State of the Market Report for PJM

Volume 1: Introduction

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Independent Market Monitor for PJM

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PREFACE

The PJM Market Monitoring Plan provides:

> The Market Monitoring Unit shall prepare and submit contemporaneously to the Commission, the State Commissions, the PJM Board, PJM Management and to the PJM Members Committee, annual state-of-the-market reports on the state of competition within, and the efficiency of, the PJM Markets, and quarterly reports that update selected portions of the annual report and which may focus on certain topics of particular interest to the Market Monitoring Unit. The quarterly reports shall not be as extensive as the annual reports. In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview. The annual reports shall, and the quarterly reports may, address, among other things, the extent to which prices in the PJM Markets reflect competitive outcomes, the structural competitiveness of the PJM Markets, the effectiveness of bid mitigation rules, and the effectiveness of the PJM Markets in signaling infrastructure investment. These annual reports shall, and the quarterly reports may include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required.[1]

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2009 State of the Market Report for PJM*, the twelfth such annual report.

1 PJM Open Access Transmission Tariff (OATT), "Attachment M: PJM Market Monitoring Plan," § IV.A, Sixth Revised Sheet No. 452–452A. Capitalized terms used herein and not otherwise defined have the meaning provided in the OATT, PJM Operating Agreement, PJM Reliability Assurance Agreement or other tariff that PJM has on file with the Federal Energy Regulatory Commission (FERC or Commission).

2 OATT Attachment M § II(f).

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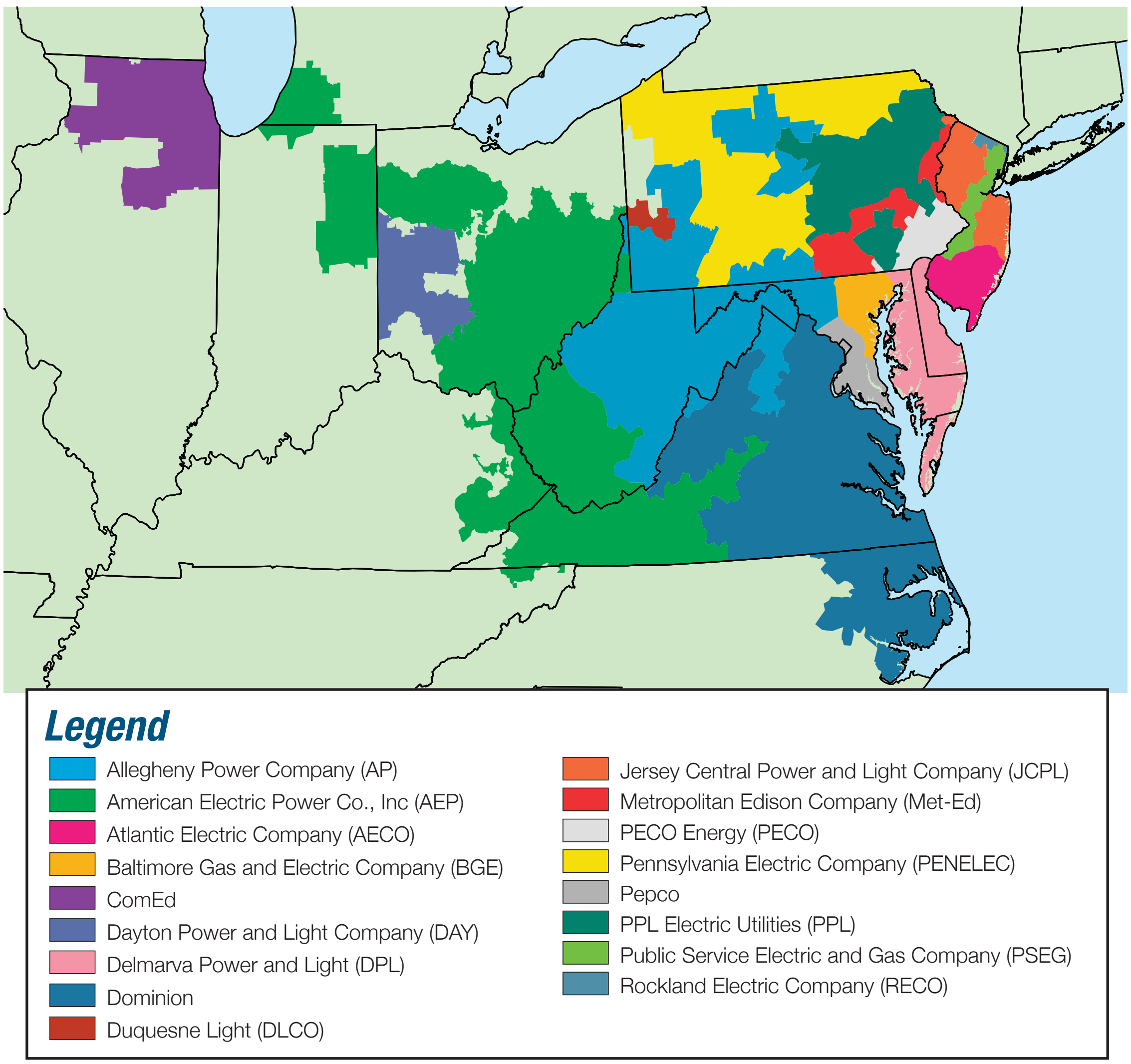
SECTION 1 - INTRODUCTION

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of December 31, 2009, had installed generating capacity of 167,326 megawatts (MW) and more than 500 market buyers, sellers and traders of electricity in a region including more than 51 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. (See Figure 1)[1] As part of that function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

Figure 1 PJM's footprint and its 17 control zones



1 See the *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution.

PJM Market Background

PJM operates the Day-Ahead Energy Market, the Real-Time Energy Market, the Reliability Pricing Model (RPM) Capacity Market, the Regulation Market, the Synchronized Reserve Markets, the Day Ahead Scheduling Reserve (DASR) Market and the Long Term, Annual and Monthly Balance of Planning Period Auction Markets in Financial Transmission Rights (FTRs).

PJM introduced energy pricing with cost-based offers and market-clearing nodal prices on April 1, 1998, and market-clearing nodal prices with market-based offers on April 1, 1999. PJM introduced the Daily Capacity Market on January 1, 1999, and the Monthly and Multimonthly Capacity Markets in mid-1999. PJM implemented an auction-based FTR Market on May 1, 1999. PJM implemented the Day-Ahead Energy Market and the Regulation Market on June 1, 2000. PJM modified the regulation market design and added a market in spinning reserve on December 1, 2002. PJM introduced an Auction Revenue Rights (ARR) allocation process and an associated Annual FTR Auction effective June 1, 2003. PJM introduced the RPM Capacity Market effective June 1, 2007. PJM implemented the DASR Market on June 1, 2008.[2, 3]

Conclusions

This report assesses the competitiveness of the markets managed by PJM in 2009, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the independent Market Monitoring Unit (MMU) for PJM.

The MMU concludes that in 2009:

- The Energy Market results were competitive;
- The Capacity Market results were competitive;
- The Regulation Market results were not competitive;[4]
- The Synchronized Reserve Market results were competitive;
- The Day Ahead Scheduling Reserve Market results were competitive; and
- The FTR Auction Market results were competitive.

2 See also the *2009 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."

3 Analysis of 2009 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

4 The regulation market results are not the result of the offer behavior of market participants, which is competitive as a result of the application of the three pivotal supplier test. The regulation market results are not competitive because the changes in market rules, in particular the changes to the calculation of the opportunity cost, resulted in a price greater than the competitive price. The competitive price is the actual marginal cost of the marginal resource in the market. The competitive price in the Regulation Market is the price that would have resulted from the application of the prior, correct approach to the calculation of the opportunity cost. The correct way to calculate opportunity cost and maintain incentives across both regulation and energy markets is to treat the offer on which the unit is dispatched for energy as the measure of its marginal costs for the energy market. To do otherwise is to impute a lower marginal cost to the unit than its owner does and therefore impute a higher opportunity cost than its owner does.

Role of MMU in Market Design Recommendations

The PJM Market Monitoring Plan provides under the heading "Market Design," in the section setting forth the MMU's function and responsibilities:

> PJM is responsible for proposing for approval by the Commission, consistent with tariff procedures and applicable law, changes to the design of the PJM Markets. If the Market Monitoring Unit detects a design flaw or other problem with the PJM Markets, the Market Monitoring Unit may initiate and propose, through the appropriate stakeholder processes, changes to the design of such market. In support of this function, the Market Monitoring Unit may engage in discussions with stakeholders, State Commissions, PJM Management, or the PJM Board; participate in PJM stakeholder meetings or working groups regarding market design matters; publish proposals, reports or studies on such market design issues; and make filings with the Commission on market design issues.[5]

In addition, the PJM Market Monitoring Plan provides, in describing MMU Reports: "In its annual, quarterly and other reports, the Market Monitoring Unit may make recommendations regarding any matter within its purview."[6]

Recommendations

The MMU recommends retention of key market rules, specific enhancements to those rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets. The recommendations are for new action in areas where PJM has not yet identified a plan or where the plan should be modified. The recommendations for each category follow the order in which they appear in the report. The recommendations are for continued action where PJM has already implemented effective market rules or where PJM has already identified areas for improvement.

New Action

- The MMU recommends that the option to specify a minimum dispatch price under the Demand Side Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. 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

5 PJM OATT Attachment M § IV.D.

6 PJM OATT Attachment M § VI.A. *See also* Order No. 719 at P 357 ("[W]e do expect the MMU to advise the Commission, the RTO or ISO, and other interested entities of its views regarding any needed rule and tariff changes. Likewise, in the event an RTO or ISO files for a proposed tariff change with which the MMU disagrees, we expect the RTO or ISO to inform the Commission of that disagreement, although not necessarily to include a written proposal with its filing."), codified at 18 C.F.R. § 35.28 (g)(3)(ii)(A) ("The Market Monitoring Unit must perform the following core functions: (A) Evaluate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes to the Commission-Approved independent system operator or regional transmission organizations, to the Commission's Office of Energy Market Regulation staff and to other interested entities such as state commissions and market participants"). In its order of December 18, 2009 on PJM's filing in compliance with Order No. 719, the Commission required additional changes to ensure that the PJM Market Monitoring Plan fully conforms with Order No. 719's requirements concerning the role of MMUs in market design. 125 FERC ¶ 61,250 at P 113 (2009) ("PJM's OATT fails to specify the MMU's responsibility for evaluating existing and proposed market rules, tariff provisions and market design elements, and for recommending proposed rule and tariff changes to PJM, the Commission's Office of Energy Market Regulation and to other interested entities (i.e., state commissions and market participants). Attachment M, section IV.C, in this regard, provides only that, if the MMU "detects a design flaw or other problem with the PJM Markets," it may initiate and propose changes to such market design. This language, however, is limited to "design" issues relating to existing provisions and thus does not address the full scope of the core MMU function addressed by the Commission in Order No. 719.").

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 MMU recommends that the Demand Side Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program. There is no economic reason to compensate load reductions up to $1,000/MWh during an emergency event regardless of the hourly LMP.

- The MMU recommends that PJM carefully consider the implications of the potential loss of the relatively small subcritical coal units identified as at risk in the MMU net revenue analysis and whether market design changes are required to address that potential loss.

- The MMU recommends that any proposal to modify scarcity pricing include the following essential components: reserve requirements modeled as constraints for specific transmission constraint defined regions, with administrative reserve scarcity penalty factors, in the security constrained dispatch; a maximum price of $1,000 per MWh; an appropriate operating reserve target, e.g. 10 minute synchronized reserves; accurate measurement of the operating reserve levels used as a scarcity trigger; an accurate and effective offset mechanism for RPM revenues; maintaining local market power mitigation mechanisms; and 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 MMU recommends that PJM require all import and export up-to congestion transactions to pay day-ahead and balancing operating reserve charges. This would continue to exclude wheel through transactions from operating reserve charges. Up-to congestion transactions are being used as matching INC and DEC bids and have corresponding impacts on the need for operating reserves charges.

- The MMU recommends that PJM eliminate all internal PJM buses for use in up-to congestion bidding and for all import and export transactions in the Day-Ahead and the Real-Time Markets. The use of specific buses is equivalent to creating a scheduled transaction to a specific point which will not be matched by the actual corresponding power flow.

- The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make the data necessary for loop flow analysis available to the RTOs and market monitors to make a full market analysis possible. PJM continues to face significant loop flows for reasons that continue not to be fully understood because PJM, other balancing authority operators and market monitors have inadequate access to the data required for a complete analysis of loop flow in the Eastern Interconnection.

- The MMU recommends that the obligation of capacity resources to offer energy in the Day-Ahead Energy Market should be applied without exception to all capacity resources, including both generation and demand resources. This means that capacity resources must be available every hour of the year at a competitive price.

- The MMU recommends that the rules making capacity auctions mandatory for both load and generation be clarified. In PJM, load has a must bid requirement, which is enforced through the use of a system demand curve and the allocation of total capacity costs to all load. In

PJM, capacity has a must offer requirement, which means that all capacity resources must offer into the capacity auctions unless they have a contract with an entity outside PJM or are physically unable to perform. The must bid and must offer requirements must extend to all resources. Thus, there should be no reduction of demand on the bid side. The current 2.5 percent reduction in the demand curve, to provide for short term resources, distorts the market price. The reduction in demand results in a price lower than the competitive level thus reducing the incentives to both new and existing generation. There should be no reductions in the demand for capacity, which should reflect all capacity needed to provide reliability.

- The MMU recommends that the must offer requirement for capacity should also apply generally to out of market transactions. Out of market transactions include the construction of new capacity by regulated utilities receiving out of market payments for such capacity via rate base treatment of the investment; by companies receiving out of market payments for such capacity via long term contracts; by companies receiving out of market payments for such capacity via Reliability Must Run (RMR) payments; and by companies receiving out of market payments for such capacity under renewable portfolio programs.

- The MMU recommends that PJM take the required steps to ensure that capacity prices reflect local supply and demand conditions. If capacity cannot be delivered into an area as a result of transmission constraints, a local market exists and capacity market prices should reflect the local market conditions. The CETO/CETL analysis currently used by PJM to define local markets in combination with consideration of local supply and demand is not adequate to define local markets in RPM. PJM should perform a more detailed reliability analysis of all at risk units, including all units that do not clear in RPM auctions, units that do not cover avoidable costs, and units that face significant investment requirements due, for example, to environmental requirements.

- The MMU recommends that the recently implemented modification to the definition of opportunity cost in the Regulation Market be reversed and that the correct definition of opportunity cost be reinstated. The change to the tariff is inconsistent with the definition of opportunity cost, is inconsistent with the way in which opportunity cost is calculated elsewhere in the PJM tariff and is inconsistent with the way in which opportunity cost has been calculated for regulation under the PJM tariff for approximately ten years.

- The MMU recommends that the recently implemented modification to the treatment of net revenues from the Regulation Market be reversed and that the net revenues earned in the Regulation Market be offset against operating reserve credits in the same manner that all net revenues from all other PJM markets are offset against operating reserve credits and in the same manner that Regulation Market credits were offset against operating reserve credits prior to December 1, 2008.

- Based on the experience of the MMU during its eleventh year and its analysis of the PJM markets and based on the experience of the MMU during its first complete year as the external Independent Market Monitor, the MMU confirms that the market monitoring function remains independent, well-organized and consistent with the policies of the FERC.[7, 8] The MMU has not identified any changes that are required to maintain the general effectiveness of the MMU, but recommends that the Commission continue to consider ways to strengthen the market monitoring function.

7 PJM. "Open Access Transmission Tariff (OATT)," "Attachment M: PJM Market Monitoring Plan," Fourth Revised Sheet No. 452 (Effective August 1, 2008). Section VII.A. states: "The reports to the PJM Board shall include recommendations as to whether changes to the Market Monitoring Unit or the Plan are required."

8 On December 19, 2007, the parties filed a settlement with the Federal Energy Regulatory Commission, pursuant to the September 20, 2007, order in Docket Nos. EL07-56-000 and EL07-58-000 (consolidated).

Detailed Recommendations in the 2009 State of the Market Report

This section includes the additional detailed recommendations made in the *2009 State of the Market Report for PJM*.

Section 2 – Energy Market Part 1

Demand-Side Response (DSR)

- Load Management test results are submitted by CSPs directly to PJM. The test results consist of metered load data provided by the CSP which are compared to some baseline consumption level or firm service level determined by LM participation type. There is no physical or technical oversight or verification by PJM or by the relevant LSE of actual testing. PJM screens the data for unreasonable test results, but relies on the CSP to submit accurate metered load data for the testing period with no verification. This form of testing is not an adequate measurement and verification protocol to ensure that demand side capacity resources can reliably reduce during a system emergency. The MMU recommends that the testing program be modified to require verification of test methods and results.

- The MMU recommends that any settlement submitted with a consecutive 24 hour period of CBL greater than metered load should initiate a CBL review by PJM and that a customer should be required to provide documentation of load reduction actions taken, prior to acceptance of such settlements. Further, in order for PJM or the MMU to assess the accuracy of the CBL for a particular customer or for the Program in general, more hourly load data is required than is currently captured by PJM.

- While it is reasonable to limit the authority of LSE/EDCs in the review of demand side settlements as the LSE/EDCs have economic incentives to deny settlements, the MMU recommends that LSE/EDCs should be able to initiate PJM settlement reviews.

- The MMU recommends that regression analysis capturing the effect of ambient temperature be incorporated in any GLD testing that estimates unrestricted load consumption based on a comparable day or a comparable set of days.

- While the introduction of Load Management testing for any delivery year without an emergency event is an improvement to the Program, the current state of testing does not constitute an adequate measurement and verification protocol to ensure that demand side capacity resources can reliably reduce during a system emergency. The MMU recommends that the testing program be modified to require verification of test methods and results. In addition, the MMU recommends that when used to determine compliance in Load Management testing for GLD customers, the CBL calculation should include statistical analysis that captures the effect of ambient conditions.

- The MMU recommends two ways to further improve the Economic Program by increasing the probability that payments are made only for economic and deliberate load reducing activities in response to price. Load reduction in response to price must be clearly defined in the business rules and verified in a transparent daily settlement screen. The four steps in the normal operations review should be routinely applied to all registrations from the beginning of participation.

Section 4 – Transactions

- The MMU recommends that a change in the interface pricing methodology be addressed directly by the Broader Regional Markets group. The MMU recommends that the parties consider the uniform adoption of a GCA to LCA pricing methodology, similar to that used by PJM, to set transaction prices based on the actual flow of energy from source to sink. With the appropriate pricing, the incentive for market participants to schedule around specific RTOs/ISOs would be eliminated.

- The MMU recommends that PJM monitor, and adjust as necessary, the buses and weightings applied to the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis.

- The MMU supports congestion management agreements but recommends that such agreements be implemented on a regional basis rather than between RTOs and individual external utility companies. In addition, there are a number of issues in the PJM/PEC agreement that need to be addressed. Most fundamentally, any congestion management agreement must ensure that the interface price established reflects the economic fundamentals of an LMP market.

- The MMU recommends modifying the evaluation criteria for not willing to pay congestion transactions via a change to PJM's market software, to ensure that a not willing to pay congestion transactions is not permitted to flow in the presence of congestion.

- The MMU recommends that the EES application be modified further to require that transactions be scheduled for a constant MW level over the entire 45 minutes as soon as possible.

- Generating units that do not respond to RTO dispatch signals may contribute to the need for PJM and the Midwest ISO to implement market to market redispatch and result in payments under the JOA. The MMU recommends that the JOA be modified so as to eliminate payments between RTOs in the event that payments result from the failure of generating units to respond to appropriate pricing signals.

- At the time of the consolidation of the Southeast and Southwest Interface pricing points, some market participants requested grandfathered treatment for specific transactions from PJM under which they would be allowed to keep the Southeast and Southwest Interface pricing. The MMU recommends that these agreements be terminated, as the interface prices received for these agreements do not represent the economic fundamentals of locational marginal pricing. As an alternative, the agreements should be made public and the same terms should be made available to all qualifying entities.

Section 5 – Capacity Markets

- The market rules should explicitly require that offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate.

- The sale of capacity is also the sale of recall rights to the energy from capacity resources during an emergency. Regardless of where the energy from a unit is sold, it must be recallable by PJM when PJM is in an emergency condition or a scarcity condition. 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.

- The MMU recommends that PJM review all requests for OMC outages carefully, develop a transparent set of rules governing the designation of outages as OMC and post those guidelines.

Section 6 – Ancillary Service Markets

- The MMU recommends that PJM, FERC and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market.

- The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test. The MMU concludes that the DASR Market results were competitive in 2009.

- The MMU recommends that a full list of potential reasons for unit deselection be published in PJM's M-11 Scheduling Operations Manual. The MMU recommends that dispatchers classify the reasons for unit deselection and document all unit deselections.

Section 8 – Financial Transmission Rights

- The MMU recommends that when load switches among LSEs during the planning period, a proportional share of the underlying self scheduled FTRs follow the load in the same manner that ARRs do. This would include both FTRs that are directly self scheduled and FTRs on paths identical to the ARR, which are financially equivalent to self scheduled FTRs. ARRs are assigned to firm transmission service customers because these customers pay the costs of the transmission system that enables firm energy delivery. The underlying FTRs are obtained as the direct result of the ARR assignment and should therefore follow the reassignment of ARRs when load switches.

- The MMU supports PJM's actions to reduce unsecured credit including the elimination of unsecured credit in PJM's FTR markets. The MMU continues to recommend the complete elimination of unsecured credit, over an appropriate transition period, based on the MMU's view of PJM's role in evaluating the credit worthiness of complex corporate entities and due to a concern about inappropriate shifts of risks and costs among PJM members.

Continued Action

- Retention and application of the improved local market power mitigation rules to prevent the exercise of local market power in the Energy Market while ensuring appropriate economic signals when investment is required.

  PJM applies the three pivotal supplier test to determine whether local energy markets are structurally competitive. The three pivotal supplier test, as implemented, is consistent with the United States Federal Energy Regulatory Commission's (FERC's) market power tests, encompassed under the delivered price test. The test is a flexible, targeted real-time measure of market structure which replaced the previous mitigation method of offer capping of all units required to relieve a constraint. The application of the three pivotal supplier test successfully limits offer capping in the Energy Market to situations where the local market is structurally noncompetitive and where specific owners have structural market power.

- Retention, application and improvement of the RPM rules included in PJM's Tariff to stimulate competition, to provide direct incentives for performance, to provide locational price signals, to provide forward auctions to permit competition from new entrants and to limit market power by the application of clear and explicit market power mitigation rules. Implementation of enhancements to incentives for capacity resource performance to ensure stronger, market-based incentives for actual performance when needed.

  Market power remains a serious concern in the PJM Capacity Market based on market structure conditions in this market including high levels of supplier concentration, frequent occurrences of pivotal suppliers and extreme inelasticity of demand. The RPM Capacity Market design explicitly allows competitive prices to reflect local scarcity without relying on the exercise of market power to achieve the objectives of the Capacity Market design and explicitly limits the exercise of market power via the application of the three pivotal supplier test.

  RPM rules could be improved by ensuring that capacity payments are made only to units that perform, that the must offer requirement does not permit either physical or economic withholding, that the requirement for capacity resources to make offers in the Day-Ahead Energy Market explicitly require competitive offers and that locational price separation is determined by market fundamentals rather than by rule.

- Retention of the $1,000 per MWh offer cap in the PJM Energy Market and other rules that limit incentives to exercise market power.

  The PJM market design includes a variety of rules that effectively limit the incentive to exercise market power and ensure competitive outcomes. These should be retained and enforced and any proposed PJM market rule change should be evaluated for its impact on competitive outcomes.

- Retention and application of the improved market power mitigation rules in the Regulation Market to prevent the exercise of market power in the Regulation Market while ensuring appropriate economic signals when investment is required and an efficient market mechanism. The PJM Regulation Market continues to be characterized by structural market power. PJM's application of targeted, flexible real-time, market power mitigation in the Regulation Market addresses only the hours in which structural market power exists and therefore provides an incentive for the continued development of competition.

- Retention and application of enhancements to rules governing the payment of operating reserve credits to generators and the allocation of operating reserves charges among market participants that were implemented on December 1, 2008. The new operating reserve rules represent positive steps towards the goals of removing the ability to exercise market power and refining the allocation of operating reserves charges to better reflect causal factors.

- Implementation of rules governing the definition of final prices to ensure certainty for market participants.

