State of the Market Report for PJM

Volume 2: Detailed Analysis

Monitoring Analytics, LLC

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.[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.

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;

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.
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."

- 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.

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.

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.

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.").

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 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.

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

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).

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 1-1 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]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[15]

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.
15 PJM Operating Agreement Schedule 1-3.2.3A.01 and OATT Schedule 6.

- 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 1-1 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%

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.

SECTION 2 – 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 Market Monitoring Unit (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.[1] 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.[2] 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.

Overview

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.[3] 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.

1 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."

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

3 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.

- **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.[4] 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 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.

4 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).

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 4498.2 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.

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 United States Federal Energy Regulatory Commission's (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.

Market Structure

Supply

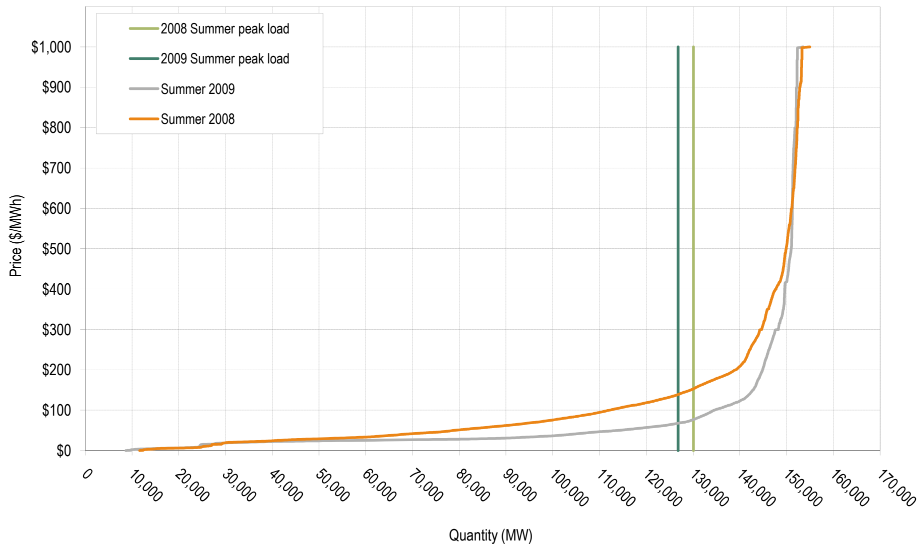
During the June to September 2009 summer period, the PJM Energy Market received a daily average of 153,520 MW in total supply offers including hydroelectric generation. The summer 2009 average daily offered supply was 1,439 MW lower than the summer 2008 average daily offered supply of 154,959 MW. An extended outage at a nuclear power plant was the primary cause of the decrease. American Electric Power's Cook Nuclear Plant Unit 1, for example, was on a full outage for the entire summer.[5] Other outages, mainly of coal units in the western PJM region, contributed to the decreases in offered supply. The 2009 summer period outages were partially offset by the addition of 1,881.5 MW (full capacity) of wind generation.

During the summer of 2009, the peak demand was 3,295 MW, or 2.5 percent, lower than the 2008 peak, which, when combined with the shift down of the 2009 supply curve, resulted in a lower price level at the intersection of supply and demand. (See Figure 2-1)

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

Supply offer prices for the summer of 2009 were lower than those in 2008 primarily due to a decline in fuel costs in the PJM region. All fuel types experienced price decreases, including a 33.2 percent decrease in coal prices, a 65.9 percent decrease in natural gas prices, and a 45.8 percent decrease in oil-related commodity prices.[6]

Figure 2-1 Average PJM aggregate supply curves: Summers 2008 and 2009



Total internal capacity in the RPM auction for the 2008/2009 delivery year increased 350.2 MW from 156,968.0 MW on June 1, 2008, to 157,318.2 MW on June 1, 2009.[7] This increase was the result of 439.2 MW of new generation, 74.1 MW of generation uprates, and 220.6 MW of demand resource (DR) mods, offset in part by 383.7 MW from higher EFORds. In the 2008/2009 auction, 15 more generating resources made offers than in the 2007/2008 RPM Auction. The increase included five new wind resources (66.1 MW), three new diesel resources (23.3 MW) and two resources (112.6 MW) which came out of retirement while the remaining five resources were the result of a reclassification of external resources. In 2009, 1,881.5 MW of non-derated wind capacity also entered service in PJM, which is not accounted for in the RPM auction. There were no unit retirements in 2009.

The net result of these factors was that the summer 2009 average aggregate supply curve shifted down.

Demand

Table 2-1 shows the actual coincident summer peak loads for the years 1999 through 2009. The 2009 actual summer peak load of 126,805 was 3,295 MW less than the 2008 summer peak load of 130,100 MW and was the lowest peak demand since 2005, the year of the last transmission

6 Natural gas, light oil, and heavy oil prices are the average of daily fuel price indices in the PJM footprint. Coal prices are the average of daily fuel prices for 1.2 percent sulfur content Central Appalachian coal and Powder River Basin coal. All fuel prices are from Platts.

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

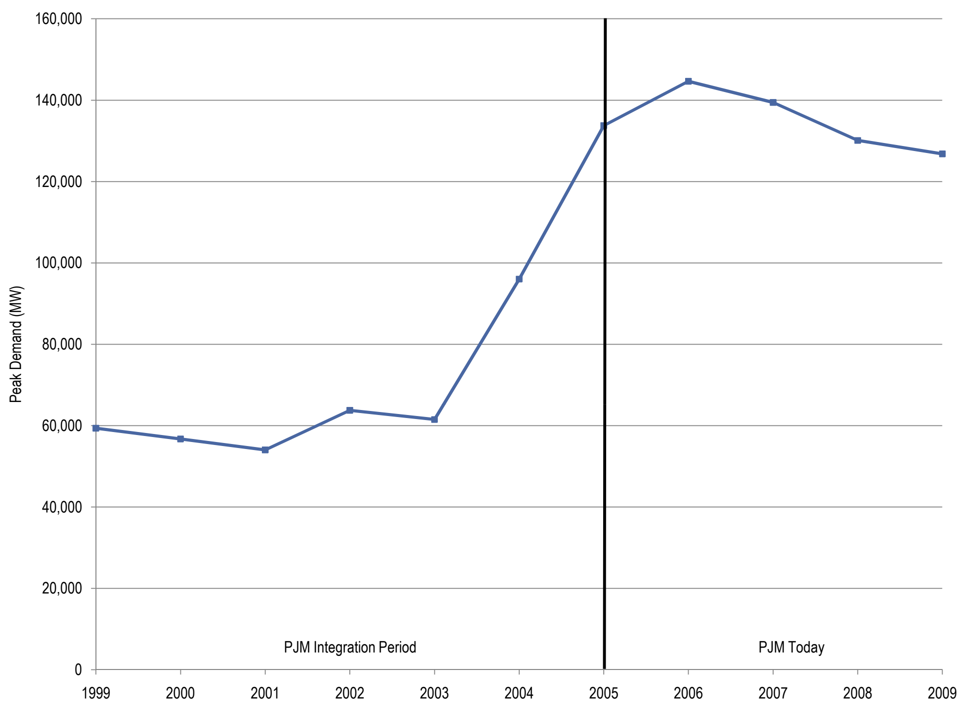
system integrations (Duquesne Light and Dominion) into PJM. This measure of peak load is the total amount of generation output and net energy imports required to meet the peak demand on the system, including losses, rather than the actual load served.[8]

Table 2-1 Actual PJM footprint summer peak loads: 1999 to 2009

Year	Date	Hour Ending (EPT)	PJM Load (MW)	Difference (MW)	Difference (%)
1999	Jul 6, 1999	1400	59,365	NA	NA
2000	Jun 26, 2000	1600	56,727	(2,638)	(4.4%)
2001	Aug 9, 2001	1500	54,015	(2,712)	(4.8%)
2002	Aug 14, 2002	1600	63,762	9,747	18.0%
2003	Aug 22, 2003	1600	61,499	(2,263)	(3.5%)
2004	Dec 20, 2004	1900	96,016	34,517	56.1%
2005	Jul 26, 2005	1600	133,761	37,746	39.3%
2006	Aug 2, 2006	1700	144,644	10,883	8.1%
2007	Aug 8, 2007	1600	139,428	(5,216)	(3.6%)
2008	Jun 9, 2008	1700	130,100	(9,328)	(6.7%)
2009	Aug 10, 2009	1700	126,805	(3,295)	(2.5%)

Figure 2-2 shows the yearly peak loads since 1999.

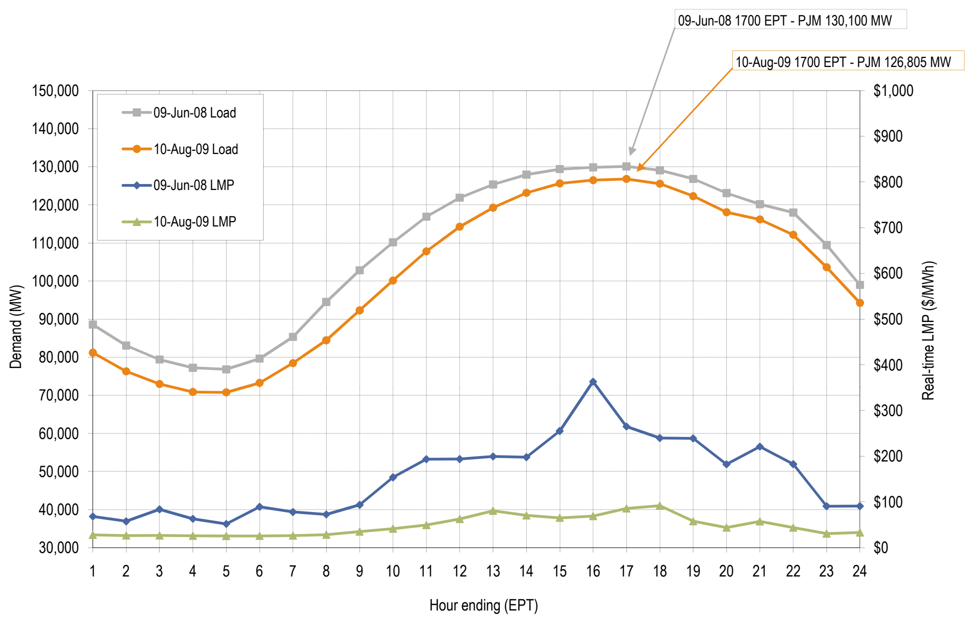
Figure 2-2 Actual PJM footprint summer peak loads: 1999 to 2009



8 Peak loads shown are eMTR load. See the *2009 State of the Market Report for PJM*, Volume II, Appendix I, "Load Definitions," for detailed definitions of load.

The hourly load and average PJM LMP for the 2009 and 2008 summer peak days are shown in Figure 2-3. The peak for 2009 occurred on August 10, at hour ending 1700. The hourly integrated LMP for this hour was $85.64 per MWh. The peak for 2008 occurred on June 9, at hour ending 1700. The hourly integrated LMP for this hour was $265.19 per MWh.

Figure 2-3 PJM summer peak-load comparison: Monday, August 10, 2009, and Monday, June 9, 2008



Market Concentration

During 2009, concentration in the PJM Energy Market was moderate overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.[9] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal during high demand periods. When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall Energy Market. PJM offer-capping rules that limit the exercise of local market power and generation owners' obligations to serve load were effective in most cases in preventing the exercise of market power in these areas during 2009. If those obligations were to change or the rules were to change, however, the market power related incentives and impacts would change as a result.

Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate that comparatively small numbers of sellers dominate a market; low concentration ratios mean larger numbers of sellers split market sales more equally. The best tests of market competitiveness are direct tests of the conduct of individual participants and their

9 For the market concentration analysis, supply curve segments are based on a classification of units that generally participate in the PJM Energy Market at varying load levels. Unit class is a primary factor for each classification; however, each unit may have different characteristics that influence the exact segment for which it is classified.

impact on price. The direct examination of offer behavior by individual market participants is one such test. Low aggregate market concentration ratios establish neither that a market is competitive nor that participants are unable to exercise market power. High concentration ratios do, however, indicate an increased potential for participants to exercise market power.

Despite their significant limitations, concentration ratios provide useful information on market structure. The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market. Hourly PJM Energy Market HHIs were calculated based on the real-time energy output of generators, adjusted for hourly net imports by owner. (See Table 2-2)

Actual net imports and import capability were incorporated in the hourly Energy Market HHI calculations because imports are a source of competition for generation located in PJM. Energy can be imported into PJM under most conditions. The hourly HHI was calculated by combining all export and import transactions from each market participant with its generation output from each hour. A market participant's market share increases with imports and decreases with exports.

Hourly HHIs were also calculated for baseload, intermediate and peaking segments of generation supply. Hourly Energy Market HHIs by supply curve segment were calculated based on hourly Energy Market shares, unadjusted for imports.

The "Merger Policy Statement" of the FERC states that a market can be broadly characterized as:

- **Unconcentrated.** Market HHI below 1000, equivalent to 10 firms with equal market shares;
- **Moderately Concentrated.** Market HHI between 1000 and 1800; and
- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[10]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during 2009 was moderately concentrated. (See Table 2-2). Based on the hourly Energy Market measure, average HHI was 1242 with a minimum of 935 and a maximum of 1628 in 2009. The highest hourly market share was 32 percent and the highest average market share for 2009 was 22 percent.

10 77 FERC ¶ 61,263, "Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement," Order No. 592, pp. 64-70.

Table 2-2 PJM hourly Energy Market HHI: Calendar year 2009[11]

	Hourly Market HHI
Average	1242
Minimum	935
Maximum	1628
Highest market share (One hour)	32%
Highest market share (All hours)	22%
# Hours	8760
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

Table 2-3 includes 2009 HHI values by supply curve segment, including base, intermediate and peaking plants. The hourly measure indicates that, on average, intermediate and peaking segments of the supply curve are highly concentrated, while the baseload segment is moderately concentrated.

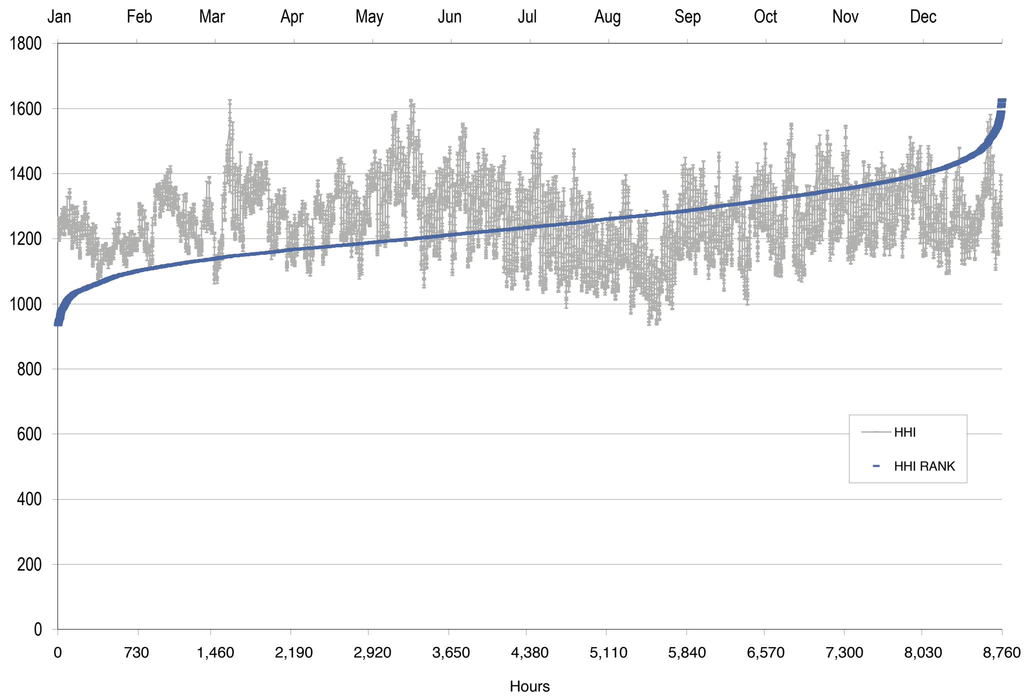
Table 2-3 PJM hourly Energy Market HHI (By segment): Calendar year 2009

	Minimum	Average	Maximum
Base	1117	1273	1616
Intermediate	872	1954	7176
Peak	669	5644	10000

Figure 2-4 presents the 2009 hourly HHI values in chronological order and an HHI duration curve that shows 2009 HHI values in ascending order of magnitude. The HHI values were in the unconcentrated range for 0.8 percent of the hours while HHI values were in the moderately concentrated range in the remaining 99.2 percent of hours, with a maximum value of 1628, as shown in Table 2-2.

11 This analysis includes all hours of 2009, regardless of congestion.

Figure 2-4 PJM hourly Energy Market HHI: Calendar year 2009



Local Market Structure and Offer Capping

In the PJM Energy Market, offer capping occurs only as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets. There are no explicit rules governing market structure or the exercise of market power in the aggregate Energy Market. PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power.

PJM has clear rules limiting the exercise of local market power.[12] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market (as measured by the three pivotal supplier test), when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer-capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules. The offer-capping rules exempted certain units from offer capping based on the date of their construction. Such exempt units could, and

12 See "Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.," Schedule 1, Section 6.4.2. (February 1, 2010).

did, exercise market power, at times, that would not have been permitted if the units had not been exempt. The FERC eliminated the exemption effective May 17, 2008.[13]

Under existing rules, PJM does not apply offer capping to suppliers when structural market conditions, as measured by the three pivotal supplier test, indicate that such suppliers are reasonably likely to behave in a competitive manner. The goal is to apply a clear rule to limit the exercise of market power by generation owners in load pockets, but to apply the rule in a flexible manner in real time and to lift offer capping when the exercise of market power is unlikely based on the real-time application of the market structure screen.

PJM's three pivotal supplier test represents the practical application of the FERC market power tests in real time.[14] The three pivotal supplier test is passed if no three generation suppliers in a load pocket are jointly pivotal. Stated another way, if the incremental output of the three largest suppliers in a load pocket is removed and enough incremental generation remains available to solve the incremental demand for constraint relief, where the relevant competitive supply includes all incremental MW at a cost less than, or equal, to 1.5 times the clearing price, then offer capping is suspended.

Levels of offer capping have historically been low in PJM, as shown in Table 2-4.

Table 2-4 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%

Table 2-5 presents data on the frequency with which units were offer capped in 2009. Table 2-5 shows the number of generating units that met the specified criteria for total offer-capped run hours and percentage of total run hours that were offer-capped for 2009. For example, in 2009, only 1 unit was offer-capped for greater than, or equal to, 80 percent of its run hours and had 200 or more offer-capped run hours.

13 123 FERC ¶ 61,169 (2008).

14 See the *2009 State of the Market Report for PJM*, Volume II, Appendix L, "Three Pivotal Supplier Test."

Table 2-5 Offer-capped unit statistics: Calendar year 2009

	2009 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	0	1	6
80% and < 90%	0	0	0	1	2	13
75% and < 80%	0	0	0	1	0	6
70% and < 75%	0	0	0	1	1	9
60% and < 70%	0	0	0	0	1	21
50% and < 60%	0	0	0	0	1	19
25% and < 50%	0	1	1	2	3	56
10% and < 25%	1	0	0	0	6	53

Table 2-5 shows that a small number of units are offer capped for a significant number of hours or for a significant proportion of their run hours. For example, only 8 units (about 0.6 percent of all units) that had offer-capped run hours of at least 200 hours (about 2.3 percent of all hours) in 2009 were offer capped for 10 percent or more of their run hours. Only 2 units (or about 0.2 percent of all units) that had greater than, or equal to, 400 offer-capped run hours were offer capped for 10 percent or more of their run hours.

When compared to the 2008 offer-capped statistics, 8.3 percent of the categories show an increase in the number of units; 39.6 percent of the categories show no change and 52.1 percent of the categories show a decrease in the number of units.[15]

When compared to the 2007 offer-capped statistics, 29.2 percent of the categories show an increase in the number of units; 33.3 percent of the categories show no change and 37.5 percent of the categories show a decrease in the number of units.[16]

Units that are offer capped for greater than, or equal to, 60 percent of their run hours are designated as frequently mitigated units (FMUs). An FMU or units that are associated with the FMU (AUs) are entitled to include adders in their cost-based offers that are a form of local scarcity pricing.

Local Market Structure

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. Using the three pivotal supplier results for calendar year 2009, actual competitive conditions associated with each of these frequently binding constraints were analyzed in real time.[17] The DAY, DPL, JCPL, Met-Ed, PPL and RECO Control Zones were not affected by constraints binding for 100 or more hours.

15 See the *2009 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market" Table C-23 for 2008 data.
16 See the *2009 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market" Table C-22 for 2007 data.
17 See the *2009 State of the Market Report for PJM*, Volume II, Appendix L, "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test.

The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required to prevent the exercise of local market power for any constraint not exempt from offer capping. The FERC eliminated the exemption of interfaces effective May 17, 2008.[18] The MMU analyzed the results of the three pivotal supplier tests conducted by PJM for the Real-Time Energy Market for the period January 1, 2009, through December 31, 2009.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and does not result in offer capping when that is not the case. Local markets are noncompetitive when there is a small number of suppliers. The number of hours in which one or more suppliers pass the three pivotal supplier test and are not subject to offer capping increases as the number of suppliers in the local market increases. For example, the regional constraints have a larger number of suppliers and more than 54 percent of the three pivotal supplier tests have one or more passing owners. In contrast, more local constraints like the Tiltonsville – Windsor 138 kV line in the AP Control Zone have only two suppliers and therefore are always structurally noncompetitive.

