU proposal the effective "penalty factor effect" on the marginal bus price is flexible and always sufficient to set the marginal bus price equal to $1,000 (or some other predefined price target). This in turn, affects the opportunity costs of providing reserves, as reflected as shifts in the opportunity costs (the Tier 2 supply curve) in Figure 4. Note that Figure 4 shows that the enforced penalty factor for the relaxed (and now non-binding) constraint remains at $1,000 within the optimization engine. The optimization engine will therefore find a dispatch solution that meets the 1100 MW of load and the newly reduced reserve target of 90 MW, so long as the maximum opportunity cost for reserves is less than $1,000. At a $1,000 LMP Generator C is providing reserves at an opportunity cost of $200/MW and Generator B is providing reserves at an opportunity cost of $940/MW.

Assuming this condition held for the entire hour the units would each be paid $940 for their reserves for the hour, as this would be the hourly integrated clearing price for Tier 2 reserves based on the hourly integrated point of intersection between the ORDC curve and Tier 2 supply in the hour (see Figure 4). As noted earlier, this example and result ignores the hour ahead commitment process and any associated effect on Tier 2 pricing. With an hour ahead commitment structure, any within-hour assignment to Tier 2 reserves will be a residual assignment over and above hour ahead commitments. Resources committed within the hour are modeled, on a five minute basis, as additions to the total Tier 2 supply stack, which includes hour ahead commitments carried into the hour. The point of intersection between the ORDC curve and this total five minute Tier 2 supply stack determines the prices of Tier 2 reserves every 5 minutes within the hour. These five minute values are integrated over the hour to determine the price of Tier 2 reserves for the hour.

Figure 4: Reserve Supply and ORDC Requirement, Relaxing the Constraint



As load increases from 1100 MW, the least cost source of an additional MW of energy would now switch from being Generator C with an incremental cost of $800 to Generator B with an incremental cost of energy of $60. At 1110 MW of load, therefore, the least expensive solution is to have Generator B provide the additional 10 MW of energy needed to meet load, at the expense of 10 MW of the reserves being provided by Generator B. Since the least cost solution requires additional MW from Generator B, Generator B is marginal with a marginal cost of $60.

Absent the imposition of a price target and/or some penalty factor on the marginal unit bus price, the price for energy will fall from $800/MW to $60/MW as the system goes short.

Such a drop in price would require that Unit C receive out of market uplift payments to remain indifferent to staying on line. Under the MA proposal, this issue is resolved by the imposition of $1,000 price targets and/or flexible penalty factors that raise the marginal cost of energy to $1,000 when the reserve constraint is relaxed. At 1110 MW of load, the LMPs at Generator B's bus reflect the $1,000 scarcity price, providing a margin of $940 for every MW of energy produced and requiring $940 in opportunity costs to be paid to Generator B to continue to provide reserves. Generator B is thereby made indifferent between providing energy or reserves. Generator B's reserves cost less than the $1,000 penalty factor, so the optimization engine will still find it economic to dispatch Generator B to meet the new 90 MW reserve target. Further, Generator C will see prices of $1,000 for energy, providing a margin of $200/MW for energy and it will see opportunity costs of $200/MW of reserves, also making it indifferent between providing energy and reserves at its dispatch of 350 MW of energy and 50 MW of reserves.

At 1170 MW of load, there continue to be insufficient reserves to meet the un-relaxed 100 MW reserve target at a cost of less than the $1,000 penalty factor used in the optimization. Having reserves fall short of the full reserve requirement continues to provide a clear trigger that the system is in a reserve shortage. Under the MA proposal, the reserve constraint would continue to be relaxed so that the constraint does not bind within the optimization engine, and prices at the marginal unit bus(es) would continue to be set equal to $1,000 within the reserve region(s) that have a shortage. The price at the marginal unit bus(es) will be maintained at $1,000 so long as the reserve requirement constraint needs to be relaxed (lessened) to prevent a violation and the penalty factor on violating the relaxed (and now non binding) constraint remains at $1,000. This means that the optimization engine will be able to find a dispatch solution that meets the 1100 MW of load and the newly reduced reserve target of 30 MW.

Since at 1170 MW of load, the least cost solution requires additional MW from Generator C, Generator C is marginal with a marginal cost of $800. Actual LMPs at Generator C's bus reflect the $1,000 scarcity price, requiring $200 in opportunity costs to be paid to Generator C to continue to provide reserves. Generator C is being paid $200 a MW in margin for each MW of energy and $200 for every MW of reserves it provides, so Generator C is indifferent between providing energy or reserves. Assuming this condition held for the entire hour, and in the absence of hour ahead commitments for reserves, Unit C would be paid $200 for its reserves for the hour, as this would be the hourly integrated clearing price for Tier 2 reserves based on the hourly integrated point of intersection between the ORDC curve and Tier 2 supply in the hour.

Appendix B: PJM Scarcity Pricing Offset Affect on RPM Market Outcomes

PJM has proposed that revenues generated by the scarcity mechanism during scarcity events, be passed through RPM's three-year average energy and ancillary net revenue offset along with non-scarcity energy and ancillary service revenues. PJM's proposal allows capacity resources to keep scarcity revenues in the delivery year along with the RPM related scarcity rents for that delivery year. This will tend to, all else held equal, increase the three year average net revenues of actual and potential capacity resources in the delivery year, thereby reducing net CONE and the net Avoidable Cost Requirements (ACR) based offers of those resources in three subsequent RPM auctions for capacity.