  Changing market prices after the fact should be avoided, even when the reason is a failure to mitigate local market power. Markets depend on prices and market participants depend on the finality and certainty of prices. Ideally, observed prices in real time would be final, but this has not yet been possible in the PJM markets. PJM should consider and implement rules defining when prices are final. This approach to final prices is also consistent with the view that market power mitigation should be done ex ante, whenever possible, to ensure that market price signals are accurate in real time.

  PJM has actively responded to this recommendation and there are several proposals being considered in the membership process.

- Modification of rules governing demand-side programs to ensure appropriate levels of payment and to ensure appropriate measurement and verification of demand-side response. Evaluation of additional actions to address institutional issues which may inhibit the evolution of demand-side price response.

  PJM and the MMU should continue efforts to ensure that market power is not exercised on the demand side of the market, particularly via gaming of the measurement and verification process. There are significant issues with the current approach to measuring demand-side response MW, which is the basis on which program participants are paid. Recent changes to the settlement review process represent clear improvements, but do not go far enough. Additional improvements in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. The principal barriers to the further development of demand-side response are in the interface between wholesale and retail markets.

- Continued improvement of pricing between PJM and surrounding areas, both market and non market.

  Transactions with other market areas are largely driven by the market fundamentals within each area and between market areas. However, there is room to improve current market-to-market coordination to ensure that these areas together more closely approach the outcomes and opportunities of a single, transparent market. PJM and NYISO, as neighboring market areas, should develop market-based congestion management protocols, modeled on the PJM and Midwest ISO JOA, as soon as practicable.

  Transactions with non market areas are driven by a mix of incentives including market fundamentals but are more difficult to manage because of the inherent inconsistency between the contract path approach taken in non market areas and the explicit locational price approach in market areas. A significant issue is the ability of non market transactions to impose uncompensated costs on market areas in the absence of transparency and appropriate market signals. The reverse can also occur. For interactions with non market areas, the goal should be to increase the role of market forces consistent with actual power flows and more closely approach the outcomes and opportunities of a single, transparent market.

Total Price of Wholesale Power

The total price of wholesale power is the total price per MWh of purchasing wholesale electricity from PJM markets. The total price is an average price and actual prices vary by location. The total price includes the price of energy, capacity, ancillary services, transmission service, administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1 provides the components of the total average price for wholesale power in PJM. Each of these items is defined in PJM's Open Access Transmission Tariff (OATT) and PJM Operating Agreement and each is collected through PJM's billing system.

Components of Total Price

- The Load Weighted Energy component is the load weighted average PJM locational marginal price (LMP).
- The Capacity component is the average price per MWh of Reliability Pricing Model (RPM) payments in 2009.
- The Transmission Service Charge component is the average price per MWh of network integration charges and firm and non firm point to point transmission service.[9]
- The Operating Reserve (Uplift) component is the average price per MWh of day ahead and real time operating reserve charges.[10]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[11]
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[12]
- The PJM Administrative Fees component is the average cost per MWh of PJM's monthly expenses for a number of administrative services, including Advanced Control Center (AC^2) and OATT Schedule 9 funding of FERC, OPSI and the MMU.
- The Transmission Enhancement Cost Recovery component is the average cost per MWh of PJM billed (and not otherwise collected through utility rates) costs for transmission upgrades and projects, including annual recovery for the TrAILCo and PATH projects.[13]
- The Transmission Owner (Schedule 1A) component is the average cost per MWh of transmission owner scheduling, system control and dispatch services charged to transmission customers.[14]

9 PJM OATT Section 13.7, Section 14.5 & 27A and Section 34.
10 PJM Operating Agreement Schedules 1-3.2.3 & 1-3.3.3.
11 PJM OATT Schedule 2 and Operating Agreement Schedule 1-3.2.3B.
12 PJM Operating Agreement Schedules 1-3.2.2, 1-3.2.2A, 1-3.3.2, 1-3.3.2A and OATT Schedule 3.
13 PJM OATT Schedule 12.
14 OATT Schedule 1A.

- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[15]
- The Black Start component is the average cost per MWh of black start service.[16]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[17]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[18]
- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.[19]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[20]

Table 1 Total price per MWh: Calendar year 2009

Category	$/MWh	Percent
Load Weighted Energy	$39.05	70.2%
Capacity	$10.75	19.3%
Transmission Service Charges	$4.00	7.2%
Operating Reserve (Uplift)	$0.49	0.9%
Reactive	$0.36	0.7%
Regulation	$0.34	0.6%
PJM Administrative Fees	$0.31	0.5%
Transmission Enhancement Cost Recovery	$0.09	0.2%
Transmission Owner (Schedule 1A)	$0.08	0.2%
Synchronized Reserves	$0.05	0.1%
Black Start	$0.02	0.0%
RTO Startup and Expansion	$0.01	0.0%
NERC/RFC	$0.01	0.0%
Load Response	$0.00	0.0%
Transmission Facility Charges	$0.00	0.0%
Total	$55.58	100.0%

15 PJM Operating Agreement Schedule 1-3.2.3A.01 and OATT Schedule 6.
16 OATT Schedule 6A.
17 OATT Attachments H-13 and H-14 and Schedule 13.
18 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
19 Operating Agreement Schedule 1-3.6.
20 Operating Agreement Schedule 1-5.3b.

Energy Market, Part 1

The PJM Energy Market comprises all types of energy transactions, including the sale or purchase of energy in PJM's Day-Ahead and Real-Time Energy Markets, bilateral and forward markets and self-supply. Energy transactions analyzed in this report include those in the PJM Day-Ahead and Real-Time Energy Markets. These markets provide key benchmarks against which market participants may measure results of transactions in other markets.

The MMU analyzed measures of market structure, participant conduct and market performance for 2009, including market size, concentration, residual supply index, price-cost markup, net revenue and price.[21] The MMU concludes that the PJM Energy Market results were competitive in 2009.

PJM markets are designed to promote competitive outcomes derived from the interaction of supply and demand in each of the PJM markets. Market design itself is the primary means of achieving and promoting competitive outcomes in PJM markets. One of the MMU's primary goals is to identify actual or potential market design flaws.[22] The approach to market power mitigation in PJM has focused on market designs that promote competition (a structural basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.

Market Structure

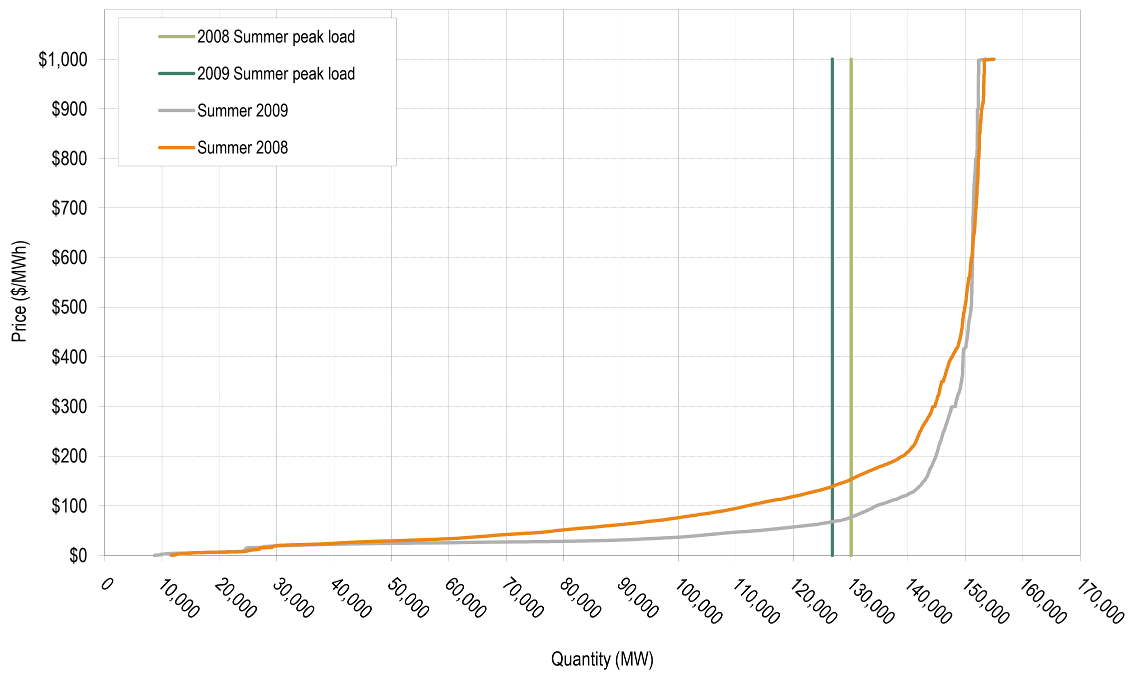
- **Supply.** During the June to September 2009 summer period, the PJM Energy Market received an hourly average of 153,520 MW in supply offers including hydroelectric generation.[23] The summer 2009 average daily offered supply was 1,439 MW lower than the summer 2008 average daily offered supply of 154,959 MW. An extended outage at a nuclear power plant was the primary cause of the decrease. Lower fuel prices in the 2009 summer period resulted in a shift down of the 2009 summer period supply curve.

21 Analysis of 2009 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones: ComEd, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion. By convention, control zones bear the name of a large utility service provider working within their boundaries. The nomenclature applies to the geographic area, not to any single company. For additional information on the control zones, the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

22 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment M: Market Monitoring Plan," First Revised Sheet No. 448.05 (Effective June 29, 2009).

23 Calculated values shown in Section 2, "Energy Market, Part 1," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

Figure 2 Average PJM aggregate supply curves: Summers 2008 and 2009



- **Demand.** The PJM system peak load in 2009 was 126,805 MW in the hour ended 1700 EPT on August 10, 2009, while the PJM peak load in 2008 was 130,100 MW in the hour ended 1700 EPT on June 9, 2008.[24] The 2009 peak load was 3,295 MW, or 2.5 percent, lower than the 2008 peak load. This is the lowest annual peak load since the last transmission system integration.

- **Market Concentration.** Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate comparatively smaller numbers of sellers dominating a market, while low concentration ratios mean larger numbers of sellers splitting market sales more equally. High concentration ratios indicate an increased potential for participants to exercise market power, although low concentration ratios do not necessarily mean that a market is competitive or that participants cannot exercise market power. Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.

- **Local Market Structure and Offer Capping.** Noncompetitive local market structure is the trigger for offer capping. PJM applied a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in 2009. PJM offer caps units only when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer-capping levels have historically been low in PJM. In the

24 For the purpose of Volume I and Volume II of the *2009 State of the Market Report for PJM*, all hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See Appendix N, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

Day-Ahead Energy Market offer-capped unit hours were 0.1 percent in 2009, lower from 0.2 percent in 2008. In the Real-Time Energy Market offer-capped unit hours fell from 1.0 percent in 2008 to 0.4 percent in 2009.

- **Local Market Structure.** A summary of the results of PJM's application of the three pivotal supplier test is presented for all constraints which occurred for 100 or more hours during calendar year 2009. In 2009, the AECO, AEP, AP, BGE, ComEd, DLCO, Dominion, PECO, PENELEC, Pepco and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 100 or more hours. The analysis of the application of the three pivotal supplier test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.

Table 2 Annual offer-capping statistics: Calendar years 2005 to 2009

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2005	1.8%	0.4%	0.2%	0.1%
2006	1.0%	0.2%	0.4%	0.1%
2007	1.1%	0.2%	0.2%	0.0%
2008	1.0%	0.2%	0.2%	0.1%
2009	0.4%	0.1%	0.1%	0.0%

Market Performance: Markup, Load and Locational Marginal Price

- **Markup.** The markup conduct of individual owners and units has an impact on market prices. The MMU calculates explicit measures of the impact of marginal unit markups on LMP. The LMP impact is a measure of market power. The price impact of markup must be interpreted carefully. The price impact is not based on a full redispatch of the system, as such a full redispatch is practically impossible because it would require reconsideration of all dispatch decisions and unit commitments. The markup impact includes the maximum impact of the identified markup conduct on a unit by unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the Energy Market.

  The markup component of the overall PJM real-time, load-weighted, average LMP was -$2.38 per MWh, or -6.1 percent. Coal steam units contributed -$2.54, or 106.7 percent, to the total markup component of LMP. Combined cycle units that use gas as their primary fuel source contributed -$0.00 or 0.2 percent to the total markup component of LMP. The markup was -$1.67 per MWh during peak hours and -$3.15 per MWh during off-peak hours.

  The markup component of the overall PJM day-ahead, load-weighted, average LMP was -$1.65 per MWh, or -4.2 percent. Coal steam units contributed -$1.53 or 93.0 percent to the total markup component of LMP. Natural gas steam units contributed -$0.12 or 7.4 percent to the total markup component of LMP. The markup was -$1.12 per MWh during peak hours and -$2.22 per MWh during off-peak hours.

The overall results support the conclusion that prices in PJM are set, on average, by marginal units operating at or close to their marginal costs. This is strong evidence of competitive behavior and competitive market performance.

- **Load.** On average, PJM real-time load decreased in 2009 by 4.4 percent from 2008, falling from 79,515 MW to 76,035 MW. PJM day-ahead load decreased in 2009 by 7.1 percent from 2008, falling from 95,522 MW to 88,707 MW.

- **Prices.** PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although the number of factors influencing the overall level of prices means it must be analyzed carefully. Among other things, overall average prices reflect the generation fuel mix, the cost of fuel and local price differences caused by congestion.

  PJM Real-Time Energy Market prices decreased in 2009 compared to 2008. The system simple average LMP was 44.1 percent lower in 2009 than in 2008, $37.08 per MWh versus $66.40 per MWh. The load-weighted LMP was 45.1 percent lower in 2009 than 2008, $39.05 per MWh versus $71.13 per MWh. The real-time fuel cost adjusted, load-weighted, average LMP was 10.5 percent lower in 2009 than the load-weighted, average LMP in 2008, $63.66 per MWh compared to $71.13 per MWh. In other words, if fuel costs for 2009 had been the same as 2008, the 2009 load-weighted LMP would have been higher, $63.66 per MWh, instead of the observed $39.05 per MWh, and 10.5 percent lower than the load-weighted average LMP for 2008. Fuel costs and lower loads in 2009 contributed to downward pressure on LMP.

  PJM Day-Ahead Energy Market prices decreased in 2009 compared to 2008. The system simple average LMP was 44.0 percent lower in 2009 than in 2008, $37.00 per MWh versus $66.12 per MWh. The load-weighted LMP was 44.7 percent lower in 2009 than in 2008, $38.82 per MWh versus $70.25 per MWh.

- **Load and Spot Market.** Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a single PJM parent company that serves load, its load could be supplied by any combination of its own generation, net bilateral market purchases and net spot market purchases. In 2009, 12.9 percent of real-time load was supplied by bilateral contracts, 17.0 percent by spot market purchases and 70.1 percent by self-supply. Compared with 2008, reliance on bilateral contracts decreased by 1.8 percentage points; reliance on spot supply decreased by 3.1 percentage points; and reliance on self-supply increased by 4.9 percentage points in 2009.

Demand-Side Response

- **Demand-Side Response (DSR).** Markets require both a supply side and a demand side to function effectively. PJM wholesale market, demand-side programs should be understood as one relatively small part of a transition to a fully functional demand side for its Energy Market. A fully developed demand side will include retail programs and an active, well-articulated interaction between wholesale and retail markets.

If retail markets reflected hourly wholesale prices and customers received direct savings associated with reducing consumption in response to real-time prices, there would not be a need for an RTO Economic Load Response Program, or for extensive measurement and verification protocols. In the transition to that point, however, there is a need for robust measurement and verification techniques to ensure that transitional programs incent the desired behavior.

There are significant issues with the current approach to measuring demand-side response MW, which is the basis on which program participants are paid. A substantial improvement in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. Recent changes to the settlement review process represent clear improvements, but do not go far enough.

- **Demand-Side Response Activity.** 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. On the peak load day, August 10, 2009, there were 2,486.6 MW in the Economic Load Response Program.

  In 2009, the Emergency Program, specifically, the Load Management (LM) Program, participation increased compared to 2008. For the 2009/2010 delivery year, there were 7,294.3 MW registered in the LM Program, compared to 4,498.2 MW registered in the 2008/2009 delivery year.

  Since the introduction of the capacity market on June 1, 2007 the capacity market has been the source of growth in total demand side revenues and demand side revenues from the capacity market were the only significant source of revenue in 2009. In 2009, payments from the Economic Program decreased from 2008 by $26 million or 96 percent, from $27.7 million to $1.2 million, while capacity revenue increased from 2008 by $161 million or 114 percent, from $141 million to $303 million since 2008. Synchronized Reserve credits decreased by $1.1 million, from $5.1 million to $4.0 million from 2008 to 2009.

Energy Market, Part 1 Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance for the year 2009, including aggregate supply and demand, concentration ratios, local market concentration ratios, price-cost markup, offer capping, participation in demand-side response programs, loads and prices in this section of the report. The next section continues the analysis of the PJM Energy Market including additional measures of market performance.

Aggregate supply decreased by about 1,439 MW when comparing the summer months of 2009 to the summer months of 2008 while aggregate peak load decreased by 3,295 MW, modifying the general supply demand balance from 2008 with a corresponding impact on Energy Market prices. Overall load was also lower than in 2008. Market concentration levels remained moderate and average markup was negative. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load. LMP is a broader indicator of the level of competition. While PJM has experienced price spikes, these have been limited in duration and, in general, prices in PJM have been well below the marginal cost of the highest cost unit installed on the system. The significant price spikes in PJM have been directly related to scarcity conditions. In PJM, prices tend to increase as the market approaches scarcity conditions as a result of generator offers and the associated shape of the aggregate supply curve. The pattern of prices within days and across months and years illustrates how prices are directly related to demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price.

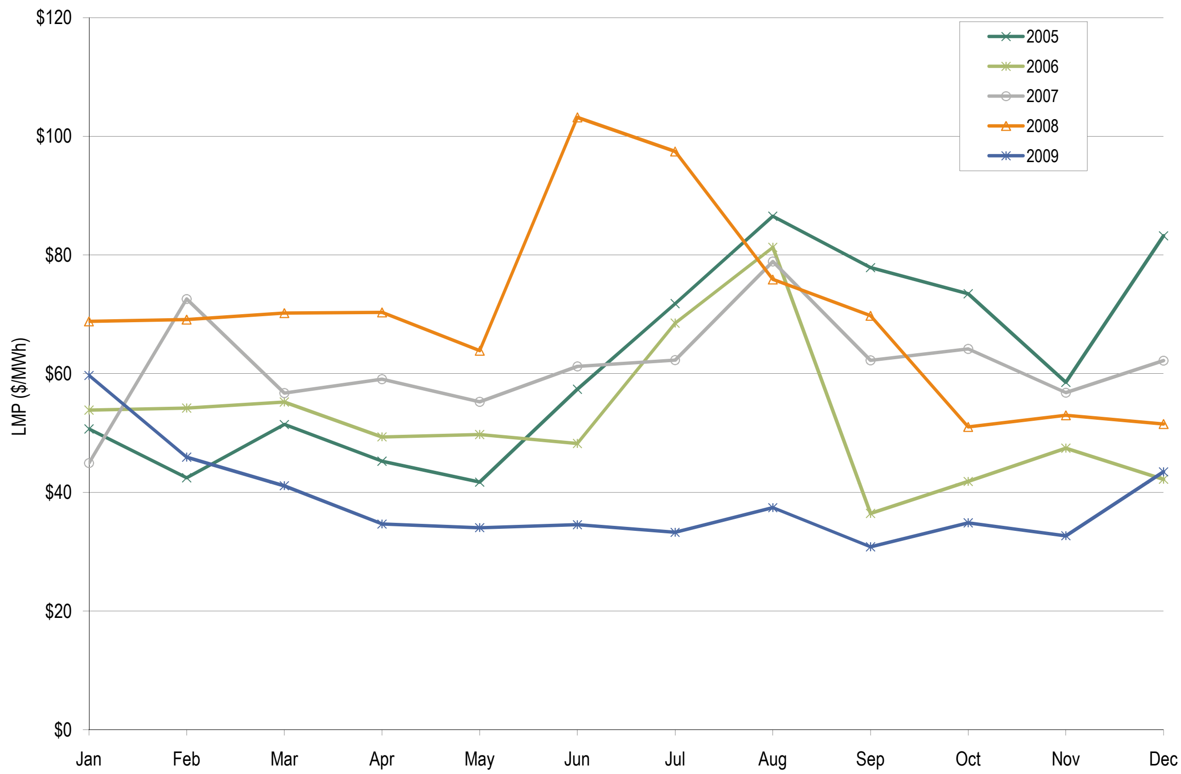
The three pivotal supplier test is applied by PJM on an ongoing basis for local energy markets in order to determine whether offer capping is required for transmission constraints. This is a flexible, targeted real-time measure of market structure which replaced the offer capping of all units required to relieve a constraint. A generation owner or group of generation owners is pivotal for a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test, as implemented, is consistent with the FERC's market power tests, encompassed under the delivered price test. The three pivotal supplier test is an application of the delivered price test to both the Real-Time Market and hourly Day-Ahead Market. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests.

The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.

Energy Market results for 2009 generally reflected supply-demand fundamentals. Lower prices in the Energy Market were the result of lower fuel costs and of lower demand. PJM Real-Time, load-weighted, average LMP for 2009 was $39.05, or 45.1 percent lower than the load-weighted, average LMP for 2008, which was $71.13. The real-time fuel cost adjusted, load-weighted, average LMP was 10.5 percent lower in 2009 than the load-weighted, average LMP in 2008, $63.66 per MWh compared to $71.13 per MWh. In other words, if fuel costs for 2009 had been the same as 2008, the 2009 load-weighted LMP would have been higher, $63.66 per MWh, instead of the observed $39.05 per MWh, and 10.5 percent lower than the load-weighted average LMP for 2008. Lower fuel prices in 2009 resulted in lower energy prices in 2009 than would have occurred if fuel prices had remained at 2008 levels. Lower demand also contributed to lower prices.

The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior remain potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in 2009.

Figure 3 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2005 to 2009



Energy Market, Part 2

The MMU analyzed measures of PJM Energy Market structure, participant conduct and market performance for 2009. As part of the review of market performance, the MMU analyzed the net revenue performance of PJM markets, the characteristics of existing and new capacity in PJM, the definition and existence of scarcity conditions in PJM and the performance of the PJM operating reserve construct.

Net Revenue

- **Net Revenue Adequacy.** Net revenue quantifies the contribution to total fixed costs received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Net revenue is the amount that remains, after short run variable costs have been subtracted from gross revenue, to cover total fixed costs which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Total fixed costs, in this sense, include all but short run variable costs.

The adequacy of net revenue can be assessed both by comparing net revenue to total fixed costs and by comparing net revenue to avoidable costs. The comparison of net revenue to total fixed costs is an indicator of the incentive to invest in new and existing units. The comparison of net revenue to avoidable costs is an indicator of the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM Markets.

- **Net Revenue and Total Fixed Costs.** When compared to total fixed costs, net revenue is an indicator of generation investment profitability and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation and in existing generation to serve PJM markets. Net revenue quantifies the contribution to total fixed costs received by generators from all PJM markets. Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the total fixed costs of investing in new generating resources when there is a market based need, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher.

  In 2009, net revenues were not adequate to cover total fixed costs for a new entrant CT, CC or CP in any zone. While the results varied by zone, the net revenues for the CT and CC technologies generally covered a larger proportion of total fixed costs, reflecting their greater reliance on capacity market revenues. Energy net revenues are generally lower for each technology in most zones compared to 2008, while capacity market revenues are higher in every zone compared to 2008. For the combustion turbine (CT) and combined cycle (CC) technologies, the increase in capacity revenue offset the reduction in energy market revenue, while that was not the case for the coal plant (CP) which is more dependent on energy market net revenues to cover total fixed costs.

  For the new entrant CT, nine zones had higher net revenue and eight zones had lower net revenue compared to 2008. All zones but one had lower energy net revenue and higher capacity revenue compared to 2008 for the new entrant CT, and, for zones that cleared in the RTO Locational Delivery Area (LDA) for the 2007/2008 and the 2008/2009 BRA, this decrease in energy net revenue was more than offset by higher capacity revenues in the 2009/2010 delivery year. For the new entrant CC, twelve zones had lower net revenue and five zones had higher net revenue compared to 2008, which reflects a decrease in energy market revenue and an increase in capacity revenue in all zones. In AEP, AP, ComEd, DAY, DLCO and PENELEC, the increase in capacity revenues more than offset lower energy net revenues. For the new entrant coal plant (CP), all zones show a significant decrease in net revenue compared to 2008, which is driven by lower energy revenues.