The fact that some constraints never had any generation resources that failed the three pivotal supplier test during the period analyzed does not lead to the conclusion that such constraints should never have offer capping for local market power. The same logic applies to interface constraints which were exempt from offer capping prior to May 17, 2008. Even if no generation resources associated with any of the previously exempt interface constraints failed the three pivotal suppler test during the period analyzed, that does not mean that such interfaces should always be exempt from offer capping for local market power. The fact that one or more generation resources, required to resolve these interfaces, did fail the three pivotal supplier test at times simply reinforces the point. If the generation resources associated with these interfaces always pass the three pivotal supplier test, there will be no offer capping; and conversely if such resources at times fail the three pivotal supplier test, appropriate offer capping will be applied.

Information is provided for each constraint including the number of tests applied and the number of tests in which one or more owners passed and/or failed the three pivotal supplier test.[19] Additional information is provided for each constraint including the average MW required to relieve a constraint, the average supply available, the average number of owners included in each test and the average number of owners that passed or failed each test.

- **Regional 500 kV Constraints.** In 2009, several regional transmission constraints occurred for more than 100 hours. The Kammer 765/500 kV transformer, along with two interface constraints (5004/5005 and AP South) all experienced more than 100 hours of congestion, while the Bedington – Black Oak Interface constraint occurred for 73 hours in 2009.[20] The three pivotal supplier test was applied to all of these constraints. The AP South is one of the four interfaces for which generation owners were exempt from offer capping prior to May 17, 2008.

18 123 FERC ¶ 61,169 (2008).

19 The three pivotal supplier test in the Real-Time Energy Market is applied by PJM as necessary and may be applied multiple times within a single hour for a specific constraint. Each application of the test is done in a five-minute interval.

20 The 5004/5005 Interface is comprised of two, 500 kV lines, which include the Keystone – Juniata 5004 and the Conemaugh – Juniata 5005. These two lines are located between central and western Pennsylvania.

Table 2-6 includes information on the three pivotal supplier test results for the two regional constraints (the Kammer 765/500 kV transformer and the 5004/5005 Interface) that were never exempt from offer capping.[21] The percentage of tested intervals resulting in one or more owners passing ranged from 87 percent to 97 percent while 7 percent to 26 percent of the tests show one or more owners failing.

For the AP South Interface, which was exempt from offer capping prior to May 17, 2008, the percentage of tested intervals resulting in one or more owners passing ranged from 54 percent to 57 percent while 64 percent to 68 percent of the tests show one or more owners failing in 2009.

Table 2-6 Three pivotal supplier results summary for regional constraints: Calendar year 2009

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
5004/5005 Interface	Peak	714	691	97%	49	7%
	Off Peak	216	206	95%	26	12%
AP South	Peak	1,777	1,012	57%	1,134	64%
	Off Peak	951	518	54%	642	68%
Kammer	Peak	3,786	3,508	93%	624	16%
	Off Peak	4,145	3,619	87%	1,064	26%

Table 2-7 shows that, on average, during 2009 peak periods, the local markets created by the 5004/5005 Interface and the Kammer transformer had 19 owners with available supply and 21 owners with available supply, respectively. Of those owners, an average of 19 passed the test for the 5004/5005 Interface and an average of 19 passed the test for the Kammer transformer.[22] During off-peak periods, on average, the 5004/5005 Interface and the Kammer transformer had 18 owners with available supply and 17 owners with available supply. Of those owners, an average of 17 passed the test for the 5004/5005 Interface and an average of 14 passed the test for the Kammer transformer. For AP South, on average, 6 out of 12 owners passed the test during both on-peak and off-peak periods in 2009.

Table 2-7 Three pivotal supplier test details for three regional constraints: Calendar year 2009

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
5004/5005 Interface	Peak	61	347	19	19	1
	Off Peak	59	316	18	17	1
AP South	Peak	92	278	12	6	6
	Off Peak	100	290	12	6	6
Kammer	Peak	51	249	21	19	2
	Off Peak	52	221	17	14	3

21 The number of tests with one or more failing owners plus the number of tests with one or more passing owners can exceed the total number of tests applied. A single test can result in one or more owners passing and one or more owners failing. In such a case, the interval would be counted as including one or more passing owners and one or more failing owners.

22 The average number of owners passing and the average number of owners failing are rounded to the nearest whole number and may not sum to the average number of owners, also rounded to the nearest whole number.

- **Central, East and West Interfaces.** The remaining three interfaces that were exempt until May 2008, the Central, East and West Interface constraints occurred for fewer than 100 hours. The East Interface did not constrain in 2009, while the Central and West Interface constraints occurred for 8 hours and 87 hours in 2009. Table 2-8 shows that in 2009, the percentage of tested intervals resulting in one or more owners passing ranged from 97 percent to 100 percent while no more than 9 percent of the tests showed one or more owners failing. No tests were applied to the East Interface in 2009.

Table 2-8 Three pivotal supplier results summary for the Central, East and West Interfaces: Calendar year 2009

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Central	Peak	23	23	100%	0	0%
	Off Peak	9	9	100%	0	0%
East	Peak	0	NA	NA	NA	NA
	Off Peak	0	NA	NA	NA	NA
West	Peak	332	321	97%	30	9%
	Off Peak	65	65	100%	0	0%

Table 2-9 shows that the local market created by the Central Interface had 18 owners during on-peak periods and 19 owners during off-peak periods and all passed the test in 2009. The local market created by the West Interface, on average, had 18 owners during off-peak periods and all passed the test. During on-peak periods, 21 of 22 passed the test for the West Interface.

Table 2-9 Three pivotal supplier test details for the Central, East and West interfaces: Calendar year 2009

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Central	Peak	54	514	18	18	0
	Off Peak	84	884	19	19	0
East	Peak	NA	NA	NA	NA	NA
	Off Peak	NA	NA	NA	NA	NA
West	Peak	125	627	22	21	1
	Off Peak	118	717	18	18	0

- **AECO Control Zone Constraints.** In 2009, there was only one constraint in the AECO Control Zone that occurred for more than 100 hours. Table 2-10 and Table 2-11 show the results of the three pivotal supplier test applied to this constraint. The average number of owners with available supply was one on peak and one off peak for the Absecon – Lewis 69 kV line. The three pivotal supplier test results reflect this, as all tests were failed.

Table 2-10 Three pivotal supplier results summary for constraints located in the AECO Control Zone: Calendar year 2009

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Absecon - Lewis	Peak	61	0	0%	61	100%
	Off Peak	16	0	0%	16	100%

Table 2-11 Three pivotal supplier test details for constraints located in the AECO Control Zone: Calendar year 2009

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Absecon - Lewis	Peak	8	19	1	0	1
	Off Peak	7	27	1	0	1

- **AEP Control Zone Constraints.** In 2009, there were five constraints that occurred for more than 100 hours in the AEP Control Zone. Table 2-12 and Table 2-13 show the results of the three pivotal supplier tests applied to the constraints in the AEP Control Zone. For four of the five constraints, the average number of owners with available supply was one. The three pivotal supplier test results reflect this, as the average number of owners that passed is significant only for the Cloverdale – Lexington 500 kV line with the largest number of owners, on average. The Cloverdale – Lexington 500 kV line had more owners and more effective supply and thus a higher percentage of tests with one or more owners that passed.

Table 2-12 Three pivotal supplier results summary for constraints located in the AEP Control Zone: Calendar year 2009

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Cloverdale - Lexington	Peak	425	252	59%	278	65%
	Off Peak	1,841	1,024	56%	1,244	68%
Kammer - Ormet	Peak	1,439	28	2%	1,411	98%
	Off Peak	1,965	0	0%	1,965	100%
Kanawha River - Kincaid	Peak	318	0	0%	318	100%
	Off Peak	300	0	0%	300	100%
Poston - Postel Tap	Peak	461	0	0%	461	100%
	Off Peak	39	0	0%	39	100%
Ruth - Turner	Peak	1,397	0	0%	1,397	100%
	Off Peak	1,847	0	0%	1,847	100%

Table 2-13 Three pivotal supplier test details for constraints located in the AEP Control Zone: Calendar year 2009

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Cloverdale - Lexington	Peak	72	212	15	8	8
	Off Peak	68	183	14	7	8
Kammer - Ormet	Peak	18	21	1	0	1
	Off Peak	22	31	1	0	1
Kanawha River - Kincaid	Peak	12	4	1	0	1
	Off Peak	9	4	1	0	1
Poston - Postel Tap	Peak	8	14	1	0	1
	Off Peak	11	18	1	0	1
Ruth - Turner	Peak	18	3	1	0	1
	Off Peak	21	2	1	0	1

- **AP Control Zone Constraints.** In 2009, there were seven constraints that occurred for more than 100 hours in the AP Control Zone. Table 2-14 and Table 2-15 show the results of the three pivotal supplier tests applied to the constraints in the AP Control Zone. For three of the seven constraints, the average number of owners with available supply was four or less. The three pivotal supplier test results reflect this, as the average number of owners that passed is significant only for the four constraints with a larger number of owners, on average. Four constraints, the Elrama – Mitchell 138 kV line, the Mount Storm – Pruntytown 500 kV line, the Sammis – Wylie Ridge 345 kV line and the Wylie Ridge transformer had more owners and more effective supply and thus a higher percentage of tests with one or more owners that passed.

Table 2-14 Three pivotal supplier results summary for constraints located in the AP Control Zone: Calendar year 2009

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Bedington	Peak	895	125	14%	895	100%
	Off Peak	333	11	3%	333	100%
Doubs	Peak	844	39	5%	830	98%
	Off Peak	245	10	4%	244	100%
Elrama - Mitchell	Peak	770	385	50%	488	63%
	Off Peak	328	189	58%	173	53%
Mount Storm - Pruntytown	Peak	461	331	72%	248	54%
	Off Peak	254	165	65%	143	56%
Sammis - Wylie Ridge	Peak	346	245	71%	154	45%
	Off Peak	657	467	71%	319	49%
Tiltonsville - Windsor	Peak	1,470	1	0%	1,469	100%
	Off Peak	405	0	0%	405	100%
Wylie Ridge	Peak	695	577	83%	182	26%
	Off Peak	945	653	69%	378	40%

Table 2-15 Three pivotal supplier test details for constraints located in the AP Control Zone: Calendar year 2009

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Bedington	Peak	31	5	3	0	3
	Off Peak	38	4	3	0	3
Doubs	Peak	15	12	4	0	4
	Off Peak	18	14	4	0	4
Elrama - Mitchell	Peak	19	59	11	7	4
	Off Peak	16	57	11	8	3
Mount Storm - Pruntytown	Peak	85	306	12	8	4
	Off Peak	97	273	11	6	4
Sammis - Wylie Ridge	Peak	44	118	20	13	7
	Off Peak	51	127	17	11	6
Tiltonsville - Windsor	Peak	10	5	2	0	2
	Off Peak	8	5	2	0	2
Wylie Ridge	Peak	36	147	17	15	2
	Off Peak	37	141	14	12	2

- **BGE Control Zone Constraints.** In 2009, the Graceton – Raphael 230 kV line was the only constraint in the BGE Control Zone to occur for more than 100 hours. Table 2-16 and Table 2-17 show the results of the three pivotal supplier test applied to this constraint. The average number of owners with available supply was 19 on peak and 20 off peak. In 2009, 90 percent of the tests during on-peak periods and 86 percent of the tests during off-peak periods showed one or more owners passing.

Table 2-16 Three pivotal supplier results summary for constraints located in the BGE Control Zone: Calendar year 2009

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Graceton - Raphael Road	Peak	531	478	90%	93	18%
	Off Peak	342	294	86%	94	27%

Table 2-17 Three pivotal supplier test details for constraints located in the BGE Control Zone: Calendar year 2009

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Graceton - Raphael Road	Peak	31	115	19	17	2
	Off Peak	41	141	20	17	3

- **ComEd Control Zone Constraints.** In 2009, there were three constraints that occurred for more than 100 hours in the ComEd Control Zone. Table 2-18 and Table 2-19 show the results of the three pivotal supplier tests applied to the constraints in the ComEd Control Zone. The average number of owners with available supply was three or less for the Pleasant Valley – Belvidere 138 kV line and the Electric Jct – Nelson 345 kV line and five for the Crete – East Frankfurt 345 kV line during on-peak periods. The three pivotal supplier test results reflect this, as the average number of owners that passed is significant only for the Crete – East Frankfurt 345 kV line during on-peak periods.

Table 2-18 Three pivotal supplier results summary for constraints located in the ComEd Control Zone: Calendar year 2009

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Crete - East Frankfurt	Peak	320	33	10%	313	98%
	Off Peak	3,538	86	2%	3,508	99%
Electric Jct - Nelson	Peak	262	5	2%	261	100%
	Off Peak	740	1	0%	740	100%
Pleasant Valley - Belvidere	Peak	528	0	0%	528	100%
	Off Peak	1,560	0	0%	1,560	100%

Table 2-19 Three pivotal supplier test details for constraints located in the ComEd Control Zone: Calendar year 2009

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Crete - East Frankfurt	Peak	30	104	5	0	4
	Off Peak	32	44	4	0	4
Electric Jct - Nelson	Peak	31	15	3	0	3
	Off Peak	35	4	2	0	2
Pleasant Valley - Belvidere	Peak	11	1	1	0	1
	Off Peak	10	0	1	0	1

- **DLCO Control Zone Constraints.** In 2009, only one constraint in the DLCO Control Zone experienced more than 100 hours of congestion. Table 2-20 and Table 2-21 show the results of the three pivotal supplier test applied to this constraint. The average number of owners with available supply was one on peak and one off peak for the Logans Ferry – Universal 138 kV line. The three pivotal supplier test results reflect this, as all tests were failed.

Table 2-20 Three pivotal supplier results summary for constraints located in the DLCO Control Zone: Calendar year 2009

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Logans Ferry - Universal	Peak	963	0	0%	963	100%
	Off Peak	197	0	0%	197	100%

Table 2-21 Three pivotal supplier test details for constraints located in the DLCO Control Zone: Calendar year 2009

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Logans Ferry - Universal	Peak	7	42	1	0	1
	Off Peak	6	37	1	0	1

- **Dominion Control Zone Constraints.** In 2009, there was only one constraint in the Dominion Control Zone that occurred for more than 100 hours. Table 2-22 and Table 2-23 show the results of the three pivotal supplier test applied to this constraint. The average number of owners with available supply was one on peak and one off peak for the Beechwood – Kerr Dam 115 kV line. The three pivotal supplier test results reflect this, as all tests were failed.

Table 2-22 Three pivotal supplier results summary for constraints located in the Dominion Control Zone: Calendar year 2009

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Beechwood - Kerr Dam	Peak	928	0	0%	928	100%
	Off Peak	125	0	0%	125	100%

Table 2-23 Three pivotal supplier test details for constraints located in the Dominion Control Zone: Calendar year 2009

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Beechwood - Kerr Dam	Peak	4	3	1	0	1
	Off Peak	4	2	1	0	1

- **PECO Control Zone Constraints.** In 2009, the Emilie transformer was the only constraint in the PECO Control Zone to occur for more than 100 hours. Table 2-24 and Table 2-25 show the results of the three pivotal supplier test applied to this constraint. The average number of owners with available supply was four on peak and four off peak. The three pivotal supplier test results reflect this, as nearly all tests were failed.

Table 2-24 Three pivotal supplier results summary for constraints located in the PECO Control Zone: Calendar year 2009

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Emilie	Peak	1,374	35	3%	1,365	99%
	Off Peak	712	3	0%	712	100%

Table 2-25 Three pivotal supplier test details for constraints located in the PECO Control Zone: Calendar year 2009

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Emilie	Peak	15	59	4	0	4
	Off Peak	14	83	4	0	4

- **PENELEC Control Zone Constraints.** In 2009, there was only one constraint in the PENELEC Control Zone that occurred for more than 100 hours. Table 2-26 and Table 2-27 show the results of the three pivotal supplier tests applied to this constraint. The average number of owners with available supply was four on peak and five off peak for the Homer City – Shelocta 230 kV line. The three pivotal supplier test results reflect this, as nearly all tests were failed.

Table 2-26 Three pivotal supplier results summary for constraints located in the PENELEC Control Zone: Calendar year 2009

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Homer City - Shelocta	Peak	685	24	4%	674	98%
	Off Peak	149	3	2%	149	100%

Table 2-27 Three pivotal supplier test details for constraints located in the PENELEC Control Zone: Calendar year 2009

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Homer City - Shelocta	Peak	24	57	4	0	4
	Off Peak	40	54	5	0	5

- **Pepco Control Zone Constraints.** In 2009, the Buzzard – Ritchie 230 kV line was the only constraint in the Pepco Control Zone to occur for more than 100 hours. Table 2-28 and Table 2-29 show the results of the three pivotal supplier test applied to this constraint. The average number of owners with available supply was two on peak and no tests were applied to this constraint during off-peak periods. The three pivotal supplier test results reflect this, as all tests were failed.

Table 2-28 Three pivotal supplier results summary for constraints located in the Pepco Control Zone: Calendar year 2009

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Buzzard - Ritchie	Peak	366	0	0%	366	100%
	Off Peak	NA	NA	NA	NA	NA

Table 2-29 Three pivotal supplier test details for constraints located in the Pepco Control Zone: Calendar year 2009

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Buzzard - Ritchie	Peak	6	26	2	0	2
	Off Peak	NA	NA	NA	NA	NA

- **PSEG Control Zone Constraints.** In 2009, two constraints in the PSEG Control Zone occurred for more than 100 hours. Table 2-30 and Table 2-31 show the results of the three pivotal supplier tests applied to these constraints. For both of the constraints, the average number of owners with available supply was three or less. The three pivotal supplier test results reflect this, as nearly all tests were failed.

Table 2-30 Three pivotal supplier results summary for constraints located in the PSEG Control Zone: Calendar year 2009

Constraint	Period	Total Tests Applied	Tests with One or More Passing Owners	Percent Tests with One or More Passing Owners	Tests with One or More Failing Owners	Percent Tests with One or More Failing Owners
Athenia - Saddlebrook	Peak	333	8	2%	329	99%
	Off Peak	135	5	4%	134	99%
Plainsboro - Trenton	Peak	592	0	0%	592	100%
	Off Peak	13	0	0%	13	100%

Table 2-31 Three pivotal supplier test details for constraints located in the PSEG Control Zone: Calendar year 2009

Constraint	Period	Average Constraint Relief (MW)	Average Effective Supply (MW)	Average Number Owners	Average Number Owners Passing	Average Number Owners Failing
Athenia - Saddlebrook	Peak	13	38	3	0	3
	Off Peak	10	42	3	0	3
Plainsboro - Trenton	Peak	9	122	1	0	1
	Off Peak	7	141	1	0	1

Market Performance: Markup

The markup index is a summary measure of the behavior or conduct of individual marginal units. However the markup conduct measure does not explicitly capture the impact of this behavior on market prices. As an example, if unit A has a $90 cost and a $100 price, while unit B has a $9 cost and a $10 price, both would show a markup of 10 percent, but the price impact of unit A's markup at the generator bus would be $10 while the price impact of unit B's markup at the generator bus would be $1. Depending on each unit's location on the transmission system, those bus-level impacts could also translate to different impacts on total system price.

The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of price based on a comparison between the price-based offer and the cost-based offer of each actual marginal unit on the system.[23]

The price impact of markup must be interpreted carefully. The markup calculation is not based on a full redispatch of the system to determine the marginal units and their marginal costs that would have occurred if all units had made all offers at marginal cost. Thus the results do not reflect a

23 This is the same method used to calculate the fuel-cost-adjusted LMP and the components of LMP.

counterfactual market outcome based on the assumption that all units made all offers at marginal cost. It is important to note that a full redispatch analysis is practically impossible and a limited redispatch analysis would not be dispositive. Nonetheless, such a hypothetical counterfactual analysis would reveal the extent to which the actual system dispatch is less than competitive if it showed a difference between dispatch based on marginal cost and actual dispatch. It is possible that the unit-specific markup, based on a redispatch analysis, would be lower than the markup component of price if the reference point were an inframarginal unit with a lower price and a higher cost than the actual marginal unit. If the actual marginal unit has marginal costs that would cause it to be inframarginal, a new unit would be marginal. If the offer of that new unit were greater than the cost of the original marginal unit, the markup impact would be lower than the MMU measure. If the newly marginal unit is on a price-based schedule, the analysis would have to capture the markup impact of that unit as well.

The MMU calculates an explicit measure of the impact of marginal unit markups on LMP. 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.

Real-Time Markup

Ownership of Marginal Resources

Table 2-32 shows the contribution to PJM real-time, annual, load-weighted LMP by individual marginal resource owner, utilizing generator sensitivity factors.[24] The contribution of each marginal resource to price at each load bus is calculated for the year and summed by the company that offers the marginal resource into the Real-Time Energy Market. The results show that, during calendar year 2009, the offers of one company contributed 17 percent of the real-time, annual, load-weighted PJM system LMP and that the offers of the top four companies contributed 48 percent of the real-time, annual, load-weighted, average PJM system LMP.