All else held equal, this will tend to reduce the RPM clearing price of capacity in three subsequent auctions for capacity to be delivered five, six and seven years after the event. This pass through would affect the Cost of New Entry ("CONE") unit used to derive the demand curve in the RPM market for three subsequent auctions, which would, all else held equal, also tend to reduce the RPM clearing price for capacity that will be delivered five, six and seven years after the event. PJM's offset will cause the energy market scarcity mechanism to distort the longer-term price signal provide by the RPM market. The PJM proposal will therefore work to deter new entry, via its effect on the RPM price signal, and protect incumbents that receive real time scarcity rents and capacity market revenues. Reducing the RPM price signal for capacity five, six and seven years into the future after a scarcity event is not only counter intuitive, it is counterproductive to forward price signals needed to incent new entry after a scarcity event. This problem is eliminated with a perfect rea- time scarcity pricing revenue true up, and greatly reduced with the MMU proposed scarcity pricing revenue true up.

Simulation analysis, shown below, shows that under the PJM proposal scarcity events will tend to cause, all else held equal, the price for forward capacity in the RPM auction to fall five, six and seven years after the scarcity event. However, the effect on net total payments, on a LDA footprint basis, to generation and from load is dependent on supply and demand fundamentals at the point of intersection that would occur with and without PJM's proposed pass through of scarcity revenues. There are circumstances under which PJM's proposed offset will cause total payments, in terms of both energy based scarcity rents and RPM payments, to decrease and there are circumstances under which total payments to capacity would increase. Generally however, the simulation analysis shows that, based on likely points of intersection, it is more probable that PJM's offset will result in a net increase in total payments to generation at the expense of load, when scarcity pricing revenues and capacity revenues are accounted for.

Analysis

A number of scenarios were generated using the 2012/2013 RTO-wide planning parameters and a number of ACR supply curves. For ease of exposition, a representative subset of the results is provided here. The 2012/2013 planning parameters, including CONE assumptions, were used to generate a base case scenario for the parameters of the Variable Resource Requirement Curve (VRR). These parameters and resulting VRR curve are outlined in Table 1.

Under the base case scenario conditions, defined by the 2012/2013 planning parameters, the CONE unit is assumed to earn $18,585 MW/year in net revenues from energy and ancillary service revenues. For purposes of the analysis, the CONE unit is assumed to have a constant marginal cost of production of $100. Under base case conditions there can be one of two prices, $200 or $100. At $200 the CONE unit is infra-marginal, meaning it earns revenues over and above incremental cost. It takes 185.85 hours at $200 to generate $18,585 per MW/year in a base case scenario year. The remaining hours of a base case year are priced at $100. Scarcity events are modeled as substitutes for one or more of the 185.85 hours at $200/MW of a base case year. In other words, in the analysis any scarcity hours assumed in a scarcity event year replace peak hours which would otherwise have a value of $200/MW in a base case year. So, if 20 hours of scarcity were assumed in a scarcity event year, there would be 165.85 remaining hours valued at $200/MW. In a scarcity event year, scarcity events are assumed to drive the price to $2,700 within the predetermined number of scarcity event hours. This increases the CONE unit revenues in the scarcity event year. This in turn affects the three year average energy and ancillary service revenues of the CONE unit, increasing it from the base case year assumption of $18,585 a MW/year. This in turn causes the VRR curve to shift downward, relative to the base case, in three subsequent auctions five, six and seven years after a scarcity event year.

Table 1 2012-2013 RPM Base Residual Auction Planning Parameters

2012-2013 RPM Base Residual Auction Planning Parameters	
	RTO
Installed Reserve Margin (IRM)	16.2%
Pool-Wide Average EFORd	6.44%
Forecast Pool Requirement (FPR)	1.0872
Demand Resource (DR) Factor	0.950
Preliminary Forecast Peak Load	144,857.0
Short-Term Resource Procurement Target	2.5%
Pre-Clearing BRA Credit Rate, $/MW	$27,273
Post-Clearing BRA Credit Rate, $/MW	$4,070
	RTO
Reliability Requirement	157,488.5
Total Peak Load of FRR Entities	21,850.7
Preliminary FRR Obligation	23,756.1
Reliability Requirement adjusted for FRR	133,732.4
Short-Term Resource Procurement Target	3,343.3
Cost of New Entry (CONE), $/MW-Year	$112,868
Energy & Ancillary Services, $/MW-Year	$18,585
Net CONE, $/MW-Day (ICAP Price)	$258.31
Net CONE, $/MW-Day (UCAP Price)	$276.09
Variable Resource Requirement Curve:	RTO
Point (a) UCAP Price, $/MW-Day	$414.14
Point (b) UCAP Price, $/MW-Day	$276.09
Point (c) UCAP Price, $/MW-Day	$55.22
Point (a) UCAP Level, MW	126,936.5
Point (b) UCAP Level, MW	131,540.0
Point (c) UCAP Level, MW	136,143.5

A number of ACR supply curves are assumed in order to analyze the effect of the PJM offset on RPM market results and total payments. A specific ACR supply curve defines a scenario. In each scenario an ACR supply curve intersects a different segment of the VRR curve. In each scenario the ACR supply curve parameters are defined for the base case price assumptions outlined above. In a scarcity event year, total energy and ancillary revenues are increased for all the units in the supply curve in the scarcity event year. This in turn causes the ACR supply curve to shift downward, relative to the base case, in three subsequent auctions five, six and seven years after a scarcity event year. The result is a scarcity revenue affected version of the scenario's ACR curve. This analysis is for real-time only and does not address the day-ahead market. All resources are assumed scheduled and compensated in the real time market. This is a simplifying assumption that affects the magnitude of the effects of PJM's pass through, but does not affect the proportional or the substantive outcomes of the simulations.