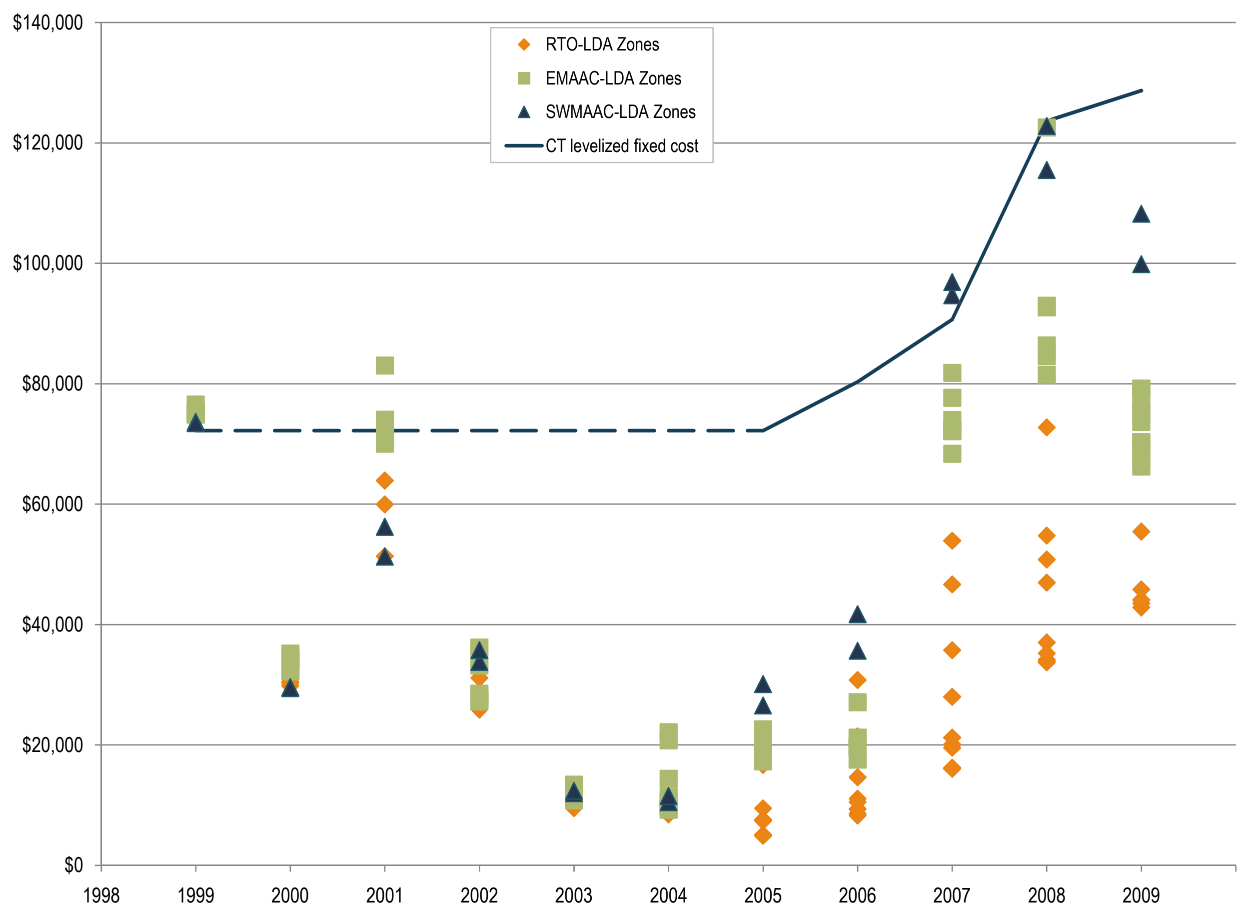
- **Net Revenue and Avoidable Costs.** Avoidable costs are the costs which must be paid each year in order to keep a unit operating. Avoidable costs are less than total fixed costs, which include the return on and of capital, and more than marginal costs, which are the short run incremental costs of producing energy. It is rational for an owner to continue to operate a unit if it is covering its avoidable costs and therefore contributing to covering fixed costs. It is not rational for an owner to continue to operate a unit if it is not covering and not expected to cover its avoidable costs. As a general matter, under those conditions, retirement of the unit is the logical option. Thus, this comparison of actual net revenues to avoidable costs is a measure of the extent to which units in PJM may be at risk of retirement. When other factors are considered, including additional fixed and variable costs associated with complying with environmental mandates, this is a key first measure.

For both the CT technologies and the CC technology, RPM revenue has provided an adequate supplemental revenue stream to incent continued operations in PJM for units that do not recover 100 percent of fixed costs through energy market revenue.

There is a set of sub-critical coal units in 2008 and 2009 and a set of supercritical coal units in 2009 that did not recover avoidable costs even with capacity revenues. The total installed capacity associated with coal units that did not cover avoidable costs in 2009 was 11,250 MW. There were 122 coal units in PJM in 2009 with capacity less than or equal to 200 MW. Of those units, 35 did not cover avoidable costs and 52 were close to not covering avoidable costs.

The coal plant technologies have higher avoidable costs and are more dependent on net revenues received in the energy market. In 2009, with lower load levels and, generally, lower price levels relative to operating costs, some coal-fired units in PJM did not fully recover avoidable costs even with capacity revenues. If this result is expected to continue, the retirement of these plants would be an economically rational decision.

Figure 4 New entrant CT real-time net revenue and 20-year levelized fixed cost as of 2009 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2009



Existing and Planned Generation

- **PJM Installed Capacity.** During the period January 1, through December 31, 2009, PJM installed capacity resources rose slightly from 164,898.9 MW on January 1 to 167,326.4 MW on December 31, an increase of 2,427.5 MW or 1.5 percent.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity at the end of 2009, 40.7 percent was coal; 29.2 percent was natural gas; 18.4 percent was nuclear; 6.4 percent was oil; 4.7 percent was hydroelectric; 0.4 percent was solid waste, and 0.2 percent was wind.

- **Generation Fuel Mix.** During 2009, coal provided 50.5 percent, nuclear 36.0 percent, gas 9.7 percent, oil 0.2 percent, hydroelectric 2.0 percent, solid waste 0.8 percent and wind 0.8 percent of total generation.

- **Planned Generation.** A potentially significant change in the distribution of unit types within the PJM footprint is likely as a combined result of the location of generation resources in the queue and the location of units likely to retire. In both the EMAAC and SWMAAC LDAs, the capacity mix is likely to shift to more natural gas-fired combined cycle (CC) and combustion turbine (CT) capacity. Elsewhere in the PJM footprint, continued reliance on steam (mainly coal) seems likely, although potential changes in environmental regulations may have an impact on coal units throughout the footprint.

Scarcity

- **Scarcity Pricing Events in 2009.** PJM did not declare a scarcity event in 2009.

  Scarcity exists when demand plus reserve requirements approach the available generating capacity of the system. Scarcity pricing means that market prices reflect the fact that the system is using close to its available capacity and that competitive prices may exceed accounting short-run marginal costs. 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. As demand increases and units with higher offers are required to meet demand, prices increase.

- **Scarcity.** 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. The mandated reserve margin requires units that are called on only under relatively unusual load conditions, if at all. Thus, the energy market alone frequently does not directly compensate some of the resources needed to provide for reliability.

  The Reliability Pricing Model (RPM) capacity market design reflects the recognition that the energy markets, by themselves and in the absence of a carefully designed expansion of scarcity pricing, will not result in adequate revenues. The revenues in the capacity market are scarcity revenues. If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, energy market design should permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing is part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design, as long as the market rules are designed to ensure that energy market scarcity revenues directly offset RPM revenues to prevent double collection of scarcity revenues.

- **Modifications to Scarcity Pricing.** PJM's scarcity pricing rules need refinement.

  The essential components of a new approach to scarcity pricing include: reserve requirements modeled as constraints for specific transmission constraint defined regions, with administrative reserve scarcity penalty factors, in the security constrained dispatch; an appropriate operating reserve target, e.g. 10 minute synchronized reserves; accurate measurement of the operating reserve levels used as a scarcity trigger; an accurate and effective offset mechanism for RPM revenues; and maintaining local market power mitigation mechanisms.

  There is no reason to increase the maximum price in PJM markets in order to implement scarcity pricing. Given the significant nature of the changes to the PJM markets that is required in order to implement any significant change to scarcity pricing, a step by step approach is warranted. If scarcity pricing is implemented successfully and the markets gain experience with it, higher offer caps should be considered. However, the assertion that much higher prices are required now in order to incent the participation of additional resources is unsupported, particularly given the absence of metering adequate to facilitate a response by the demand side of the market. In addition, the PJM RPM market is designed to achieve the target reliability levels with the resources acquired through the capacity market.

Credits and Charges for Operating Reserve

- **Operating Reserve Issues.** Day-ahead and real-time operating reserve credits are paid to generation owners under specified conditions in order to ensure that units are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or revenue requirement make whole, operating reserve payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. From the perspective of those participants paying operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

- **Operating Reserve Charges in 2009.** The level of operating reserve credits and corresponding charges decreased in 2009 by 24.1 percent compared to 2008. This decrease was comprised of a 35.5 percent decrease, or $125,479,054, in the amount of balancing operating reserve credits, and an increase of 36.4 percent, or $25,317,144, in day-ahead credits.

- **New Operating Reserve Rules.** New rules governing the payment of operating reserves credits and the allocation of operating reserves charges became effective on December 1, 2008. The new operating reserve rules represent positive steps towards the goals of removing the ability to exercise market power and refining the allocation of operating reserves charges to better reflect causal factors. The MMU calculated the impact of the new operating reserve rules in three areas.

  The rule changes allocated an increased proportion of balancing operating reserve credits to real-time load and exports. The purpose of this rule change was to reallocate a portion of the balancing operating reserve charges to those requiring additional resources to maintain system reliability, determined to be real-time load and exports. The new operating reserve rules resulted in an increase of $30,625,896 in charges assigned to real-time load and exports for 2009. These increases were matched by a decrease of $16,390,083 in charges to demand deviations, a decrease of $9,761,656 in charges to supply deviations, and a decrease of $4,474,157 in charges to generator deviations.

  The rule changes resulted in a reduced allocation of charges to deviations, which reduced operating reserve payments assigned to virtual market activity. The net result is that virtual offers and bids paid $10,441,564 less in operating reserve charges as a result of the change in rules than they would have paid under the old rules. These charges were paid by real time load and exports.

  The rule changes included the introduction of segmented make whole payments, which results in a calculation of operating reserve credits for periods shorter than the 24 hours used under the old rules. As a result of the introduction of segmented make whole payments in place of 24 hour make whole payments, balancing operating credits were $7,489,486, or 4.13 percent, higher for the calendar year 2009.

- **Parameter Limited Schedule rules.** On March 19, 2009, the Commission issued an order rejecting PJM's proposed revisions to Section 6.6(c) of Schedule 1 of the PJM Operating Agreement that would have altered the application of the rules for evaluating requests for exceptions to the values included in or derived on a formulaic basis from the Parameter Limited Schedule Matrix.[25] As a consequence, the business rules approved by the Members Committee on November 15, 2007, were reinstated. PJM and the Market Monitor jointly administered these rules for the spring cycle.

25 126 FERC ¶ 61,251 (2009).

Table 3 Total day-ahead and balancing operating reserve credits: Calendar years 1999 to 2009

	Total Operating Reserve Credits	Annual Credit Change	Operating Reserve as a Percent of Total PJM Billing	Day-Ahead $/MWh	Day-Ahead Change	Balancing $/MWh	Balancing Change
1999	$133,897,428	NA	7.5.%	NA	NA	NA	NA
2000	$216,985,147	62.1%	9.6%	0.341	NA	0.535	NA
2001	$290,867,269	34.0%	8.7%	0.275	(19.5%)	1.070	100.2%
2002	$237,102,574	(18.5%)	5.0%	0.164	(40.4%)	0.787	(26.4%)
2003	$289,510,257	22.1%	4.2%	0.226	38.2%	1.197	52.0%
2004	$414,891,790	43.3%	4.8%	0.230	1.7%	1.236	3.3%
2005	$682,781,889	64.6%	3.0%	0.076	(66.9%)	2.758	123.1%
2006	$322,315,152	(52.8%)	1.5%	0.078	2.6%	1.331	(51.7%)
2007	$459,124,502	42.4%	1.5%	0.057	(27.0%)	2.331	75.1%
2008	$429,253,836	(6.5%)	1.3%	0.084	48.0%	2.113	(9.3%)
2009	$325,842,346	(24.1%)	1.2%	0.120	42.3%	1.1100*	(47.5%)

Energy Market, Part 2 Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. With a capacity market design that appropriately reflects a direct and explicit offset for scarcity revenues in the energy market, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power.

A capacity market is a formal mechanism, with both administrative and market-based components, used to allocate the costs of maintaining the level of capacity required to maintain the reliability target. A capacity market is an explicit mechanism for valuing capacity and is preferable to non market and nontransparent mechanisms for that reason.

The historical level of net revenues in PJM markets was 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 means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly compensate the resources needed to provide for reliability, although the contribution of the Energy Market will be more consistent with reliability signals if the Energy Market appropriately provides for scarcity pricing when scarcity does occur.

PJM's RPM is an explicit effort to address these issues. RPM is a Capacity Market design intended to send supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability in the context of a long-run competitive equilibrium in the Energy Market.

In 2009, energy market revenues were lower as a result of lower energy prices in all zones compared to the same period in 2008. The change in energy market net revenue is a function of the change in locational price levels and fuel costs. In 2009, energy market prices decreased more significantly than fuel prices, and, as a result, energy market net revenues are lower compared to 2008 for all technologies in nearly all locations.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices, when they run. When this occurs, CT energy market net revenues are small and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs. There were relatively few high demand days in 2009. Scarcity revenues in the energy market contribute to covering fixed costs, when they occur, but scarcity revenues are not a predictable and systematic source of net revenue. In the PJM design, the balance of the net revenue required to cover the fixed costs of peaking units comes from the Capacity Market. However, when the actual fixed costs of capacity increase rapidly, or, when energy net revenues available for new entrants decreases rapidly, there is a corresponding lag in Capacity Market prices which will tend to lead to an under recovery of the fixed costs of CTs.

Coal plants (CP) are marginal in the PJM system for a substantial number of hours. When this occurs, CP energy market net revenues are small and there is little contribution to fixed costs. When less efficient coal units are on the margin, net revenues are higher for more efficient coal units. Coal units also receive higher net revenue when CTs set price based on gas costs. In 2009, with generally lower load levels, CTs ran less often, which reduced the net revenue received by coal plants. Similarly, with lower gas prices in 2009, and with the spread between the delivered price of natural gas and the delivered price of coal narrowing, there are hours in which the more efficient CC has lower generating costs than the CP.

While the net revenue results demonstrate the role of the capacity market in ensuring appropriate incentives for generating units, the net revenue results also demonstrate that there is a set of units, relatively small subcritical coal units, that is at risk. PJM should ensure that it carefully considers the implications of the potential loss of these units and whether market design changes are required to address that potential loss.

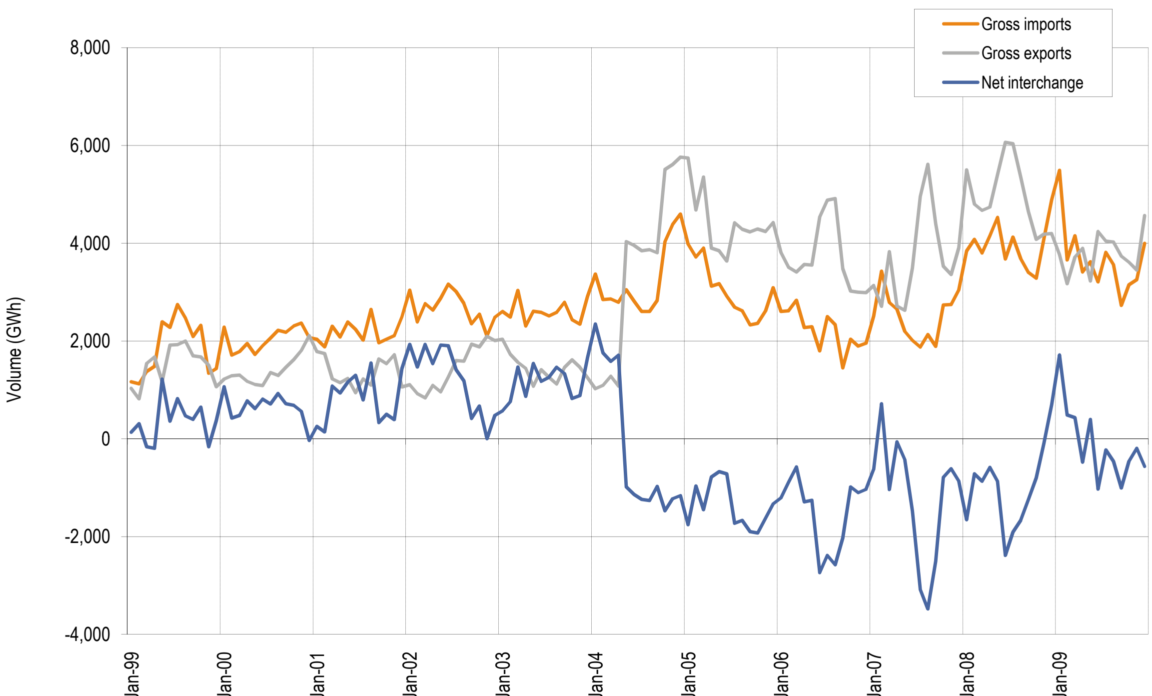
Interchange Transactions

PJM market participants import energy from, and export energy to, external regions continuously. The transactions involved may fulfill long-term or short-term bilateral contracts or take advantage of short-term price differentials. The external regions include both market and non market balancing authorities.

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Market.** PJM was a net importer of energy in the Real-Time Market in January, February, March and May of 2009, and a net exporter of energy in the remaining months. In the Real-Time Market, monthly net interchange averaged -117 GWh.[26] Gross monthly import volumes averaged 3,671 GWh while gross monthly exports averaged 3,788 GWh.

Figure 5 PJM scheduled import and export transaction volume history: 1999 through December 2009



- **Aggregate Imports and Exports in the Day-Ahead Market.** PJM was a net importer of energy in the Day-Ahead Market in July, and a net exporter of energy in the remaining months. In the Day-Ahead Market, monthly net interchange averaged -753 GWh. Gross monthly import volumes averaged 4,073 GWh while gross monthly exports averaged 4,826 GWh.

26 Net interchange is gross import volume less gross export volume. Thus, positive net interchange is equivalent to net imports and negative net interchange is equivalent to net exports.

- **Aggregate Imports and Exports in the Day-Ahead Market versus the Real-Time Market.** In 2009, gross imports in the Day-Ahead Energy Market were 111 percent of the Real-Time Market's gross imports (90 percent in 2008), gross exports in the Day-Ahead Market were 127 percent of the Real-Time Market's gross exports (106 percent in 2008) and net interchange in the Day-Ahead Energy Market was 642 percent of net interchange in the Real-Time Energy Market (-1,407 GWh in the Real-Time Market and -9,033 GWh in the Day-Ahead Market).

- **Interface Imports and Exports in the Real-Time Market.** In the Real-Time Market in 2009, there were net exports at 12 of PJM's 21 interfaces.[27] The top three net exporting interfaces in the Real-Time Market accounted for 62 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 28 percent, PJM/Neptune (NEPT) with 25 percent and PJM/Carolina Power and Light-East (CPLE) with 9 percent of the net export volume. There are three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)). Combined, these interfaces made up 55 percent of the total net PJM exports in the Real-Time Market. Nine PJM interfaces had net imports, with two importing interfaces accounting for 88 percent of total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 68 percent and PJM/Michigan Electric Coordinated System (MECS) with 20 percent.

- **Interface Imports and Exports in the Day-Ahead Market.** In the Day-Ahead Market, there were net exports at 14 of PJM's 21 interfaces. The top three net exporting interfaces accounted for 58 percent of the total net exports, PJM/western Alliant Energy Corporation (ALTW) with 24 percent, PJM/eastern Alliant Energy Corporation (ALTE) with 17 percent and PJM/Neptune (NEPT) with 17 percent. Seven PJM interfaces had net imports in the Day-Ahead Market, with three interfaces accounting for 85 percent of the total net imports: PJM/OVEC with 53 percent, PJM/Wisconsin Energy Corporation (WEC) with 18 percent and PJM/Michigan Electric Coordinated System (MECS) with 15 percent.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and Midwest Independent System Operator (MISO) Interface Prices.** During 2009, the relationship between prices at the PJM/MISO Interface and at the MISO/PJM Interface reflected economic fundamentals as did the relationship between interface price differentials and power flows between PJM and the Midwest ISO.

- **PJM and New York ISO Interface Prices.** During 2009, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus reflected economic fundamentals, as did the relationship between interface price differentials and power flows between PJM and the NYISO. Both continued to be affected by differences in institutional and operating practices between PJM and the NYISO.

27 In September 2009, the Linden Variable Frequency Transformer (VFT) facility began testing. This facility is treated as a separate interface with PJM, bringing the total interfaces with PJM to 21.

Operating Agreements with Bordering Areas

- **PJM and New York Independent System Operator, Inc. Joint Operating Agreement (JOA).**[28] On May 22, 2007, the JOA between PJM and the New York Independent System Operator (NYISO) became effective. This agreement was developed to improve reliability. It also formalizes the process of electronic checkout of schedules, the exchange of interchange schedules to facilitate calculations for available transfer capability (ATC) and standards for interchange revenue metering. While the JOA does not include provisions for market based congestion management or other market to market activity, in 2008, at the request of PJM, PJM and the NYISO began discussion of a market based congestion management protocol, which continued into 2009. By order issued July 16, 2009, the Commission directed the NYISO to "develop and file a report on long-term comprehensive solutions to the loop flow problem, including addressing interface pricing and congestion management, and any associated tariff revisions, within 180 days of the date of this order."[29] After working in collaboration with PJM, the Midwest ISO and the Ontario Independent Electricity System Operator (IESO), including an opportunity to comment from their stakeholders and market monitors, the NYISO filed on January 12, 2010, a *Report on Broader Regional Markets; Long-Term Solutions to Lake Erie Loop Flow.*[30]

- **PJM and Midwest ISO Joint Operating Agreement.** The Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., executed on December 31, 2003, continued during 2009. The market based congestion management process is reviewed and modified as necessary through the Congestion Management Process (CMP) protocols.[31]

  In 2009, the Midwest ISO requested that PJM review the components of the CMP to verify data accuracy. During this review, it was found that some data inputs to the market flow calculator were incorrect during the time period from April 2005 through June 2009. The resulting inaccuracies in the market flow calculation meant that the Midwest ISO received less compensation than appropriate. While the errors in input data have been corrected for market to market activity moving forward, the Midwest ISO and PJM are currently in the process of calculating the shortfall. PJM reported an estimate of 77.5 million dollars.[32]

  As of December 31, 2009, PJM and the Midwest ISO had not agreed upon a method to estimate the amount for the entire period. Differences have also emerged over how the parties are administering the JOA, such as the use by the Midwest ISO of proxy flowgates. This practice, if confirmed, measured and determined inconsistent with the JOA, would mean that the Midwest ISO received more compensation than appropriate. The parties are currently engaged in a confidential FERC mediated settlement process to resolve these issues.

28 See PJM. "Joint Operating Agreement Among And Between New York Independent System Operator Inc. And PJM Interconnection, L.L.C." (May 22, 2007) (Accessed January 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20071102-nyiso-pjm.ashx> (208 KB).

29 128 FERC ¶ 61,049 (Ordering Para. B), *order on clarification*, 128 FERC ¶ 61,239.

30 See NYISO. "Report on Broader Regional Markets: Long-Term Solutions to Lake Erie Loop Flow" (January 12, 2010) (Accessed January 25, 2010) <http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/01/NYISO_Rpt_BRM_01_12_10FNL.pdf> (131 KB).

31 See PJM. "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) (Accessed January 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (1,294 KB).

32 See PJM. "PJM/MISO Market Flow Calculation Error"(September 10, 2009) (Accessed January 15, 2010) <http://www.pjm.com/committees-and-groups/committees/~/media/committees-groups/committees/mic/20090910/20090910-item-07-m2m-calculation-error.ashx> (49 KB).

- **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[33] The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. The agreement continued to be in effect through 2009.