Table 2-32 Marginal unit contribution to PJM real-time, annual, load-weighted LMP (By parent company): Calendar year 2009

Company	Percent of Price
1	17%
2	14%
3	9%
4	8%
5	7%
6	6%
7	5%
8	4%
9	3%
Other (57 companies)	27%

24 See the *2009 State of the Market Report for PJM*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

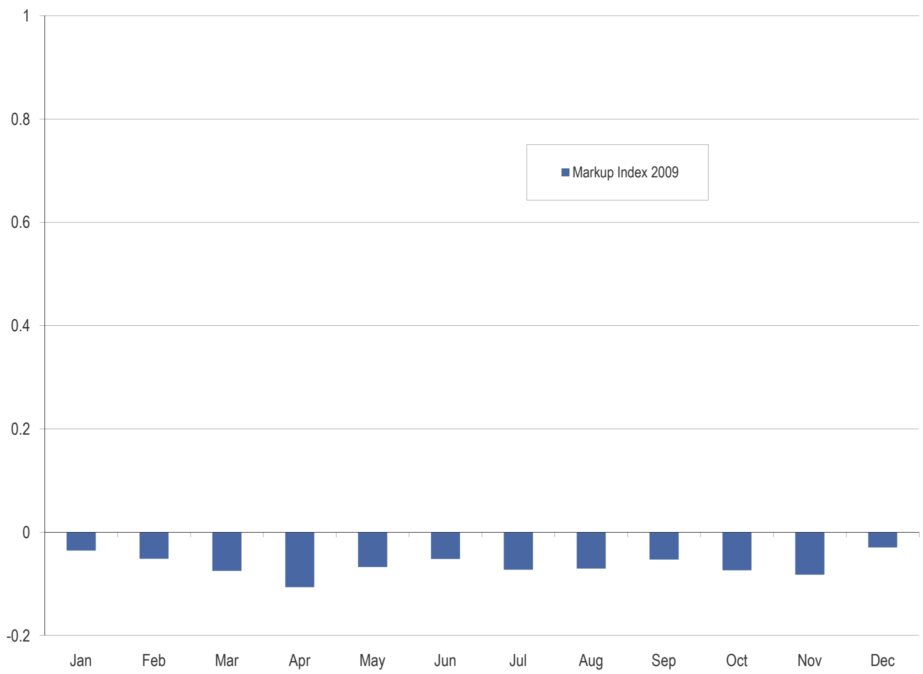
Table 2-33 shows the type of fuel used by marginal resources. In 2009, coal units were 74 percent of marginal resources and natural gas units were 22 percent of marginal resources.

Table 2-33 Type of fuel used (By real-time marginal units): Calendar year 2009

Fuel Type	2009
Coal	74%
Natural Gas	22%
Petroleum	3%
Landfill Gas	1%
Interface	0%
Misc	0%

Figure 2-5 shows the real-time, load-weighted, unit markup index. The markup index for each marginal unit is calculated as (Price – Cost)/Price. The markup index is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost.[25] This index calculation method weights the impact of individual unit markups using sensitivity factors. In 2009, the annual average markup index was -0.06 with a maximum of -0.03 in December and a minimum of -0.11 in April.

Figure 2-5 Real-time, LMP contribution and load-weighted, unit markup index: Calendar year 2009



25 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00), the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost. Also the markup index was weighted by the percentage of the LMP of each type of marginal resources.

Unit Markup Characteristics

In order to contribute to a more complete description of markup behavior, this section includes information on markup index by unit and fuel type and by offer price category.

Table 2-34 shows the annual average unit markup index for marginal units, by unit type and primary fuel.

Table 2-34 The markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: Calendar year 2009

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($2.54)	106.7%
Gas	CC	($0.00)	0.2%
Gas	CT	$0.11	(4.5%)
Gas	Diesel	$0.00	(0.1%)
Gas	Steam	($0.01)	0.3%
Interface	Interface	$0.00	(0.0%)
Municipal Waste	Diesel	$0.00	0.0%
Municipal Waste	Steam	($0.01)	0.3%
Oil	CT	$0.02	(0.9%)
Oil	Diesel	($0.00)	0.2%
Oil	Steam	$0.05	(2.2%)
Uranium	Steam	($0.00)	0.0%
Water	Hydro	$0.00	0.0%
Wind	Wind	$0.00	(0.0%)
Total		($2.38)	100.0%

Table 2-35 shows the average markup index of marginal units in the Real-Time Market, by offer price category. A unit is assigned to a price category for each interval in which it was marginal, based on its offer price at that time.

Table 2-35 Average, real-time marginal unit markup index (By price category): Calendar year 2009

Price Category	Average Markup Index	Average Dollar Markup
< $25	(0.06)	($2.35)
$25 to $50	(0.09)	($4.17)
$50 to $75	(0.01)	($1.14)
$75 to $100	0.04	$2.75
$100 to $125	0.09	$9.78
$125 to $150	0.08	$10.17
> $150	0.04	$8.14

Markup Component of System Price

The price component measure uses real-time, load-weighted, price-based LMP and real-time, load-weighted LMP computed using cost-based offers for all marginal units in the Real-Time Market. The price component of markup is computed by calculating the system price, based on the price-based offers of the marginal units and comparing that to the system price, based on the cost-based offers of the marginal units. Both results are compared to the actual system price to determine how much of the LMP can be attributed to markup.

Table 2-36 shows the markup component of average prices and of average monthly on-peak and off-peak prices. In 2009, -$2.38 per MWh of the PJM real-time, load-weighted average LMP was attributable to markup. In 2009, the markup component of LMP was -$3.15 per MWh off peak and -$1.67 per MWh on peak.

Table 2-36 Monthly markup components of real-time load-weighted LMP: Calendar year 2009

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
Jan	($1.22)	($0.05)	($2.33)
Feb	($1.09)	($0.42)	($1.80)
Mar	($3.03)	($3.14)	($2.92)
Apr	($4.50)	($3.62)	($5.53)
May	($2.78)	($2.35)	($3.19)
Jun	($1.84)	($0.79)	($3.15)
Jul	($1.93)	($1.34)	($2.70)
Aug	($3.14)	($1.43)	($4.97)
Sep	($2.62)	($2.08)	($3.22)
Oct	($2.86)	($2.14)	($3.64)
Nov	($3.15)	($2.86)	($3.43)
Dec	($1.07)	($0.70)	($1.45)
2009	($2.38)	($1.67)	($3.15)

Markup Component of Real-Time Zonal Prices

The annual average real-time price component of unit markup is shown for each zone in Table 2-37. The smallest zonal all hours' annual average markup component was in the DLCO Control Zone, -$3.62 per MWh, while the highest all hours' annual average zonal markup component was in the DPL Control Zone, -$1.55 per MWh. On peak, the smallest annual average zonal markup was in the DLCO Control Zone, -$3.05 per MWh, while the highest annual average zonal markup was in the Pepco Control Zone, -$0.60 per MWh. Off peak, the smallest annual average zonal markup was in the DAY Control Zone, -$4.26 per MWh, while the highest annual average zonal markup was in the DPL Control Zone, -$1.99 per MWh.

Table 2-37 Average real-time zonal markup component: Calendar year 2009

	Markup Component (All Hours)	Peak Markup Component	Off Peak Markup Component
AECO	($2.13)	($1.34)	($2.97)
AEP	($3.25)	($2.55)	($4.00)
AP	($2.10)	($1.27)	($2.98)
BGE	($1.84)	($0.91)	($2.81)
ComEd	($2.86)	($2.51)	($3.24)
DAY	($3.42)	($2.67)	($4.26)
DLCO	($3.62)	($3.05)	($4.24)
Dominion	($1.67)	($0.84)	($2.54)
DPL	($1.55)	($1.13)	($1.99)
JCPL	($1.99)	($1.12)	($2.96)
Met-Ed	($1.79)	($1.23)	($2.40)
PECO	($2.06)	($1.35)	($2.83)
PENELEC	($2.47)	($1.74)	($3.26)
Pepco	($1.58)	($0.60)	($2.65)
PPL	($2.05)	($1.28)	($2.90)
PSEG	($2.11)	($1.28)	($3.04)
RECO	($2.16)	($1.28)	($3.21)

Markup by Real-Time System Price Levels

The price component measure uses load-weighted, price-based LMP and load-weighted LMP computed using cost-based offers for all marginal units. The markup component of price is computed by calculating the system price, based on the cost-based offers of the marginal units and comparing that to the actual system price to determine how much of the LMP can be attributed to markup.

Table 2-38 shows the average markup component of observed price when the PJM system LMP was in the identified price range.

Table 2-38 Average real-time markup component (By price category): Calendar year 2009

	Average Markup Component	Frequency
Below $20	($1.58)	3.8%
$20 to $40	($4.11)	67.6%
$40 to $60	($1.24)	20.8%
$60 to $80	$2.18	4.9%
$80 to $100	$8.25	1.8%
$100 to $120	$5.49	0.6%
$120 to $140	$37.62	0.3%
$140 to $160	$16.44	0.1%
Above $160	$47.88	0.1%

Day-Ahead Markup

Ownership of Marginal Resources

Table 2-39 shows the contribution to PJM day-ahead, annual, load-weighted LMP by individual marginal resource owner, utilizing generator sensitivity factors.[26] The contribution of each marginal resource to price at each load bus is calculated for the year and summed by the company that offers the marginal resource into the Day-Ahead Energy Market. The results show that, during calendar year 2009, the offers of one company contributed 32 percent of the day-ahead, annual, load-weighted PJM system LMP and that the offers of the top four companies contributed 52 percent of the day-ahead, annual, load-weighted, average PJM system LMP.

Table 2-39 Marginal unit contribution to PJM day-ahead, annual, load-weighted LMP (By parent company): Calendar year 2009

Company	Percent of Price
1	32%
2	8%
3	6%
4	6%
5	5%
6	4%
7	3%
8	3%
9	3%
Other (119 companies)	30%

Table 2-40 shows the type of fuel used by marginal resources. In 2009, the transactions that were on the margin accounted for 33 percent of marginal resources and the decrement bids that were on the margin accounted for 30 percent of all marginal resources.

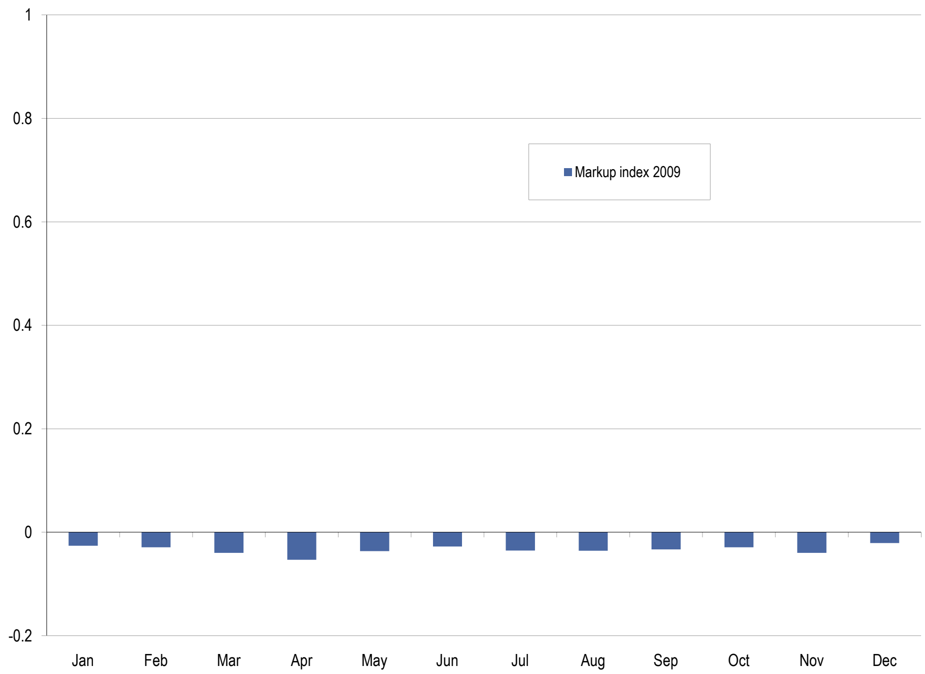
Table 2-40 Day-ahead marginal resources by type/fuel: Calendar year 2009

Type/Fuel	2009
Transaction	33%
DEC	30%
INC	21%
Coal	12%
Natural gas	3%
Price sensitive demand	1%
Oil	0%
Wind	0%
Municipal waste	0%
Diesel	0%

26 See the *2009 State of the Market Report for PJM*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Figure 2-6 shows the day-ahead, load-weighted, unit markup index. The markup index for each marginal unit is calculated as (Price – Cost)/Price. The markup index is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost.[27] This index calculation method weights the impact of individual unit markups using sensitivity factors. In 2009, the annual average markup index was -0.03 with a maximum of -0.02 in December and a minimum of -0.05 in April.

Figure 2-6 Day-ahead, LMP contribution and load-weighted unit markup index: Calendar year 2009



27 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00), the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost. Also the markup index was weighted by the percentage of the LMP of each type of marginal resources. The markup index of transaction marginal resources, INC marginal resources and DEC marginal resources was zero.

Unit Markup Characteristics

In order to contribute to a more complete description of markup behavior, this section includes information on markup index by unit and fuel type and by offer price category.

Table 2-41 shows the annual average unit markup index for marginal units, by unit type and primary fuel.

Table 2-41 Average, day-ahead marginal unit markup index (By primary fuel and unit type): Calendar year 2009

Fuel Type	Unit Type	Average Markup Index	Average Dollar Markup
Coal	Steam	(0.08)	($3.71)
Diesel	Diesel	(0.07)	($5.34)
Municipal waste	Steam	(0.05)	($1.43)
Natural gas	CT	0.05	$2.81
Natural gas	Diesel	(0.04)	($2.60)
Natural gas	Steam	0.01	($0.15)
Oil	Steam	0.01	$1.15
Wind	Wind	1.00	$52.11

Table 2-42 shows the average markup index of marginal units in Day-Ahead Market, by offer price category. A unit is assigned to a price category for each interval in which it was marginal, based on its offer price at that time.

Table 2-42 Average marginal unit markup index (By price category): Calendar year 2009

Price Category	Average Markup Index	Average Dollar Markup
< $25	($0.05)	($1.93)
$25 to $50	($0.08)	($3.73)
$50 to $75	($0.02)	($1.60)
$75 to $100	$0.01	($0.24)
$100 to $125	($0.01)	($2.01)
$125 to $150	($0.03)	($4.30)
> $150	$0.00	$0.00

Markup Component of System Price

The price component measure uses day-ahead, load-weighted, price-based LMP and day-ahead, load-weighted LMP computed using cost-based offers for all marginal units in Day-Ahead Market. The price component of markup is computed by calculating the system price, based on the price-based offers of the marginal units and comparing that to the system price, based on the cost-based offers of the marginal units. Both results are compared to the actual system price to determine how much of the LMP can be attributed to markup.

Table 2-43 shows the markup component of average prices and of average monthly on-peak and off-peak prices. In 2009, -$1.65 per MWh of the PJM day-ahead, load-weighted average LMP was attributable to markup. In 2009, the markup component of LMP was -$2.22 per MWh off peak and -$1.12 per MWh on peak.

Table 2-43 Monthly markup components of day-ahead, load-weighted LMP: Calendar year 2009

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($2.07)	($1.32)	($2.79)
Feb	($1.84)	($0.83)	($2.90)
Mar	($2.01)	($1.48)	($2.59)
Apr	($2.49)	($2.06)	($3.00)
May	($1.52)	($0.79)	($2.22)
Jun	($1.13)	($0.43)	($2.00)
Jul	($1.65)	($1.37)	($2.01)
Aug	($1.78)	($1.73)	($1.84)
Sep	($1.34)	($1.07)	($1.65)
Oct	($1.29)	($0.85)	($1.78)
Nov	($1.59)	($0.91)	($2.25)
Dec	($1.03)	($0.51)	($1.56)
Annual	($1.65)	($1.12)	($2.22)

Markup Component of Zonal Prices

The annual average price component of unit markup is shown for each zone in Table 2-44. The smallest zonal all hours' markup component was in the DAY Control Zone, -$2.72 per MWh, while the highest all hours' zonal markup component was in the BGE Control Zone, -$1.02 per MWh. On peak, the smallest zonal markup was in the DAY Control Zone, -$2.01 per MWh, while the highest markup was in the BGE Control Zone, -$0.44 per MWh. Off peak, the smallest zonal markup was in the DAY Control Zone, -$3.52 per MWh, while the highest markup was in the Pepco Control Zone, -$1.59 per MWh.

Table 2-44 Day-ahead, average, zonal markup component: Calendar year 2009

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($1.29)	($0.73)	($1.90)
AEP	($2.60)	($1.87)	($3.37)
AP	($1.44)	($0.92)	($1.99)
BGE	($1.02)	($0.44)	($1.64)
ComEd	($1.77)	($1.53)	($2.02)
DAY	($2.72)	($2.01)	($3.52)
DLCO	($2.62)	($1.98)	($3.31)
Dominion	($1.26)	($0.89)	($1.65)
DPL	($1.24)	($0.65)	($1.86)
JCPL	($1.35)	($0.72)	($2.06)
Met-Ed	($1.20)	($0.63)	($1.84)
PECO	($1.25)	($0.64)	($1.91)
PENELEC	($1.60)	($1.02)	($2.25)
Pepco	($1.03)	($0.53)	($1.59)
PPL	($1.32)	($0.73)	($1.95)
PSEG	($1.32)	($0.79)	($1.92)
RECO	($1.40)	($0.88)	($2.05)

Markup by System Price Levels

The annual average markup component of the identified price range and its frequency are shown in Table 2-45.

Table 2-45 shows the average markup component of observed price when the PJM day-ahead, system LMP was in the identified price range.

Table 2-45 Average, day-ahead markup (By price category): Calendar year 2009

	Average Markup Component	Frequency
Below $20	($0.49)	4%
$20 to $40	($2.37)	64%
$40 to $60	($0.68)	26%
$60 to $80	($0.93)	4%
$80 to $100	$0.30	1%
$100 to $120	$0.08	0%
$120 to $140	($0.76)	0%
Above $160	$0.00	0%

Markup Component by Fuel, Unit Type

The markup component of the overall PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 2-46. The coal steam units accounted for 93.0 percent of the markup component of overall PJM day-ahead, load-weighted average LMP. The natural gas steam units accounted for 7.4 percent.

Table 2-46 The markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: Calendar year 2009

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($1.53)	93.0%
Diesel	Diesel	($0.00)	0.1%
Municipal waste	Steam	($0.00)	0.0%
Natural gas	CT	$0.00	(0.1%)
Natural gas	Diesel	($0.00)	0.1%
Natural gas	Steam	($0.12)	7.4%
Oil	Steam	($0.01)	0.3%
Wind	Wind	$0.01	(0.7%)
Total		($1.65)	100.0%

Frequently Mitigated Unit and Associated Unit Adders – Component of Price

On January 25, 2005, the FERC ordered that frequently offer-capped units be provided additional compensation as a form of scarcity pricing, consistent with a recommendation of the MMU.[28] A frequently mitigated unit (FMU) was defined to be a unit that was offer capped for 80 percent or more of its run hours during the prior calendar year. FMUs were allowed either a $40 adder to their cost-based offers in place of the 10 percent adder, or the unit-specific, going-forward costs of the affected unit as a cost-based offer.

In the second half of 2005, discussions were held regarding scarcity pricing and local market power mitigation that led to a settlement agreement accepted by the FERC on January 27, 2006.[29] The settlement agreement revised the definition of FMUs to provide for a set of graduated adders associated with increasing levels of offer capping.[30] Units capped for 60 percent or more of their run hours and less than 70 percent are entitled to an adder of either 10 percent of their cost-based offer or $20 per MWh. Units capped 70 percent or more of their run hours and less than 80 percent are entitled to an adder of either 15 percent of their cost-based offer (not to exceed $40) or $30 per MWh. Units capped 80 percent or more of their run hours are entitled to an adder of $40 per MWh or the unit-specific, going-forward costs of the affected unit as a cost-based offer.[31] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.

The settlement agreement further amended the OA to designate associated units (AUs), also at the recommendation of the MMU. An AU is a unit that is electrically and economically identical to an FMU, but does not qualify for the same adder. The settlement agreement provides for monthly designation of FMUs and AUs, where a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[32]

For example, if a generating station had two identical units, one of which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier 3 FMU. If the second unit were capped for 30 percent of its run hours, that unit would be an AU and receive the same Tier 3 adder as the FMU at the site, to ensure that the associated unit is not dispatched in place of the FMU, resulting in no effective adder for the FMU. In the absence of the AU designation, the associated unit would be an FMU after its dispatch and the FMU would be dispatched in its place after losing its FMU designation.

As another example, if a generating station had two identical units, one of which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier 3 FMU. If the second unit were capped for 72 percent of its run hours, that unit would be eligible for a Tier 2 FMU adder. However, the second unit is an AU to the first unit and would, therefore, be eligible for the higher Tier 3 adder.

28 110 FERC ¶ 61,053 (2005).
29 114 FERC ¶ 61, 076 (2006).
30 *PJM Interconnection, L.L.C.*, Settlement Agreement, Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).
31 OA, Fifth Revised Sheet No. 131B (Effective July 3, 2007).
32 OA, Fifth Revised Sheet No. 132 (Effective July 3, 2007). In 2007, the FERC approved OA revisions to clarify the AU criteria.

Table 2-47 shows the number of FMUs and AUs in each month of 2009. For example, in December 2009, there were 43 FMUs and AUs in Tier 1, 24 FMUs and AUs in Tier 2, and 29 FMUs and AUs in Tier 3.