In the following analysis, the intersection between the base case VRR curve and the scenario base case ACR curve defines an RPM price baseline result, with resulting price and quantity cleared. The intersection of the scarcity affected VRR curve, in auctions five, six and seven years after an event and an unadjusted ACR curve defines a RPM VRR only event. The intersection of the scarcity affected VRR curve, in auctions five, six and seven years after an event and an unadjusted ACR curve defines a RPM VRR only event. The intersection of a scarcity affected VRR curve, in auctions five, six and seven years after an event and a scenario's scarcity revenues adjusted ACR curve defines a RPM Full Effect event. For each scenario and set of events, the resulting RPM price and quantity is calculated, along with changes in energy revenues and RPM payments relative to the base year scenario.

Scenario 1

Table 2 outlines the parameters of Scenario 1. In Scenario 1, the base ACR supply curve intersects the VRR curve on its horizontal portion, defined between the Y-intercept and point (a). A total of 28 scarcity hours are assumed. Table 3 and Table 4 outline the results. Figure 1 illustrates the points of intersection between the adjusted and base ACR curves and the adjusted and base VRR curve. In this scenario, under both the RPM VRR only and RPM Full Effect total scarcity payments are exceeded by total savings in RPM payments. In this scenario capacity resources lose money relative the perfect offset case. In both cases the forward price for capacity falls in year 5 through 7 after a scarcity event.

Table 2 Scenario 1 Parameters

VRR Curve Parameters	Base	Scarcity Effect	% change from Base
Point (a) UCAP Price, $/MW-Day	$414	$316	-24%
Point (b) UCAP Price, $/MW-Day	$276	$211	-24%
Point (c) UCAP Price, $/MW-Day	$55	$42	-24%
Point (a) UCAP Level, MW	$126,937	$126,937	0%
Point (b) UCAP Level, MW	$131,540	$131,540	0%
Point (c) UCAP Level, MW	$136,144	$136,144	0%
ACR Supply	**Baseline**	**Scarcity Effect**	**% change from Base**
Intercept	-$500	-$561	12%
Slope	0.025	0.025	0%

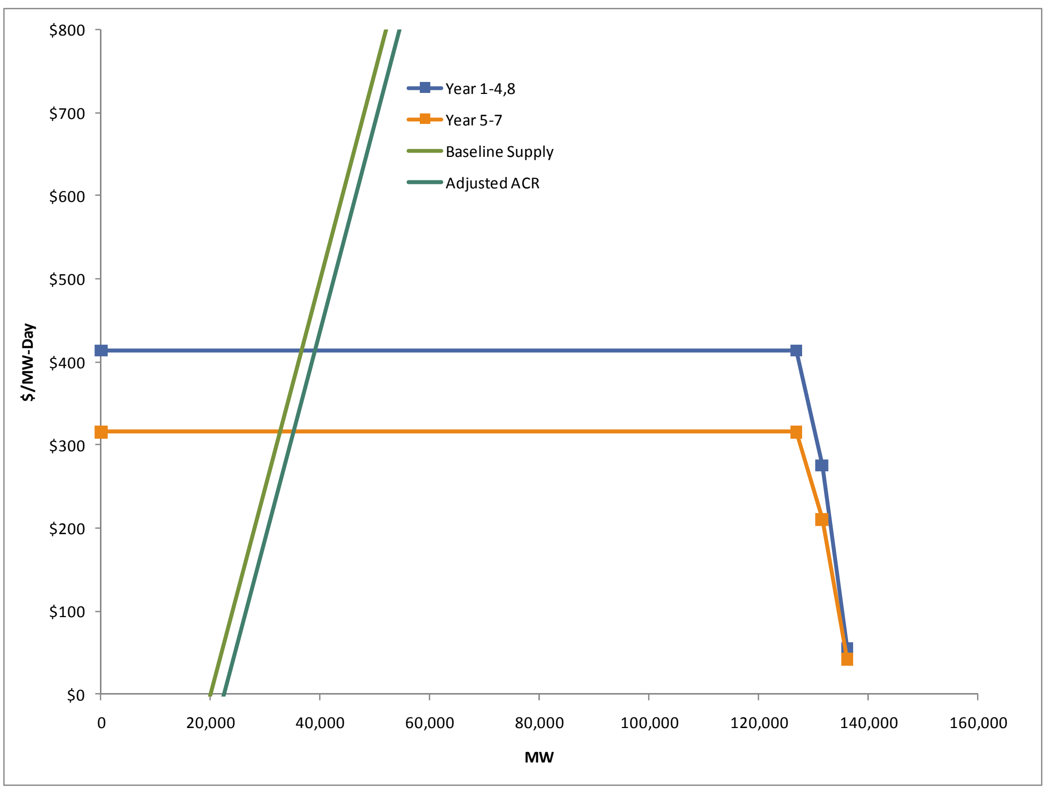
Table 3 Scenario 1 Results

RPM market solution	Price	% change from Base	MW	% change from Base
RPM price baseline	$414		36,566	
RPM VRR only	$316	-24%	32,630	-11%
RPM Full Effect	$316	-24%	35,085	-4%

Table 4 Scenario 1 Results

Scenario	Net Change in Revenues (millions of dollars)	Perfect Real Time Offset
Scarcity Revenues	$2,457	$0
VRR Adjusted RPM Charges Offset to Load	-$5,300	$0
Net Cost to Load: RPM VRR Only	-$2,843	$0
Scarcity Revenues	$2,457	$0
VRR and ACR Adjusted RPM Charges Offset to Load	-$4,451	$0
Net Cost to Load: RPM Full Effect	-$1,994	$0

Figure 1 Scenario 1



Scenario 2

Table 5 outlines the parameters of Scenario 1. In Scenario 1, the base ACR supply curve intersects the VRR curve on its horizontal portion, defined between the Y-intercept and point (a). A total of 28 scarcity hours are assumed. Table 6 and Table 7 outline the results. Figure 2 illustrates the points of intersection between the adjusted and base ACR curves and the adjusted and base VRR curve. In this scenario, under the RPM VRR only result, total scarcity payments exceed savings in RPM payments. In the RPM VRR only results this scenario scarcity revenues are only partially offset by changes in capacity payments. In the RPM Full Effect result, total scarcity payments are exceeded by total savings in RPM payments. In this scenario capacity resources lose money relative the perfect offset case. In both cases the forward price for capacity falls in year 5 through 7 after a scarcity event.