- **PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement.**[34] On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. The agreement remained in effect through 2009. As part of this agreement, both parties agreed to develop a formal CMP. During 2009, PEC and PJM continued confidential discussions on more granular interface pricing as well as the development of the CMP.

- **PJM and Virginia and Carolinas Area (VACAR) South Reliability Coordination Agreement.**[35] On May 23, 2007, PJM and VACAR South (VACAR is a sub-region within the NERC Southeastern Electric Reliability Council (SERC) Region) entered into a reliability coordination agreement. It provides for system and outage coordination, emergency procedures and the exchange of data. Provisions are also made for regional studies and recommendations to improve the reliability of interconnected bulk power systems.

Other Agreements with Bordering Areas

- **Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts.** During 2009, PJM continued to operate under the terms of the operating protocol developed in 2005.[36]

- **Neptune Underwater Transmission Line to Long Island, New York.** On July 1, 2007, a 65-mile direct current (DC) transmission line from Sayreville, New Jersey, to Nassau County on Long Island, via undersea and underground cable, was placed in service, providing a direct connection from PJM to the New York Independent System Operator, Inc. (NYISO). This is a merchant 230 kV transmission line with a capacity of 660 MW. The line is bidirectional, but Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York.[37] The average hourly flow for 2009 was -555 MW.

- **Linden Variable Frequency Transformer (VFT) Facility.** On November 1, 2009, the Linden VFT facility was placed in service, providing an additional direct connection from PJM to the NYISO. A variable frequency transformer allows for fast responding continuous bidirectional power flow control, similar to that of a phase angle regulating transformer.[38] The facility includes 350 feet of new 230 kV transmission line and 1,000 feet of new 345 kV transmission line, with a capacity of 300 MW. While the Linden VFT is a bidirectional facility, Schedule 16 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York.[39] The average hourly flow for 2009 was -136 MW.[40]

33 See PJM. "Congestion Management Process (CMP) Master" (May 1, 2008) (Accessed January 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20080502-miso-pjm-tva-baseline-cmp.ashx> (432 KB).
34 See PJM. "Joint Operating Agreement (JOA) between Progress Energy Carolinas, Inc. and PJM" (July 29, 2005) (Accessed January 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/20081114-progress-pjm-joa.ashx> (2,983 KB).
35 See PJM. "Adjacent Reliability Coordinator Coordination Agreement" (May 23, 2007) (Accessed January 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx> (528 KB).
36 111 FERC ¶ 61,228 (2005).
37 See PJM. "PJM Open Access Transmission Tariff" (October 15, 2009) (Accessed January 15, 2010) <http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx> (9,403 KB).
38 A phase angle regulating transformer (PAR) allows dispatchers to change the flow of MW over a transmission line by changing the impedance of the transmission facility.
39 See PJM. "PJM Open Access Transmission Tariff" (October 15, 2009) (Accessed January 15, 2010) <http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx> (9,884 KB).
40 The average hourly flow reported for the Linden Variable Frequency Transformer includes the scheduled flow during the testing period that occurred starting in September 2009.

Interchange Transaction Issues

- **Loop Flows.** Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. Loop flows arise from transactions on contract paths that do not correspond to the actual physical paths that the energy takes. Although PJM's total scheduled and actual flows differed by 2.2 percent in 2009, greater differences existed at individual interfaces. Loop flows are a significant concern because they have negative impacts on the efficiency of market areas with explicit locational pricing, including impacts on locational prices, on Financial Transmission Right (FTR) revenue adequacy and on system operations, and can be evidence of attempts to game such markets.

  — **Loop Flows at the PJM/MECS and PJM/TVA Interfaces.** As it had in 2008, the PJM/Michigan Electric Coordinated System (MECS) Interface continued to exhibit large imbalances between scheduled and actual power flows (-14,441 GWh during 2009 and -14,014 GWh during the calendar year 2008), particularly during the overnight hours. The PJM/TVA Interface also exhibited large mismatches between scheduled and actual power flows (3,840 GWh during 2009 and 4,065 GWh during the calendar year 2008). The net difference between scheduled flows and actual flows at the PJM/TVA Interface was imports while the net difference at the PJM/MECS Interface was exports.

  — **Loop Flows at PJM's Southern Interfaces.** The difference between scheduled and actual power flows at PJM's southern interfaces (PJM/TVA and PJM/Eastern Kentucky Power Corporation (EKPC) to the west and PJM/eastern portion of Carolina Power & Light Company (CPLE), PJM/western portion of Carolina Power & Light Company (CPLW) and PJM/DUK to the east) was significant during 2009.

  The southern interfaces have historically experienced significant loop flows.[41] A portion of the historic loop flows were the result of the fact that the interface pricing points (Southeast and Southwest) allowed the opportunity for market participants to falsely arbitrage pricing differentials, creating a mismatch between actual and scheduled flows. On October 1, 2006, PJM modified the southern interface pricing points by creating a single import pricing point (SouthIMP) and a single export interface pricing point (SouthEXP). At the time of the consolidation of the Southeast and Southwest Interface pricing points, some market participants requested grandfathered treatment for specific transactions from PJM under which they would be allowed to keep the Southeast and Southwest Interface pricing. (The average difference between the Locational Marginal Price (LMP) at the Southeast pricing points and the SouthEXP pricing point was $2.61 in 2009 and the average difference between LMP at the Southwest pricing points and the SouthEXP pricing point was -$1.42 in 2009. In other words, it was more expensive to buy from PJM for export to the south under the old pricing for Southeast pricing point and less expensive to buy from PJM for export to the south under the old pricing for the Southwest pricing point.) These agreements remain in place. The MMU recommends that these agreements be terminated, as the interface prices received for these agreements do not represent the economic fundamentals of locational marginal pricing. As an alternative, the agreements should be made public and the same terms should be made available to all qualifying entities.

41 See *2002 State of the Market Report,* Part 2, Section 3, "Interchange Transactions." (March 5, 2003) (Accessed January 19, 2010) <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2002/SOM2002-part2.pdf> (4,068 KB).

Loop flows result, in part, from a mismatch between incentives to use a particular scheduled path and the market based price differentials that result from the actual physical flows on the transmission system. PJM's approach to interface pricing attempts to match pricing with physical flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SWPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SWPP, through the Midwest ISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (the Midwest ISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south would require the market participant to acquire transmission through non-market balancing authorities, and thus incurring additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SWPP and sinking in PJM will create flows across the southern border and prices those transactions at the SouthIMP Interface price. As a result, the transaction is priced appropriately, but a difference between scheduled and actual flows is created at both the Midwest ISO border (higher scheduled than actual flows) as well as the southern border (higher actual than scheduled flows).

— **Loop Flows at PJM's Northern Interfaces.** In 2008, new loop flows were created when pricing rules gave participants an incentive to schedule power flows in a manner inconsistent with the associated actual power flows.[42] PJM's interface pricing calculations correctly reflected the actual power flows, but the NYISO's interface pricing did not. One result was increased congestion charges in the NYISO system. PJM's interface pricing rules eliminated the incentive to schedule power flows on paths inconsistent with actual power flows in order to take advantage of price differences. In this case, PJM interface pricing rules resulted in PJM paying for the import based on its source in the NYISO and appropriately disregarded the scheduled path.

By order issued July 16, 2009, the Commission directed the NYISO to "develop and file a report on long-term comprehensive solutions to the loop flow problem, including addressing interface pricing and congestion management, and any associated tariff revisions, within 180 days of the date of this order."[43]

Consistent with the Commission's direction, during the third quarter of 2009, the NYISO convened the Broader Regional Markets group, which included representatives from PJM, the NYISO, the Midwest ISO and the IESO, to develop a solution to the northeastern loop flow issues. The group solicited comments from stakeholders and the market monitors. The MMU filed comments on November 13, 2009.[44]

The group developed several recommendations, including the use of phase angle regulators (PARs) to control energy flows, a buy-through congestion method, the development of a new tool, using existing functionality within the NERC Interchange Distribution Calculator (IDC), to visualize the loop flows and an interregional transaction coordination approach to

42 See the *2008 State of the Market Report for PJM*, Volume II, "Interchange Transactions."
43 128 FERC ¶ 61,049 (Ordering Para. B), *order on clarification*, 128 FERC ¶ 61,239.
44 See "IMM Comments on Draft Loop Flow Recommendations of the Broader Regional Markets"(November 13, 2009) (Accessed January 21, 2010) <http://www.monitoringanalytics.com/reports/Reports/2009/IMM_Comments_on_Draft_Loop_Flow_Recommendations_20091113.pdf> (86 KB).

align business rules across the northeast ISOs/RTOs. On January 12, 2010, in compliance with the Commission's directive, NYISO submitted its *Report on Broader Regional Markets; Long-Term Solutions to Lake Erie Loop Flow.*[45]

Engineering approaches to address loop flows, such as PARs and variable frequency transformers, are a means to help ameliorate loop flow issues, but they do not address the root cause of loop flows. So long as these physical solutions are used in conjunction with more comprehensive market solutions, the MMU supports cost effective investment in additional PARs for system control. With the possible exception of cost allocation issues, the use of PARs does not appear to be controversial. Engineering approaches should not serve as a basis to defer or deflect attention from the development of market solutions.

Implementing a buy-through congestion methodology is also unlikely to resolve the underlying pricing issue. PJM offers a similar product, where market participants are allowed to continue to flow their transactions when they would otherwise be curtailed by a transmission loading relief procedure (TLR), if they are willing to pay the congestion costs of their parallel flows affecting the PJM system. This product, called "TLR Buy-Through", was implemented in PJM in 2001. In the nearly eight years that PJM has offered this product, it has never been used by market participants. Instead, the transactions were curtailed in the TLR process to alleviate the loop flows.

The report also included a recommendation that the NYISO move to a less than hourly dispatch timeframe through interregional coordination. While this recommendation did not include details, redispatch on the quarter hour would allow NYISO market participants to respond more quickly to the NYISO pricing signals.

Parallel flow visualization will provide additional information to the reliability coordinators, and will also assign a non-firm generation to load component to congestion within non-market areas. The MMU supports this project, as it will provide additional details and archived data to better analyze loop flows. However, the work of the Broader Regional Market group and the continued development of this tool within the North American Electric Reliability Corporation (NERC)/North American Energy Standards Board (NAESB) arena do not require linkage. It would be more productive to focus on direct solutions to loop flow issues rather than the already ongoing development of loosely related industry tools.

Faulty market rules, which provided incentives to market participants to schedule energy on paths inconsistent with the physical flows, were responsible for the loop flows that motivated the NYISO's initial filing in this proceeding. The solution to this problem should start with and give priority to appropriate interface pricing that reflects the actual flow of energy. Although the buy-through congestion approach also attempts to address this issue, a more cost effective solution would assign interface prices based on the Generation Control Area (GCA) for imports and Load Control Area (LCA) for exports, as designated on the NERC e-Tag. This method for interface pricing has been used by PJM and the Midwest ISO for several years, and could be implemented immediately by other RTOs/ISOs at minimal cost.

45 See NYISO. "Report on Broader Regional Markets: Long-Term Solutions to Lake Erie Loop Flow" (January 12, 2010) (Accessed January 25, 2010) <http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/01/NYISO_Rpt_BRM_01_12_10FNL.pdf> (131 KB).

The MMU recommends that a change in the interface pricing methodology be addressed directly. The MMU recommends that the parties consider the uniform adoption of a GCA to LCA pricing methodology, similar to that used by PJM, to set transaction prices based on the actual flow of energy from source to sink. With the appropriate pricing, the incentive for market participants to schedule around specific RTOs/ISOs would be eliminated.

— **Data Required for Full Loop Flow Analysis.** Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. The differences between actual and scheduled power flows can be the result of a number of underlying causes. To adequately investigate the causes of loop flows, complete data are required.

Actual power flows are the metered flows at an interface for a defined period. Scheduled power flows are the flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for a balancing authority (net actual interchange) and the total scheduled flows for the balancing authority (net scheduled interchange) for a defined period. Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface. The result is loop flow, despite the fact that system actual and scheduled flow could net to a zero difference. As an illustration, although PJM's total scheduled and actual flows differed by only 2.2 percent in 2009, much greater differences existed at individual interfaces.

Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. Loop flows can arise from transactions scheduled into, out of or around a balancing authority on contract paths that do not correspond to the actual physical paths on which energy flows. Outside of LMP-based energy markets, energy is scheduled and paid for based on contract path, without regard to the path of the actual energy flows. Loop flows can also result from actions within balancing authorities.

Loop flows are a significant concern. Loop flows have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. In general, the detailed sources of the identified differences between scheduled and actual flows remain unclear as a result of incomplete or inadequate access to the required data.

A complete analysis of loop flow would provide additional insight that could lead to enhanced overall market efficiency and clarify the interactions among market areas and among market and non market areas. A complete analysis of loop flow would improve the overall transparency of electricity transactions. There are areas with transparent markets, and there are areas with less transparent markets (non market areas), but these areas together comprise a market, and overall market efficiency would benefit from the increased transparency that would derive from a better understanding of loop flows.

For a complete loop flow analysis, several types of data are required from all balancing authorities in the Eastern Interconnection. NERC Tag data, dynamic schedule and pseudo-tie data and actual tie line data are required in order to analyze the differences between actual and scheduled transactions. The area control error (ACE) data, market flow impact data and generation and load data are required in order to understand the sources, within each balancing authority, of loop flows that do not result from differences between actual and scheduled transactions. All data should be made available in downloadable format in order to make analysis possible. A data viewing tool alone is not adequate.

- **Dynamic Interface Pricing.** According to the *PJM Interface Price Definition Methodology,* dynamic interface pricing calculations use actual system conditions to determine a set of weighting factors for each external pricing point in an interface price definition.[46] The weighting factors are determined in such a manner that the interface reflects actual system conditions. The topology of the transmission system is constantly changing, as generation comes on and off line, and transmission lines come in and out of service. The interface pricing methodology implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are generally static, and are modified only occasionally. The MMU recommends that PJM monitor, and adjust as necessary, the buses and weightings applied to the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis.

- **PJM Transmission Loading Relief Procedures (TLRs).** During 2009, PJM issued 129 TLRs. Of the 129 TLRs issued, the highest levels reached were TLR 3a in 61 instances and TLR 3b in the remaining 68 events. This represents a decrease of 14 percent in TLRs from the 150 TLRs issued during 2008 (55 TLR 3a, 92 TLR 3b, 2 TLR 4 and 1 TLR 5b).

- **Up-To Congestion.** The original purpose of up-to congestion transactions was to allow market participants to submit a maximum congestion charge, up to $25, they were willing to pay on an import, export or wheel through transaction in the Day-Ahead Market. This product was offered as a tool for market participants to limit their congestion exposure on physical transactions in the Real-Time Market.

  Submitting an up-to congestion bid is similar to entering a matched pair of incremental offers (INC) and decrement bids (DEC). However, there are a number of advantages to using the up-to congestion product relative to using sets of INC and DEC bids. For example: an up-to congestion transaction is approved or denied as a single transaction; an up-to congestion bid will only clear the Day-Ahead Market if the maximum congestion bid criterion is met; and an up-to congestion transaction is not subject to day-ahead or balancing operating reserve charges.

  In 2008, market participants requested that PJM increase the maximum value for up-to congestion offers, and to also allow negative offers for these transactions. PJM expressed concerns regarding the mismatch between up-to congestion transactions in the Day-Ahead Market and real-time transactions.[47] In the Day-Ahead Energy Market, an up-to congestion import transaction is submitted and modeled as an injection at the interface and a withdrawal

46 See "PJM Interface Pricing Definition Methodology." (September 29, 2006) (Accessed January 20, 2010) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20060929-interface-definition-methodology1.ashx> (33 KB).

47 See PJM. "Up-to Congestion Transactions. Proposed Interim Changes Pending Development of a Spread Product" (February 21, 2008) (Accessed January 15, 2010) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20080221/20080221-item-03-up-to-congestion-transactions.ashx> (39KB).

at a specific PJM node. In real time, the power does not flow to the PJM node specified in the day-ahead transaction. This mismatch results in inaccurate pricing and can provide a gaming opportunity. Increasing the offer cap, and allowing negative offers, could increase the cleared volume of up-to congestion transactions, and aggravate the issue.

On February 21, 2008, the PJM Markets and Reliability Committee (MRC) approved PJM's proposed resolution to the request for implementation on March 1, 2008.[48] The proposal allowed for a modification to the offer cap from $25 to ± $50, including an explicit allowance for negative offers. PJM also eliminated a relatively small number of available sources and sinks in an effort to partially address the mismatch between the Day-Ahead and Real-Time Market scheduling. In the period following the March 1, 2008 modifications to the up-to congestion bids, through December 31, 2009, the monthly average of up-to congestion bidding increased from 3,027.1 GWh to 4,556.8 GWh.

The up-to congestion transactions in 2009 were comprised of 45.6 percent imports, 51.7 percent exports and 2.7 percent wheeling transactions. Only 0.2 percent of the up-to congestion transactions had matching Real-Time Market transactions. Of the up-to congestion transactions with matching Real-Time Market transactions, 26.5 percent were imports, 58.5 percent were exports and 15.0 percent were wheel through transactions.

When the up-to congestion product was used as intended, with matching Real-Time Market transactions, 57.0 percent of the total cleared transaction MW were profitable in 2009. The net profit on all these transactions was approximately $100,000. When up-to congestion transactions did not have a matching Real-Time Market transaction, 61.7 percent of the total cleared transaction MW were profitable. The net loss on all these transactions was approximately $31.5 million.

The MMU recommends that PJM require all import and export up-to congestion transactions to pay day-ahead and balancing operating reserve charges. This would continue to exclude wheel through transactions from operating reserve charges. Up-to congestion transactions are being used as matching INC and DEC bids and have corresponding impacts on the need for operating reserves charges.

The MMU also recommends that PJM eliminate all internal PJM buses for use in up-to congestion bidding and for all import and export transactions in the Day-Ahead and the Real-Time Markets. The use of specific buses is equivalent to creating a scheduled transaction to a specific point which will not be matched by the actual corresponding power flow.

- **Interface Pricing Agreements with Individual Companies.** PJM entered into confidential locational interface pricing agreements with Duke Energy Carolinas, Progress Energy Carolinas and North Carolina Municipal Power Agency (NCMPA) in 2007 that provided more advantageous pricing to these companies than the applicable interface pricing rules. Each of these agreements established a locational price for purchases and sales between PJM and the individual company that applied under specified conditions. There were a number of issues with these agreements including that they were not made public until specifically requested

48 See PJM. "20080221-minutes.pdf" (February 21, 2008) (Accessed January 15, 2010) <http://www.pjm.com/~/media/committees-groups/committees/mrc/20080221/20080221-minutes.ashx> (61KB).

by the MMU, that the pricing was not available to other participants in similar circumstances, that the pricing was not designed to reflect actual power flows, that the pricing did not reflect full security constrained economic dispatch in the external areas and that the pricing did not reflect appropriate price signals. PJM recognized that the price signals in the agreements were inappropriate, and in 2008 provided the required notification to terminate the agreements. The agreements were terminated on February 1, 2009.

In addition to terminating the agreements, PJM worked through the stakeholder process to develop a revision to the tariff that would enhance the method for calculating interface pricing with all neighboring balancing authorities that wish to take advantage of the more granular interface pricing. The new interface pricing methodology includes three options available for interface pricing between PJM and neighboring balancing authorities (BA).[49] These options are: the existing SouthIMP/SouthEXP prices; the "Hi/Low" method; and the "Marginal Cost Proxy Method."

The proposed tariff revisions were filed with FERC on December 2, 2008, and approved on May 1, 2009.[50] As a condition of the approval, the Commission required that PJM establish procedures to negotiate, in good faith, a congestion management agreement (which is necessary for eligibility to continue the marginal cost proxy pricing method beyond January 31, 2010), and to file such agreements unexecuted, if requested, after 90 days.[51] As of December 31, 2009, Duke Energy Carolinas and Progress Energy Carolinas were in the process of negotiating a congestion management agreement with PJM.

In September 2009, Progress Energy Carolinas provided an update to the PJM Market Implementation Committee (MIC) on the proposed congestion management agreement.[52] As presented, the proposal includes three parts: enhanced available transmission capability (ATC) coordination; monitoring of real-time parallel flow impacts; and managing real-time congestion.

The MMU supports congestion management agreements but recommends that such agreements be implemented on a regional basis rather than between RTOs and individual external utility companies. In addition, there are a number of issues in the PJM/PEC agreement that need to be addressed. Most fundamentally, any congestion management agreement must ensure that the interface price established reflects the economic fundamentals of an LMP market.

- **Spot Import.** Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. However, PJM interpreted its JOA with the Midwest ISO to require a limitation on cross-border transmission service and energy schedules in order to limit the impact of such transactions on selected external flowgates.[53] The rule caused the availability of spot import service to be limited by ATC on the transmission path. As a result of the rule, requests for service sometimes exceeded the amount of service available

49 The NERC functional model classifies the balancing authority as a reliability service function, with, among other things, the responsibility for balancing generation, demand and interchange balance. See "Reliability Functional Model" (August 2008) (Accessed January 20, 2010) <http://www.nerc.com/files/Functional_Model_V4_CLEAN_2008Dec01.pdf> (381 KB).

50 PJM Interconnection, L.L.C., Transmittal Letter, Docket No. ER09-369-000 (December 2, 2008). PJM Interconnection, L.L.C., Letter Order, Docket No. ER09-369-000 (May 1, 2009).

51 127 FERC ¶ 61,101.

52 See "PJM-Progress Draft Congestion Management Agreement"(September 10, 2009) (Accessed January 15, 2010) <http://www.pjm.com/~/media/committees-groups/committees/mic/20090910/20090910-item-08-pjm-progress-draft-congestion-management-agreement.ashx> (69 KB).

53 See "WPC White Paper" (April 20, 2007) (Accessed January 15, 2010) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx> (97 KB).

to customers. Unlike non-firm, point to point, willing to pay congestion (WPC) service, spot import (a network service) is provided at no charge to the market participant offering into the PJM spot market.

The new spot import rules provided incentives to hoard spot import capability. In the *2008 State of the Market Report for PJM*, the MMU recommended that PJM reconsider whether a new approach to limiting spot import service is required or whether a return to the prior policy with an explicit system of managing any related congestion is preferable. PJM and the MMU jointly addressed this issue through the stakeholder process, recommending that all unused spot import service be retracted if not tagged within 30 minutes from the reservations queued time intraday, and within two hours from the queue time when queued the day prior. On June 23, 2009, PJM implemented the new business rules. Since the implementation of the rule changes, the spot import service usage has been over 99 percent, compared to 70 percent prior to the modification. The MMU will continue to monitor participant use of spot import service.

- **Willing to Pay Congestion and Not Willing to Pay Congestion.** When reserving non-firm transmission, the market participant has the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system, if necessary, to allow the energy transaction to continue to flow.

  If a market participant is not willing to pay congestion, it is the responsibility of the PJM operators to curtail their transaction as soon as there is a difference in LMPs between the source and sink associated with their transaction.

  Uncollected congestion charges occur when PJM operators do not curtail a not willing to pay congestion transaction when there is congestion. The method that PJM uses to curtail not willing to pay congestion requires the transaction to be loaded. While loaded, if congestion occurs for a not willing to pay congestion transaction, a message is sent to the PJM operators requesting the transaction be curtailed at the next 15 minute interval.

  The total uncollected congestion charges for 2009 were $688,547 which was a reduction of 92 percent from the 2008 total of $8,662,695. The MMU recommends modifying the evaluation criteria via a change to PJM's market software, to ensure that a not willing to pay congestion transactions is not permitted to flow in the presence of congestion.

- **Ramp Availability.** The purpose of imposing a ramp limit is to help ensure the reliable operation of the PJM system. The 1,000 MW ramp limit was set based on the generally available ramping capability of generators on the PJM system. PJM must limit the amount of imports or exports at each 15 minute interval to account for the physical characteristics of the generation to meet the imports and exports. In 2008, there was an increase in 15 minute external energy transactions that caused swings in imports and exports submitted in response to intra-hour LMP changes. As a result, a new business rule was proposed, and approved, to require all transactions to be at least 45 minutes in duration.[54] On May 1, 2008, the Enhanced Energy Scheduling (EES) system was modified to require that transactions be 45 minutes in duration. Since that modification, market participants have scheduled 1 MW for the first 30 minutes, and increased to a larger MW value for the last 15 minutes, thus continuing to create significant swings in imports and exports. The MMU recommends that the EES application be modified further to require that transactions be scheduled for a constant MW level over the entire 45 minutes as soon as possible.