Table 2-47 Frequently mitigated units and associated units (By month): Calendar year 2009

	FMUs and AUs			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	26	56	55	137
February	46	46	36	128
March	31	48	54	133
April	33	41	63	137
May	32	43	61	136
June	40	42	62	144
July	27	32	75	134
August	27	37	64	128
September	40	23	56	119
October	31	49	38	118
November	38	31	27	96
December	43	24	29	96

Table 2-48 shows the number of months FMUs and AUS were eligible for any adder (Tier 1, Tier 2 or Tier 3) during 2009. Of the 186 units eligible in at least one month during 2009, 88 units (47 percent) were FMUs or AUs for more than eight months. Approximately one third of the units (61 units or 33 percent) were eligible every month during the year. This demonstrates that the group of FMUs and AUs is fairly stable, although units may move between the tier levels, month-to-month.

Table 2-48 Frequently mitigated units and associated units total months eligible: Calendar year 2009

Months Adder-Eligible	FMU & AU Count
1	16
2	18
3	6
4	2
5	6
6	3
7	20
8	17
9	8
10	19
11	10
12	61
Total	186

FMU and AU adders contributed $0.17 per MWh to system average LMP in 2009, out of a real-time, load weighted LMP of $39.05 per MWh.

Market Performance: Load and LMP

The PJM system load and LMP reflect the configuration of the entire RTO. The PJM Energy Market includes the Real-Time Energy Market and the Day-Ahead Energy Market.

Load

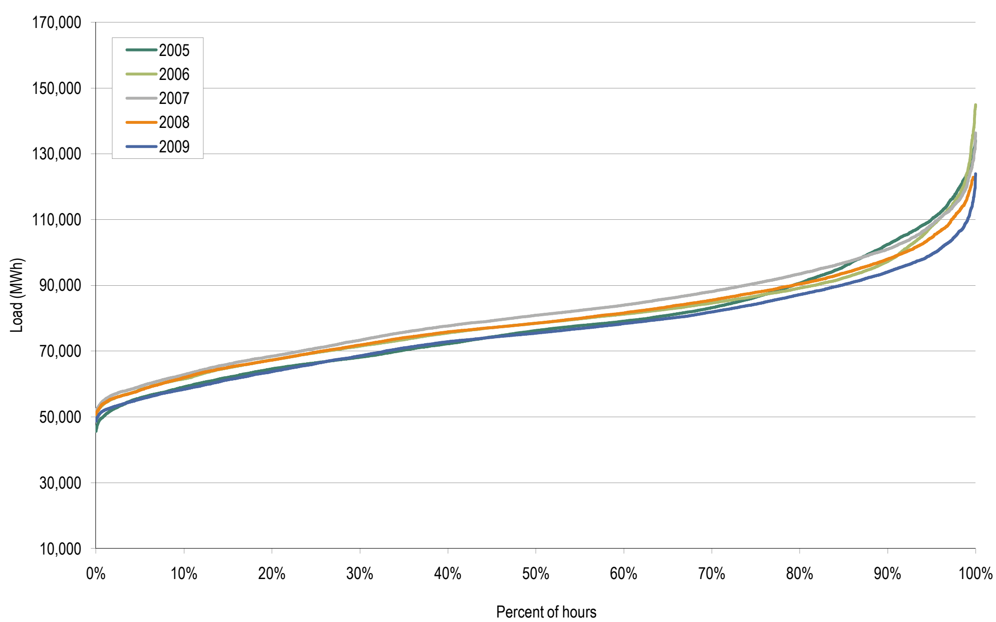
Real-Time Load

PJM real-time load is the total hourly accounting load in real time.[33]

PJM Real-Time Load Duration

Figure 2-7 shows PJM real-time load duration curves from 2005 to 2009. A load duration curve shows the percent of hours that load was at, or below, a given level for the year.

Figure 2-7 PJM real-time load duration curves: Calendar years 2005 to 2009



PJM Real-Time, Annual Average Load

Table 2-49 presents summary real-time load statistics for the 12-year period 1998 to 2009. The average load of 76,035 MWh in 2009 was 4.4 percent lower than the 2008 annual average hourly

33 All real-time load data in Section 2, "Energy Market, Part 1," "Market Performance: Load and LMP" are based on PJM accounting load. See the *2009 State of the Market Report for PJM*, Volume II, Appendix I, "Load Definitions," for detailed definitions of accounting load.

load. This average load was based on the PJM hourly accounting load. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load because of the implementation of marginal loss pricing.[34]

Table 2-49 PJM real-time average load: Calendar years 1998 to 2009

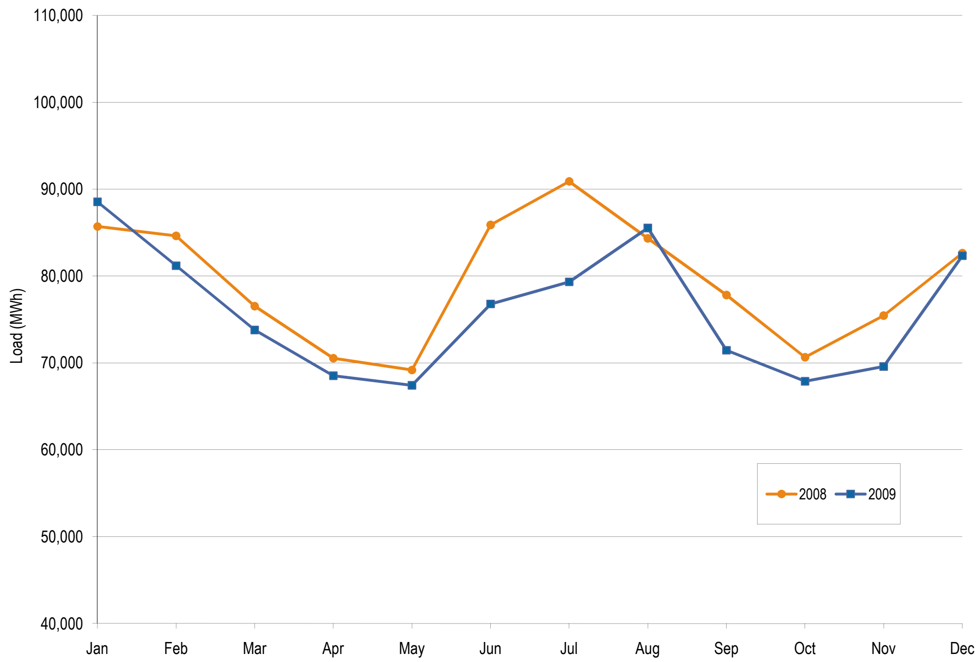
	PJM Real-Time Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	28,578	28,653	5,511	NA	NA	NA
1999	29,641	29,341	5,956	3.7%	2.4%	8.1%
2000	30,113	30,170	5,529	1.6%	2.8%	(7.2%)
2001	30,297	30,219	5,873	0.6%	0.2%	6.2%
2002	35,731	34,746	8,013	17.9%	15.0%	36.5%
2003	37,398	37,031	6,832	4.7%	6.6%	(14.7%)
2004	49,963	48,103	13,004	33.6%	29.9%	90.3%
2005	78,150	76,247	16,296	56.4%	58.5%	25.3%
2006	79,471	78,473	14,534	1.7%	2.9%	(10.8%)
2007	81,681	80,914	14,618	2.8%	3.1%	0.6%
2008	79,515	78,481	13,758	(2.7%)	(3.0%)	(5.9%)
2009	76,035	75,471	13,260	(4.4%)	(3.8%)	(3.6%)

34 Accounting load is used here because PJM uses accounting load in the settlement process, which determines how much load customers pay for. In addition, the use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP, which excludes losses prior to June 1 and includes losses after June 1.

PJM Real-Time, Monthly Average Load

Figure 2-8 compares the real-time, monthly average hourly loads of 2009 with those of 2008.

Figure 2-8 PJM real-time average load: Calendar years 2008 to 2009



PJM real-time load is significantly affected by temperature. PJM uses the Temperature-Humidity Index (THI), the Winter Weather Parameter (WWP) and the average temperature as the weather variables in the PJM load forecast model for different seasons. THI is a measure of effective temperature using temperature and relative humidity for the cooling season (June, July and August).[35] Table 2-50 shows the monthly minimum, average and maximum of the PJM hourly THI for the cooling months in 2008 and 2009. When comparing 2009 to 2008, changes in THI were mixed, consistent with the changes in load. For the cooling months of 2009, the average THI was 69.64, 1.5 percent lower than the average 70.71 THI for 2008. The maximum THI (80.82) and minimum THI (52.61) in 2009 were 0.6 percent lower and 4.2 percent lower, respectively, than the maximum THI (81.30) and minimum THI (54.94) in 2008 during the cooling months.

35 Temperature and relative humidity data that were used to calculate THI were obtained from Telvent DTN. PJM hourly THI is the weighted-average zonal hourly THI weighted by average, annual peak zonal share (Coincident Factor) from 1998 to the year for which the calculation is made. For additional information on THI calculations, see PJM. "Manual 19: Load Forecasting and Analysis," Revision 15 (October 1, 2009), Section 3, pp. 9-10.

Table 2-50 Monthly minimum, average and maximum of PJM hourly THI: Cooling periods of 2008 and 2009

	2008			2009			Difference		
	Min	Avg	Max	Min	Avg	Max	Min	Avg	Max
Jun	54.94	70.16	81.30	52.61	67.83	77.92	(4.2%)	(3.3%)	(4.2%)
Jul	62.00	72.25	80.34	58.57	69.48	78.10	(5.5%)	(3.8%)	(2.8%)
Aug	59.89	69.70	78.62	57.21	71.57	80.82	(4.5%)	2.7%	2.8%

WWP is the wind-adjusted temperature for the heating season (January, February and December). The average temperatures are used for the months not covered by the THI or WWP. Table 2-51 shows the load weighted THI, WWP and average temperature for heating, cooling and shoulder seasons.[36]

Table 2-51 PJM annual Summer THI, Winter WWP and average temperature: cooling, heating and shoulder months of 2005 through 2009

	Summer THI	Winter WWP	Shoulder Average Temperature
2005	76.64	26.56	54.26
2006	75.59	31.67	54.62
2007	75.45	27.10	56.55
2008	75.35	27.52	54.10
2009	74.23	25.56	55.09

Day-Ahead Load

In the PJM Day-Ahead Energy Market, three types of financially binding demand bids are made and cleared:

- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of energy up to a specified LMP, above which the bid is zero. A decrement bid is a financial bid that can be submitted by any market participant.

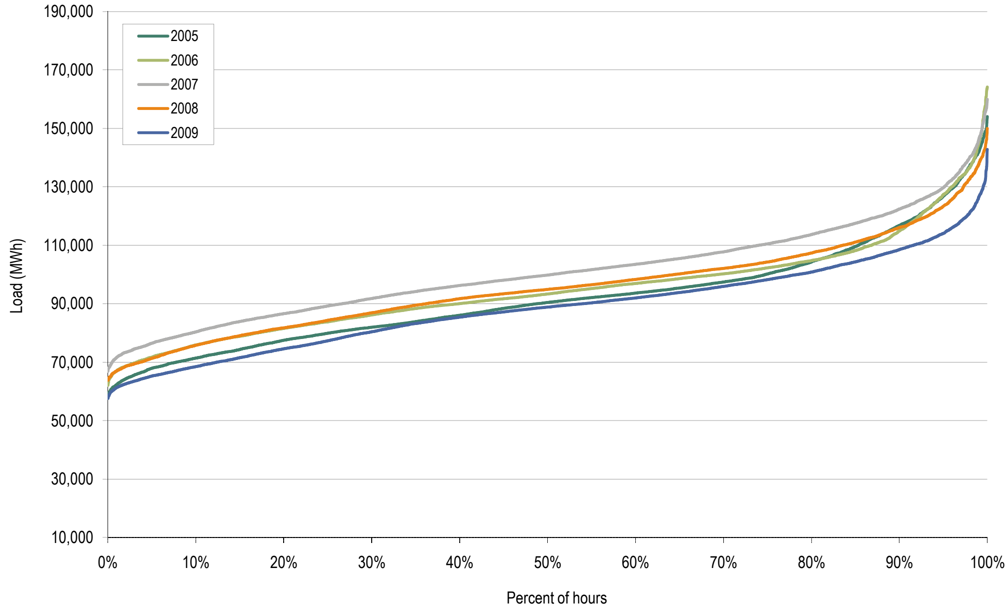
PJM day-ahead load is the hourly total of the above three types of cleared demand bids.

36 The Summer THI is calculated by taking average of daily maximum THI in June, July and August. The Winter WWP is calculated by taking average of daily minimum WWP in January, February and December. Average temperature is used for the rest of months. For additional information on the calculation of these weather variables, see PJM "Manual 19: Load Forecasting and Analysis," Revision 15 (October 1, 2009), Section 3, pp. 16. Load weighting using real-time zonal accounting load.

PJM Day-Ahead Load Duration

Figure 2-9 shows PJM day-ahead load duration curves from 2005 to 2009.

Figure 2-9 PJM day-ahead load duration curves: Calendar years 2005 to 2009



PJM Day-Ahead, Annual Average Load

Table 2-52 presents summary day-ahead load statistics for the 10 year period 2000 to 2009. The average load of 88,707 MWh in 2009 was 7.1 percent lower than the 2008 annual average load. The cleared fixed demand accounted for 81.2 percent, the cleared decrement bids accounted for 17.1 percent and the cleared price sensitive demand accounted for 1.7 percent of average load in 2009. The cleared decrement bids, fixed demand and price-sensitive demand in 2009 were 18.5 percent, 4.1 percent and 18.8 percent lower than in 2008. The cleared decrement bids in 2009 dropped to 15,136 MWh from 18,561 MWh in 2008, the cleared fixed demand in 2009 dropped to 72,073 MWh from 75,115 MWh, and the price-sensitive demand in 2009 dropped to 1,498 MWh from 1,846 MWh in 2008.

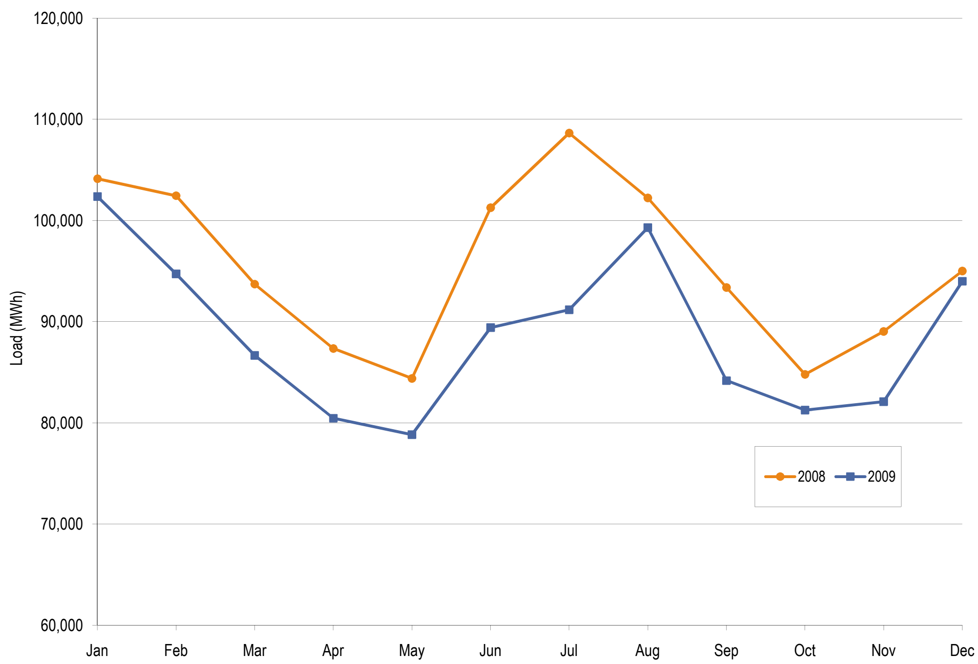
Table 2-52 PJM day-ahead average load: Calendar years 2000 to 2009

	PJM Day-Ahead Load (MWh)			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	33,045	33,217	6,850	NA	NA	NA
2001	33,318	32,812	6,489	0.8%	(1.2%)	(5.3%)
2002	42,131	40,720	10,130	26.4%	24.1%	56.1%
2003	44,340	44,368	7,883	5.2%	9.0%	(22.2%)
2004	61,034	58,544	16,318	37.7%	32.0%	107.0%
2005	92,002	90,424	17,381	50.7%	54.5%	6.5%
2006	94,793	93,331	16,048	3.0%	3.2%	(7.7%)
2007	100,912	99,799	16,190	6.5%	6.9%	0.9%
2008	95,522	94,886	15,439	(5.3%)	(4.9%)	(4.6%)
2009	88,707	88,833	14,896	(7.1%)	(6.4%)	(3.5%)

PJM Day-Ahead, Monthly Average Load

Figure 2-10 compares the day-ahead, monthly average loads of 2009 with those of 2008.

Figure 2-10 PJM day-ahead average load: Calendar years 2008 to 2009



Real-Time and Day-Ahead Load

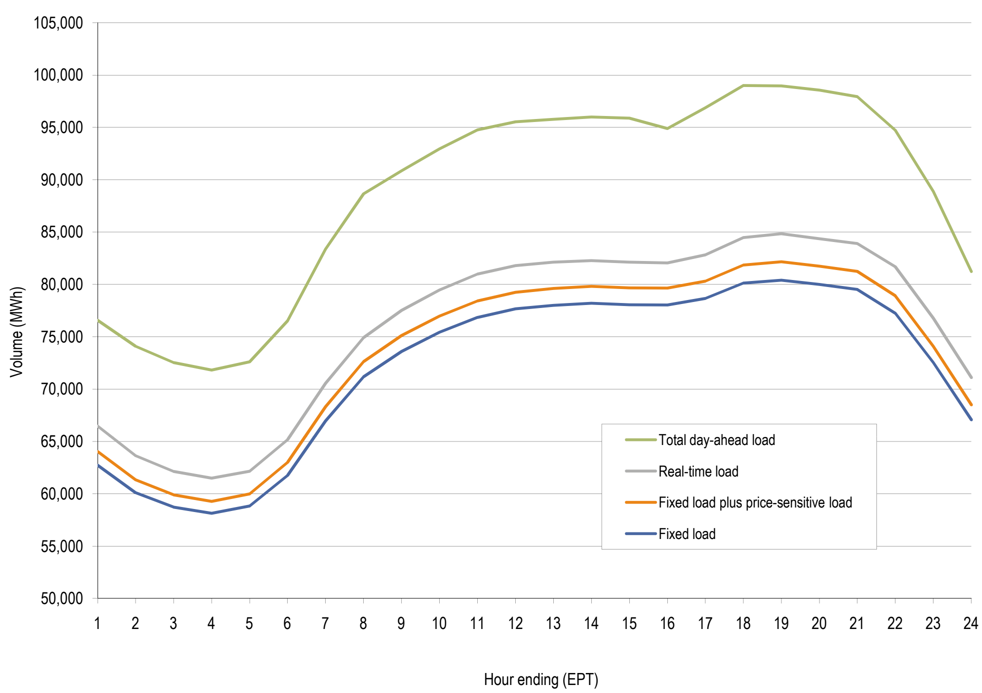
Table 2-53 presents summary statistics for the 2009 day-ahead and real-time loads and the average difference between them. The sum of day-ahead cleared fixed demand and price-sensitive demand averaged 2,464 MWh less than real-time average load. Total day-ahead load (the sum of the three types of cleared demand bids) averaged 12,672 MWh more than real-time load. Table 2-53 shows that, at 81.2 percent, fixed demand was the largest component of day-ahead load. At 1.7 percent, price-sensitive load was the smallest component, with cleared decrement bids accounting for the remaining 17.1 percent of day-ahead load.

Table 2-53 Cleared day-ahead and real-time load (MWh): Calendar year 2009

	Day Ahead				Real Time	Average Difference	
	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bid	Total Load	Total Load	Total Load	Total Load Minus DEC Bid
Average	72,073	1,498	15,136	88,707	76,035	12,672	(2,464)
Median	71,649	1,448	15,246	88,833	75,471	13,362	(1,884)
Standard deviation	12,515	451	2,624	14,896	13,260	1,636	(988)

Figure 2-11 shows the average 2009 hourly cleared volumes of fixed-demand bids, the sum of cleared fixed-demand and price-sensitive bids, total day-ahead load and real-time load. During 2009, real-time, hourly average load was higher than cleared fixed-demand load plus cleared price-sensitive load in the Day-Ahead Energy Market, although the reverse was true for 4.5 percent of the hours. When cleared decrement bids are included, day-ahead load always exceeded real-time load.

Figure 2-11 Day-ahead and real-time loads (Average hourly volumes): Calendar year 2009



Real-Time and Day-Ahead Generation

Real-time generation is the actual production of electricity during the operating day.

In the Day-Ahead Energy Market, three types of financially binding generation offers are made and cleared:[37]

- **Self-Scheduled.** Offer to supply a fixed block of MWh that must run from a specific unit, or as a minimum amount of MWh that must run on a specific unit that also has a dispatchable component above the minimum.[38]
- **Generator Offer.** Offer to supply a schedule of MWh from a specific unit and the corresponding offer prices.
- **Increment Offer (INC).** Financial offer to supply specified MWh at, or above, a given price. An increment offer is a financial offer that can be submitted by any market participant.

Table 2-54 presents summary statistics for 2009 day-ahead and real-time generation and the average differences between them. Day-ahead cleared generation from physical units averaged 468 MWh higher than real-time generation. Day-ahead cleared generation plus cleared INC offers averaged 13,128 MWh more than real-time generation. Table 2-54 also shows that cleared generation and INC offers accounted for 86.1 percent and 13.9 percent of day-ahead supply, respectively.