Table 5 Scenario 2 Parameters

VRR Curve Parameters	Base	Scarcity Effect	% change from Base
Point (a) UCAP Price, $/MW-Day	$414	$316	-24%
Point (b) UCAP Price, $/MW-Day	$276	$211	-24%
Point (c) UCAP Price, $/MW-Day	$55	$42	-24%
Point (a) UCAP Level, MW	$126,937	$126,937	0%
Point (b) UCAP Level, MW	$131,540	$131,540	0%
Point (c) UCAP Level, MW	$136,144	$136,144	0%
ACR Supply	**Baseline**	**Scarctiy Effect**	**% change from Base**
Intercept	-$2,900	-$2,961	2%
Slope	0.025	0.025	0%

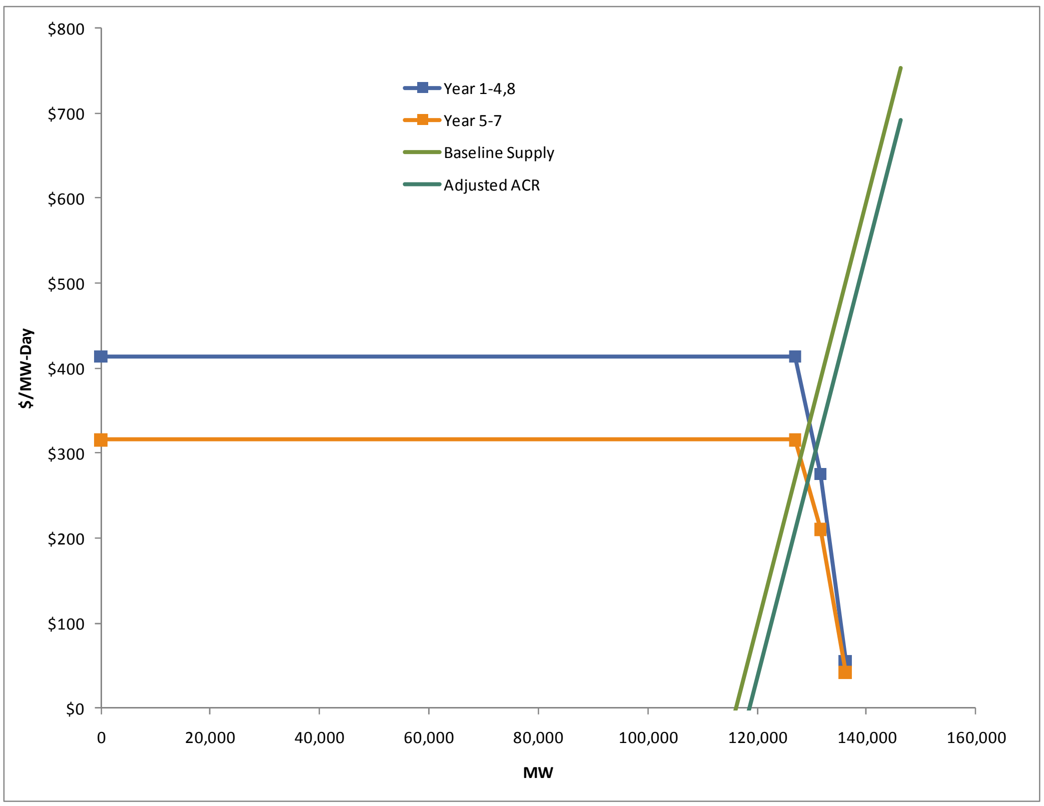
Table 6 Scenario 2 Results

RPM market solution	Price	% change from Base	MW	% change from Base
RPM price baseline	$337		129,496	
RPM VRR only	$296	-12%	127,821	-1%
RPM Full Effect	$266	-21%	129,103	0%

Table 7 Scenario 2 Results

Scenario	Net Change in Revenues (millions of dollars)	Perfect Real Time Offset
Scarcity Revenues	$8,702	$0
VRR Adjusted RPM Charges Offset to Load	-$6,479	$0
Net Cost to Load: RPM VRR Only	$2,224	$0
Scarcity Revenues	$8,702	$0
VRR and ACR Adjusted RPM Charges Offset to Load	-$10,208	$0
Net Cost to Load: RPM Full Effect	-$1,506	$0

Figure 2 Scenario 2



Scenario 3

Table 8 outlines the parameters of Scenario 1. In Scenario 1, the base ACR supply curve intersects the VRR curve on its horizontal portion, defined between the Y-intercept and point (a). A total of 28 scarcity hours are assumed. Table 9 and Table 10 outline the results. Figure 3 illustrates the points of intersection between the adjusted and base ACR curves and the adjusted and base VRR curve. In this scenario, under the RPM VRR only and the RPM Full Effect results, the total scarcity payments are less than total savings in RPM payments. In the RPM VRR only result there is no affect on the RPM price and only a small adjustment in clearing MW. There is effectively no offset of the scarcity revenues occurs via the RPM construct. In the RPM Full Effect result the scarcity revenues are only partially offset by a drop in RPM payments. In the RPM Full Effect result the forward price for capacity falls in year 5 through 7 after a scarcity event.