54 PJM "Manual 41: Managing Interchange," Revision 03 (November 24, 2008), p. 5.

Interchange Transactions Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed non market areas, all electricity transactions are part of a single energy market. Nonetheless, there are significant differences between market and non market areas. Market areas, like PJM, include essential features such as locational marginal pricing, financial hedging tools (FTRs and Auction Revenue Rights (ARRs) in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Non market areas do not include these features. The market areas are extremely transparent and the non market areas are not transparent.

The MMU analyzed the transactions between PJM and neighboring balancing authorities for 2009, including evolving transaction patterns, economics and issues. During 2009, PJM was a net exporter of energy and a large share of both import and export activity occurred at a small number of interfaces. Three interfaces accounted for 62 percent of the total real-time net exports and two interfaces accounted for 88 percent of the real-time net import volume. Three interfaces accounted for 58 percent of the total day-ahead net exports and three interfaces accounted for 85 percent of the day-ahead net import volume.

In order to manage interactions with other market areas, PJM has entered into formal agreements with a number of balancing authorities. The redispatch agreement between PJM and the Midwest ISO is a model for such agreements and is being continuously improved. As interactions with external areas are increasingly governed by economic fundamentals, interface prices and volumes reflect supply and demand conditions. However, more needs to be done to ensure that market signals are used to manage constraints affecting interarea transactions. PJM and the NYISO, as neighboring market areas, should develop market based congestion management protocols as soon as practicable. The NYISO and the neighboring balancing authorities have taken initial steps to do so. In addition, PJM should continue its efforts to gain access to the data required to understand loop flows in real-time and to ensure that responsible parties pay their appropriate share of the costs of redispatch.

In order to manage interactions with non market areas, PJM has entered into coordination agreements with other balancing authorities as a first step. In addition, PJM has attempted to address loop flows by creating and modifying interface prices that reflect actual power flows, regardless of contract path. Loop flows are also managed through the use of redispatch and TLR procedures. PJM has entered into dynamic scheduling agreements with generation owners for specific units to permit transparent, market based signals and responses. PJM has modified the rules governing the use of limited transaction ramp capability between PJM and contiguous balancing authorities to help ensure that transactions are free to respond to market signals and to reduce the ability to game or hoard ramp. PJM also entered into agreements with specific balancing authorities for separate interface pricing that have been questioned with respect to transparency and equal access. PJM needs to ensure that such pricing is transparent, accurately reflects actual LMP impacts on PJM, and that all participants have access to the defined pricing when in the same position. The goal of such pricing agreements should be to replicate LMP price signals that reflect the actual loads and the actual dispatch of units for all parties to such agreements.

Loop flows are defined as the difference between actual and scheduled (contract path) power flows at one or more specific interfaces. Loop flows do not exist within markets because power flows are explicitly priced under locational marginal pricing, but markets can create loop flows in external balancing authorities. PJM attempts to manage loop flows by creating interface prices that reflect the actual power flows, regardless of contract path. This approach cannot be completely successful as long as it is possible to schedule a transaction and be paid based on that schedule, regardless of how the power flows.

PJM continues to face significant loop flows for reasons that continue not to be fully understood as a result of inadequate access to the required data. A complete analysis of loop flow across the Eastern Interconnection could improve overall market efficiency, shed light on the interactions among market and non market areas and permit market based congestion management across the Eastern Interconnection. Loop flows can have negative impacts on the efficiency of market prices in markets with explicit locational pricing and can be evidence of attempts to game such markets. Loop flows also have poorly understood impacts on non market areas. The MMU recommends that the RTOs request action, and that both NERC and FERC consider taking the action required to make these data available to the RTOs and market monitors to make a full market analysis possible.

PJM needs to continue to pay careful attention to all the mechanisms used to manage flows at the interfaces between PJM and surrounding areas. PJM manages its interface with external areas, in part, through limitations on the amount of change in net interchange within 15-minute intervals. The change in net interchange is referred to as ramp. Changes in net interchange affect PJM operations and markets as they require increases or decreases in generation to meet load. As a result of the fact that ramp is free but is a valuable resource, there are strong incentives to game the ramp rules. The same is true of spot import service. Up-to congestion service is a Day-Ahead Market option used to import power to or export power from PJM which can create mismatches between transactions in the Day-Ahead Energy Market and the Real-Time Energy Market that result in inaccurate pricing and can provide a gaming opportunity. The MMU recommends that PJM eliminate all internal PJM buses for use in up-to congestion bidding and for all import and export transactions in the Day-Ahead and the Real-Time Markets. The use of specific buses is equivalent to creating a scheduled transaction to a specific point which will not be matched by the actual corresponding power flow.

Capacity Market

Each organization serving PJM load must meet its capacity obligations by acquiring capacity resources through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can affect the financial consequences of purchasing capacity in the capacity market by constructing generation and offering it into the capacity market, by entering into bilateral contracts, by developing demand-side resources and Energy Efficiency (EE) resources and offering them into the capacity market, or by constructing transmission upgrades and offering them into the capacity market.

The MMU analyzed market structure, participant conduct and market performance in the PJM Capacity Market for calendar year 2009, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.

RPM Capacity Market

Market Design

On June 1, 2007, the Reliability Pricing Model (RPM) Capacity Market design was implemented in the PJM region, replacing the Capacity Credit Market (CCM) design that had been in place since 1999.[55] The RPM design represents a significant change in the structure of the Capacity Market in PJM. The RPM is a forward-looking, annual, locational market, with a must offer requirement for capacity and mandatory participation by load, with performance incentives for generation, that includes clear, market power mitigation rules and that permits the direct participation of demand-side resources.

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future. Effective with the 2012/2013 delivery year, First, Second and Third Incremental Auctions (IA) are held for each delivery year.[56] Prior to the 2012/2013 delivery year, the second incremental auction is conducted if PJM determines than an unforced capacity resource shortage exceeds 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[57] Previously, First, Second, and Third Incremental Auctions were conducted 23, 13, and four months, respectively, prior to the delivery year. Also effective for the 2012/2013 delivery year, a conditional incremental auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.

RPM prices are locational and may vary depending on transmission constraints.[58] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option.

55 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2009 State of the Market Report for PJM*, Section 5, "Capacity Market" and include all capacity within the PJM footprint.
56 126 FERC ¶ 61,275 (2009).
57 Docket No. ER10-366-000.
58 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power, that define offer caps based on the marginal cost of capacity and that have flexible criteria for competitive offers by new entrants or by entrants that have an incentive to exercise monopsony power. Demand-side resources and Energy Efficiency resources may be offered directly into RPM auctions and receive the clearing price without mitigation.

Market Structure

- **Supply.** Total internal capacity increased 350.2 MW from 156,968.0 MW on June 1, 2008, to 157,318.2 MW on June 1, 2009.[59] This increase was the result of 439.2 MW of new generation, 74.1 MW of generation uprates, 220.6 MW of demand resource (DR) mods, and a decrease of 383.7 MW due to higher EFORds.

  In the 2010/2011, 2011/2012, and 2012/2013 auctions, new generation increased 3,271.9 MW; 651.9 MW came out of retirement and net generation deratings were 2,994.9 MW, for a total of 928.9 MW. DR and Energy Efficiency (EE) offers increased 9,409.3 MW through June 1, 2012. A decrease of 890.3 MW was due to higher EFORds. The reclassification of the Duquesne resources as internal added 3,187.2 MW to total internal capacity. The net effect from June 1, 2009, through June 1, 2012, was an increase in total internal capacity of 12,635.1 MW (8.0 percent) from 157,318.2 MW to 169,953.3 MW.

  In the 2009/2010 auction, 17 more generating resources made offers than in the 2008/2009 RPM Auction. The increase consisted of 11 new resources (439.2 MW), nine resources that were previously entirely FRR committed (82.5 MW), two less resources exported (698.6 MW), and two fewer resources excused from offering into the auction (37.3 MW) offset by five excused resources (44.5 MW), one less external resource that did not offer (60.4 MW), and one additional resource committed fully to FRR (10.0 MW). The new resources consisted of eight new CT resources (380.2 MW), two new diesel resources (9.2 MW) and one new steam resource (49.8 MW).

  In the 2010/2011 auction, 11 more generating resources made offers than in the 2009/2010 RPM auction. The increase consisted of 15 new resources (406.9 MW), four reactivated resources (161.7 MW) and three that were previously entirely FRR committed (10.9 MW), one less resource excused from offering (3.9 MW), and one less resource entirely exported (39.9 MW), offset by four deactivated resources (59.6 MW), four resources exported from PJM (554.0 MW), three retired resources (348.4 MW), and two resources excused from offering (108.8 MW). The new resources consisted of seven CT resources (270.5 MW), five new wind resources (120.0 MW), three new diesel resources (16.4 MW), and four reactivated resources (165.0 MW).

59 Unless otherwise specified, all volumes are in terms of UCAP.

In the 2011/2012 auction, 21 more generating resources made offers than in the 2010/2011 RPM auction. The increase consisted of 20 new resources (2,203.7 MW), four reactivated resources (486.9 MW), three fewer excused resources (126.3 MW), and one additional resource imported (663.2 MW), offset by five additional resources committed fully to FRR (1.0 MW) and two retired resources (87.3 MW). The new resources consisted of 11 new CT resources (728.7 MW), four new wind resources (75.2 MW), two new steam resources (838.0 MW), one new combined cycle resource (556.5 MW), one new diesel resource (4.2 MW) and one new solar resource (1.1 MW).

In the 2012/2013 auction, eight more generating resources made offers than in the 2011/2012 RPM auction. The net increase of eight resources consisted of 16 new resources (772.5 MW), four resources that were previously entirely FRR committed (13.4 MW), three additional resources imported (276.8 MW), two additional resources resulting from disaggregation of RPM resources, and one resource formerly unoffered (1.9 MW), offset by nine retired resources (1,044.5 MW), four additional resources committed fully to FRR (39.5 MW), four less resources resulting from aggregation of RPM resources, and one less external resource that did not offer (663.2 MW).[60] In addition, there were the following retirements of resources that were either exported or excused in the 2011/2012 BRA: two combustion turbine resources (5.3 MW) and three combined cycle resources (297.6 MW). Also, resources that are no longer PJM capacity resources consisted of three CT units (521.5 MW) in the RTO. The new units consisted of six new diesel resources (13.9 MW), four new wind resources (57.9 MW), three new steam units (560.4 MW), and three new CT units (140.3 MW).

Table 4 PJM capacity summary (MW): June 1, 2007, through May 31, 2012[61, 62]

	01-Jun-07	01-Jun-08	01-Jun-09	01-Jun-10	01-Jun-11	01-Jun-12
Installed capacity (ICAP)	163,721.1	164,444.1	166,916.0	168,061.5	172,666.6	181,159.7
Unforced capacity	154,076.7	155,590.2	157,628.7	158,634.2	163,144.3	171,147.8
Cleared capacity	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5
RPM reliability requirement (pre-FRR)	148,277.3	150,934.6	153,480.1	156,636.8	154,251.1	157,488.5
RPM reliability requirement (less FRR)	125,805.0	128,194.6	130,447.8	132,698.8	130,658.7	133,732.4
RPM net excess	5,240.5	5,011.1	8,265.5	1,149.2	3,156.6	5,754.4
Imports	2,809.2	2,460.3	2,505.4	2,750.7	6,420.0	3,831.6
Exports	(3,938.5)	(3,838.1)	(2,194.9)	(3,147.4)	(3,158.4)	(2,637.1)
Net exchange	(1,129.3)	(1,377.8)	310.5	(396.7)	3,261.6	1,194.5
DR cleared	127.6	536.2	892.9	939.0	1,364.9	7,047.2
EE cleared						568.9
ILR	1,636.3	3,608.1	6,481.5	2,110.5	1,593.8	
FRR DR	445.6	452.8	423.6	452.9	452.9	488.1
Short-Term Resource Procurement Target						3,343.3

60 Disaggregation and aggregation of RPM resources reflect changes in how units are offered in RPM. For example, multiple units at a plant may be offered as a single unit or multiple units.

61 FRR DR values have been revised since the *2008 State of the Market Report for PJM* was posted.

62 Prior to the 2012/2013 delivery year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For 2008/2009 and 2009/2010, certified ILR was used in the calculation. For 2010/2011, forecast ILR less FRR DR is used in the calculation because PJM forecast ILR including FRR DR for the first four base residual auctions. FRR DR is not subtracted in the calculation for the 2011/2012 auction, because PJM forecast ILR excluding FRR DR for the 2011/2012 BRA. Net excess calculations for auctions prior to 2010/2011 were originally calculated as cleared capacity less the reliability requirement. For delivery years 2012/2013 and beyond, net excess under RPM is calculated as cleared capacity less the reliability requirement plus the Short-Term Resource Procurement Target.

- **Demand.** There was a 2,545.5 MW increase in the RPM reliability requirement from 150,934.6 MW on June 1, 2008 to 153,480.1 MW on June 1, 2009. On June 1, 2009, PJM EDCs and their affiliates maintained a 79.6 percent market share of load obligations under RPM, down from 80.1 percent on June 1, 2008.

- **Market Concentration.** For the 2009/2010, 2010/2011, 2011/2012, and 2012/2013 RPM Auctions, all defined markets failed the preliminary market structure screen (PMSS). In the 2009/2010 BRA, 2009/2010 Third IA, 2010/2011 BRA, 2011/2012 BRA, and 2011/2012 First IA all participants in the total PJM market as well as the locational deliverability area (LDA) markets failed the three pivotal supplier (TPS) market structure test. In the 2012/2013 BRA, all participants in the RTO as well as MAAC, PSEG North, and DPL South RPM markets failed the TPS test. Six participants included in the incremental supply of EMAAC passed the test. Offer caps were applied to all sell offers that did not pass the test.

- **Imports and Exports.** Net exchange increased 1,688.3 MW from June 1, 2008 to June 1, 2009. Net exchange, which is imports less exports, increased due to an increase in imports of 45.1 MW and a decrease in exports of 1,643.2 MW.

- **Demand-Side and Energy Efficiency Resources.** 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. Prior to the 2012/2013 delivery year, demand-side resources included DR cleared in the RPM Auctions and certified/forecast interruptible load for reliability (ILR). For delivery years 2012/2013 and beyond, ILR was eliminated and demand-side resources include DR and Energy Efficiency (EE) resources.

- **Net Excess.** Net excess increased 3,254.4 MW from 5,011.1 MW on June 1, 2008 to 8,265.5 MW on June 1, 2009.

Market Conduct

- **2009/2010 RPM Base Residual Auction.** Of the 1,093 generating resources which submitted offers, unit-specific offer caps were calculated for 151 resources (13.8 percent). Offer caps of all kinds were calculated for 550 resources (50.3 percent), of which 377 were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2009/2010 Third Incremental Auction.** Of the 267 generating resources which submitted offers, 255 resources chose the offer cap option of 1.1 times the BRA clearing price (95.5 percent).[63] Unit-specific offer caps were calculated for two resources (0.7 percent). Offer caps of all kinds were calculated for five resources (1.9 percent), of which one was based on the technology specific default (proxy) ACR calculated by the MMU.

- **2010/2011 RPM Base Residual Auction.** Of the 1,104 generating resources which submitted offers, unit-specific offer caps were calculated for 154 resources (13.9 percent). Offer caps of all kinds were calculated for 532 resources (48.1 percent), of which 370 were based on the technology specific default (proxy) ACR calculated by the MMU.

63 124 FERC ¶ 61,140 (2008).

- **2011/2012 RPM Base Residual Auction.** Of the 1,125 generating resources which submitted offers, unit-specific offer caps were calculated for 145 resources (12.9 percent). Offer caps of all kinds were calculated for 472 resources (42.0 percent), of which 303 were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2011/2012 RPM First Incremental Auction.** Of the 129 generating resources which submitted offers, unit-specific offer caps were calculated for 19 resources (14.8 percent). Offer caps of all kinds were calculated for 68 resources (52.8 percent), of which 47 were based on the technology specific default (proxy) ACR calculated by the MMU.

- **2012/2013 RPM Base Residual Auction.**[64] Of the 1,133 generating resources which submitted offers, unit-specific offer caps were calculated for 120 resources (10.6 percent). Offer caps of all kinds were calculated for 607 resources (53.6 percent), of which 479 were based on the technology specific default (proxy) ACR calculated by the MMU.

Market Performance

2009/2010 RPM Base Residual Auction

- **RTO.** Total internal RTO unforced capacity of 157,318.2 MW includes all generating units and DR that qualified as a PJM capacity resource for the 2009/2010 RPM Base Residual Auction, excludes external units and reflects owners' modifications to installed capacity (ICAP) ratings. After accounting for FRR committed resources and imports, RPM capacity was 136,300.4 MW. The 132,231.8 MW of cleared resources for the entire RTO represented a reserve margin of 17.8 percent, which was 1,784.0 MW greater than the reliability requirement of 130,447.8 MW (installed reserve margin (IRM) of 15.0 percent) and resulted in a clearing price of $102.04 per MW-day.

  Total cleared resources in the RTO were 132,231.8 MW which resulted in a net excess of 8,265.5 MW, an increase of 3,254.4 MW from the net excess of 5,011.1 MW in the 2008/2009 RPM BRA. Certified interruptible load for reliability (ILR) was 6,481.5 MW.

  Cleared resources across the entire RTO will receive a total of $7.5 billion based on the unforced MW cleared and the prices in the 2009/2010 RPM BRA, an increase of approximately $1.4 billion from the 2008/2009 planning year.

- **MAAC+APS.**[65] Total internal MAAC+APS unforced capacity of 73,012.9 MW includes all generating units and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. Including imports into MAAC+APS, RPM unforced capacity was 73,102.2 MW.[66] Of the 5,764.9 MW of incremental supply, 5,314.7 MW cleared, which resulted in a resource-clearing price of $191.32 per MW-day.

64 For a more detailed analysis of the 2012/2013 RPM Base Residual Auction, see "Analysis of the 2012/2013 RPM Base Residual Auction" (August 6, 2009) <http://www.monitoringanalytics.com/reports/Reports/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090806.pdf>

65 MAAC was an acronym for Mid-Atlantic Area Council, EMAAC was an acronym for Eastern Mid-Atlantic Area Council, and SWMAAC was an acronym for Southwestern Mid-Atlantic Area Council. MAAC no longer exists as its role was taken on by Reliabilty*First* Corporation. MAAC, EMAAC and SWMAAC are now regions of PJM.

66 Rules for RPM auctions state that imports are modeled in the unconstrained region of the RTO. See PJM. "Manual 18: PJM Capacity Market," Revision 6 (Effective June 18, 2009), p. 31, <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.25 MB). The import MW into MAAC+APS consist of MW under a grandfathered agreement related to Rural Electric Cooperatives (RECs) generation.

Total resources in MAAC+APS were 77,488.7 MW, which when combined with certified ILR of 3,081.0 MW resulted in a net excess of 2,666.8 MW (3.4 percent) greater than the reliability requirement of 77,902.9 MW.

- **SWMAAC.** Total internal SWMAAC unforced capacity of 10,345.2 MW includes all generating units and DR that qualified as a PJM capacity resource, excludes external units and reflects owners' modifications to ICAP ratings. There were no imports from outside PJM into SWMAAC. Of the 2,413.7 MW of incremental supply, 2,016.6 cleared, which resulted in a resource-clearing price of $237.33 per MW-day.

  Total resources in SWMAAC were 16,305.6 MW, which when combined with certified ILR of 519.3 MW resulted in a net excess of 506.1 MW (3.1 percent) greater than the reliability requirement of 16,318.8 MW.

2009/2010 RPM Third Incremental Auction

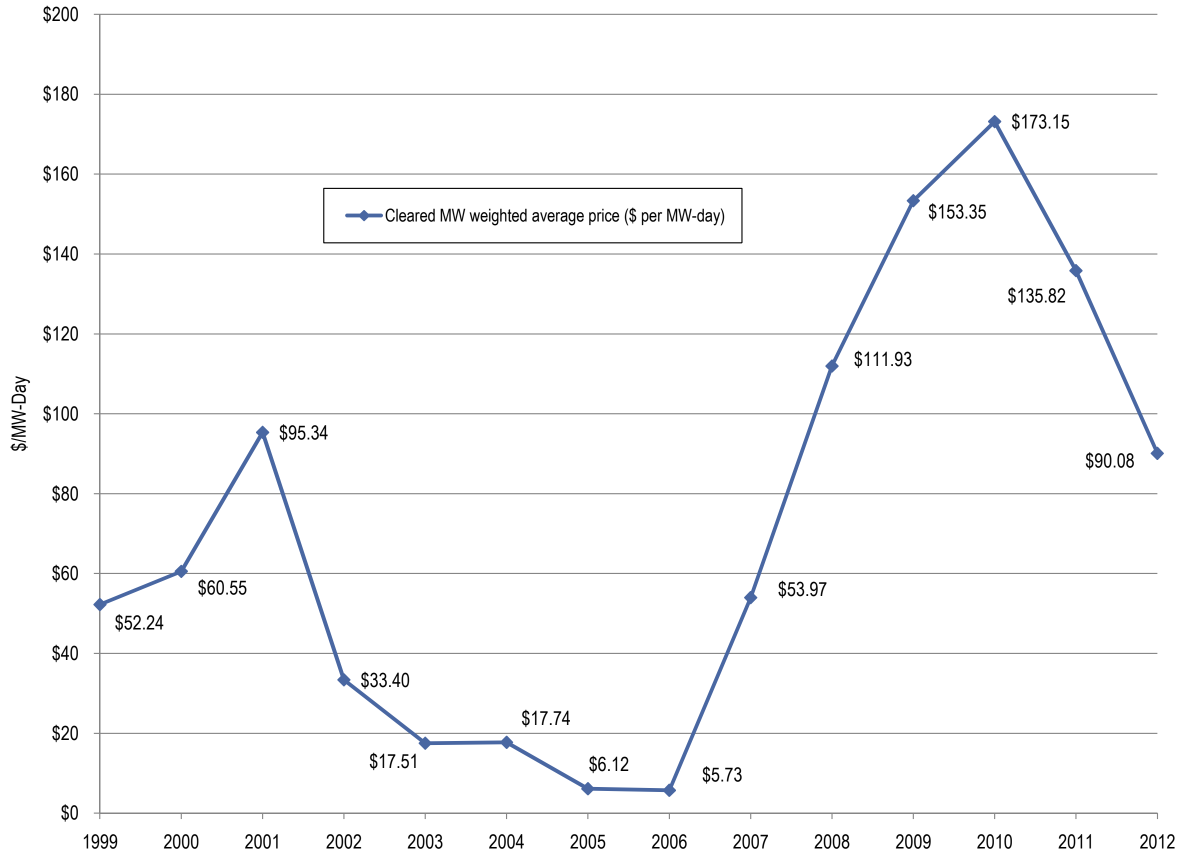
- **RTO.** There were 3,255.8 MW offered into the Third Incremental Auction while buy bids totaled 2,697.6 MW. Cleared volumes in the RTO were 1,798.4 MW, resulting in an RTO clearing price of $40.00 per MW-day. The 1,457.4 MW of uncleared volumes can be used as replacement capacity or traded bilaterally.

  Cleared resources across the entire RTO will receive a total of $47.7 million based on the unforced MW cleared and the prices in the 2009/2010 RPM Third Incremental Auction.

- **MAAC+APS.** In MAAC+APS, 2,142.3 MW were offered into the auction while buy bids in MAAC+APS totaled 1,953.2 MW. Cleared volumes in MAAC+APS were 1,275.3 MW, resulting in a MAAC+APS clearing price of $86.00 per MW-day. The 867.0 MW of uncleared volumes can be used as replacement capacity or traded bilaterally.

- **SWMAAC.** Although SWMAAC was a constrained LDA in the 2009/2010 BRA, supply and demand curves resulted in a price less than the MAAC+APS clearing price. Supply offers in the incremental auction in SWMAAC (985.1 MW) exceeded SWMAAC demand bids (135.5 MW). The result was that all of SWMAAC supply which cleared received the MAAC+APS clearing price.

Figure 6 History of capacity prices: Calendar year 1999 through 2012[67, 68]



Generator Performance

- **Forced Outage Rates.** Average PJM EFORd remained constant at 7.5 percent in 2008 and 2009. PJM EFORp decreased from 4.5 percent in 2008 to 4.0 percent in 2009.[69] Average PJM EFORd was significantly affected by a single nuclear unit, AEP's Cook Nuclear Plant Unit 1, which was on forced outage for a majority of the year.[70] If this unit were excluded from the results, 2009 EFORd would decrease to 6.9 percent.