Table 2-54 Day-ahead and real-time generation (MWh): Calendar year 2009

	Day Ahead			Real Time	Average Difference	
	Cleared Generation	Cleared INC Offer	Cleared Generation Plus INC Offer	Generation	Cleared Generation	Cleared Generation Plus INC Offer
Average	78,494	12,660	91,154	78,026	468	13,128
Median	78,667	12,505	91,318	77,639	1,028	13,679
Standard deviation	14,820	1,661	15,406	13,647	1,173	1,759

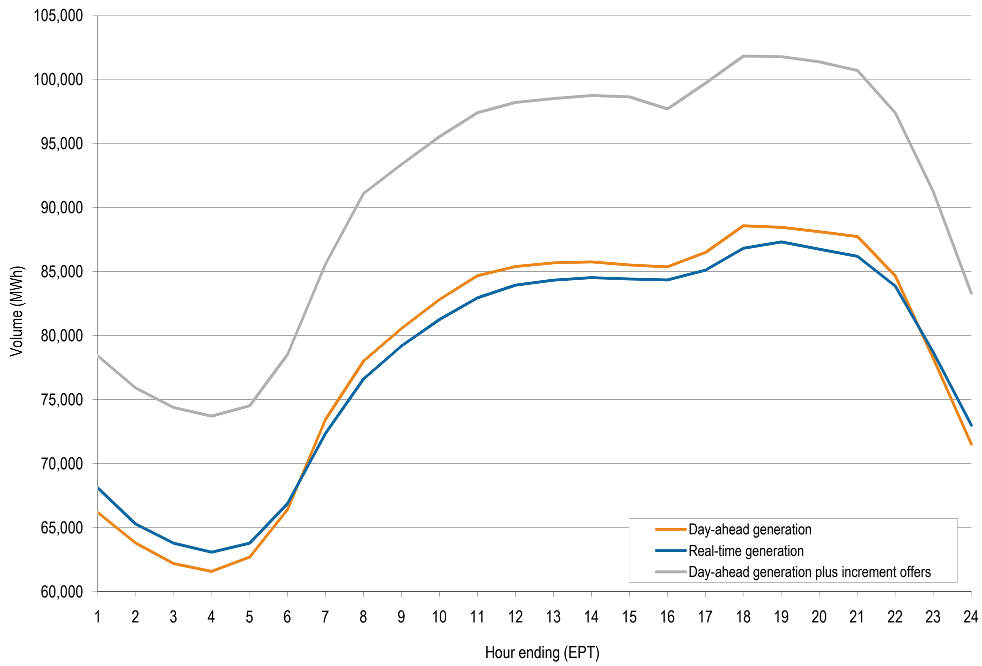
Figure 2-12 shows average hourly cleared volumes of day-ahead generation, day-ahead generation plus increment offers and real-time generation for 2009.[39] Day-ahead generation is all the self-scheduled and generator offers cleared in the Day-Ahead Energy Market. Real-time hourly average generation was lower than day-ahead generation from physical units 57.5 percent of the hours in 2009. Overall, day-ahead generation from physical units was higher than real-time generation on an hourly average basis. However, on an hourly average basis, real-time generation did exceed day-ahead generation from physical units between hours ending 1 and 6, and during hours ending 23 and 24. When cleared increment offers are included, average hourly total day-ahead cleared MW offers exceeded real-time generation.

37 All references to day-ahead generation and increment offers are presented in cleared MWh in the "Real-Time and Day-Ahead Generation" portion of the *2009 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part 1."

38 The definition of self-scheduled is based on documentation from PJM. "eMKT User Guide" (December 1, 2008), pp. 50-52.

39 Generation data are the sum of MWh at every generation bus in PJM with positive output.

Figure 2-12 Day-ahead and real-time generation (Average hourly volumes): Calendar year 2009



Locational Marginal Price (LMP)

The conduct of individual market entities within a market structure is reflected in market prices. The overall level of prices is a good general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them.[40]

Real-Time LMP

Real-time LMP is the hourly LMP for the PJM Real-Time Energy Market.

Real-Time Average LMP

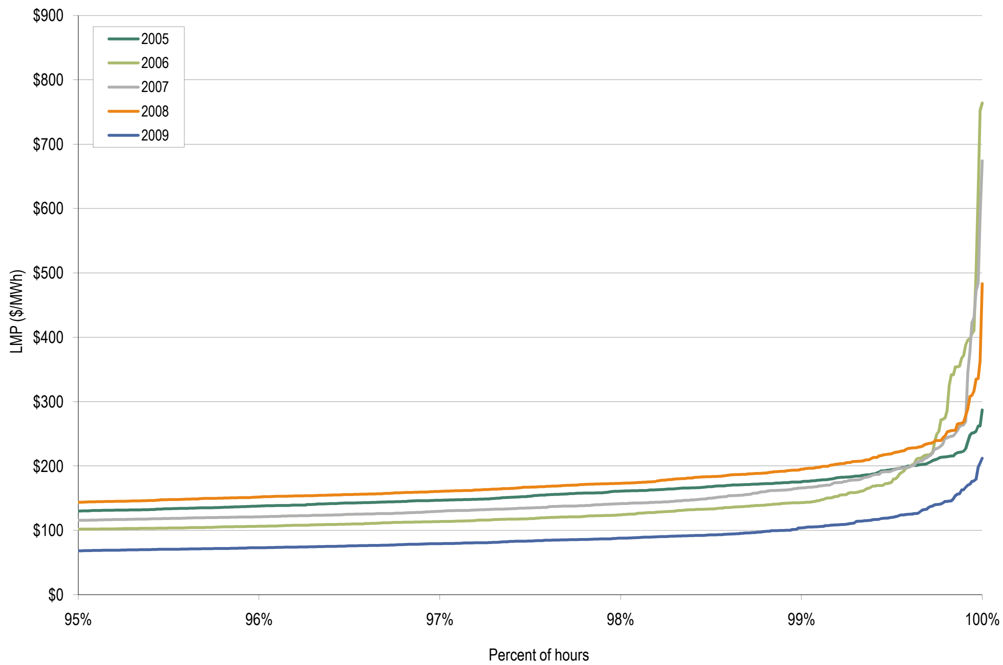
PJM Real-Time LMP Duration

A price duration curve shows the percent of hours when LMP is at, or below, a given price for the year. Figure 2-13 presents price duration curves for hours above the 95th percentile from 2005 to 2009. As Figure 2-13 shows, LMPs were less than $100 per MWh during 95 percent or more of the

40 See the *2009 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market," for methodological background, detailed price data and comparisons and Appendix H, "Calculating Locational Marginal Price" for more information on how bus LMPs are aggregated to system LMPs.

hours for the year 2009 and less than $150 during 95 percent or more of the hours for the years 2005 to 2008.[41]

Figure 2-13 Price duration curves for the PJM Real-Time Energy Market during hours above the 95th percentile: Calendar years 2005 to 2009



PJM Real-Time, Annual Average LMP

Table 2-55 shows the PJM real-time, annual, simple average LMP for the 12-year period 1998 to 2009.[42] The system simple average LMP for 2009 was 44.1 percent lower than the 2008 annual average, $37.08 per MWh versus $66.40 per MWh. The PJM real-time, annual, simple average LMP in 2009 was lower than the average LMP in every year since 2003.

41 See the *2009 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

42 The system annual, simple average LMP is the average of the hourly LMP without any weighting. The only exception is that market-clearing prices (MCPs) are included for January to April 1998. MCP was the single market-clearing price calculated by PJM prior to implementation of LMP.

Table 2-55 PJM real-time, simple average LMP (Dollars per MWh): Calendar years 1998 to 2009

	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.72	$16.60	$31.45	NA	NA	NA
1999	$28.32	$17.88	$72.42	30.4%	7.7%	130.3%
2000	$28.14	$19.11	$25.69	(0.6%)	6.9%	(64.5%)
2001	$32.38	$22.98	$45.03	15.1%	20.3%	75.3%
2002	$28.30	$21.08	$22.41	(12.6%)	(8.3%)	(50.2%)
2003	$38.28	$30.79	$24.71	35.2%	46.1%	10.3%
2004	$42.40	$38.30	$21.12	10.8%	24.4%	(14.5%)
2005	$58.08	$47.18	$35.91	37.0%	23.2%	70.0%
2006	$49.27	$41.45	$32.71	(15.2%)	(12.1%)	(8.9%)
2007	$57.58	$49.92	$34.60	16.9%	20.4%	5.8%
2008	$66.40	$55.53	$38.62	15.3%	11.2%	11.6%
2009	$37.08	$32.71	$17.12	(44.1%)	(41.1%)	(55.7%)

Zonal Real-Time, Annual Average LMP

Table 2-56 shows PJM zonal real-time, simple average LMP for 2008 and 2009. The largest zonal decrease was in the AECO Control Zone which experienced a $40.03, or 49.6 percent decrease from 2008 and the smallest decrease was in the DLCO Control Zone which experienced a $16.08 decrease, or 33.0 percent, from 2008.

Table 2-56 Zonal real-time, simple average LMP (Dollars per MWh): Calendar years 2008 to 2009

	2008	2009	Difference	Difference as Percent of 2008
AECO	$80.70	$40.68	($40.03)	(49.6%)
AEP	$53.42	$33.63	($19.79)	(37.0%)
AP	$65.85	$38.29	($27.56)	(41.9%)
BGE	$80.05	$41.71	($38.33)	(47.9%)
ComEd	$49.38	$29.05	($20.33)	(41.2%)
DAY	$53.68	$33.49	($20.19)	(37.6%)
DLCO	$48.81	$32.73	($16.08)	(33.0%)
Dominion	$75.87	$40.00	($35.87)	(47.3%)
DPL	$77.20	$41.23	($35.96)	(46.6%)
JCPL	$78.80	$40.93	($37.87)	(48.1%)
Met-Ed	$74.70	$39.94	($34.77)	(46.5%)
PECO	$75.07	$40.00	($35.07)	(46.7%)
PENELEC	$63.37	$36.85	($26.52)	(41.9%)
Pepco	$80.45	$41.88	($38.57)	(47.9%)
PPL	$73.35	$39.44	($33.91)	(46.2%)
PSEG	$79.14	$41.27	($37.87)	(47.9%)
RECO	$77.46	$40.36	($37.10)	(47.9%)

Real-Time, Annual Average LMP by Jurisdiction

Table 2-57 shows the real-time, simple average LMP for all or part of the jurisdictions within the PJM footprint during 2008 and 2009. The largest decrease was in New Jersey which experienced a $38.19, or 48.2 percent decrease from 2008, and the smallest decrease was in Ohio which experienced a $19.39, or 36.8 percent, decrease from 2008.

Table 2-57 Jurisdiction real-time, simple average LMP (Dollars per MWh): Calendar years 2008 to 2009

	2008	2009	Difference	Difference as Percent of 2008
Delaware	$76.26	$40.80	($35.47)	(46.5%)
Illinois	$49.38	$29.05	($20.33)	(41.2%)
Indiana	$53.01	$33.08	($19.93)	(37.6%)
Kentucky	$53.80	$33.48	($20.32)	(37.8%)
Maryland	$79.75	$41.66	($38.09)	(47.8%)
Michigan	$54.07	$34.09	($19.98)	(36.9%)
New Jersey	$79.27	$41.08	($38.19)	(48.2%)
North Carolina	$71.69	$38.92	($32.77)	(45.7%)
Ohio	$52.64	$33.25	($19.39)	(36.8%)
Pennsylvania	$68.98	$38.47	($30.50)	(44.2%)
Tennessee	$54.36	$33.54	($20.82)	(38.3%)
Virginia	$73.20	$39.29	($33.91)	(46.3%)
West Virginia	$55.02	$34.60	($20.42)	(37.1%)
District of Columbia	$80.57	$42.98	($37.59)	(46.7%)

Hub Real-Time, Annual Average LMP

Table 2-58 shows the real-time, simple average LMPs at the PJM hubs for 2008 and 2009. Hub prices are average LMPs across a defined set of buses, created to provide market participants with trading points that exhibit greater price stability than individual buses. The largest price decrease was for the New Jersey Hub which experienced a $37.98, or 48.1 percent decrease from 2008, and the smallest decrease was for the AEP Gen Hub which experienced a $18.52, or 36.8 percent, decrease from 2008.

Table 2-58 Hub real-time, simple average LMP (Dollars per MWh): Calendar years 2008 to 2009

	2008	2009	Difference	Difference as Percent of 2008
AEP Gen Hub	$50.35	$31.83	($18.52)	(36.8%)
AEP-DAY Hub	$53.05	$33.23	($19.82)	(37.4%)
Chicago Gen Hub	$48.60	$28.28	($20.32)	(41.8%)
Chicago Hub	$49.43	$29.25	($20.18)	(40.8%)
Dominion Hub	$73.89	$39.27	($34.63)	(46.9%)
Eastern Hub	$77.15	$41.23	($35.92)	(46.6%)
N Illinois Hub	$48.99	$28.85	($20.14)	(41.1%)
New Jersey Hub	$79.02	$41.04	($37.98)	(48.1%)
Ohio Hub	$53.09	$33.24	($19.85)	(37.4%)
West Interface Hub	$58.40	$34.66	($23.74)	(40.7%)
Western Hub	$68.53	$38.30	($30.22)	(44.1%)

Real-Time, Load-Weighted, Average LMP

Higher demand (load) generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than simple average prices. Load-weighted LMP reflects the average LMP paid for actual MWh consumed during a year. Load-weighted, average LMP is the average of PJM hourly LMPs, each weighted by the PJM total hourly load.

PJM Real-Time, Annual, Load-Weighted, Average LMP

Table 2-59 shows the PJM real-time, annual, load-weighted, average LMP for the 12-year period 1998 to 2009. The load-weighted, average system LMP for 2009 was 45.1 percent lower than the 2008 annual, load-weighted, average, $39.05 per MWh versus $71.13 per MWh. The real-time, annual, load-weighted, average LMP in 2009 was lower than the load-weighted, average LMP in every year since 2003.

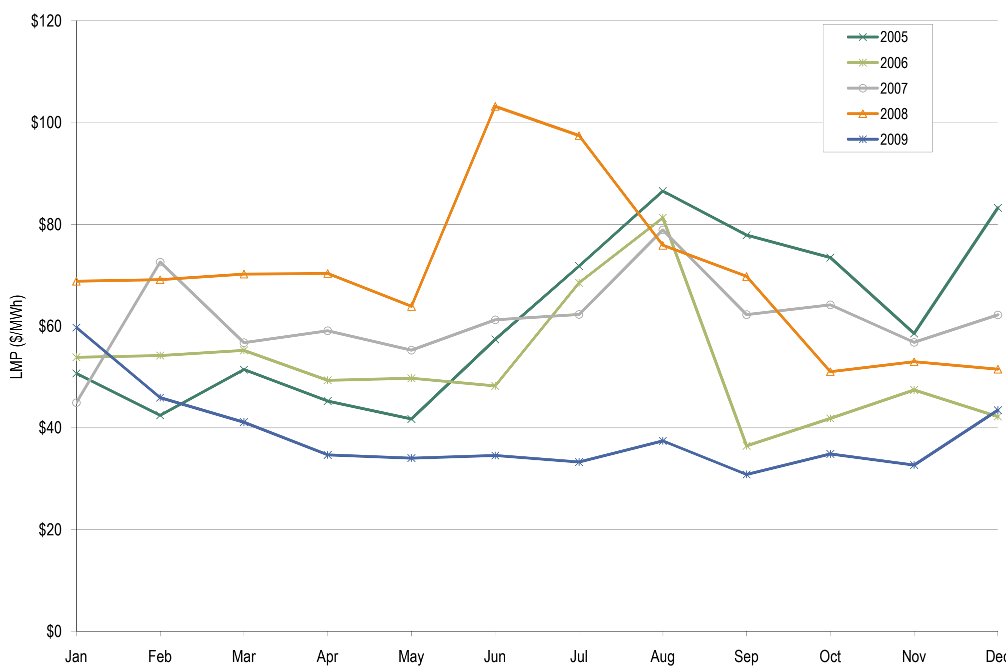
Table 2-59 PJM real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 1998 to 2009

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$24.16	$17.60	$39.29	NA	NA	NA
1999	$34.07	$19.02	$91.49	41.0%	8.1%	132.8%
2000	$30.72	$20.51	$28.38	(9.8%)	7.9%	(69.0%)
2001	$36.65	$25.08	$57.26	19.3%	22.3%	101.8%
2002	$31.60	$23.40	$26.75	(13.8%)	(6.7%)	(53.3%)
2003	$41.23	$34.96	$25.40	30.5%	49.4%	(5.0%)
2004	$44.34	$40.16	$21.25	7.5%	14.9%	(16.3%)
2005	$63.46	$52.93	$38.10	43.1%	31.8%	79.3%
2006	$53.35	$44.40	$37.81	(15.9%)	(16.1%)	(0.7%)
2007	$61.66	$54.66	$36.94	15.6%	23.1%	(2.3%)
2008	$71.13	$59.54	$40.97	15.4%	8.9%	10.9%
2009	$39.05	$34.23	$18.21	(45.1%)	(42.5%)	(55.6%)

PJM Real-Time, Monthly, Load-Weighted, Average LMP

Figure 2-14 shows the PJM real-time, monthly, load-weighted LMP from 2005 through 2009.

Figure 2-14 PJM real-time, monthly, load-weighted, average LMP: Calendar years 2005 to 2009



Zonal Real-Time, Annual, Load-Weighted, Average LMP

Table 2-60 shows PJM zonal real-time, load-weighted, average LMP for 2008 and 2009. The largest zonal decrease was in the AECO Control Zone which experienced a $48.00, or 53.0 percent, decrease from 2008, and the smallest decrease was in the DLCO Control Zone which experienced a $18.59, or 35.4 percent, decrease from 2008.

Table 2-60 Zonal real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2008 to 2009

	2008	2009	Difference	Difference as Percent of 2008
AECO	$90.55	$42.55	($48.00)	(53.0%)
AEP	$56.65	$35.20	($21.45)	(37.9%)
AP	$69.88	$40.59	($29.29)	(41.9%)
BGE	$87.11	$44.28	($42.83)	(49.2%)
ComEd	$53.63	$30.69	($22.94)	(42.8%)
DAY	$57.81	$35.11	($22.70)	(39.3%)
DLCO	$52.45	$33.86	($18.59)	(35.4%)
Dominion	$82.88	$42.67	($40.21)	(48.5%)
DPL	$83.88	$44.05	($39.83)	(47.5%)
JCPL	$86.43	$43.26	($43.17)	(50.0%)
Met-Ed	$79.81	$42.32	($37.49)	(47.0%)
PECO	$80.76	$42.03	($38.72)	(48.0%)
PENELEC	$66.47	$38.57	($27.91)	(42.0%)
Pepco	$87.89	$44.50	($43.39)	(49.4%)
PPL	$77.79	$42.10	($35.69)	(45.9%)
PSEG	$85.54	$43.08	($42.46)	(49.6%)
RECO	$85.26	$42.41	($42.85)	(50.3%)

Real-Time, Annual, Load-Weighted, Average LMP by Jurisdiction

Table 2-61 shows the real-time, load-weighted, average LMPs for all or part of the jurisdictions within the PJM footprint during 2008 and 2009[43]. The largest decrease was in New Jersey which experienced a $43.43, or 50.2 percent, decrease from 2008, and the smallest decrease was in Ohio which experienced a $21.19, or 37.9 percent, decrease from 2008.

Table 2-61 Jurisdiction real-time, annual, load-weighted, average LMP (Dollars per MWh): Calendar years 2008 to 2009

	2008	2009	Difference	Difference as Percent of 2008
Delaware	$82.25	$43.20	($39.05)	(47.5%)
Illinois	$53.63	$30.69	($22.94)	(42.8%)
Indiana	$55.98	$34.15	($21.83)	(39.0%)
Kentucky	$57.45	$35.72	($21.73)	(37.8%)
Maryland	$87.10	$44.48	($42.62)	(48.9%)
Michigan	$58.07	$35.35	($22.72)	(39.1%)
New Jersey	$86.48	$43.05	($43.43)	(50.2%)
North Carolina	$80.28	$41.24	($39.04)	(48.6%)
Ohio	$55.90	$34.71	($21.19)	(37.9%)
Pennsylvania	$73.29	$40.54	($32.75)	(44.7%)
Tennessee	$56.67	$35.47	($21.21)	(37.4%)
Virginia	$79.65	$41.97	($37.68)	(47.3%)
West Virginia	$58.21	$36.52	($21.69)	(37.3%)
District of Columbia	$86.68	$45.35	($41.33)	(47.7%)

Real-Time, Fuel-Cost-Adjusted, Load-Weighted LMP

Fuel Cost

Changes in LMP can result from changes in the marginal costs of marginal units, the units setting LMP. In general, fuel costs make up between 80 percent and 90 percent of marginal cost depending on generating technology, unit efficiency, unit age and other factors. The impact of fuel cost on marginal cost and on LMP depends on the fuel burned by marginal units and changes in fuel costs.[44] Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. To account for the changes in fuel and allowance costs between 2008 and 2009, the 2009 load-weighted LMP was adjusted to reflect the change in the daily price of fuels and emission allowances used by marginal units and the change in the amount of load affected by marginal units, using sensitivity factors.[45]

43 The PJM footprint includes 17 control zones. Each control zone is in one or more states or the District of Columbia, but such jurisdictions generally are not entirely covered by PJM control zones. The term jurisdiction is used here to refer to the states in which one or more of these control zones are located. For maps showing the PJM footprint and its control zones, see the *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

44 See the *2009 State of the Market Report for PJM*, Volume II, Section 2,"Energy Market, Part 1," at Table 2-33, "Type of fuel used (By marginal units): Calendar year 2009."