Table 8 Scenario 3 Parameters

VRR Curve Parameters	Base	Scarcity Effect	% change from Base
Point (a) UCAP Price, $/MW-Day	$414	$316	-24%
Point (b) UCAP Price, $/MW-Day	$276	$211	-24%
Point (c) UCAP Price, $/MW-Day	$55	$42	-24%
Point (a) UCAP Level, MW	$126,937	$126,937	0%
Point (b) UCAP Level, MW	$131,540	$131,540	0%
Point (c) UCAP Level, MW	$136,144	$136,144	0%
ACR Supply	**Baseline**	**Scarcity Effect**	**% change from Base**
Intercept	$150.00	$88.63	-41%
Slope	-	-	0%

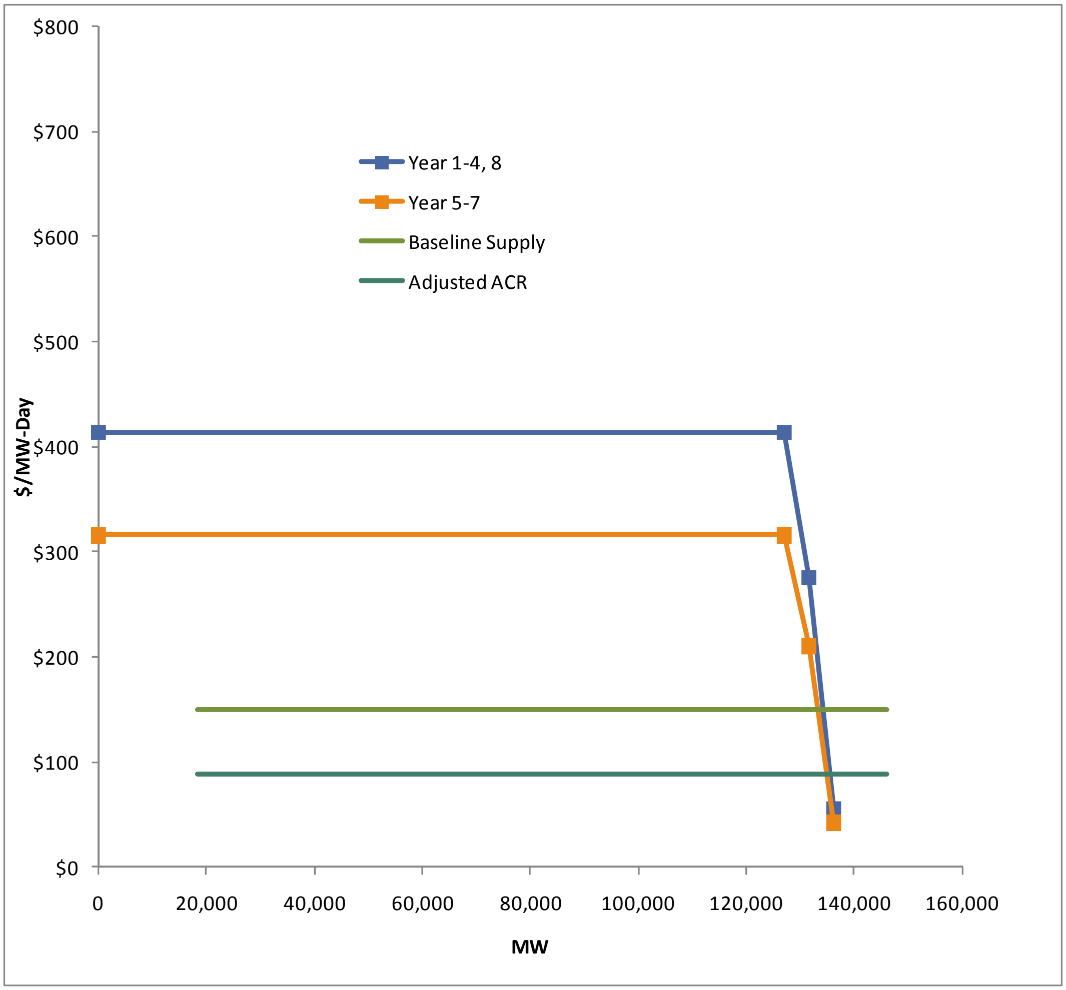
Table 9 Scenario 3 Results

RPM market solution	Price	% change from Base	MW	% change from Base
RPM price baseline	$150		134,168	
RPM VRR only	$150	0%	133,194	-1%
RPM Full Effect	$89	-41%	134,872	1%

Table 10 Scenario 3 Results

Scenario	Net Change in Revenues (millions of dollars)	Perfect Real Time Offset
Scarcity Revenues	$9,016	$0
VRR Adjusted RPM Charges Offset to Load	-$160	$0
Net Cost to Load: RPM VRR Only	$8,856	$0
Scarcity Revenues	$9,016	$0
VRR and ACR Adjusted RPM Charges Offset to Load	-$8,948	$0
Net Cost to Load: RPM Full Effect	$68	$0

Figure 3 Scenario 3



Appendix C: Synchronized Reserves: Current Market Rules

Under existing market rules, Synchronized reserve is a form of primary reserve. Synchronized reserve is an ancillary service defined as generation or curtailable load that is synchronized to the system and capable of producing output or shedding load within 10 minutes. Synchronized reserve can, at present, be provided by a number of resources, including steam units with available ramp, condensing hydroelectric units, condensing combustion turbines (CTs) and CTs running at minimum generation. Synchronized reserve can also be supplied by demand side resources subject to the limit that they provide no more than 25 percent of the total synchronized reserve requirement. Synchronized reserve demand side resources can be provided by behind the meter generation or by load reductions.