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor decreased from 86.5 percent in 2008 to 85.7 percent in 2009.

- **Outages Deemed Outside Management Control (OMC).** According to NERC criteria, an outage may be classified as an OMC outage only if the generating unit outage was caused by other than failure of the owning company's equipment or other than the failure of the practices, policies and procedures of the owning company. OMC outages are excluded from the calculation of the forced outage rate, termed the XEFORd, used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

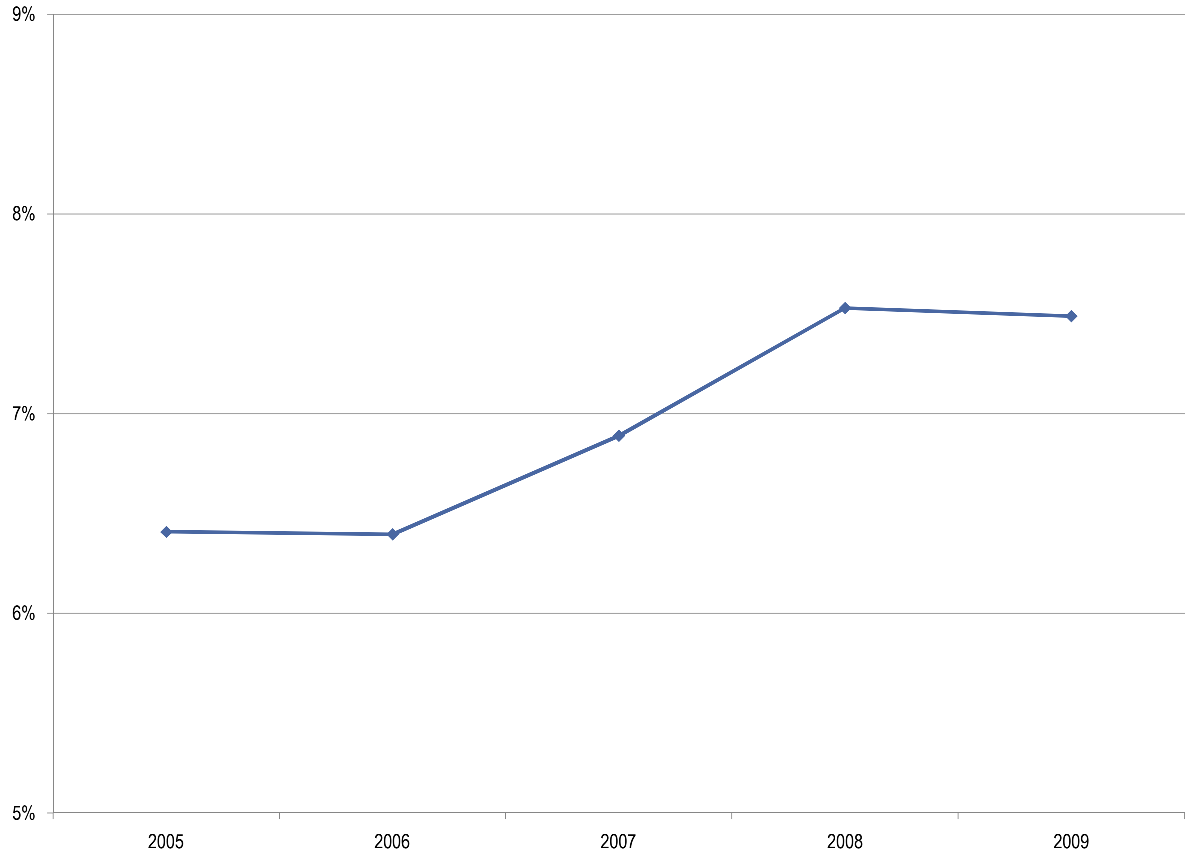
67 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2012 capacity prices are RPM weighted average prices.

68 The calculation of the 2007 weighted average price has been revised since the value in the *2007 State of the Market Report* was posted.

69 2008 data is for the 12 months ended December 31, 2008, as downloaded from the PJM GADS database on February 23, 2010. 2009 data is for the year ending December 31, 2009, as downloaded from the PJM GADS database on February 23, 2010. Annual EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

70 "AEP's Cook Nuclear Unit 1 Reaches Full Reactor Power." AEP press release, December 23, 2009. <http://www.aep.com/newsroom/newsreleases/?id=1582>.

Figure 7 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2005 to 2009



Capacity Market Conclusion

Capacity Market Design and Scarcity Revenues

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 and in the absence of a carefully designed expansion of scarcity pricing, 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 Definition of Capacity

In order for capacity markets to work, it is essential that the product definition be correct.

The definition of the capacity product is central to refining the market rules governing the sale and purchase of capacity. The current definition of capacity includes several components: the obligation to offer the energy of the unit into the Day-Ahead Market; the obligation to permit PJM to recall the energy from the unit under emergency procedures; the obligation to provide outage data to PJM; the obligation to provide energy during the defined high demand hours each year; and the obligation that the energy output from the resource be deliverable to load in PJM.

The most critical of these components of the definition of capacity is the obligation to offer the energy of the unit into the Day-Ahead Market. If buyers are to pay the high prices associated with RPM, it must be clear what they are buying and what the obligations of the sellers are. The fundamental energy market design should assure all market participants that the outcomes are competitive. This works to the ultimate advantage of all market participants including existing and prospective load and existing and prospective generation. The market rules should explicitly require that offers into the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. The short run marginal cost should reflect opportunity cost when and where appropriate.

An offer that exceeds short run marginal cost is not a competitive offer in the Day-Ahead Energy Market. Such an offer assumes the need to exercise market power to ensure revenue adequacy. An offer to provide energy only in an emergency is not a competitive offer in the Day-Ahead Energy Market. A unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage rather than indicating its availability to supply energy on an emergency basis.

The obligation to offer energy in the Day-Ahead Energy Market should be applied without exception to all capacity resources, including both generation and demand resources. This means that capacity resources must be available every hour of the year at a competitive price. Demand resources that agree to interrupt only 10 days per year are not capacity resources. Generation resources that agree to provide an energy offer only under PJM emergency conditions are not capacity resources. Generation resources that agree to provide energy only when the price is extremely high (and greater than the short run marginal cost of such units) are not capacity resources. The only exception, and it is not really an exception, is that units which have a legitimate short term emergency condition, may appropriately offer the relevant portion of the unit as an emergency resource.

For the 2008/2009 Delivery Year, a daily average of approximately 2,700 MW (about 1.7 percent of all capacity cleared in RPM) of generation capacity were not offered into the energy market because they were designated as available only in a emergency.

Capacity resources are required to ensure the reliability of the system. Reliability is not defined as the operation of the system only during an emergency but the reliable operation of the system in every hour of the year. If the system reserve margin were comprised of demand resources that would only interrupt for 10 days or generation resources that would only perform during an emergency or generation that will only perform when the price is $999 per MWh, the probability of needing those resources would increase significantly and the number of hours during which those resources are needed would increase significantly. As a general matter, the probability of needing such resources increases with the level of such resources that are defined to be capacity and thus needed for reliability.

The actual dispatch of resources in the energy market should be a function of the marginal cost to produce energy for each resource and not based on the refusal of a resource to make a competitive offer. Net revenues from the energy market, the ancillary services markets and the capacity market are the market based compensation. Investment decisions result from this total compensation.

The sale of capacity is also the sale of recall rights to the energy from capacity resources during an emergency. Regardless of where the energy from a unit is sold, it must be recallable by PJM when PJM is in an emergency condition or a scarcity condition. 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.

Capacity Prices and the Structure of Capacity Auctions

If capacity markets are to work to provide incentives for maintaining existing generation and building new generation, capacity market prices must reflect actual, local supply and demand conditions. For example, getting the price a little too low at the margin could result in undermining the incentives exactly where they need to be clear. If the prices are too low as a result of the market design, this would mean that the capacity market is a mechanism for transferring wealth rather than a functioning market providing market based incentives.

Capacity auctions must be mandatory for both load and generation, if they are to work. In PJM, load has a must bid requirement, which is enforced through the use of a system demand curve and the allocation of total capacity costs to all load. In PJM, capacity has a must offer requirement, which means that all capacity resources must offer into the capacity auctions unless they have a contract with an entity outside PJM or are physically unable to perform.[71]

The must bid and must offer requirements must extend to all resources. Thus, there should be no reduction of demand on the bid side. The current 2.5 percent reduction in the demand curve, to provide for short term resources, distorts the market price. The reduction in demand results in a price lower than the competitive level thus reducing the incentives to both new and existing generation. There should be no reductions in the demand for capacity, which should reflect all capacity needed to provide reliability.

The three year forward auction was implemented in order to provide the potential for new resources to compete with existing resources and to provide an incentive for such new entry. The prior capacity credit structure did not provide for either. The three year forward structure creates both opportunity and risks. A new generation unit that offers into an auction for a delivery year three years in the future is taking the risk that the unit will not be completed, that its costs will exceed its estimates or that the clearing price will be lower than anticipated in the first or subsequent years. Demand resources also face both opportunities and risks in a three year forward auction. A demand resource that is offered into an auction for a delivery year three years in the future is taking the risk that the customer with the demand side resource will no longer exist, that its costs will exceed its estimates or that the clearing price will be lower than anticipated in the first or subsequent years. There is nothing unique about demand resources that requires a shorter lead time or that requires

71 There is ongoing discussion in the PJM stakeholder process about exactly what the must offer provisions in the current tariff mean. The intent is clear and the tariff language should be conformed to the intent, which is that all capacity resources must make offers into each capacity auction.

distorting the market design. The fact that some generation resources or demand resources can be developed in less than three years is not a reason to distort the market design. It would be possible to shorten the time frame of the auctions for all participants but at the cost of reducing competition from new generation projects.

The must offer requirement for capacity should also apply generally to out of market transactions. Out of market transactions include the construction of new capacity by regulated utilities receiving out of market payments for such capacity via rate base treatment of the investment; by companies receiving out of market payments for such capacity via long term contracts; by companies receiving out of market payments for such capacity via Reliability Must Run (RMR) payments; and by companies receiving out of market payments for such capacity under renewable portfolio programs.

The market design goal is to ensure that out of market payments do not permit offers at less than competitive prices, including zero, which suppress the market clearing prices. All generation should be offered in to the auctions and receive capacity credit if cleared and not receive capacity credit if not cleared.

The must offer requirement should also extend to the elimination of the FRR exception to capacity markets.

Locational Prices

Capacity prices must reflect local supply and demand conditions. If capacity cannot be delivered into an area as a result of transmission constraints, a local market exists and capacity market prices should reflect the local market conditions. The CETO/CETL analysis currently used by PJM to define local markets in combination with consideration of local supply and demand is not adequate to define local markets in RPM. For example, if a unit does not clear in an RPM auction and makes an economic decision to retire but is then informed by PJM that it is needed for reliability, this is evidence that the market is not working because the local market is not properly defined. PJM determinations that a unit is needed for reliability are based on a more detailed analysis than the CETO/CETL analysis. PJM should perform such a more detailed reliability analysis of all at risk units, including all units that do not clear in RPM auctions and units that face significant investment requirements due, for example, to environmental requirements. If such units are needed for reliability, this could result in the definition of additional LDAs to reflect the actual reliability requirements of the system. Accurate locational pricing also requires that generation owners make offers that reflect their legitimate investment requirements. For example, units that will be forced to retire by environmental regulators unless they make defined investments in new technology should reflect the costs of that investment in their capacity market offer. That is essential to the functioning of the forward looking capacity market.

Capacity Markets and Incentives

If the revenues collected in the RPM market are adequate, it is not essential that a scarcity pricing mechanism exist in the energy market. Nonetheless, it would be preferable to also have a scarcity pricing mechanism in the energy market because it provides direct, hourly market-based incentives to load and generation, as long as it is designed to ensure that scarcity revenues directly offset RPM revenues. This hybrid approach would include both a capacity market and scarcity pricing in the energy market.

Capacity market design should reflect the fact that the capacity market is a mechanism for the collection of scarcity revenues and thus reflect the incentive structure of energy markets to the maximum extent possible. For example, if a generation unit does not produce power during a high price hour, it receives no revenues from the energy market. It does not receive some revenues simply for existing, it receives zero revenues. The reason that the unit does not produce energy is not relevant. It does not receive revenues if it does not produce energy even if the reason for non performance is outside management's control. That is the basic performance incentive structure of energy markets. The same performance incentive structure should be replicated in capacity market design. If a unit that is a capacity resource does not produce energy during the 500 hours defined as critical in RPM, it will receive no energy revenues for those hours. If a unit defined as a capacity resource does not produce energy when called upon during any of the hours defined as critical, it should receive no capacity revenues. This approach to performance is also consistent with the reduction or elimination of administrative penalties associated with failure to meet capacity tests, for example.

A hybrid market design can provide scarcity revenues both via scarcity pricing in the energy market and via the capacity market. However, if there is scarcity pricing in the energy market, the market design must ensure that units receiving scarcity revenues in the capacity market do not also receive scarcity revenues in the energy market. This would be double payment of scarcity revenues. This offset must reflect the actual scarcity revenues and not those reflected in forward curves or forecasts, or those reflected in results from prior years. Scarcity revenues are episodic and unlikely to be fully reflected in historical data or in forward curves, even if such curves were based on a liquid market three years forward, which they are not, and reflected locational results, which they do not. The most straightforward way to ensure that such double payment does not occur would be to ensure that capacity resources do not receive scarcity revenues in the energy market in the first place. The settlements process can remove any scarcity 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.

Market Power

The RPM Capacity Market design explicitly addresses the underlying issues of ensuring that competitive prices can reflect local scarcity while not relying on the exercise of market power to achieve the design objective and explicitly limiting the exercise of market power.

The Capacity Market is, by design, always tight in the sense that total supply is generally only slightly larger than demand. The demand for capacity includes expected peak load plus a reserve margin. Thus, the reliability goal is to have total supply equal to, or slightly above, the demand for capacity. The market may be long at times, but that is not the equilibrium state. Capacity in excess of demand is not sold and, if it does not earn adequate revenues in other markets, will retire. Demand is almost entirely inelastic because the market rules require loads to purchase their share of the system capacity requirement. The result is that any supplier that owns more capacity than the difference between total supply and the defined demand is pivotal and has market power.

In other words, the market design for capacity leads, almost unavoidably, to structural market power. Given the basic features of market structure in the PJM Capacity Market, including significant market structure issues, inelastic demand, tight supply-demand conditions, the relatively small number of nonaffiliated LSEs and supplier knowledge of aggregate market demand, the MMU concludes that the potential for the exercise of market power continues to be high. Market power is and will remain endemic to the existing structure of the PJM Capacity Market. This is not surprising in that the Capacity Market is the result of a regulatory/administrative decision to require a specified level of reliability and the related decision to require all load serving entities to purchase a share of the capacity required to provide that reliability. It is important to keep these basic facts in mind when designing and evaluating capacity markets. The Capacity Market is unlikely ever to approach the economist's view of a competitive market structure in the absence of a substantial and unlikely structural change that results in much more diversity of ownership.

RPM has explicit market power mitigation rules designed to permit competitive, locational capacity prices while limiting the exercise of market power. The RPM construct is consistent with the appropriate market design objectives of permitting competitive prices to reflect local scarcity conditions while explicitly limiting market power. The RPM Capacity Market design provides that competitive prices can reflect locational scarcity while not relying on the exercise of market power to achieve that design objective by limiting the exercise of market power via the application of the three pivotal supplier test.

Competitive prices are the lowest possible prices, consistent with the resource costs. But, competitive prices are not necessarily low prices. In the Capacity Market, it is essential that the cost of new entry (CONE) be based on the actual resource costs of bringing a new capacity resource into service. If RPM is to provide appropriate incentives for new entry, the marginal price signal must reflect the actual cost of new entry.

The existence of a capacity market that links payments for capacity to the level of unforced capacity and therefore to the forced outage rate creates an incentive to improve forced outage rates. The performance incentives in the RPM Capacity Market design need to be strengthened. The energy market also provides incentives for improved performance with somewhat different characteristics. Generators want to maximize their sales of energy when prices are high and if they are successful, this will also result in lower forced outage rates. Well designed scarcity pricing could also provide strong, complementary incentives for reduced outages during high load periods. It would be preferable to rely on strong market-based incentives for capacity resource performance rather than the current structure of penalties, which has its own incentive effects.

Results

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The MMU found serious market structure issues, measured by the three pivotal supplier test results, by market shares and by HHI, but no exercise of market power in the PJM Capacity Market during calendar year 2009. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive during calendar year 2009.

Ancillary Service Markets

The FERC defined six ancillary services in Order 888: 1) scheduling, system control and dispatch; 2) reactive supply and voltage control from generation service; 3) regulation and frequency response service; 4) energy imbalance service; 5) operating reserve – synchronized reserve service; and 6) operating reserve – supplemental reserve service.[72] Of these, PJM currently provides regulation, energy imbalance, synchronized reserve, and operating reserve – supplemental reserve services through market-based mechanisms. PJM provides energy imbalance service through the Real-Time Energy Market. PJM provides the remaining ancillary services on a cost basis. Although not defined by the FERC as an ancillary service, black start service plays a comparable role. Black start service is provided on a cost basis.

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.[73] 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. Synchronized reserve is a form of primary reserve. To provide synchronized reserve a generator must be synchronized to the system and capable of providing output within 10 minutes. Synchronized reserve can also be provided by DSR. The term, Synchronized Reserve Market, refers only to supply of and demand for Tier 2 synchronized reserve.

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, interarea transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the settlement in the RPM case.[74] The purpose of this market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at the market clearing price.

PJM does not provide a market for reactive power, but does ensure its adequacy through member requirements and scheduling. Generation owners are paid according to FERC-approved, reactive revenue requirements. Charges are allocated to network customers based on their percentage of load, as well as to point-to-point customers based on their monthly peak usage.

The MMU analyzed measures of market structure, conduct and performance for the PJM Regulation Market, the two regional Synchronized Reserve Markets, and the PJM DASR Market for 2009.

72 75 FERC ¶ 61,080 (1996).

73 Regulation is used to help control the area control error (ACE). See *2008 State of the Market Report for PJM,* Volume II, Appendix F, "Ancillary Service Markets," for a full definition and discussion of ACE. Regulation resources were almost exclusively generating units in 2009.

74 See 117 FERC ¶ 61,331 at P 29 n32 (2006).

Regulation Market

The PJM Regulation Market in 2009 continues to be operated as a single market. There have been no structural changes since December 1, 2008. On December 1, 2008, PJM implemented four changes to the Regulation Market: introducing the Three Pivotal Supplier test for market power; increasing the margin for cost-based regulation offers; modifying the calculation of lost opportunity cost (LOC); and terminating the offset of regulation revenues against operating reserve credits. At the FERC's direction, the MMU prepared and submitted a report on November 30, 2009, on the impact of these changes.[75] The findings of the report have been updated and corrected and the results are presented below. The changes to the Regulation Market rules resulted in a significant (23 percent) increase in payments to the providers of regulation compared to what they would have otherwise received and compared to what they would have received in a competitive market design.

Market Structure

- **Supply.** During 2009, the supply of offered and eligible regulation in PJM was generally both stable and adequate. Although PJM rules allow up to 25 percent of the regulation requirement to be satisfied by demand resources, none qualified to make regulation offers in 2009. The ratio of eligible regulation offered to regulation required averaged 2.98 throughout 2009, an increase from the 2008 ratio of 2.39.

- **Demand.** Beginning August 7, 2008, PJM began to define separate on-peak and off-peak regulation requirements. The on-peak requirement is equal to 1.0 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement is equal to 1.0 percent of the forecast valley load for the PJM RTO for the day. Previously the requirement had been fixed daily at 1.0 percent of the daily forecast operating load. The average hourly regulation demand for all of 2009 was 849 MW, compared to 922 MW for 2008.

- **Market Concentration.** During 2009, the PJM Regulation Market had a load weighted, average Herfindahl-Hirschman Index (HHI) of 1365 which is classified as "moderately concentrated."[76] The minimum hourly HHI was 699 and the maximum hourly HHI was 9405. The largest hourly market share in any single hour was 97 percent, and 71 percent of all hours had a maximum market share greater than 20 percent. The maximum HHI and the average HHI were higher in 2009 than in 2008. The increase in concentration began in May 2009, when there was a significant increase in self-scheduled regulation during off-peak hours, which reduced the amount of regulation purchased in the market.

  For 2009, 52 percent of hours had one or more pivotal suppliers. The MMU concludes from these results that the PJM Regulation Market for 2009 was characterized by structural market power in 52 percent of the hours.

75 The MMU report filed in Docket No. ER09-13-000 is posted at: <http://www.monitoringanalytics.com/reports/Reports/2009/IMM_PJM_Regulation_Market_Impact_20081201_Changes_20091130.pdf>*(465 KB)*.

76 See the *2008 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part I," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Beginning December 1, 2008, owners are required to submit unit specific cost based offers and owners also have the option to submit price based offers. All offers remain subject to the $100 per MWh cap.[77] In computing the market solution, PJM adds opportunity cost. The offers made by unit owners and the opportunity cost adder comprise the total offer to the Regulation Market for each unit. Using a supply curve based on these offers, PJM solves the regulation market and then tests that solution to see which, if any, suppliers of eligible regulation are pivotal. All units of owners who fail the three pivotal supplier test for an hour have their offers capped at the lesser of their cost based or price based offer. The regulation market is then re-solved.

  As part of the changes to the regulation market implemented on December 1, 2008, cost based offers may include a margin of $12.00 rather than the prior maximum margin of $7.50. The impact of this change was to increase cost based offer prices.

  As part of the changes to the regulation market implemented on December 1, 2008, PJM calculates opportunity costs using LMP forecasts and the lesser of the available price based offer or the most expensive available cost based offer as the reference, rather than the offer on which the unit is operating.[78] PJM adds this opportunity cost to the offers of the market participants. The impact of this change was to increase cost based and price based offer prices.

Market Performance

- **Price.** For the PJM Regulation Market during 2009, the load weighted, average price per MWh (the regulation market clearing price, including opportunity cost) associated with meeting PJM's demand for regulation was $23.56. This was a decrease of $18.53, or 44 percent, from the average price for regulation during 2008.

- **Price and Opportunity Cost.** Prices in the PJM Regulation Market were approximately 19 percent higher than they would have been but for the change to the definition of opportunity cost.

77 See PJM. "Manual 11: Scheduling Operations," Revision 43 (September 24, 2009), p.39.

78 See PJM. "Manual 11: Scheduling Operations," Revision 43 (September 24, 2009), p. 43: "SPREGO utilizes the lesser of the available price-based energy schedule or most expensive available cost-based energy schedule (the "lost opportunity cost energy schedule"), and forecasted LMPs to determine the estimated opportunity cost each resource would incur if it adjusted its output as necessary to provide its full amount of regulation".

Figure 8 Monthly load weighted, average regulation cost and price: Calendar year 2009

Synchronized Reserve Market

PJM retained the two synchronized reserve markets it implemented on February 1, 2007. The RFC Synchronized Reserve Zone reliability requirements are set by the Reliability*First* Corporation. The Southern Synchronized Reserve Zone (Dominion) reliability requirements are set by the Southeastern Electric Reliability Council (SERC).

PJM made two significant changes to the Synchronized Reserve Market in 2009. These changes were intended to ensure that the synchronized reserve requirement accurately reflects the needs of PJM dispatch. This includes ensuring that the forecast amount of Tier 1 synchronized reserve is actually available to PJM dispatch during the operating hour. PJM changed the primary constraint which defines the Mid-Atlantic Subzone within the RFC Synchronized Reserve Market from Bedington—Black Oak to AP South. PJM reduced from 70 percent to 15 percent the percentage of Tier 1 available west of the AP South interface that it will consider as available to the Mid-Atlantic Subzone when it calculates the amount of Tier 2 required. These changes were made to address the fact that PJM Dispatch needed more synchronized reserve than was defined as the requirement to be met by the market. This problem has existed in the Synchronized Reserve Market since late 2007. These changes reduced the amount of additional, out of market, synchronized reserve required by PJM dispatch, which reduced opportunity cost payments and aligned the total cost of synchronized reserves more closely with Synchronized Reserve Market prices. Synchronized reserves added out of market were two percent of all synchronized reserve during April through

December of 2009, while they were 39 percent for the same time period in 2008. Opportunity cost payments accounted for 23 percent of total costs during April through December of 2009 compared to 43 percent during the same time period in 2008.