45 For more information, see the *2009 State of the Market Report for PJM*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity Factors."

The prices of the primary fuel types used in the PJM footprint, including coal, natural gas and oil, all decreased in price in 2009. In 2009, for example, the price of 1.2 percent sulfur content Central Appalachian coal was 42.6 percent lower than in 2008. The Western Rail Powder River Basin coal price was 22.1 percent lower than in 2008. Natural gas prices were 53.8 percent lower in 2009 than in 2008. No. 2 (light) oil prices were 31.9 percent lower and No. 6 (heavy) oil prices were 27.0 percent lower in 2009 than in 2008. Figure 2-15 shows spot average fuel prices for 2008 and 2009.[46]

Figure 2-15 Spot average fuel price comparison: Calendar years 2008 to 2009

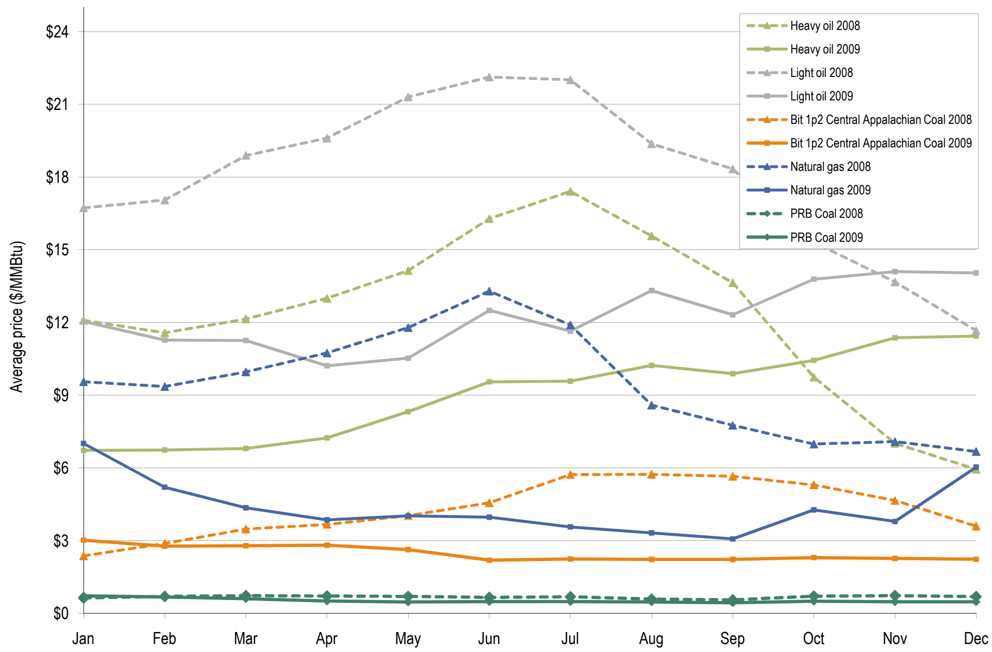
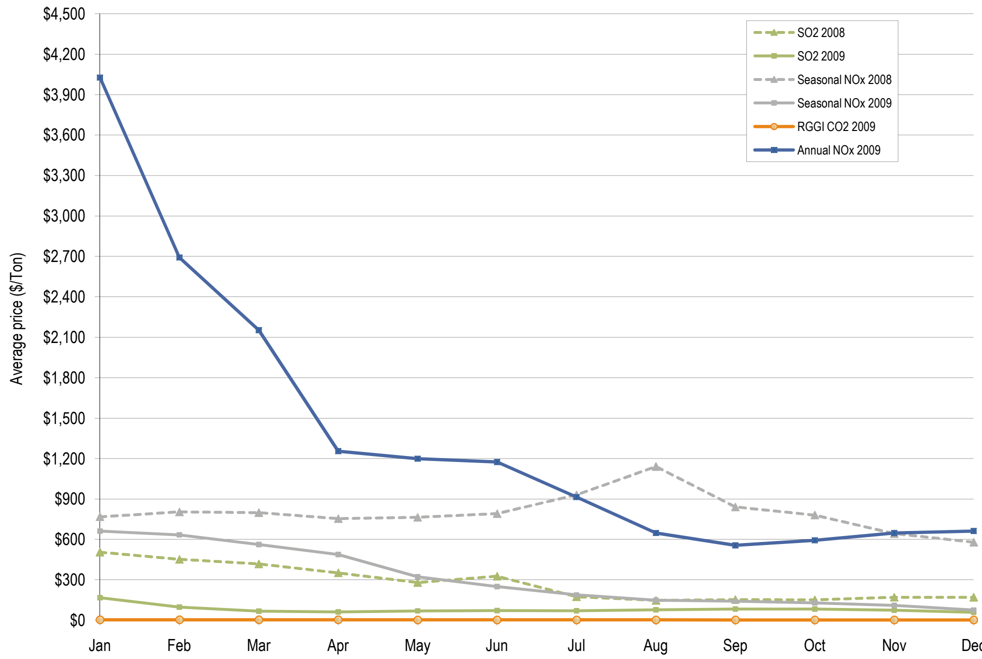


Figure 2-16 shows average, daily settled prices for NO_x and SO_2 emission within PJM. In 2009, seasonal NO_x prices were 61.6 percent lower than in 2008. SO_2 prices were 70.1 percent lower in 2009 than in 2008. Figure 2-10 also shows the average, daily settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances. RGGI allowances are required by generation in participating RGGI states. This includes PJM generation located in Delaware, Maryland, and New Jersey.

46 Natural gas, light oil, and heavy oil prices are the average of daily fuel price indices in the PJM footprint. Coal prices are the average of daily fuel prices for 1.2 percent sulfur content Central Appalachian coal and Powder River Basin coal. All fuel prices are from Platts.

Figure 2-16 Spot average emission price comparison: Calendar years 2008 to 2009



The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities. Under RGGI, each state has its own CO_2 Budget Trading Program that has been implemented through state regulations based on a common set of reciprocal rules that allow the ten individual state programs to function as a single regional compliance market for CO_2 allowances. Starting in 2009, the RGGI rules require that qualifying power generators hold allowances sufficient to cover their total CO_2 emissions over each three year compliance period. Qualifying power generators can purchase their allowances for the compliance period directly from the quarterly auctions held before and during the compliance period, or from holders of allowances from previous auctions. Additional allowances can be made available via RGGI state approved qualifying offset projects, although offset allowances can make up only a limited portion of a regulated power plant's compliance obligation. The current maximum allowable contribution of CO_2 offset allowances to a power generation facility's compliance obligation is 3.3 percent of emissions per compliance period. The cap on the contribution of CO_2 offset allowances can be raised to 5 percent or to 10 percent if the calendar year average price of CO_2 allowances exceeds annual Consumer Price Index (CPI) adjusted stage 1 ($7) or stage 2 ($10) trigger prices, respectively.

Since September 25, 2008, a total of six auctions have been held for 2009- 2011 compliance period allowances, and four auctions have been held for 2012-2014 compliance period allowances. Table 2-62 shows the RGGI CO_2 auction clearing prices and quantities for the six 2009-2011 compliance period auctions held as of the end of calendar year 2009. The weighted average allowance auction price for the 2009-2011 compliance period auctions held from September 2008 through the 2009 calendar year was $2.91. Auction prices within the 2009 calendar year for the 2009-2011 compliance period peaked at $3.51 in March 18, 2009. Subsequent 2009 calendar year auctions for the 2009-2011 compliance period saw the clearing price fall, with the last auction of the year, the December 2, 2009 auction, providing the lowest auction price of the year at $2.05 an allowance. The monthly average 2009 spot price for a 2009-2011 compliance period allowance was $3.06 per ton. Monthly average spot prices for the 2009-2011 compliance period varied during the year, peaking in March at $3.80 per ton and declining to $2.16 per ton by December.

Table 2-62 RGGI CO_2 allowance auction prices and quantities: 2009-2011 Compliance Period

Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387
December 17, 2008	$3.38	31,505,898	31,505,898
March 18, 2009	$3.51	31,513,765	31,513,765
June 17, 2009	$3.23	30,887,620	30,887,620
September 9, 2009	$2.19	28,408,945	28,408,945
December 2, 2009	$2.05	28,591,698	28,591,698

The first phase of the Environmental Protection Agency's (EPA) Clean Air Interstate Rule (CAIR) went into effect across the 28 eastern states and the District of Columbia on January 1, 2009, mandating emissions cuts of NO_x. CAIR requires upwind states to implement control measures to reduce emissions of NO_x and SO_2 and created an optional interstate cap and trade program for these pollutants. Mandates for SO_2 emissions will commence on January 1, 2010. The EPA expects that CAIR, when fully implemented, will reduce SO_2 emissions in these states by over 70 percent and NO_x emissions by over 60 percent from 2003 levels. During this period, the EPA must, consistent with court action on CAIR, develop a replacement rule, but it is unclear at this time what practical effect this might have on the substance of the EPA's program.[47]

Table 2-63 compares the 2009 PJM fuel-cost-adjusted, load-weighted, average LMP to the 2008 load-weighted, average LMP. The load-weighted, average LMP for 2009 was 45.1 percent lower than the load-weighted, average LMP for 2008. The real-time fuel-cost-adjusted, load-weighted, average LMP in 2009 was 10.5 percent lower than the load-weighted LMP in 2008. If fuel costs for the year 2009 had been the same as for 2008, the 2009 load-weighted LMP would have been higher, $63.66 per MWh instead of the observed $39.05 per MWh. Lower coal, gas and oil prices in 2009 resulted in lower prices in 2009 than would have occurred if fuel prices had remained at their 2008 levels. Net fuel cost decreases were the primary reason for the lower LMPs in 2009. Lower loads also contributed to lower LMPs.

Table 2-63 PJM annual, fuel-cost-adjusted, load-weighted LMP (Dollars per MWh): Year-over-year method

	2008 Load-Weighted LMP	2009 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$71.13	$63.66	(10.5%)

47 See North Carolina v. Environmental Protection Agency, et al., 531 F.3d 896 (D.C. Circuit 2008).

Components of Real-Time, Load-Weighted LMP

Observed LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal units generally determine system LMPs, based on their offers. Those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs and markup. As a result, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal. Spot fuel prices were used, and emission costs were calculated using spot prices for NO_x, SO_2, and CO_2 and emission allowance costs and unit-specific emission rates, when applicable.

Table 2-64 shows that 52.6 percent of the annual, load-weighted LMP was the result of coal costs; 31.0 percent was the result of gas costs and 5.6 percent was the result of the cost of emission allowances. Markup was -6.1 percent of LMP. The fuel-related components of LMP reflect the impact of the cost of the identified fuel on LMP rather than all of the components of the offers of units burning that fuel on LMP.

As a result of the way in which LMP is calculated, there are differences between the components of LMP associated with individual unit characteristics, e.g. fuel costs and VOM, and observed LMP. This total net difference in 2009 was -$0.67 per MWh. (Numbers in parentheses in the table are negative.) The components of this difference are listed in Table 2-64.[48]

Table 2-64 Components of PJM real-time, annual, load-weighted, average LMP: Calendar year 2009

Element	Contribution to LMP	Percent
Coal	$20.53	52.6%
Natural Gas	$12.10	31.0%
10% Cost Adder	$3.73	9.6%
VOM	$2.50	6.4%
Oil	$0.88	2.3%
NO_x	$0.80	2.1%
SO_2	$0.76	1.9%
CO_2	$0.61	1.6%
FMU Adder	$0.17	0.4%
Offline CT Adder	$0.03	0.1%
Municipal Waste	$0.02	0.0%
NA	$0.01	0.0%
Unit LMP Differential	$0.00	0.0%
Shadow Price Limit Adder	($0.01)	(0.0%)
M2M Adder	($0.14)	(0.3%)
Dispatch Differential	($0.15)	(0.4%)
UDS Override Differential	($0.43)	(1.1%)
Markup	($2.38)	(6.1%)
LMP	$39.05	100.0%

48 These components are explained in the *2009 State of the Market Report for PJM,* Volume II, Appendix K, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Day-Ahead LMP

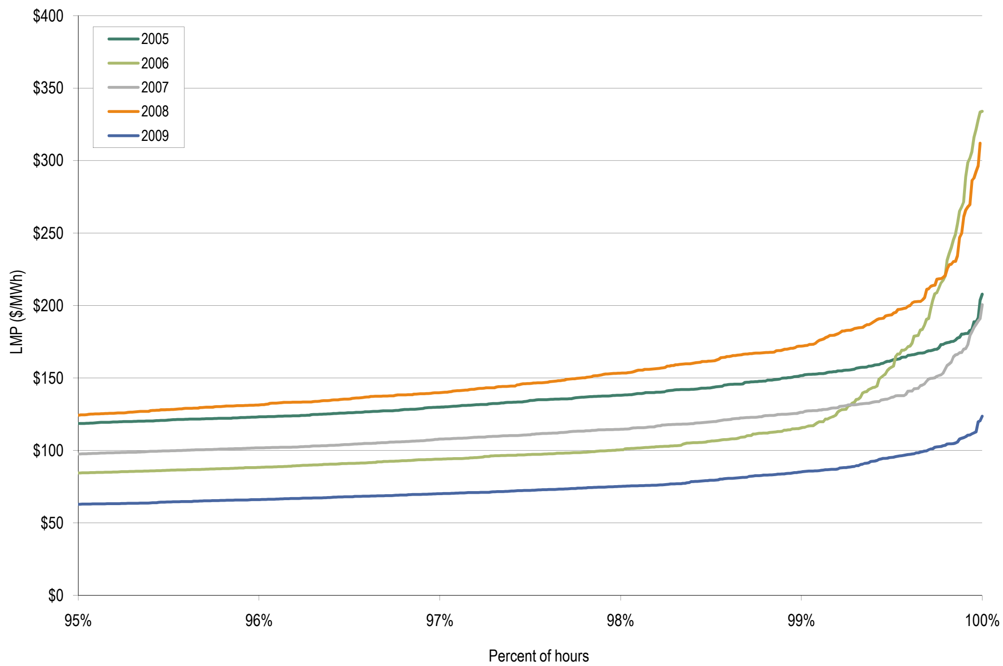
Day-ahead LMP is the hourly LMP for the PJM Day-Ahead Energy Market.

Day-Ahead Average LMP

PJM Day-Ahead LMP Duration

A price duration curve shows the percent of hours when LMP is at, or below, a given price for the year. Figure 2-17 presents day-ahead price duration curves for hours above the 95th percentile from 2005 to 2009. As Figure 2-11 shows, day-ahead LMP was less than \$100 per MWh during 95 percent or more of the hours for the years 2006, 2007 and 2009 and less than \$150 during 95 percent or more of the hours for 2005 and 2008.

Figure 2-17 Price duration curves for the PJM Day-Ahead Energy Market during hours above the 95th percentile: Calendar years 2005 to 2009



PJM Day-Ahead, Annual Average LMP

Table 2-65 shows the PJM day-ahead annual, simple average LMP for the 10 year period 2000 to 2009. The system simple average LMP for 2009 was 44.0 percent lower than the 2008 annual average, $37.00 per MWh versus $66.12 per MWh. The PJM day-ahead annual, simple average LMP in 2009 was lower than every prior year since 2003.

Table 2-65 PJM day-ahead, simple average LMP (Dollars per MWh): Calendar years 2000 to 2009

	Day-Ahead LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$31.97	$24.42	$21.33	NA	NA	NA
2001	$32.75	$27.05	$30.42	2.4%	10.8%	42.6%
2002	$28.46	$23.28	$17.68	(13.1%)	(14.0%)	(41.9%)
2003	$38.73	$35.22	$20.84	36.1%	51.3%	17.8%
2004	$41.43	$40.36	$16.60	7.0%	14.6%	(20.4%)
2005	$57.89	$50.08	$30.04	39.7%	24.1%	81.0%
2006	$48.10	$44.21	$23.42	(16.9%)	(11.7%)	(22.0%)
2007	$54.67	$52.34	$23.99	13.7%	18.4%	2.4%
2008	$66.12	$58.93	$30.87	20.9%	12.6%	28.7%
2009	$37.00	$35.16	$13.39	(44.0%)	(40.3%)	(56.6%)

Zonal Day-Ahead, Annual Average LMP

Table 2-66 shows PJM zonal day-ahead, simple average LMP for 2008 and 2009. The largest zonal decrease was in the Pepco Control Zone which experienced a $38.72, or 47.6 percent, decrease from 2008 and the smallest decrease was in the DLCO Control Zone which experienced a $18.59, or 36.5 percent, decrease from 2008.

Table 2-66 Zonal day-ahead, simple average LMP (Dollars per MWh): Calendar years 2008 to 2009

	2008	2009	Difference	Difference as Percent of 2008
AECO	$78.99	$41.44	($37.54)	(47.5%)
AEP	$53.61	$33.44	($20.17)	(37.6%)
AP	$65.09	$37.80	($27.29)	(41.9%)
BGE	$80.70	$42.57	($38.13)	(47.3%)
ComEd	$50.50	$28.94	($21.55)	(42.7%)
DAY	$53.53	$32.94	($20.59)	(38.5%)
DLCO	$50.92	$32.33	($18.59)	(36.5%)
Dominion	$75.60	$40.58	($35.02)	(46.3%)
DPL	$77.95	$41.73	($36.22)	(46.5%)
JCPL	$79.74	$41.36	($38.38)	(48.1%)
Met-Ed	$75.54	$40.35	($35.19)	(46.6%)
PECO	$76.23	$40.79	($35.44)	(46.5%)
PENELEC	$65.11	$37.09	($28.02)	(43.0%)
Pepco	$81.26	$42.54	($38.72)	(47.6%)
PPL	$74.25	$39.90	($34.35)	(46.3%)
PSEG	$79.77	$41.84	($37.93)	(47.6%)
RECO	$78.08	$40.92	($37.16)	(47.6%)

Day-Ahead, Annual Average LMP by Jurisdiction

Table 2-67 shows PJM's day-ahead, simple average LMPs for 2008 and 2009, by jurisdiction. The largest decrease was in New Jersey which experienced a $38.05, or 47.7 percent, decrease from 2008, and the smallest decrease was in Ohio which experienced a $20.02, or 37.9 percent, decrease from 2008.

Table 2-67 Jurisdiction day-ahead, simple average LMP (Dollars per MWh): Calendar years 2008 to 2009

	2008	2009	Difference	Difference as Percent of 2008
Delaware	$76.88	$41.15	($35.73)	(46.5%)
Illinois	$50.50	$28.94	($21.55)	(42.7%)
Indiana	$53.58	$32.87	($20.71)	(38.7%)
Kentucky	$53.36	$33.22	($20.14)	(37.7%)
Maryland	$80.01	$42.38	($37.63)	(47.0%)
Michigan	$54.48	$33.94	($20.53)	(37.7%)
New Jersey	$79.68	$41.64	($38.05)	(47.7%)
North Carolina	$71.66	$39.50	($32.16)	(44.9%)
Ohio	$52.85	$32.83	($20.02)	(37.9%)
Pennsylvania	$70.04	$38.80	($31.24)	(44.6%)
Tennessee	$54.24	$33.66	($20.58)	(37.9%)
Virginia	$73.01	$39.88	($33.13)	(45.4%)
West Virginia	$54.67	$34.34	($20.33)	(37.2%)
District of Columbia	$81.04	$43.38	($37.66)	(46.5%)

Day-Ahead, Load-Weighted, Average LMP

Day-ahead, load-weighted LMP reflects the average LMP paid for day-ahead demand MWh cleared during a year. Day-ahead, load-weighted LMP is the average of PJM day-ahead hourly LMPs, each weighted by the PJM total cleared day-ahead hourly load, including day-ahead fixed load, price-sensitive load and decrement bids.

PJM Day-Ahead, Annual, Load-Weighted, Average LMP

Table 2-68 shows the PJM day-ahead, annual, load-weighted, average LMP for the 10-year period 2000 to 2009. The day-ahead, load-weighted, average LMP for 2009 was 44.7 percent lower than the 2008 annual, load-weighted, average, at $38.82 per MWh versus $70.25 per MWh. The day-ahead, load-weighted, average LMP for 2009 was lower than in every prior year since 2003.