The term, Synchronized Reserve Market, refers only to supply of and demand for Tier 2 synchronized reserve. Tier 1 resources are those resources that are online, following economic dispatch, and able to respond to a spinning event by ramping up from their present output. All resources operating on the PJM system are considered potential Tier 1 resources, except for those explicitly assigned to Tier 2 synchronized reserve. Tier 2 resources include units that are backed down to provide synchronized reserve capability, condensing units synchronized to the system and available to increase output and demand side resources.

The Synchronized Reserve Market is currently cleared on a real-time basis. A unit can be selected for either regulation or synchronized reserve, but not for both. Sixty minutes before the market hour, PJM runs Synchronized Reserve and Regulation Market-clearing software (SPREGO) to determine the amount of Tier 2 synchronized reserve required, to develop regulation and synchronized reserve supply curves, to assign regulation and synchronized reserve to specific units and to determine the RMCP. The Regulation and Synchronized Reserve Markets are cleared interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products subject to reactive limits, resource constraints, unscheduled power flows, interarea transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

PJM retained the two synchronized reserve markets it implemented on February 1, 2007. The RFC Synchronized Reserve Zone Market's reliability requirements are set by the Reliability*First* Corporation. The Southern Synchronized Reserve Zone Market's (Dominion) reliability requirements are set by the Southeastern Electric Reliability Council (SERC). PJM sets the synchronized reserve requirement for the RFC Synchronized Reserve Zone as the larger of Reliability*First* Corporation's imposed minimum requirement or the largest contingency on the system. The Southern Region's Synchronized Reserve Market remains a separate market. It falls under the reliability requirements of SERC and is referred to as the Southern Synchronized Reserve Zone. Although the RFC Synchronized Reserve Market is one market, transmission constraints often limit the amount of Tier 1 synchronized reserve that can be made available in the PJM Mid-Atlantic Subzone of the RFC. This subzone is defined as the RFC Synchronized

Reserve Zone exclusive of parts of AP, parts of AEP, Dayton, Duquesne, and ComEd zones.[1] Therefore PJM's market must clear enough Tier 2 synchronized reserve in the Mid-Atlantic (Eastern) Subzone of the RFC Synchronized Reserve Market to ensure that the Mid-Atlantic locational synchronized reserve requirement of 1,150 MW is met, after accounting for available Tier 1 supply. This results in a separate Mid-Atlantic Subzone clearing price.

Under Synchronized Reserve Market rules, Tier 1 resources are paid when they respond to an identified spinning event as an incentive to respond when needed.[2] Tier 1 synchronized reserve payments or credits are equal to the integrated increase in MW output above economic dispatch from each generator over the length of a spinning event, multiplied by the synchronized reserve energy premium less the hourly integrated LMP. The synchronized reserve energy premium is defined as the average of the five minute LMPs calculated during the spinning event plus $50 per MWh. All units called on to supply Tier 1 or Tier 2 synchronized reserve have their actual MW monitored. Tier 1 units are not penalized if their output fails to match their expected response as they are only compensated for their actual response. In the absence of a spin event, Tier 1 resources are not paid for the reserves they provide and the opportunity costs associated with the providing the reserves is zero, as they are following economic dispatch for energy.

Under Synchronized Reserve Market rules, Tier 2 synchronized reserve resources are paid to be available as synchronized reserve, regardless of whether the units are called upon to generate in response to a spinning event, and are subject to penalties if they do not provide synchronized reserve when called. The price for Tier 2 synchronized reserve is determined in a market for Tier 2 synchronized reserves. This market is termed the Synchronized Reserve Market. Several steps are necessary before the hourly Synchronized Reserve Market is cleared. Ninety minutes prior to the start of the hour, PJM estimates the amount of Tier 1 reserve available from every unit; 60 minutes prior to the start of the hour, self-scheduled Tier 2 units are identified. Thirty minutes prior to the hour, Tier 1 is estimated again. If synchronized reserve requirements are not met by Tier 1 and self-scheduled Tier 2 resources, then a Tier 2 clearing price is determined at least 30 minutes prior to the start of the hour. This Tier 2 price is equivalent to the merit-order price of the highest-priced, Tier 2 resource needed to meet the demand for synchronized reserve requirements, the marginal unit, based on the simultaneous clearing of the Regulation Market and the Synchronized Reserve Market.[3]

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1 See PJM. "Manual 11: Scheduling Operations," Revision 43 (September 24, 2009), p. 51.

2 See PJM. "Manual 11: Scheduling Operations," Revision 43 (September 24, 2009), p. 58.

3 Although it is unusual, a PJM dispatcher can deselect units which have been committed after the clearing price has been established. This only happens if real-time system conditions require dispatch of a spinning unit for constraint control, or problems with a generator or monitoring equipment are reported.

Synchronized Reserves: Current Supply

The synchronized reserve offer price submitted for a unit can be no greater than the unit's incremental operating and maintenance cost plus a $7.50 per MWh margin.[4, 5] The market clearing price is comprised of the marginal unit's synchronized reserve offer price, the cost of energy use, the startup cost (if the unit is not running) and the unit's lost opportunity cost. Opportunity cost is calculated by PJM based on forecast LMPs and generation schedules from the unit dispatch system. Opportunity cost for demand-side resources is always zero. All units cleared in the Synchronized Reserve Markets are paid the higher of either the market-clearing price or the unit's synchronized reserve offer plus the unit specific opportunity cost and the cost of energy use incurred.

The Tier 2 Synchronized Reserve Market in each of PJM's synchronized reserve areas is cleared on cost based offers because the structural conditions for competition do not exist. The market structure issue can be even more severe when the Synchronized Reserve Market becomes local because of transmission constraints.