Market Structure

- **Supply.** For 2009, the offered and eligible excess supply ratio was 1.53 for the PJM Mid-Atlantic Synchronized Reserve Region.[79] For the RFC zone, the excess supply ratio was 1.93. The excess supply ratio is determined using the administratively required level of synchronized reserve. The actual requirement for Tier 2 synchronized reserve is lower than the required reserve level because there is usually a significant amount of Tier 1 synchronized reserve available. In 2009, the contribution of DSR resources to the Synchronized Reserve Market remained significant and resulted in lower overall Synchronized Reserve prices.

- **Demand.** The average synchronized reserve requirements were 1,351 MW for the RFC Synchronized Reserve Zone and 1,168 MW for the Mid-Atlantic Subzone. Market demand is less than the requirement by the amount of forecast Tier 1 synchronized reserve available at the time a Synchronized Reserve Market is cleared.

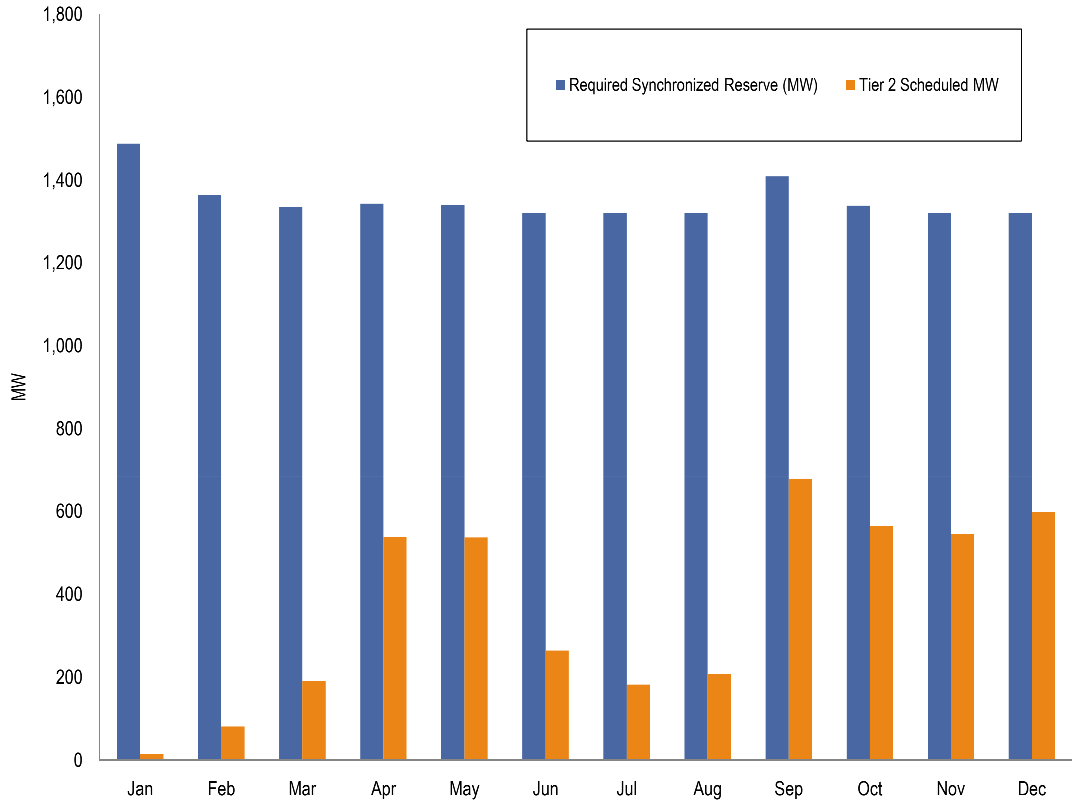
  Demand for Tier 2 synchronized reserve varied substantially during the first quarter of 2009 as a result of PJM changes to the definition of the market. On December 1, 2008, PJM began to significantly increase the amount of Tier 1 forecast during the market solution, which reduced the demand for Tier 2 in January and February 2009. On March 13, 2009 PJM reduced the amount of Tier 1 from outside the Mid-Atlantic Subzone that is included for the operational hour, which increased demand for Tier 2.

  The problem of additional procurement of Tier 2 synchronized reserves by PJM dispatch after Synchronized Reserve Market settlement has been greatly reduced. For all of 2009, 9 percent of all purchased Tier 2 synchronized reserves were added after the market cleared. Most of the added synchronized reserve occurred in the January through March period. From April through December 2009 two percent of all purchased Tier 2 synchronized reserves were added after the market cleared.

  As a result of the level of Tier 1 reserves in the RFC Synchronized Reserve Zone, less than three percent of hours cleared a Tier 2 Synchronized Reserve Market in the RFC. In the Southern Synchronized Reserve Zone only one half of one percent of hours cleared a Tier 2 market in 2009. In the PJM Mid-Atlantic Synchronized Reserve Region, 74 percent of hours cleared a Tier 2 Synchronized Reserve Market. The average demand for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone was 297 MW.

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

Figure 9 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: Calendar year 2009



- **Market Concentration.** The average load weighted cleared 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.”[80] For purchased synchronized reserve (cleared plus added) the HHI was 3070. Less than one percent of all hours had a market share of 100 percent. In 36 percent of hours the maximum market share was greater than 40 percent (compared to 56 percent of hours in 2008).

  In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, for all of 2009, 95 percent of hours had three or fewer pivotal suppliers. The MMU concludes from these results that the PJM Synchronized Reserve Markets in 2009 are characterized by structural market power.

Market Conduct

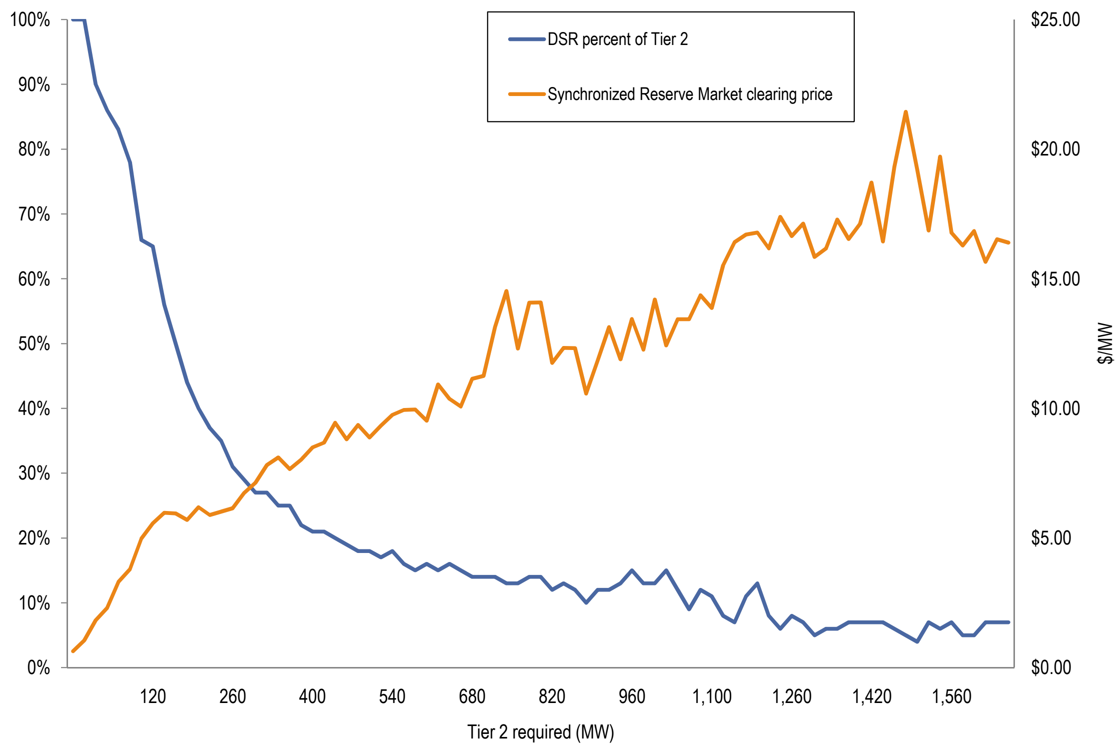
- **Offers.** Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds opportunity cost calculated using LMP forecasts, which together comprise the total offer

80 See the *2008 State of the Market Report for PJM*, Volume II, Section 2, “Energy Market, Part I,” at “Market Concentration” for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

for each unit to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost.

Demand side resources remained significant participants in the Synchronized Reserve Market in 2009. In 12 percent of hours in which a Tier 2 Synchronized Reserve Market was cleared for the Mid-Atlantic Subzone, all synchronized reserves were provided by DSR.

Figure 10 Required Tier 2 synchronized reserve, synchronized reserve market clearing price, and DSR percent of Tier 2



Market Performance

- **Price.** During January and to a lesser extent February, only a very small amount of Tier 2 was needed, which resulted in lower clearing prices. The load weighted, average PJM price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market was $7.46 per MW for all of 2009, a $3.19 per MW decrease from 2008.

- **Adequacy.** A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced a deficit during 2009.

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[81] The purpose of this market is to satisfy supplemental (30-minute) reserve requirements with a market-based mechanism that allows generation resources to offer their reserve energy at a price and compensates cleared supply at a single market clearing price. The DASR 30-minute reserve requirements are determined for each reliability region.[82] The RFC and Dominion DASR requirements are added together to form a single RTO DASR requirement which is obtained via the DASR Market. The requirement is applicable for all hours of the operating day. If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

- **Concentration.** The DASR Market for all of 2009 had three pivotal suppliers in an average of 24 percent of all hours. The MMU concludes from these results that the PJM DASR Market in 2009 was characterized by structural market power.

Market Conduct

- **Withholding.** Economic withholding remains a problem in the DASR Market. Continuing a pattern seen since the inception of the DASR Market, a significant number of units offered at levels effectively guaranteed not to clear. Almost six percent of units offered at $50 or more and four percent of units offered at $990 or more, in a market with an average clearing price of $0.05 and a maximum clearing price of $4.00.

- **DSR.** Demand side resources do participate in the DASR Market but remain insignificant.

Market Performance

- **Price.** For 2009, the load weighted price of DASR was $0.05, including the 37 percent of hours when the market cleared at a price of $0.00.

Black Start Service

Black Start Service is necessary to help ensure the reliable restoration of the grid following a blackout. Black Start Service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit with a high operating factor to automatically remain operating at reduced levels when disconnected from the grid.[83]

Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. PJM defines required black start capability zonally and ensures

81 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).
82 PJM Manual 13, Emergency Requirements, Revision 39, 01/01/2010; pp 11-12.
83 PJM OATT Schedule § 1.3BB, Second Revised Second Revised Sheet No. 33.01, March 1, 2007.

the availability of black start service by charging transmission customers according to their zonal load ratio share and compensating black start unit owners.

PJM does not have a market to provide black start service, but compensates black start resource owners for all costs associated with providing this service, as defined in the tariff. For 2008, charges to PJM members for providing black start services were just over $13 million. For 2009, charges were about $14.2 million. There was substantial zonal variation.

As a consequence of PJM's filing to revise its formula rate for black start service to allow for the recovery of the costs of compliance with Critical Infrastructure Protection standards, black start costs likely will increase substantially. The revised filing also provides a better match between the sellers' commitment period and the cost recovery period.

The MMU recommends that PJM, FERC and state regulators reevaluate the way in which black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market.

Ancillary Services Conclusion

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.[84] 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. PJM filed the proposed revisions on October 1, 2008.[85] A number of parties filed comments, including the MMU on October 20, 2008.[86]

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."

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.[87]

84 See PJM 2007 Strategic Report at 65 (April 2, 2007). This report is posted on PJM's website at: <http://www.pjm.com/~/media/documents/downloads/strategic-responses/report/20070402-pjm-strategic-report.ashx>(1.23 MB).
85 PJM submitted its initial filing in FERC Docket No. ER09-13-000.
86 Comments and Motion for Leave to Intervene of the Independent Market Monitor for PJM, Docket No. ER09-13-000. These comments are posted on the Monitoring Analytics website at <http://www.monitoringanalytics.com/reports/Reports/2008/imm-motion-to-intervene-and-comments.pdf>.
87 125 FERC ¶ 61,231, at P 18 (2008).

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."[88] 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."[89]

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.[90] 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."[91] 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."[92] 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."[93]

The MMU has updated the calculations, improved the calculations and made corrections as necessary, based in part on PJM's comments. [94] This updated and improved analysis is presented below.

Together, the changes to the tariff related to the Regulation Market resulted in an increase in payments to the providers of regulation of $55.1 million over the 13 month period from December 2008 through December 2009, compared to what they would have received in the absence of these three changes. This represents an increase in total regulation payments of 25 percent for the 13 month period. While these results are based on estimates of how the market would have worked in the absence of the changes in market design, the calculations reflect detailed hourly data about the individual units in the Regulation Market supply curve. There is no question that the changes in market design significantly increased the payments for regulation service, regardless of any disagreements about the details of the calculation methods.

88 *2009 Quarterly State of the Market Report for PJM: January through June* at 120, 124.
89 *2009 Quarterly State of the Market Report for PJM: January through September* at 115.
90 The MMU report filed in Docket No. ER09-13-000 is posted at: <http://www.monitoringanalytics.com/reports/Reports/2009/IMM_PJM_Regulation_Market_Impact_20081201_Changes_20091130.pdf>*(465 KB)*.
91 *Id.* at 2.
92 *Id.*
93 *Id.* at 8.
94 Comments of PJM Interconnection, L.L.C. to Report of Independent Market Monitor filed in ER09-13 (December 30, 2009). The Illinois Commerce Commission also filed comments on the MMU's report: Comments of the Illinois Commerce Commission filed in ER09-13 (January 6, 2010).

The MMU concludes, based on the analysis of the Regulation Market operating under the revised rules, 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 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 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.

The structure of each Synchronized Reserve Market has been evaluated and the MMU has concluded that these markets are not structurally competitive as they are characterized by high levels of supplier concentration and inelastic demand. (The term Synchronized Reserve Market refers only to Tier 2 synchronized reserve.) As a result, these markets are operated with market-clearing prices and with offers based on the marginal cost of producing the service plus a margin. As a result of these requirements, the conduct of market participants within these market structures has been consistent with competition, and the market performance results have been competitive.

The MMU concludes that the DASR Market is not structurally competitive in a significant number of hours based on the results of the three pivotal supplier test calculated by the MMU. The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test. The MMU concludes that the DASR Market results were competitive in 2009.

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

Overall, the MMU concludes that the Regulation Market results were not competitive in 2009. The MMU concludes that the Synchronized Reserve Market results were competitive in 2009. The MMU concludes that the DASR Market results were competitive in 2009.

Congestion

Congestion occurs when available, least-cost energy cannot be delivered to all loads for a period because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[95] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation. Locational marginal prices (LMPs) reflect the price of the lowest-cost resources available to meet loads, taking into account actual delivery constraints imposed by the transmission system. Thus LMP is an efficient way to price energy when transmission constraints exist. Congestion reflects this efficient pricing.

Congestion reflects the underlying characteristics of the power system including the nature and capability of transmission facilities and the cost and geographical distribution of generation facilities. Congestion is neither good nor bad but is a direct measure of the extent to which there are differences in the cost of generation that cannot be equalized because of transmission constraints. A complete set of markets would require direct competition between investments in transmission and generation. The transmission system provides a physical hedge against congestion. The transmission system is paid for by firm load and, as a result, firm load receives the corollary financial hedge in the form of Auction Revenue Rights (ARRs) and/or Financial Transmission Rights (FTRs). While the transmission system and, therefore, ARRs/FTRs are not guaranteed to be a complete hedge against congestion, ARRs/FTRs do provide a substantial offset to the cost of congestion to firm load.[96]

The MMU analyzed congestion and its influence on PJM markets during 2009.

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $1.397 billion or 66 percent, from $2.117 billion in 2008 to $719.0 million in 2009. Day-ahead congestion costs decreased by $1.760 billion or 66 percent, from $2.661 billion in 2008 to $901.4 million in 2009. Balancing congestion costs increased by $362.2 million or 67 percent, from -$544.6 million in 2008 to -$182.4 million in 2009. Total congestion costs have ranged from three percent to nine percent of PJM annual total billings since 2003. Congestion costs were three percent of total PJM billings in 2009. Total PJM billings in 2009 were $26.550 billion, a 23 percent decrease from the $34.306 billion billed in 2008.

95 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place.

96 See the *2009 State of the Market Report for PJM*, Volume II, Section 8, “Financial Transmission and Auction Revenue Rights,” at “ARR and FTR Revenue and Congestion.”

Table 5 Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to 2009

	Congestion Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
2003	$464	NA	$6,900	7%
2004	$750	62%	$8,700	9%
2005	$2,092	179%	$22,630	9%
2006	$1,603	(23%)	$20,945	8%
2007	$1,846	15%	$30,556	6%
2008	$2,117	15%	$34,306	6%
2009	$719	(66%)	$26,550	3%
Total	$9,591		$150,587	6%

- **Monthly Congestion.** Fluctuations in monthly congestion costs continued to be substantial. In 2009, these differences were driven by varying load and energy import levels, different patterns of generation, weather-induced changes in demand and variations in congestion frequency on constraints affecting large portions of PJM load. Monthly congestion costs in 2009 ranged from $23.9 million in September to $149.3 million in January. With the exception of December, monthly congestion costs decreased every month from the previous year with the largest decrease occurring during June 2009.

Congestion Component of LMP and Facility or Zonal Congestion

- **Congestion Component of Locational Marginal Price (LMP).** To provide an indication of the geographic dispersion of congestion costs, the congestion component of LMP (CLMP) was calculated for control zones in PJM. Price separation between eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface. This interface had the effect of increasing prices in eastern and southern control zones located on the constrained side of the affected facilities while reducing prices in the unconstrained western control zones.

- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in 2009.[97] Day-ahead congestion frequency increased from 2008 to 2009 by 3,048 congestion event hours or four percent. In 2009, there were 77,793 day-ahead, congestion-event hours compared to 74,745 day-ahead, congestion-event hours in 2008. Day-ahead, congestion-event hours increased on PJM transmission lines and the reciprocally coordinated flowgates between PJM and the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) while congestion frequency on internal PJM interfaces and transformers decreased. Real-time congestion frequency decreased from 2008 to 2009 by 6,995 congestion event hours. In 2009, there were 15,454 real-time, congestion-event hours compared to 22,449 real-time, congestion-event hours in 2008. Real-time, congestion-event hours increased on the reciprocally coordinated flowgates between PJM and

97 In the *2008* and in the *2009 State of the Market Report for PJM*, in order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. Comparisons to previous periods use the new standard for both current and prior periods.

the Midwest ISO, while interfaces, transmission lines and transformers saw decreases. The AP South Interface was the largest contributor to congestion costs in 2009. With $206.5 million in total congestion costs, it accounted for 29 percent of the total PJM congestion costs in 2009. The top five constraints in terms of congestion costs together contributed $361.9 million, or 50 percent, of the total PJM congestion in 2009. The top five constraints included the AP South interface, the West interface, the 5004/5005 Interface, the Pleasant Valley – Belvidere line and the Kammer transformer.

Table 6 Congestion summary (By facility type): Calendar year 2009

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	$18.0	($56.3)	$17.8	$92.1	($10.4)	$5.1	($63.2)	($78.8)	$13.3	9,202	3,328
Interface	$48.0	($263.5)	$2.1	$313.5	$4.0	($2.4)	$2.9	$9.3	$322.8	5,802	1,378
Line	$114.8	($195.8)	$41.1	$351.6	($18.8)	$11.8	($40.1)	($70.7)	$281.0	52,236	7,619
Transformer	$108.5	($14.6)	$22.9	$145.9	($13.8)	($4.4)	($32.9)	($42.3)	$103.6	10,553	3,129
Unclassified	$3.1	$4.9	$0.0	($1.7)	$0.0	$0.0	$0.0	$0.0	($1.7)	NA	NA
Total	$292.3	($525.2)	$83.9	$901.4	($39.0)	$10.1	($133.4)	($182.4)	$719.0	77,793	15,454

- **Zonal Congestion.** In 2009, the ComEd Control Zone experienced the highest congestion costs of the control zones in PJM. However, in 2009, the average congestion component of LMP in ComEd was -$5.09 for day-ahead and -$5.61 for real time. The negative congestion components in ComEd resulted in -$262.8 million in load congestion payments, -$487.0 million in generation congestion credits, and -$4.5 million in explicit congestion charges. The net positive congestion number in ComEd is an example of how accounting congestion can be a misleading measure of congestion when it results from generation congestion credits which are more negative than load congestion payments. In fact, congestion reduces prices in ComEd, and load incurs lower charges and generation receives lower credits as a result. The $219.7 million in net congestion costs in the ComEd Control Zone represented a 22.7 percent decrease from the $284.2 million in congestion costs the zone experienced in 2008. The Pleasant Valley – Belvidere line, the Dunes Acres – Michigan City flowgate, the Kammer transformer, the East Frankfort – Crete line, and the AP South interface contributed $113.3 million, or 52 percent of the total ComEd Control Zone congestion costs. The Dominion Control Zone had the second highest congestion cost in PJM in 2009. The $112.9 million in congestion costs in the Dominion Control Zone represented a 65 percent decrease from the $322.6 million in congestion costs the zone had experienced in 2008. The AP South interface contributed $69.0 million, or 61 percent of the total Dominion Control Zone congestion cost.

Table 7 Congestion cost summary (By control zone): Calendar year 2009

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$24.5	$9.2	$0.2	$15.6	($0.5)	$0.9	$0.4	($1.0)	$14.6
AEP	($60.2)	($160.5)	$9.0	$109.3	($7.2)	$8.4	($10.7)	($26.3)	$83.0
AP	$33.2	($80.7)	$12.9	$126.9	($4.5)	$5.0	($22.1)	($31.6)	$95.3
BGE	$97.6	$75.9	$2.4	$24.0	$6.9	($5.0)	($2.3)	$9.5	$33.5
ComEd	($255.3)	($493.1)	($4.1)	$233.7	($7.6)	$6.1	($0.4)	($14.0)	$219.7
DAY	($9.7)	($18.7)	($0.5)	$8.5	$0.9	$1.7	$0.1	($0.7)	$7.8
DLCO	($50.7)	($75.8)	($0.0)	$25.1	($4.0)	$5.3	($0.2)	($9.5)	$15.6
Dominion	$94.0	($15.4)	$7.5	$117.0	$1.1	($3.0)	($8.2)	($4.1)	$112.9
DPL	$49.7	$15.0	$0.4	$35.1	($1.9)	$1.6	($0.4)	($4.0)	$31.1
External	($22.2)	($56.7)	$37.3	$71.9	($1.3)	($7.6)	($79.1)	($72.8)	($1.0)
JCPL	$46.7	$18.9	$0.1	$27.9	$0.4	($2.7)	($0.2)	$2.9	$30.8
Met-Ed	$36.9	$36.8	$0.2	$0.4	$0.1	($1.0)	($0.3)	$0.8	$1.1
PECO	$19.0	$39.9	$0.1	($20.8)	($0.4)	$2.8	($0.1)	($3.3)	($24.1)
PENELEC	($6.8)	($38.9)	$0.3	$32.4	$1.3	$0.8	($0.1)	$0.4	$32.8
Pepco	$203.9	$133.9	$3.5	$73.5	($21.2)	($9.7)	($3.6)	($15.1)	$58.4
PPL	$14.6	$23.4	$2.7	($6.1)	($0.3)	($0.5)	$0.2	$0.4	($5.7)
PSEG	$74.8	$61.7	$11.7	$24.8	($0.7)	$6.9	($6.2)	($13.8)	$11.0
RECO	$2.2	$0.0	$0.1	$2.3	$0.0	($0.0)	($0.1)	($0.1)	$2.2
Total	$292.3	($525.2)	$83.9	$901.4	($39.0)	$10.1	($133.4)	($182.4)	$719.0

Economic Planning Process

- **Transmission and Markets.** As a general matter, transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. While the RPM construct does provide that qualifying transmission upgrades may be submitted as offers, there have been no such offers. More generally, network transmission is not built based directly on market signals because the owners of network transmission are compensated through a non market mechanism, typically under traditional regulation. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics. Economic evaluation metrics can be used to determine whether there are positive economic benefits associated with an investment in transmission that might warrant the investment even when it is not required for reliability. The goal of transmission planning should ultimately be the incorporation of transmission investment decisions into market driven processes as much as possible.