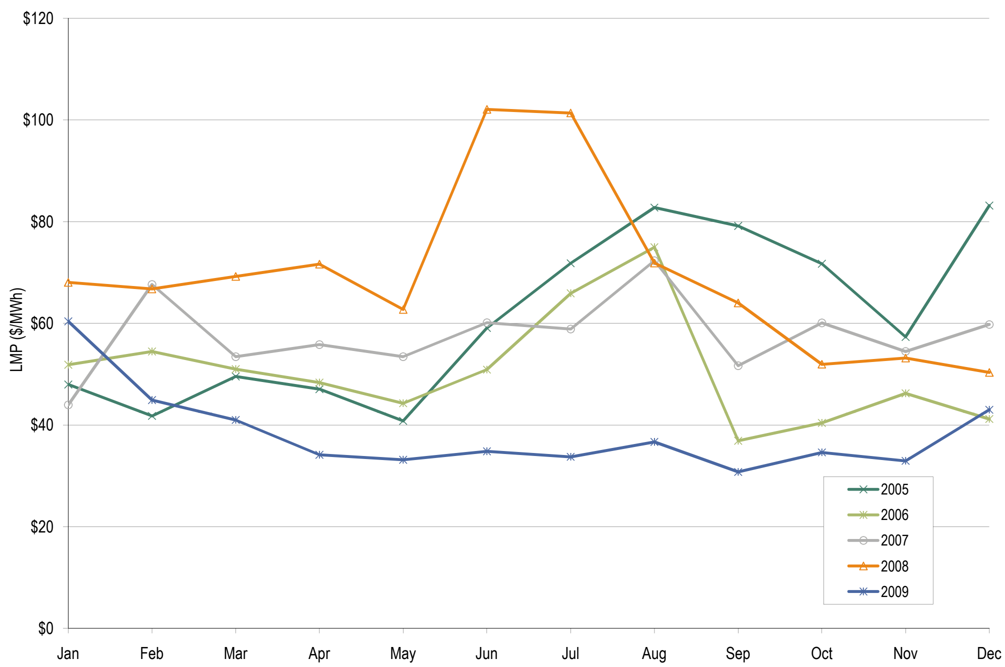
Table 2-68 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2000 to 2009

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2000	$35.12	$28.50	$22.26	NA	NA	NA
2001	$36.01	$29.02	$37.48	2.5%	1.8%	68.3%
2002	$31.80	$26.00	$20.68	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	45.8%	30.4%	94.3%
2006	$51.33	$46.72	$26.45	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	(44.7%)	(41.7%)	(57.7%)

PJM Day-Ahead, Monthly, Load-Weighted, Average LMP

Figure 2-18 shows the PJM day-ahead, monthly, load-weighted LMP from 2005 through 2009.

Figure 2-18 Day-ahead, monthly, load-weighted, average LMP: Calendar years 2005 to 2009



Zonal Day-Ahead, Annual, Load-Weighted LMP

Table 2-69 shows PJM's zonal day-ahead, load-weighted, average LMPs for 2008 and 2009. The largest zonal decrease was in the AECO Control Zone which experienced a $45.23, or 51.0 percent, decrease from 2008, and the smallest decrease was in the DLCO Control Zone which experienced a $20.95, or 38.6 percent, decrease from 2008.

Table 2-69 Zonal day-ahead, load-weighted, average LMP (Dollars per MWh): Calendar years 2008 to 2009

	2008	2009	Difference	Difference as Percent of 2008
AECO	$88.77	$43.54	($45.23)	(51.0%)
AEP	$56.48	$34.92	($21.56)	(38.2%)
AP	$67.94	$39.97	($27.97)	(41.2%)
BGE	$87.50	$44.94	($42.56)	(48.6%)
ComEd	$53.83	$30.09	($23.74)	(44.1%)
DAY	$57.04	$34.38	($22.66)	(39.7%)
DLCO	$54.33	$33.37	($20.95)	(38.6%)
Dominion	$81.98	$43.16	($38.82)	(47.3%)
DPL	$84.24	$44.15	($40.09)	(47.6%)
JCPL	$86.65	$43.51	($43.14)	(49.8%)
Met-Ed	$79.88	$42.72	($37.16)	(46.5%)
PECO	$81.44	$42.80	($38.64)	(47.4%)
PENELEC	$67.56	$38.50	($29.06)	(43.0%)
Pepco	$86.36	$44.83	($41.53)	(48.1%)
PPL	$78.08	$42.32	($35.76)	(45.8%)
PSEG	$85.82	$43.70	($42.12)	(49.1%)
RECO	$84.73	$43.24	($41.49)	(49.0%)

Day-Ahead, Annual, Load-Weighted, Average LMP by Jurisdiction

Table 2-70 shows PJM's day-ahead, load-weighted, average LMP for 2008 and 2009 by jurisdiction. The largest decrease was in New Jersey which experienced a $42.79, or 49.5 percent, decrease from 2008, and the smallest decrease was in Kentucky which experienced a $20.77, or 37.1 percent, decrease from 2008.

Table 2-70 Jurisdiction day-ahead, load weighted LMP (Dollars per MWh): Calendar years 2008 to 2009

	2008	2009	Difference	Difference as Percent of 2008
Delaware	$82.99	$43.36	($39.62)	(47.7%)
Illinois	$53.83	$30.09	($23.74)	(44.1%)
Indiana	$56.53	$33.89	($22.64)	(40.0%)
Kentucky	$56.02	$35.25	($20.77)	(37.1%)
Maryland	$85.98	$44.90	($41.08)	(47.8%)
Michigan	$57.83	$35.08	($22.75)	(39.3%)
New Jersey	$86.39	$43.60	($42.79)	(49.5%)
North Carolina	$78.13	$41.93	($36.19)	(46.3%)
Ohio	$55.72	$34.22	($21.50)	(38.6%)
Pennsylvania	$73.58	$40.69	($32.89)	(44.7%)
Tennessee	$56.50	$35.51	($20.99)	(37.1%)
Virginia	$78.63	$42.40	($36.23)	(46.1%)
West Virginia	$57.56	$36.04	($21.52)	(37.4%)
District of Columbia	$85.66	$45.86	($39.80)	(46.5%)

Components of Day-Ahead, Load-Weighted LMP

Observed LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal units generally determine system LMPs, based on their offers. Those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder and the 10 percent cost offer adder. As a result, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal. Spot fuel prices were used, and emission costs were calculated using spot prices for NO_x, SO_2 and CO_2 emission credits and unit-specific emission rates. The emission costs for NO_x are applicable for the May to September ozone season and the emission costs for SO_2 are applicable throughout the year. The CO_2 emission costs are applicable to PJM units in PJM's RGGI participating states: Delaware, Maryland and New Jersey.

Table 2-71 Components of PJM day-ahead, annual, load-weighted, average LMP (Dollars per MWh): Calendar year 2009

Element	Contribution to LMP	Percent
DEC	$11.97	30.8%
INC	$11.65	30.0%
Coal	$8.73	22.5%
Natural Gas	$2.82	7.3%
Price Sensitive Demand	$1.38	3.6%
10% Cost Adder	$1.34	3.4%
VOM	$0.88	2.3%
Transaction	$0.81	2.1%
NO_x	$0.32	0.8%
SO_2	$0.30	0.8%
CO_2	$0.19	0.5%
Oil	$0.13	0.3%
Diesel	$0.00	0.0%
Constrained Off	$0.00	0.0%
FMU Adder	$0.00	0.0%
NA	($0.05)	(0.1%)
Markup	($1.65)	(4.2%)
Total	$38.82	100.0%

Marginal Losses

Marginal losses are the incremental change in system real power losses caused by changes in the system load and generation patterns.[49] Before June 1, 2007, the PJM economic dispatch and LMP models did not include marginal losses. The losses were treated as a static component of load, and the physical nature and location of power system losses were ignored. The PJM Tariff required implementation of marginal loss modeling when required technical systems became available. On June 1, 2007, PJM began including marginal losses in economic dispatch and LMP models.[50] The primary benefit of a marginal loss mechanism is that it more accurately models the physical reality of power system losses. More accurate models permit increased efficiency and optimize asset utilization. One characteristic of marginal loss modeling is that it creates a separate marginal loss price for every location on the power grid.

Table 2-72 shows the PJM real-time, simple average LMP components, including the loss component, for calendar years 2006 to 2009. As of June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While there is no effect on the total LMP, the components of LMP change with a shift in the reference bus. With a distributed load reference bus, the energy component is now a load-weighted system price. In turn, this means that there is no congestion

49 For additional information, see the *2009 State of the Market Report for PJM*, Volume II, Appendix J, "Marginal Losses."
50 For additional information, see PJM. "Open Access Transmission Tariff" (December 10, 2007), Section 3.4, Original Sheet No. 388G.

or losses included at the PJM price, unlike the case with a single node reference bus. The energy price equals the PJM price in a given hour and on a yearly average basis. Table 2-72 shows a $0.03 loss component included at the PJM price. The PJM price is weighted with accounting load, which differs from the state-estimated load used in determination of the energy component. The $0.03 loss component of the average PJM system price results from these different weights. The $2.08 and $1.00 congestion component of the average PJM system price for 2006 and 2007 respectively, resulted from the fact that the distributed load reference bus did not go into effect until June 1, 2007.

Table 2-72 PJM real-time, simple average LMP components (Dollars per MWh): Calendar years 2006 to 2009

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2006	$49.27	$47.19	$2.08	$0.00
2007	$57.58	$56.56	$1.00	$0.02
2008	$66.40	$66.30	$0.06	$0.04
2009	$37.08	$37.01	$0.05	$0.03

Table 2-73 shows the zonal real-time, simple average LMP components, including the loss component, for calendar years 2008 and 2009.

Table 2-73 Zonal real-time, simple average LMP components (Dollars per MWh): Calendar years 2008 to 2009

	2008				2009			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$80.70	$66.29	$10.77	$3.64	$40.68	$37.01	$1.83	$1.84
AEP	$53.42	$66.29	($10.46)	($2.42)	$33.63	$37.01	($2.16)	($1.22)
AP	$65.85	$66.29	$0.29	($0.73)	$38.29	$37.01	$1.32	($0.03)
BGE	$80.05	$66.29	$11.06	$2.69	$41.71	$37.01	$3.04	$1.67
ComEd	$49.38	$66.29	($13.46)	($3.46)	$29.05	$37.01	($5.61)	($2.35)
DAY	$53.68	$66.29	($11.18)	($1.43)	$33.49	$37.01	($2.72)	($0.79)
DLCO	$48.81	$66.29	($14.47)	($3.01)	$32.73	$37.01	($3.02)	($1.26)
Dominion	$75.87	$66.29	$8.76	$0.82	$40.00	$37.01	$2.37	$0.62
DPL	$77.20	$66.29	$7.69	$3.21	$41.23	$37.01	$2.32	$1.91
JCPL	$78.80	$66.29	$8.64	$3.87	$40.93	$37.01	$2.01	$1.91
Met-Ed	$74.70	$66.29	$6.51	$1.90	$39.94	$37.01	$2.03	$0.90
PECO	$75.07	$66.29	$6.11	$2.67	$40.00	$37.01	$1.71	$1.28
PENELEC	$63.37	$66.29	($2.33)	($0.59)	$36.85	$37.01	($0.06)	($0.09)
Pepco	$80.45	$66.29	$12.40	$1.76	$41.88	$37.01	$3.74	$1.13
PPL	$73.35	$66.29	$5.50	$1.55	$39.44	$37.01	$1.75	$0.68
PSEG	$79.14	$66.29	$8.92	$3.92	$41.27	$37.01	$2.27	$2.00
RECO	$77.46	$66.29	$7.62	$3.54	$40.36	$37.01	$1.55	$1.80

Table 2-74 shows the real-time, annual, simple average LMP loss component at the PJM hubs for 2009, for each hub in PJM.

Table 2-74 Hub real-time, simple average LMP components (Dollars per MWh): Calendar year 2009

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$31.83	$37.01	($2.82)	($2.35)
AEP-DAY Hub	$33.23	$37.01	($2.40)	($1.38)
Chicago Gen Hub	$28.28	$37.01	($5.90)	($2.82)
Chicago Hub	$29.25	$37.01	($5.43)	($2.33)
Dominion Hub	$39.27	$37.01	$2.00	$0.26
Eastern Hub	$41.23	$37.01	$2.14	$2.08
N Illinois Hub	$28.85	$37.01	($5.62)	($2.53)
New Jersey Hub	$41.04	$37.01	$2.12	$1.91
Ohio Hub	$33.24	$37.01	($2.42)	($1.34)
West Interface Hub	$34.66	$37.01	($1.20)	($1.15)
Western Hub	$38.30	$37.01	$1.42	($0.12)

Zonal and PJM Real-Time, Annual, Load-Weighted, Average LMP Components

Table 2-75 shows the real-time, annual, load-weighted, average LMP components, for PJM and its 17 control zones for 2009.

Table 2-75 Zonal and PJM real-time, annual, load-weighted, average LMP components (Dollars per MWh): Calendar year 2009

	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$42.55	$38.60	$1.98	$1.97
AEP	$35.20	$39.03	($2.53)	($1.30)
AP	$40.59	$39.24	$1.41	($0.06)
BGE	$44.28	$39.07	$3.43	$1.78
ComEd	$30.69	$38.59	($5.50)	($2.40)
DAY	$35.11	$39.02	($3.12)	($0.79)
DLCO	$33.86	$38.59	($3.38)	($1.35)
Dominion	$42.67	$39.24	$2.78	$0.65
DPL	$44.05	$39.25	$2.71	$2.09
JCPL	$43.26	$39.02	$2.18	$2.06
Met-Ed	$42.32	$39.08	$2.27	$0.97
PECO	$42.03	$38.80	$1.87	$1.36
PENELEC	$38.57	$38.87	($0.18)	($0.11)
Pepco	$44.50	$38.96	$4.36	$1.18
PPL	$42.10	$39.31	$2.02	$0.77
PSEG	$43.08	$38.57	$2.41	$2.10
RECO	$42.41	$38.82	$1.68	$1.91
PJM	$39.05	$38.97	$0.05	$0.03

Table 2-76 shows the PJM day-ahead, simple average LMP components, including the loss component, for calendar years 2006 through 2009. As of June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While there is no effect on the total LMP, the components of LMP change with a shift in the reference bus. With a distributed load reference bus, the energy component is now a load-weighted system price. In turn, this means that there is no congestion or losses included at the PJM price, unlike the case with a single node reference bus. The energy price equals the PJM price in a given hour and on a yearly average basis. In the Day-Ahead Energy Market, the distributed load reference bus is weighted with fixed-demand bids only and the day-ahead energy component is, therefore, a system fixed-demand-weighted price. The day-ahead system price calculation uses all types of demand, including fixed, price-sensitive and decrement bids. In the Real-Time Energy Market, the energy component equals the system load-weighted price; however, in the Day-Ahead Energy Market the energy component and the PJM system price are not equal, but the loss component and the congestion component have only a small effect. This is due to the use of all types of demand to weight the PJM price and not fixed demand only.

Table 2-76 PJM day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2006 to 2009

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2006	$48.10	$46.45	$1.65	$0.00
2007	$54.67	$54.60	$0.25	($0.18)
2008	$66.12	$66.43	($0.10)	($0.21)
2009	$37.00	$37.15	($0.06)	($0.09)

Table 2-77 shows the zonal day-ahead, simple average LMP components, including the loss component, for calendar years 2008 and 2009.[51]

Table 2-77 Zonal day-ahead, simple average LMP components (Dollars per MWh): Calendar years 2008 to 2009.

	2008				2009			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$78.99	$66.43	$7.93	$4.63	$41.44	$37.15	$2.03	$2.26
AEP	$53.61	$66.43	($9.56)	($3.26)	$33.44	$37.15	($2.12)	($1.59)
AP	$65.09	$66.43	($0.50)	($0.84)	$37.80	$37.15	$0.62	$0.03
BGE	$80.70	$66.43	$10.96	$3.31	$42.57	$37.15	$3.33	$2.08
ComEd	$50.50	$66.43	($11.37)	($4.56)	$28.94	$37.15	($5.09)	($3.12)
DAY	$53.53	$66.43	($10.04)	($2.86)	$32.94	$37.15	($2.77)	($1.45)
DLCO	$50.92	$66.43	($11.77)	($3.73)	$32.33	$37.15	($3.37)	($1.46)
Dominion	$75.60	$66.43	$8.07	$1.10	$40.58	$37.15	$2.47	$0.96
DPL	$77.95	$66.43	$7.63	$3.90	$41.73	$37.15	$2.25	$2.33
JCPL	$79.74	$66.43	$7.92	$5.39	$41.36	$37.15	$1.82	$2.39
Met-Ed	$75.54	$66.43	$6.59	$2.53	$40.35	$37.15	$2.10	$1.10
PECO	$76.23	$66.43	$5.93	$3.87	$40.79	$37.15	$1.87	$1.78
PENELEC	$65.11	$66.43	($0.91)	($0.41)	$37.09	$37.15	($0.10)	$0.03
Pepco	$81.26	$66.43	$12.28	$2.55	$42.54	$37.15	$3.75	$1.64
PPL	$74.25	$66.43	$5.62	$2.20	$39.90	$37.15	$1.88	$0.86
PSEG	$79.77	$66.43	$7.76	$5.58	$41.84	$37.15	$2.12	$2.57
RECO	$78.08	$66.43	$6.55	$5.10	$40.92	$37.15	$1.47	$2.30

51 For some zones, energy component plus congestion component plus loss component may not equal the total day-ahead LMP because the total is based on the underlying data, which is not rounded.

Zonal and PJM Day-Ahead, Annual, Load-Weighted, Average LMP Components

Table 2-78 shows zonal and PJM day-ahead, annual, load-weighted, average LMP components for calendar year 2009.

Table 2-78 Zonal and PJM day-ahead, load-weighted, average LMP components (Dollars per MWh): Calendar year 2009

	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$43.54	$38.85	$2.26	$2.43
AEP	$34.92	$39.15	($2.53)	($1.70)
AP	$39.97	$39.44	$0.51	$0.02
BGE	$44.94	$39.01	$3.71	$2.22
ComEd	$30.09	$38.38	($5.09)	($3.20)
DAY	$34.38	$39.11	($3.20)	($1.52)
DLCO	$33.37	$38.62	($3.69)	($1.55)
Dominion	$43.16	$39.27	$2.87	$1.03
DPL	$44.15	$39.10	$2.56	$2.49
JCPL	$43.51	$38.99	$1.99	$2.52
Met-Ed	$42.72	$39.16	$2.38	$1.18
PECO	$42.80	$38.87	$2.05	$1.88
PENELEC	$38.50	$38.64	($0.19)	$0.04
Pepco	$44.83	$38.80	$4.29	$1.73
PPL	$42.32	$39.21	$2.14	$0.96
PSEG	$43.70	$38.75	$2.26	$2.69
RECO	$43.24	$39.21	$1.60	$2.44
PJM	$38.82	$38.96	($0.04)	($0.09)

Marginal Loss Accounting

With the implementation of marginal loss pricing, PJM calculates transmission loss charges for each PJM member. The loss charge is based on the applicable day-ahead and real-time loss component of LMP (loss LMP). Each PJM member is charged for the cost of losses on the transmission system, based on the difference between the loss LMP at the location where the PJM member injects energy and the loss LMP where the PJM member withdraws energy.

More specifically, total loss charges are equal to the load loss payments minus generation loss credits, plus explicit loss charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

- **Day-Ahead, Load Loss Payments.** Day-ahead, load loss payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. (Decrement bids and energy sales can be thought of as scheduled load.) Day-ahead, load loss payments are calculated using MW and the load bus loss component of LMP (loss LMP), the decrement bid loss LMP or the loss LMP at the source of the sale transaction, as applicable.

- **Day-Ahead, Generation Loss Credits.** Day-ahead, generation loss credits are calculated for all cleared generation and increment offers and Day-Ahead Energy Market purchase transactions. (Increment offers and energy purchases can be thought of as scheduled generation.) Day-ahead, generation loss credits are calculated using MW and the generator bus loss LMP, the increment offer loss LMP or the loss LMP at the sink of the purchase transaction, as applicable.

- **Balancing, Load Loss Payments.** Balancing, load loss payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing, load loss payments are calculated using MW deviations and the real-time loss LMP for each bus where a deviation exists.

- **Balancing, Generation, Loss Credits.** Balancing, generation loss credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing, generation loss credits are calculated using MW deviations and the real-time loss LMP for each bus where a deviation exists.

- **Explicit Loss Charges.** Explicit loss charges are the net loss charges associated with point-to-point energy transactions. These charges equal the product of the transacted MW and loss LMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit loss charges equal the product of the differences between the real-time and day-ahead transacted MW and the differences between the real-time loss LMP at the transactions' sources and sinks.