For the RFC Synchronized Reserve Zone during 2009, the offered and eligible excess supply ratio was 1.93. Within the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone, the offered and eligible excess supply ratio was 1.53.[6] These excess supply ratios are determined using the administratively established requirement for synchronized reserve. Actual market demand for Tier 2 synchronized reserve is lower than the synchronized reserve requirement because a significant amount of Tier 1 synchronized reserve is usually available.

Synchronized Reserves: Current Demand

The market demand for Tier 2 synchronized reserve is determined by subtracting the amount of forecast Tier 1 synchronized reserve available from each synchronized reserve zone's synchronized reserve requirement for the period. Market demand is further reduced by subtracting the amount of self scheduled Tier 2 resources. The total synchronized reserve requirement is different for the two Synchronized Reserve Markets. The synchronized reserve requirement is determined at the discretion of PJM after careful review to ensure appropriate system reliability and to maintain compliance with applicable NERC and regional reliability organization requirements. RFC and Dominion reserve requirements are determined on at least

4 See PJM. "Manual 11: Scheduling Operations," Revision 43 (September 24, 2009), p. 50.

5 See PJM. "Manual 15: Cost Development Guidelines," Revision 10 (June 1, 2009), p. 41.

6 The Synchronized Reserve Market in the PJM Southern Region cleared in so few hours that related data for that market are not meaningful.

an annual basis. Mid-Atlantic Subzone requirements are established on a seasonal basis, recognizing potential deliverability issues.[7]

Currently the RFC synchronized reserve requirement is the greater of the Reliability*First* Corporation's imposed minimum requirement or the system's largest contingency. The actual synchronized reserve requirement for the RFC Zone for January, 2009 was 1,305 MW. For the rest of 2009 it has remained at 1,320 MW. Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency.

7 See PJM. "Manual 10: Pre-Scheduling Operations," Revision 25 (January 1, 2010), p. 18.

Appendix D: Regulation Market: Current Market Rules

Both the Regulation and Synchronized Reserve Markets are cleared on a real-time basis. A unit can be selected for either regulation or synchronized reserve, but not for both. The Regulation and the Synchronized Reserve Markets are cleared interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products, subject to reactive limits, resource constraints, unscheduled power flows, inter area transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements

Sixty minutes before the market hour, PJM runs Synchronized Reserve and Regulation Market-clearing software (SPREGO) to determine the amount of Tier 2 synchronized reserve required, to develop regulation and synchronized reserve supply curves, to assign regulation and synchronized reserve to specific units and to determine the RMCP. All regulation resource units which have made offers in the daily Regulation Market are evaluated by SPREGO for regulation. SPREGO then excludes units according to the following ordered criteria: a) Daily or hourly unavailable units; b) Units for which the economic minimum is set equal to economic maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); c) Units which are assigned synchronized reserve; d) Units for which regulation minimum is set equal to regulation maximum (unless the unit is a hydroelectric unit or has self-scheduled regulation); e) Units that are offline (except combustion turbine units).

Even after SPREGO has run and selected units for regulation, PJM dispatchers can dispatch units uneconomically for several reasons including: to control transmission constraints; to avoid overgeneration during periods of minimum generation alert; to remove a unit temporarily unable to regulate; or to remove a unit with a malfunctioning data link.

For each offered and eligible unit in the regulation supply, the regulation total offer price is calculated using the sum of the unit's regulation cost-based offer and the opportunity cost based on the forecast LMP, unit economic minimum and economic maximum, regulation minimum and regulation maximum, startup costs and relevant offer schedule. Based on this result, SPREGO determines if the period has three or fewer pivotal suppliers. If it does, all owners who are pivotal have their offers limited to the lesser of their cost or price offer. SPREGO uses price-based offers for those operators not offer capped and re-solves. This solution is final. The MW offered and the calculated regulation offered prices are used to create a regulation supply curve. The Regulation and Synchronized Reserve Markets are cleared interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products subject to reactive limits, resource constraints, unscheduled power flows, inter area transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

Regulation Market: Supply. The supply of regulation can be measured as regulation capability, regulation offered, or regulation offered and eligible. For purposes of evaluating the Regulation Market, the relevant regulation supply is the level of supply that is both offered to the market on an hourly basis and is eligible to participate in the market on an hourly basis. This is the only supply that is actually considered in the determination of market prices. The level of supply that clears in the market on an hourly basis is called cleared regulation. Assigned regulation is the total of self-scheduled and cleared regulation. Assigned regulation is selected from regulation that is eligible to participate.

Regulation capability is the sum of the maximum daily offers for each unit and is a measure of the total volume of regulation capability as reported by resource owners.

Regulation offered represents the level of regulation capability offered to the PJM Regulation Market. Resource owners may offer those units with approved regulation capability into the PJM Regulation Market. PJM does not require a resource capable of providing regulation service to offer its capability to the market. Regulation offers are submitted on a daily basis.

Regulation offered and eligible represents the level of regulation capability offered to the PJM Regulation Market and actually eligible to provide regulation in an hour. Some regulation offered to the market is not eligible to participate in the Regulation Market as a result of identifiable offer parameters specified by the supplier. As an example, the regulation capability of a unit is included in regulation offered based on the daily offer and availability status, but that regulation capability is not eligible in one or more hours because the supplier sets the availability status to unavailable for one or more hours of that same day. (The availability status of a unit may be set in both a daily offer and an hourly update table in the PJM market user interface.) As another example, the regulation capability of a unit is included in regulation offered if the owner of a unit offers regulation, but that regulation capability is not eligible if the owner sets the unit's economic maximum generation level equal to its economic minimum generation level. In that case, the unit cannot provide regulation and is not eligible to provide regulation. As another example, the regulation capability of a unit is included in regulation offered, but that regulation capability is not eligible if the unit is not operating, unless the unit meets specific operating parameter requirements. A unit whose owner has not submitted a cost based offer will not be eligible to regulate even if the unit is a regulation resource.