- **Process Revision.** After multiple filings in a proceeding concerning PJM's proposed economic metrics for evaluating transmission investments (Docket No. ER06-1474), the FERC approved in early 2009 an approach with predefined formulas for determining whether a transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand-response trends.[98]

Congestion Conclusion

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the cost and geographical distribution of generation facilities and the geographical distribution of load. Total congestion costs decreased by $1.397 billion or 66 percent, from $2.117 billion in 2008 to $719.0 million in 2009. Day-ahead congestion costs decreased by $1.760 billion or 66 percent, from $2.661 billion in 2008 to $901.4 million in 2009. Balancing congestion costs increased by $362.2 million or 67 percent, from -$544.6 million in 2008 to -$182.4 million in 2009. Congestion costs were significantly higher in the Day-Ahead Market than in the balancing market. Congestion frequency was also significantly higher in the Day-Ahead Market than in the Real-Time Market. Day-ahead congestion frequency increased from 2008 to 2009 by 3,048 congestion event hours. In 2009, there were 77,793 day-ahead, congestion-event hours compared to 74,745 day-ahead, congestion-event hours in 2008. Real-time congestion frequency decreased from 2008 to 2009 by 6,995 congestion event hours. In 2009, there were 15,454 real-time, congestion-event hours compared to 22,449 real-time, congestion-event hours in 2008.

ARRs and FTRs served as an effective, but not total, hedge against congestion. ARR and FTR revenues hedged more than 100 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2008 to 2009 planning period. For the first seven months of the 2009 to 2010 planning period, ARR and FTR revenue hedged 94 percent of the total congestion costs within PJM.[99] FTRs were paid at 100 percent of the target allocation for the 2008 to 2009 planning year and 98 percent of the target allocation level for the first seven months of the 2009 to 2010 planning period. Revenue adequacy for a planning period is not final until the end of the period.

There are other ways to evaluate the effectiveness of ARRs as a hedge. The value of ARRs and ARRs converted to self scheduled FTRs was 3.5 percent of total energy charges to load for the first three quarters of 2009. FTRs acquired through FTR auctions had a net negative value, probably largely as a result of lower than expected congestion.

One constraint accounted for over a quarter of total congestion costs in 2009 and the top five constraints accounted for half of total congestion costs. The AP South Interface was the largest contributor to congestion costs in 2009.

98 126 FERC ¶ 61,152.

99 See the *2009 State of the Market Report for PJM*, Volume II, Section 8, "Financial Transmission and Auction Revenue Rights," at Table 8-28, "ARR and FTR congestion hedging: Planning periods 2008 to 2009 and 2009 to 2010."

The congestion metric requires careful review. Net congestion, which includes both load congestion payments and generation congestion credits, is not a good measure of the congestion costs paid by load from the perspective of the wholesale market.[100] While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear total congestion costs. Load congestion payments, when positive, measure the total congestion cost to load in an area. Load congestion payments, when negative, measure the total congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in western control zones and higher prices in eastern and southern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative load congestion payment). Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the total congestion credit to generation in an area. Generation congestion credits, when negative, measure the total congestion cost to generation in an area. This is a cost only in the sense that revenues to generators in the area are lower, by the amount of the congestion cost, than they would have been if they had been paid LMP without a congestion component, the system marginal price. Negative generation congestion credits result when generation is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in the western control zones and higher prices in the eastern and southern control zones. Generation in the western control zones will receive lower prices and incur a congestion charge (negative generation congestion credit). Generation in the eastern and southern control zones will receive higher prices and receive a congestion credit (positive generation congestion credit).

As an example, total congestion costs in PJM for 2009 were $719.0 million, which was comprised of load congestion payments of $253.3 million, negative generation credits of $515.1 million and negative explicit congestion of $49.4 million.

100 The actual congestion payments by retail customers are a function of retail ratemaking policies and may or may not reflect an offset for congestion credits.

Financial Transmission Rights

Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs) give transmission service customers and PJM members an offset against congestion costs in the Day-Ahead Energy Market. An FTR provides the holder with revenues, or charges, equal to the difference in congestion prices in the Day-Ahead Energy Market across the specific FTR transmission path. An ARR is a related product that provides the holder with revenues, or charges, based on the price differences across the specific ARR transmission path that result from the Annual FTR Auction. FTRs and ARRs provide a hedge against congestion costs, but neither FTRs nor ARRs provide a guarantee that transmission service customers will not pay congestion charges. ARR and FTR holders do not need to physically deliver energy to receive ARR or FTR credits and neither instrument represents a right to the physical delivery of energy.

In PJM, FTRs have been available to network service and long-term, firm, point-to-point transmission service customers as a hedge against congestion costs since the inception of locational marginal pricing (LMP) on April 1, 1998. Effective June 1, 2003, PJM replaced the allocation of FTRs with an allocation of ARRs and an associated Annual FTR Auction.[101] Since the introduction of this auction, FTRs have been available to all transmission service customers and PJM members. Network service and firm point-to-point transmission service customers can take allocated ARRs or the underlying FTRs through a self scheduling process. On June 1, 2007, PJM implemented marginal losses in the calculation of LMP. Since then, FTRs have been valued based on the difference in congestion prices rather than the difference in LMPs.

Firm transmission service customers have access to ARRs/FTRs because they pay the costs of the transmission system that enables firm energy delivery. Firm transmission service customers receive requested ARRs/FTRs to the extent that they are consistent both with the physical capability of the transmission system and with ARR/FTR requests of other eligible customers.

The *2009 State of the Market Report for PJM* focuses on the annual ARR allocations, the Annual FTR Auctions and the Monthly Balance of Planning Period FTR Auctions during two FTR/ARR planning periods: the 2008 to 2009 planning period which covers June 1, 2008, through May 31, 2009, and the 2009 to 2010 planning period which covers June 1, 2009, through May 31, 2010. The *2009 State of the Market Report for PJM* also analyzes the results of the 2010 to 2013 Long Term FTR Auction that covers three consecutive planning periods: June 1, 2010 through May 31, 2011, June 1, 2011 through May 31, 2012 and June 1, 2012 through May 31, 2013.

Market Structure

- **Supply.** PJM operates an Annual FTR Auction for all control zones in the PJM footprint. PJM conducts Monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period, to allow participants to buy and sell any residual transmission capability. PJM also runs a Long Term FTR Auction for the three consecutive planning years immediately following the planning year during which the Long Term FTR Auction is conducted. The first Long Term FTR Auction was conducted during the 2008 to 2009 planning period and covers three consecutive planning periods between 2009 and 2012. The second Long Term FTR Auction is

101 87 FERC ¶ 61,054 (1999).

being conducted during the 2009 to 2010 planning period and covers three consecutive planning periods between 2010 and 2013. In addition, PJM administers a secondary bilateral market to allow participants to buy and sell existing FTRs. FTR products include FTR obligations and FTR options. FTR options are not available in the Long Term FTR Auction. For each time period, there are three FTR products: 24-hour, on peak and off peak. FTRs have terms varying from one month to three years. FTR supply is limited by the capability of the transmission system to accommodate simultaneously the set of requested FTRs and the numerous combinations of FTRs. The principal binding constraints limiting the supply of FTRs in the 2010 to 2013 Long Term FTR Auction include the Carroll Transformer and the Philipsburg – Shawville line. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2009 to 2010 planning period include the AP South Interface and the Mahans Lane — Tidd line.[102] Market participants can also sell FTRs. In the 2010 to 2013 Long Term FTR Auction, total FTR sell offers were 51,582 MW. In the Annual FTR Auction for the 2009 to 2010 planning period, total FTR sell offers were 142,154 MW, up from 83,453 MW during the 2008 to 2009 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2009) of the 2009 to 2010 planning period, there were 1,962,836 MW of FTR sell offers.

- **Demand.** There is no limit on FTR demand in any FTR auction. In the 2010 to 2013 Long Term FTR Auction, total FTR buy bids were 1,064,620 MW. In the Annual FTR Auction for the 2009 to 2010 planning period, total FTR buy bids were 1,436,335 MW, down from 2,181,273 MW during the 2008 to 2009 planning period. Total FTR self scheduled bids were 68,589 MW for the 2009 to 2010 planning period, a decrease from 72,851 MW for the 2008 to 2009 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2009) of the 2009 to 2010 planning period, total FTR buy bids were 5,339,818 MW.

- **FTR Credit Issues.** One participant defaulted for a small amount, which was covered by collateral, in 2009, and one participant had losses on annual FTRs that extended into 2009. PJM made multiple filings in 2008 and 2009 to reform its credit policies, focusing particularly on ensuring an appropriate level of credit to cover positions acquired by market participants in counter flow FTRs. On April 3, 2009, the FERC conditionally approved the second in a series of filings by PJM aimed at reform of its credit policies.[103] The proceeding for compliance with the Commission's conditions is not yet resolved.[104] Effective June 1, 2009, PJM performs weekly rather than monthly billing and payment for the majority of invoice line items, reduced the Unsecured Credit Allowance by two-thirds, eliminated the Unsecured Credit Allowance in support of trading in FTRs, and implemented procedures that allow it to close out and liquidate forward FTR positions held by market participants who have defaulted on their obligations.

- **Patterns of Ownership.** The ownership concentration of cleared FTR buy bids resulting from the 2009 to 2010 Annual FTR Auction was low to moderate for FTR obligations and high for FTR options. The level of concentration is only descriptive and is not a measure of the competitiveness of FTR market structure as the ownership positions resulted from a

102 During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones. Four of these, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion, were eligible for direct allocation FTRs during the 2006 to 2007 planning period, but not the 2007 to 2008, the 2008 to 2009 or the 2009 to 2010 planning period. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

103 127 FERC ¶ 61,017. The FERC has approved PJM's proposed revisions to its credit policy in Docket No. ER08-376. 122 FERC ¶ 61,279 (2008).

104 See FERC Docket No. ER09-650.

competitive auction. In order to provide additional information about the ownership of prevailing flow and counter flow FTRs, the MMU categorized all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. During the 2009 to 2010 planning period, physical entities own 61 percent of prevailing flow Annual FTRs while financial entities own 57 percent of counter flow Annual FTRs. Overall, financial entities own 43 percent of all Annual FTRs. Financial entities own 77 percent of prevailing flow Long Term FTRs and 80 percent of counter flow Long Term FTRs. Financial entities own about 78 percent of all Long Term FTRs. Financial entities own 68 percent of prevailing flow and 82 percent of counter flow Monthly Balance of Planning Period FTRs. Overall, financial entities own 74 percent of all Monthly Balance of Planning Period FTRs.

Market Performance

- **Volume.** The 2010 to 2013 Long Term FTR Auction cleared 86,108 MW (8.1 percent of demand) of FTR buy bids, up from 52,369 MW (6.5 percent) in the 2009 to 2012 Long Term FTR Auction. The 2010 to 2013 Long Term FTR Auction also cleared 5,147 MW (10.0 percent) of FTR sell offers, up from 1,010 MW (6.4 percent) in the 2009 to 2012 Long Term FTR Auction. For the 2009 to 2010 planning period, the Annual FTR Auction cleared 155,612 MW (10.8 percent) of FTR buy bids, down from 204,349 MW (9.4 percent) for the 2008 to 2009 planning period. The Annual FTR Auction also cleared 7,399 MW (5.2 percent) of FTR sell offers for the 2009 to 2010 planning period, up from 4,534 MW (5.4 percent) for the 2008 to 2009 planning period. For the first seven months of the 2009 to 2010 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 568,742 MW (10.7 percent) of FTR buy bids and 177,297 MW (9.0 percent) of FTR sell offers.

- **Price.** In the 2010 to 2013 Long Term FTR Auction, 93.7 percent of the Long Term FTRs were purchased for less than $1 per MWh and 96.6 percent for less than $2 per MWh. The weighted-average prices paid for Long Term buy-bid FTRs in the 2010 to 2013 Long Term FTR Auction were $0.53 per MWh for 24-hour FTRs, $0.03 per MWh for on peak FTRs and $0.10 per MWh for off peak FTRs. Weighted-average prices paid for Long Term buy-bid FTRs in the 2009 to 2012 Long Term FTR Auction were $0.76 per MWh for 24-hour FTRs, $0.10 per MWh for on peak FTRs and $0.01 per MWh for off peak FTRs. For the 2009 to 2010 planning period, 83.2 percent of the Annual FTRs were purchased for less than $1 per MWh and 90.6 percent for less than $2 per MWh. For the 2009 to 2010 planning period, the weighted-average prices paid for annual buy-bid FTR obligations were $0.66 per MWh for 24-hour FTRs, $0.57 per MWh for on peak FTRs and $0.40 per MWh for off peak FTRs. Weighted-average prices paid for annual buy-bid FTR obligations for the 2008 to 2009 planning period were $1.96 per MWh for 24-hour FTRs and $0.55 per MWh for on peak FTRs and $0.26 per MWh for off peak FTRs. The weighted-average prices paid for 2009 to 2010 planning period annual buy-bid FTR obligations and options were $0.53 per MWh and $0.35 per MWh, respectively, compared to $0.69 per MWh and $0.24 per MWh, respectively, in the 2008 to 2009 planning period.[105] The weighted-average price paid for buy-bid FTRs in the Monthly Balance of Planning Period FTR

105 Weighted-average prices for FTRs in the Long Term FTR Auction, Annual FTR Auction and Monthly Balance of Planning Period FTR Auctions are the average prices weighted by the MW and hours in a time period (planning period or month) for each FTR class type: 24-hour, on peak and off peak. For example, FTRs in the 2009 to 2010 Annual FTR Auction would be weighted by their MW and the hours in that time period for each FTR class type: 24-hour (8,760 hours), on peak (4,096 hours) and off peak (4,664 hours).

Auctions for the first seven months of the 2009 to 2010 planning period was $0.20 per MWh, compared with $0.30 per MWh in the Monthly Balance of Planning Period FTR Auctions for the full 12-month 2008 to 2009 planning period.

- **Revenue.** The 2010 to 2013 Long Term FTR Auction generated $31.1 million of net revenue for all FTRs, down from $38.9 million in the 2009 to 2012 Long Term FTR Auction. The Annual FTR Auction generated $1,329.8 million of net revenue for all FTRs during the 2009 to 2010 planning period, down from $2,422.6 million for the 2008 to 2009 planning period. The Monthly Balance of Planning Period FTR Auctions generated $13.1 million in net revenue for all FTRs during the first seven months of the 2009 to 2010 planning period.

- **Revenue Adequacy.** FTRs were 100 percent revenue adequate for the 2008 to 2009 planning period. FTRs were paid at 97.7 percent of the target allocation level for the first seven months of the 2009 to 2010 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $388.3 million of FTR revenues during the first seven months of the 2009 to 2010 planning period and $1,748.3 million during the 2008 to 2009 planning period. For the first seven months of the 2009 to 2010 planning period, the top sink and top source with the highest positive FTR target allocations were the AP Control Zone and the Mount Storm aggregate, respectively. Similarly, the top sink and top source with the largest negative FTR target allocations were the Northern Illinois Hub and the Western Hub, respectively.

Auction Revenue Rights

Market Structure

- **Supply.** ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of feasible ARRs. The principal binding constraints that limited supply in the annual ARR allocation for the 2009 to 2010 planning period were the AP South Interface and the Electric Junction — Frontenac line. Long Term ARRs are in effect for 10 consecutive planning periods and are available in Stage 1A of the annual ARR allocation. Residual ARRs are available to holders with prorated Stage 1A or 1B ARRs if additional transmission capability is added during the planning period.

- **Demand.** Total demand in the annual ARR allocation was 140,037 MW for the 2009 to 2010 planning period with 64,987 MW bid in Stage 1A, 26,517 MW bid in Stage 1B and 48,533 MW bid in Stage 2. This is down from 140,668 MW for the 2008 to 2009 planning period with 64,546 MW bid in Stage 1A, 27,291 MW bid in Stage 1B and 48,831 MW bid in Stage 2. ARR demand is limited by the total amount of network service and firm point-to-point transmission service.

- **ARR Reassignment for Retail Load Switching.** When retail load switches among load-serving entities (LSEs), a proportional share of the ARRs and their associated revenue are reassigned from the LSE losing load to the LSE gaining load. ARR reassignment occurs only if the LSE losing load has ARRs with a net positive economic value. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. There were 10,531 MW of ARRs associated with approximately $195,300 per MW-day of revenue that were reassigned in the first seven months of the 2009 to

2010 planning period. There were 15,326 MW of ARRs associated with approximately $533,900 per MW-day of revenue that were reassigned for the full 2008 to 2009 planning period.

Market Performance

- **Volume.** Of 140,037 MW in ARR requests for the 2009 to 2010 planning period, 109,413 MW (78.1 percent) were allocated. There were 64,913 MW allocated in Stage 1A, 26,514 MW allocated in Stage 1B and 17,986 MW allocated in Stage 2. Eligible market participants self scheduled 68,589 MW (62.7 percent) of these allocated ARRs as Annual FTRs. Of 140,668 MW in ARR requests for the 2008 to 2009 planning period, 112,011 MW (79.6 percent) were allocated. There were 64,520 MW allocated in Stage 1A, 26,685 MW allocated in Stage 1B and 20,806 MW allocated in Stage 2. Eligible market participants self scheduled 72,851 MW (65.0 percent) of these allocated ARRs as Annual FTRs.

- **Revenue.** As ARRs are allocated to qualifying customers rather than sold, there is no ARR revenue comparable to the revenue that results from the FTR auctions.

- **Revenue Adequacy.** During the 2009 to 2010 planning period, ARR holders will receive $1,273.5 million in ARR credits, with an average hourly ARR credit of $1.33 per MWh. During the 2009 to 2010 planning period, the ARR target allocations were $1,273.5 million while PJM collected $1,342.9 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions through December 2009, making ARRs revenue adequate. During the 2008 to 2009 planning period, ARR holders received $2,361.3 million in ARR credits, with an average hourly ARR credit of $2.41 per MWh. For the 2008 to 2009 planning period, the ARR target allocations were $2,361.3 million while PJM collected $2,489.6 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

- **ARR Proration.** When ARRs were allocated for the 2009 to 2010 planning period, some of the requested ARRs were prorated in Stage 2 as a result of binding transmission constraints. No ARRs were prorated in Stage 1A and Stage 1B since there were no constraints affecting the ARR allocation in these two stages. For the 2008 to 2009 planning period, no ARRs were prorated in Stage 1A of the annual ARR allocation. In Stage 1B, the only constraint affecting the ARR allocation was the Cedar Grove — Clifton line. There were 605.4 MW of Stage 1B ARRs denied to participants whose requested ARRs affected that binding transmission constraint.

- **ARRs and FTRs as a Hedge against Congestion.** The effectiveness of ARRs and FTRs as a hedge against actual congestion can be measured several ways. The first is to compare the revenue received by ARR holders to the congestion costs experienced by these ARR holders. The second is to compare the congestion revenue received by FTR holders to the costs of those FTRs. The final and comprehensive method is to compare the revenue received by all ARR and FTR holders to total actual congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM. For the 2008 to 2009 planning period, all ARRs and FTRs hedged more than 100 percent of the congestion costs within PJM. During the first seven months of the 2009 to 2010 planning period, total ARR and FTR revenues hedged 93.5 percent of the congestion costs within PJM.

- **ARRs and FTRs as a Hedge against Total Energy Costs.** The hedge provided by ARRs can also be measured by comparing the value of the ARR and self-scheduled FTRs that sink in a zone to the cost of real time energy in the zone. This is a measure of the value of the hedge against real time energy costs provided by ARRs received by loads during this period. The total value of ARRs was 3.5 percent of the total real time energy charges in calendar year 2009. The hedge provided by FTRs can also be measured by comparing the value of the FTRs that sink in a zone to the cost of real time energy in the zone. The total net value of FTRs was -0.9 percent of the total real time energy charges in calendar year 2009 because the purchase cost exceeded the value of the credits. When combined, the sum is a measure of the total value of ARRs plus FTRs. The total value of ARRs plus FTRs was 2.6 percent of the total real time energy charges in calendar year 2009.

Table 8 ARR and FTR congestion hedging by control zone: Planning period 2008 to 2009

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
AECO	$31,771,370	$36,858,894	$32,933,548	$35,696,716	$43,970,115	($8,273,399)	81.2%
AEP	$286,629,442	$209,802,906	$204,085,063	$292,347,285	$155,842,889	$136,504,396	>100%
AP	$786,115,867	$527,925,980	$780,244,128	$533,797,719	$298,746,849	$235,050,870	>100%
BGE	$98,283,955	$38,944,903	$57,160,496	$80,068,362	$89,929,323	($9,860,961)	89.0%
ComEd	$24,695,477	($26,152,262)	($4,320,075)	$2,863,290	$264,565,267	($261,701,977)	1.1%
DAY	$9,926,586	$1,744,872	($2,026,571)	$13,698,029	$5,493,146	$8,204,883	>100%
DLCO	$4,691,151	($9,342,004)	($16,286,386)	$11,635,533	$14,972,671	($3,337,138)	77.7%
Dominion	$463,320,908	$344,212,309	$522,524,367	$285,008,850	$254,898,027	$30,110,823	>100%
DPL	$28,077,406	$50,222,866	$42,813,893	$35,486,379	$79,599,656	($44,113,277)	44.6%
JCPL	$98,171,902	$5,730,251	$104,255,372	($353,219)	$92,985,545	($93,338,764)	<0%
Met-Ed	$50,979,701	$36,542,204	$60,190,813	$27,331,092	($1,271,642)	$28,602,734	>100%
PECO	$75,104,737	$65,545,964	$76,721,387	$63,929,314	($47,350,955)	$111,280,269	>100%
PENELEC	$95,333,189	$118,697,998	$134,333,128	$79,698,059	$112,271,697	($32,573,638)	71.0%
Pepco	$59,162,442	$204,600,376	$260,910,557	$2,852,261	$150,501,458	($147,649,197)	1.9%
PJM	$20,562,228	($3,803,359)	$2,995,857	$13,763,012	($119,445,094)	$133,208,106	>100%
PPL	$73,844,704	$74,910,276	$82,036,315	$66,718,665	$4,627,831	$62,090,834	>100%
PSEG	$154,621,742	$71,755,534	$148,376,631	$78,000,645	$15,850,146	$62,150,499	>100%
RECO	$0	$3,877	$2,660,947	($2,657,070)	$5,941,446	($8,598,516)	<0%
Total	$2,361,292,807	$1,748,201,585	$2,489,609,470	$1,619,884,922	$1,422,128,376	$197,756,546	>100%

FTR and ARR Conclusion

The annual ARR allocation and the FTR auctions provide market participants with hedging instruments. These instruments can be used for hedging positions or for speculation. The Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions provide a market valuation of FTRs. The FTR auction results for the 2009 to 2010 planning period were competitive and succeeded in providing all qualified market participants with equal access to FTRs.

The MMU recommends that when load switches among LSEs during the planning period, a proportional share of the underlying self scheduled FTRs follow the load in the same manner that ARRs do. This would include both FTRs that are directly self scheduled and FTRs on paths identical to the ARR, which are financially equivalent to self scheduled FTRs. ARRs are assigned to firm transmission service customers because these customers pay the costs of the transmission system that enables firm energy delivery. The underlying FTRs are obtained as the direct result of the ARR assignment and should therefore follow the reassignment of ARRs when load switches.

ARRs were 100 percent revenue adequate for both the 2008 to 2009 and the 2009 to 2010 planning periods. FTRs were paid at 100 percent of the target allocation level for the 12-month period of the 2008 to 2009 planning period, and at 97.7 percent of the target allocation level for the first seven months of the 2009 to 2010 planning period. Revenue adequacy for a planning period is not final until the end of the period.

Revenue adequacy must be distinguished from the adequacy of FTRs as a hedge against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion across specific paths for which FTRs were available and purchased. The adequacy of FTRs as a hedge against congestion compares FTR revenues to the costs of purchasing the FTRs. For the 2008 to 2009 planning period the total cost of all FTRs exceeded the FTR credits received, based on the value of the congestion costs for which they were purchased as a hedge. After the cost to obtain the FTRs was subtracted from the total FTR revenue, the net value of all FTRs was negative and thus the FTRs were unprofitable.

The total of ARR and FTR revenues hedged more than 100 percent of the congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2008 to 2009 planning period and 93.5 percent of the congestion costs in PJM for the first seven months of the 2009 to 2010 planning period. The ARR and FTR revenue adequacy results are aggregate results and all those paying congestion charges were not necessarily hedged at that level. Aggregate numbers do not reveal the underlying distribution of ARR and FTR holders, their revenues or those paying congestion.