Only those offers eligible to provide regulation in an hour are part of supply for that hour, and only eligible offers are considered by PJM for purposes of clearing the market. Regulation assigned represents those regulation resources selected through the regulation market clearing mechanism to provide regulation service for a given hour.

Regulation Market: Demand. Demand for regulation does not change with price, i.e. demand is price inelastic. The demand for regulation is set administratively based on reliability objectives and forecast load. Regulation demand is also referred to in the *2009 State of the Market Report for PJM* as "required regulation."

The PJM regulation requirement is set by PJM Interconnection in accordance with NERC control standards. In August 2008 the requirement was adjusted to be 1.0 percent of the forecast peak load for on peak hours and 1.0 percent of the forecast valley load for off peak hours.[1] During 2009 the PJM regulation requirements ranged from 501 MW to 1,279 MW. The average required regulation off-peak was 773 and the average required regulation on-peak was 933 MW (Table 1).

Table 1 PJM Regulation Market required MW and ratio of supply to requirement: Calendar year 2009 <<RegRSI.xls TAB: RSI>> Last update: 1/23/10 - tab

Period Type	Average Required Regulation (MW)	Ratio of Supply to Requirement
All of 2009	849	2.98
Fall	772	3.10
Spring	771	2.90
Summer	929	3.15
Winter	928	2.76
Off Peak	773	2.89
On Peak	933	3.08

Issues with PJM Current and Proposed Regulation Market Rules

In 2008, PJM and its stakeholders addressed the issue of market power mitigation for the Regulation Market in the Three Pivotal Supplier Task Force (TPSTF), which was convened pursuant to PJM's 2007 Strategic Report to review market power mitigation issues. The TPSTF achieved a consensus supporting the application of the three pivotal supplier (TPS) test to the Regulation Market, provided that three adjustments to the rules were included, all of which increased margins for regulation units. The three adjustments to the rules: (i) increasing the margin on cost based offers from $7.50 to $12.00 per MW; (ii) modifying the calculation of opportunity costs to use the lower of cost based or price based offers rather than the current dispatch schedule as the reference; and (iii) eliminating the netting of regulation revenues from make whole balancing operating reserve payments. PJM filed the proposed revisions on October 1, 2008. A number of parties filed comments, including the MMU on October 20, 2008.

The MMU welcomed the application of the TPS test to the Regulation Market, but expressed concerns regarding the three adjustments to the regulation market design. The MMU supported the October 1st filing with the caveat that if the MMU review of the actual impact of the changes "results in a conclusion that these features result in non-competitive market outcomes, the Market Monitor will request that one or more of these provisions be removed or modified."

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1 See Reliability*First* Corporation <http://www.rfirst.org/> (1 KB).

The MMU requested that the Commission direct the MMU to report on the three adjustments to the rules: (i) increasing the margin on cost based offers from $7.50 to $12.00 per MW; (ii) modifying the calculation of opportunity costs to use the lower of cost based or price based offers rather than the current dispatch schedule as the reference; and (iii) eliminating the netting of regulation revenues from make whole balancing operating reserve payments. The Commission, in its order accepting PJM's filing on November 26, 2008, directed the MMU to prepare a report due on November 26, 2009.

On December 1, 2008, the TPS test was implemented in the Regulation Market to address the identified market power problems. The three other market design changes were also implemented on December 1, 2008.

The MMU presented a preliminary analysis of the impact of the three adjustments in its quarterly state of the market reports issued August 14 and November 13, 2009. The MMU concluded, on the basis of the first six months, "The impact on market performance for these December 1, 2008 PJM changes has been significant" and that "the other changes to the Regulation Market implemented on December 1, 2008 have significantly increased the price of regulation." In the next quarterly report, the MMU similarly stated, "The MMU also concludes that the other changes to the Regulation Market implemented on December 1, 2008 significantly increased the price of regulation compared to what prices would have been absent those changes."

Consistent with the directive in the November 26th order, the MMU analyzed the impact of the three adjustments to the Regulation Market during the twelve months after implementation and submitted a report to the FERC on November 30, 2009. The report concluded, in part, that "The market design changes added a substantial cost to those paying for regulation without any evidence that this cost was required for either cost recovery or incentives." The report stated: "The MMU recommends that the modification to the definition of opportunity cost be reversed and that the elimination of the offset against operating reserve credits be reversed as they are inconsistent with the treatment of the same issues in other PJM markets and inconsistent with basic economic logic." The report also recognized that the Regulation Market is more competitive as a result of the implementation of the three pivotal supplier test but concluded that "the changes are not consistent with an efficient or competitive market design and are not consistent with the way in which the same issues are addressed for other PJM markets in the PJM tariff."

The MMU has concluded, based on the analysis of the Regulation Market operating under the revised rules and in subsequent analysis, that the results of the Regulation Market are not competitive. The results of the Regulation Market are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in offers greater than competitive offers and therefore in prices greater than competitive prices. The competitive price is the price that would have resulted from a combination of the competitive offers from market participants and the application of the prior, correct and consistent approach to the calculation of the opportunity cost. The offers from market participants are not at issue, as PJM directly calculates and adds opportunity costs to the offers of participants, following the revised market rules. The Regulation Market results are the result of the market design changes and are not the result of the behavior of market participants, which was competitive as a result of the application of the three pivotal supplier test.

The MMU continues to recommend that the modification to the definition of opportunity cost be reversed and that the elimination of the offset against operating reserve credits be reversed based on the MMU conclusion that these features result in a non-competitive market outcome, and because they are inconsistent with the treatment of the same issues in other PJM markets and inconsistent with basic economic logic.