Monthly Marginal Loss Costs

Table 2-79 shows a monthly summary of marginal loss costs by type for 2009. Marginal loss costs totaled $1.268 billion. The highest monthly loss cost was in January and totaled $207.3 million or 16.3 percent of the total. The majority of the marginal loss costs was in the Day-Ahead Energy Market and totaled $1.293 billion. The day-ahead costs were offset, in part, by a total of -$24.5 million in the balancing market. The overcollected portion of transmission losses that was credited back to load plus exports as of December 31, 2009, was $639.7 million or 50.8 percent of the total losses. In determining the overcollected loss amount, PJM accumulates the day-ahead and balancing transmission loss charges paid by all customer accounts each hour, subtracts the spot market energy value of the actual transmission loss MWh during that hour, and allocates this amount as transmission loss credits each hour.[52]

52 See PJM. "Manual 28: Operating Agreement Accounting," Revision 39 (January 1, 2008). Note that the overcollection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

Table 2-79 Marginal loss costs by type (Dollars (Millions)): Calendar year 2009

	Marginal Loss Costs (Millions)								
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
Jan	$52.4	($143.8)	$14.2	$210.5	$1.0	($2.6)	($6.8)	($3.2)	$207.3
Feb	$35.9	($88.8)	$8.2	$132.9	($0.3)	($1.2)	($4.2)	($3.2)	$129.7
Mar	$34.9	($78.6)	$8.5	$122.0	($0.8)	($1.3)	($5.3)	($4.8)	$117.2
Apr	$22.2	($59.5)	$5.9	$87.6	($1.3)	($0.1)	($3.7)	($4.9)	$82.6
May	$20.3	($53.6)	$4.6	$78.5	($0.5)	($0.4)	($2.5)	($2.5)	$76.0
Jun	$18.6	($71.2)	$3.1	$92.9	($0.5)	($1.5)	($1.5)	($0.6)	$92.3
Jul	$22.8	($70.4)	$3.1	$96.3	($0.1)	($1.6)	($0.8)	$0.8	$97.0
Aug	$27.4	($87.0)	$3.3	$117.7	($0.1)	($0.9)	($1.2)	($0.3)	$117.4
Sep	$17.1	($55.6)	$2.2	$74.9	($1.0)	($0.5)	($1.2)	($1.7)	$73.2
Oct	$14.4	($51.8)	$3.8	$69.9	($0.5)	($0.5)	($3.0)	($2.9)	$67.0
Nov	$22.0	($53.8)	$3.7	$79.6	$0.0	($0.7)	($1.7)	($1.0)	$78.6
Dec	$31.9	($93.3)	$4.8	$129.9	($0.1)	($1.7)	($1.7)	($0.1)	$129.8
Total	$319.9	($907.3)	$65.4	$1,292.6	($4.1)	($13.0)	($33.5)	($24.5)	$1,268.1

Zonal Marginal Loss Costs

Table 2-80 shows the marginal loss costs by type in each control zone in 2009. The ComEd, AEP and Dominion control zones had the highest marginal loss costs in 2009, with $264.6 million, $214.8 million and $132.9 million, respectively. Energy flows in PJM are generally from west to east, reflecting the fact that less expensive generation in the western portion of PJM is dispatched to assist in meeting the demand of load centers located in the eastern portion of PJM. Generation supplied from western resources to satisfy eastern load generally results in increased west-to-east transmission flow and increased losses. As may be seen in Table 2-80, the marginal loss generation credits in the western zones are generally greaeter in magnitude than those of the eastern zones. The characteristics of the marginal loss component of LMP are analogous to those of the congestion component of LMP, or CLMP. Generation congestion credits are generally negative for units located on the unconstrained side of a transmission element, indicating that an increase in output tends to increase the flow of energy across the constrained element. Analogously, the generation marginal loss credits are generally negative for units for which an increase in output tends to increase system losses.

Table 2-80 Marginal loss costs by control zone and type (Dollars (Millions)): Calendar year 2009

	Marginal Loss Costs by Control Zone (Millions)								
	Day Ahead				Balancing				
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$25.9	$5.2	$0.2	$21.0	$0.3	($0.2)	$0.1	$0.5	$21.5
AEP	($49.5)	($247.3)	$18.7	$216.6	($0.6)	($0.5)	($1.6)	($1.7)	$214.8
AP	$2.8	($79.2)	$6.9	$88.8	$2.6	$3.8	($2.7)	($3.9)	$84.9
BGE	$57.9	$13.9	$1.7	$45.7	$2.8	($1.9)	($1.3)	$3.3	$49.0
ComEd	($157.3)	($419.4)	($0.3)	$261.8	$0.2	($2.1)	$0.4	$2.8	$264.6
DAY	($4.4)	($56.1)	$1.3	$53.0	($0.3)	$2.4	$0.1	($2.6)	$50.4
DLCO	($21.3)	($41.9)	$0.1	$20.7	($2.2)	$0.1	($0.0)	($2.3)	$18.4
DPL	$49.7	$11.0	$0.5	$39.1	($2.6)	($1.4)	($0.3)	($1.5)	$37.6
Dominion	$84.7	($41.8)	$4.2	$130.7	$2.1	($1.9)	($1.8)	$2.2	$132.9
JCPL	$59.2	$21.8	$0.2	$37.5	$0.2	($2.2)	($0.2)	$2.2	$39.7
Met-Ed	$18.2	$3.5	$0.2	$14.9	$0.1	($0.5)	($0.1)	$0.5	$15.4
PECO	$59.0	$12.9	$0.0	$46.1	($0.5)	($0.7)	($0.0)	$0.2	$46.3
PENELEC	($13.1)	($77.8)	$0.4	$65.0	($2.3)	($0.3)	($0.1)	($2.0)	$63.0
Pepco	$81.2	$35.5	$2.4	$48.1	($2.2)	($2.5)	($1.7)	($1.4)	$46.8
PJM	($7.6)	($42.8)	$21.6	$56.8	($0.5)	($11.7)	($19.4)	($8.2)	$48.6
PPL	$36.7	($23.0)	$1.4	$61.1	($0.1)	$1.0	$0.2	($0.9)	$60.2
PSEG	$94.3	$18.2	$5.9	$82.1	($1.0)	$5.6	($5.0)	($11.6)	$70.5
RECO	$3.4	$0.1	$0.1	$3.5	$0.1	($0.1)	($0.1)	$0.0	$3.5
Total	$319.9	($907.3)	$65.4	$1,292.6	($4.1)	($13.0)	($33.5)	($24.5)	$1,268.1

Table 2-81 shows the monthly marginal loss cost, by control zone in 2009.

Table 2-81 Monthly marginal loss costs by control zone (Dollars (Millions)): Calendar year 2009

	Marginal Loss Costs by Control Zone (Millions)												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Grand Total
AECO	$3.4	$2.0	$1.7	$1.7	$1.2	$1.3	$2.0	$2.7	$1.2	$0.9	$1.3	$2.1	$21.5
AEP	$32.6	$22.9	$18.6	$13.1	$11.7	$17.5	$15.0	$21.9	$13.4	$11.0	$12.9	$24.1	$214.8
AP	$18.0	$9.4	$8.4	$6.2	$4.8	$5.4	$5.0	$7.5	$3.3	$3.6	$4.7	$8.7	$84.9
BGE	$7.0	$4.4	$4.2	$2.6	$2.8	$3.4	$4.1	$5.2	$3.4	$2.8	$3.8	$5.2	$49.0
ComEd	$36.3	$26.1	$28.0	$19.4	$16.9	$18.4	$19.3	$21.2	$16.1	$17.1	$19.4	$26.4	$264.6
DAY	$7.8	$4.6	$4.5	$3.3	$2.2	$3.7	$3.9	$4.4	$3.5	$3.9	$4.6	$4.1	$50.4
DLCO	$3.5	$1.9	$2.1	$1.2	$0.7	$1.6	$1.6	$1.4	$1.3	$0.3	$0.6	$2.2	$18.4
DPL	$6.8	$4.3	$4.0	$2.9	$2.4	$2.2	$3.0	$3.4	$2.1	$1.4	$1.8	$3.2	$37.6
Dominion	$20.2	$11.8	$11.1	$7.0	$8.2	$11.5	$12.2	$14.3	$8.2	$6.8	$7.6	$13.7	$132.9
JCPL	$8.3	$5.6	$3.7	$2.4	$2.1	$1.8	$2.5	$3.3	$1.4	$1.5	$2.0	$5.1	$39.7
Met-Ed	$2.4	$1.4	$1.2	$0.9	$0.8	$1.4	$1.4	$1.6	$1.1	$0.9	$0.6	$1.8	$15.4
PECO	$8.0	$4.3	$3.5	$2.6	$2.9	$4.1	$4.1	$5.6	$3.4	$2.3	$2.0	$3.6	$46.3
PENELEC	$12.1	$5.6	$4.3	$4.1	$5.0	$5.6	$5.9	$6.0	$3.2	$3.1	$2.8	$5.4	$63.0
Pepco	$6.0	$3.6	$4.3	$3.1	$2.8	$3.7	$4.1	$5.0	$3.2	$2.9	$3.5	$4.5	$46.8
PJM	$14.1	$6.0	$4.8	$2.0	$3.2	$1.3	$2.6	$2.2	$0.8	$1.2	$3.1	$7.4	$48.6
PPL	$10.1	$6.5	$5.5	$3.8	$3.0	$4.5	$4.9	$5.1	$3.6	$3.6	$3.6	$6.1	$60.2
PSEG	$10.1	$8.8	$7.1	$6.0	$5.1	$4.9	$5.3	$6.1	$4.0	$3.4	$4.1	$5.7	$70.5
RECO	$0.6	$0.4	$0.3	$0.3	$0.2	$0.2	$0.2	$0.3	$0.2	$0.2	$0.2	$0.4	$3.5
Total	$207.3	$129.7	$117.2	$82.6	$76.0	$92.3	$97.0	$117.4	$73.2	$67.0	$78.6	$129.8	$1,268.1

Virtual Offers and Bids

The PJM Day-Ahead Energy Market includes the ability to make increment offers (INC) and decrement bids (DEC) at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. Since increment offers and decrement bids do not require physical generation or load, they are also referred to as virtual offers and bids. Virtual offers and bids also provide participants the flexibility, for example, to cover one side of a bilateral transaction, hedge day-ahead generator offers or demand bids, and arbitrage day-ahead and real-time prices.

There is a substantial volume of virtual offers and bids in the PJM Day-Ahead Market and such offers and bids may each be marginal, based on the way in which the optimization algorithm works.

Any market participant in the PJM Day-Ahead Energy Market can use increment offers and decrement bids as financial instruments that do not require physical generation or load. Increment offers and decrement bids may be submitted at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. Table 2-82 shows the average volume of trading in virtual bids per hour, as well as the average total MW values of all virtual bids per hour.

Table 2-82 Monthly volume of cleared and submitted INCs, DECs: Calendar year 2009

	Increment Offers				Decrement Bids			
	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
Jan	13,986	21,401	423	621	16,879	26,080	487	670
Feb	13,487	22,228	484	739	15,557	24,967	420	624
Mar	13,364	22,639	552	820	15,186	23,243	459	651
Apr	11,363	19,935	380	645	13,900	21,173	428	607
May	12,853	16,863	388	750	13,973	19,274	529	805
Jun	12,375	15,369	315	750	14,777	18,402	482	802
Jul	12,187	17,654	314	821	14,554	19,322	483	808
Aug	12,347	22,931	433	1,020	16,626	23,788	641	1,069
Sep	13,936	22,449	459	993	16,736	23,285	480	957
Oct	13,178	26,649	467	1,246	15,705	26,058	364	1,041
Nov	12,914	22,725	366	903	14,976	22,266	289	726
Dec	11,679	23,958	275	850	14,998	26,715	270	862
Annual	12,873	21,233	405	847	15,322	22,881	444	804

Table 2-83 shows the frequency with which generation offers, import or export transactions, decrement bids, increment offers and price-sensitive demand are marginal for each month in 2009.[53] Together, increment offers and decrement bids represented 51.4 percent of the marginal bids or offers in 2009.

Table 2-83 Type of day-ahead marginal units: Calendar year 2009

	Generation	Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	20.6%	32.2%	33.3%	13.0%	1.0%
Feb	17.4%	38.8%	28.5%	14.6%	0.8%
Mar	14.9%	39.8%	27.6%	17.0%	0.7%
Apr	16.2%	38.7%	28.6%	16.0%	0.5%
May	12.2%	38.5%	29.1%	19.0%	1.2%
Jun	17.3%	30.7%	27.2%	24.0%	0.8%
Jul	12.4%	34.8%	31.2%	20.9%	0.7%
Aug	11.5%	29.4%	36.5%	22.2%	0.4%
Sep	12.8%	33.3%	25.7%	27.5%	0.6%
Oct	9.3%	32.8%	22.7%	34.6%	0.6%
Nov	16.3%	28.8%	27.0%	27.4%	0.6%
Dec	16.2%	20.6%	43.1%	19.0%	1.1%
Annual	14.7%	33.2%	30.1%	21.3%	0.7%

53 These percentages compare the number of times that bids and offers of the specified type were marginal to the total number of marginal bids and offers. There is no weighting by time or by load.

In order to evaluate the ownership of virtual bids, the MMU categorized all participants owning virtual bids 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. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 2-84 shows virtual bids by the type of bid parent organization: financial or physical player.

Table 2-84 PJM virtual bids by type of bid parent organization (MW): Calendar year 2009

	Category	Total Virtual Bids MW	Percentage
2009	Financial	106,470,151	31.8%
2009	Physical	228,583,038	68.2%
2009	Total	335,053,190	100%

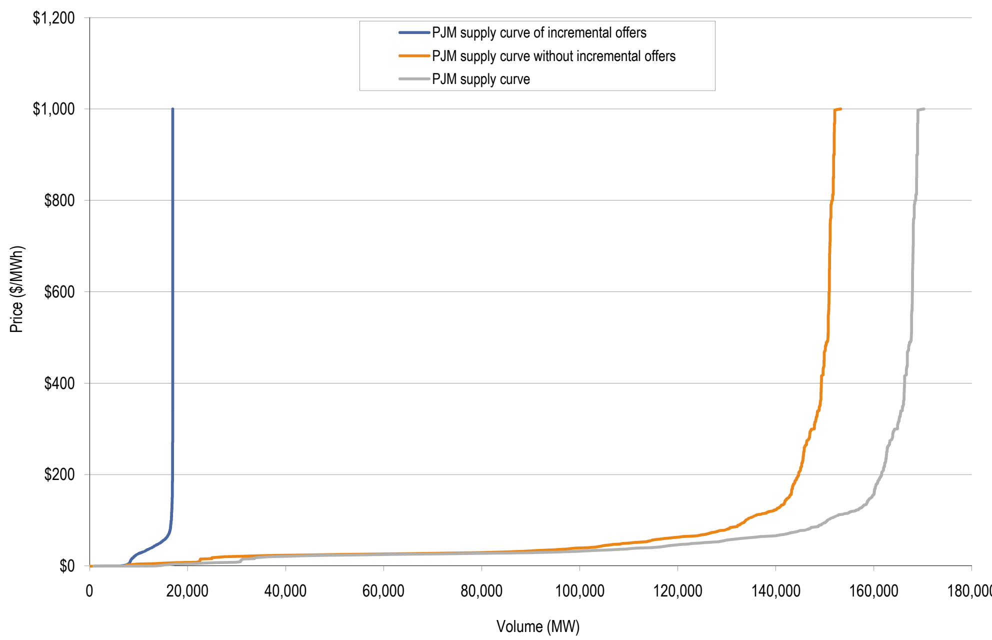
Table 2-85 shows virtual bids bid by top ten aggregates.

Table 2-85 PJM virtual bids by top ten aggregates (MW): Calendar year 2009

Aggregate Name	Aggregate Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	6,670,457	7,825,323	14,495,780
N ILLINOIS HUB	HUB	3,348,214	1,896,015	5,244,229
AEP-DAYTON HUB	HUB	1,161,223	1,546,752	2,707,976
ComEd	ZONE	214,326	1,240,075	1,454,401
PSEG	ZONE	238,864	1,120,509	1,359,373
MISO	INTERFACE	499,015	594,096	1,093,112
JCPL	ZONE	415,840	564,987	980,828
SOUTHIMP	INTERFACE	843,985	0	843,985
IMO	INTERFACE	805,834	12,185	818,019
NYIS	INTERFACE	184,642	491,293	675,935

Figure 2-19 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve without increment offers and the system aggregate supply curve with increment offers for an example day in May 2009. There were average hourly increment offers of 16,981 MW and average hourly total offers of 170,202 MW for the example day.

Figure 2-19 PJM day-ahead aggregate supply curves: 2009 example day



Price Convergence

When the PJM Day-Ahead Energy Market was introduced, it was expected that competition, exercised substantially through the use of virtual offers and bids, would tend to cause prices in the Day-Ahead and Real-Time Energy Markets to converge. But price convergence does not necessarily mean a zero or even a very small difference in prices between Day-Ahead and Real-Time Energy Markets. There may be factors, from operating reserve charges to risk that result in a competitive, market-based differential. In addition, convergence in the sense that Day-Ahead and Real-Time prices are equal at individual buses or aggregates is not a realistic expectation. PJM markets do not provide a mechanism that could result in convergence within any individual day as there is at least a one-day lag after any change in system conditions. As a general matter, virtual offers and bids are based on expectations about both Day-Ahead and Real-Time Market conditions and reflect the uncertainty about conditions in both markets and the fact that these conditions change hourly and daily. Substantial, virtual trading activity does not guarantee that market power cannot be exercised in the Day-Ahead Energy Market. Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. (See Figure 2-20) There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis. (See Figure 2-21)

As Table 2-86 shows, day-ahead and real-time prices were relatively close, on average, during 2009. The simple annual average LMP in the Real-Time Energy Market was $0.08 per MWh or 0.2 percent higher than the simple annual average LMP in the Day-Ahead Energy Market during 2009.

Table 2-86 Day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar year 2009

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
Average	$37.00	$37.08	$0.08	0.2%
Median	$35.16	$32.71	($2.45)	(7.5%)
Standard deviation	$13.39	$17.12	$3.73	21.8%

The price difference between the Real-Time and the Day-Ahead Energy Markets results, in part, from volatility in the Real-Time Energy Market that is difficult, or impossible, to anticipate in the Day-Ahead Energy Market. In 2009, the real-time, load-weighted, hourly LMPs were higher than day-ahead, load-weighted, hourly LMPs by more than $50 per MWh for 46 hours, more than $100 per MWh for 5 hours and more than $150 per MWh for 0 hours. Although real-time prices were higher than day-ahead prices on average in 2009, real-time prices were lower than day-ahead prices for 58.3 percent of the hours. During hours when real-time prices were higher than day-ahead prices, the average positive difference between them was $7.33 per MWh, which is much greater than the difference, $0.08, when all hours are included. During hours when real-time prices were less than day-ahead prices, the average negative difference was -$5.09 per MWh.

Table 2-87 shows the difference between the Real-Time and the Day-Ahead Energy Market Prices from 2000 to 2009. From 2000 to 2003, the real-time simple annual average LMP was lower than the day-ahead simple annual average LMP. Since 2004, the real-time simple annual average LMP has been higher than the day-ahead simple annual average LMP.[54]

Table 2-87 Day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar years 2000 to 2009

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
2000	$31.97	$30.36	($1.61)	(5.3%)
2001	$32.75	$32.38	($0.37)	(1.1%)
2002	$28.46	$28.30	($0.16)	(0.6%)
2003	$38.73	$38.28	($0.45)	(1.2%)
2004	$41.43	$42.40	$0.97	2.3%
2005	$57.89	$58.08	$0.18	0.3%
2006	$48.10	$49.27	$1.17	2.4%
2007	$54.67	$57.58	$2.90	5.0%
2008	$66.12	$66.40	$0.28	0.4%
2009	$37.00	$37.08	$0.08	0.2%

54 Since the Day-Ahead Energy Market starts from June 1, 2000, the data in 2000 starts from June 1, 2000. However, the starting date for years 2001 to 2008 is January 1.

Table 2-88 provides frequency distributions of the differences between PJM real-time load-weighted hourly LMP and PJM day-ahead load-weighted hourly LMP for calendar years 2005 through 2009. The table shows the number of hours (frequency) and the cumulative percent of hours (cumulative percent) when the hourly LMP difference was within a given $50 per MWh price interval. From calendar year 2005 to calendar year 2009, LMP differences occurred predominantly in the range between -$50 per MWh and $50 per MWh. The largest PJM real-time and day-ahead load-weighted hourly LMP difference occurred in the calendar year of 2006 where an hourly price difference was greater than $500 per MWh. In 2007, the PJM real-time and day-ahead load-weighted hourly LMP differences are less than $150 per MWh in all but 14 hours. In 2008, the PJM real-time and day-ahead load-weighted hourly LMP differences are less than $150 per MWh in all but 7 hours. In 2009, the PJM real-time and day-ahead load-weighted hourly LMP differences were less than $100 per MWh in all but 5 hours.

Table 2-88 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): Calendar years 2005 to 2009

	2005		2006		2007		2008		2009	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	0	0.00%	1	0.01%	0	0.00%	0	0.00%	0	0.00%
($150) to ($100)	1	0.01%	1	0.02%	0	0.00%	1	0.01%	0	0.00%
($100) to ($50)	64	0.74%	9	0.13%	33	0.38%	88	1.01%	3	0.03%
($50) to $0	5,015	57.99%	5,205	59.54%	4,600	52.89%	5,120	59.30%	5,108	58.34%
$0 to $50	3,471	97.61%	3,372	98.04%	3,827	96.58%	3,247	96.27%	3,603	99.47%
$50 to $100	190	99.78%	152	99.77%	255	99.49%	284	99.50%	41	99.94%
$100 to $150	17	99.98%	9	99.87%	31	99.84%	37	99.92%	5	100.00%
$150 to $200	2	100.00%	4	99.92%	5	99.90%	4	99.97%	0	100.00%
$200 to $250	0	100.00%	1	99.93%	1	99.91%	2	99.99%	0	100.00%
$250 to $300	0	100.00%	3	99.97%	3	99.94%	0	99.99%	0	100.00%
$300 to $350	0	100.00%	0	99.97%	2	99.97%	1	100.00%	0	100.00%
$350 to $400	0	100.00%	1	99.98%	1	99.98%	0	100.00%	0	100.00%
$400 to $450	0	100.00%	0	99.98%	1	99.99%	0	100.00%	0	100.00%
$450 to $500	0	100.00%	1	99.99%	1	100.00%	0	100.00%	0	100.00%
>= $500	0	100.00%	1	100.00%	0	100.00%	0	100.00%	0	100.00%

Figure 2-20 shows the hourly differences between day-ahead and real-time load-weighted hourly LMP in 2009. Although the average difference between the Day-Ahead and Real-Time Energy Market was $0.08 per MWh for the entire year, Figure 2-20 demonstrates the considerable variation, both positive and negative, between day-ahead and real-time prices. The highest difference between real-time and day-ahead load-weighted hourly LMP was $136.14 per MWh for the hour ended 1800 on November 1, 2009, when the real-time load-weighted hourly LMP was $176.74 and the day-ahead load-weighted hourly LMP was $40.60.

Figure 2-20 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: Calendar year 2009

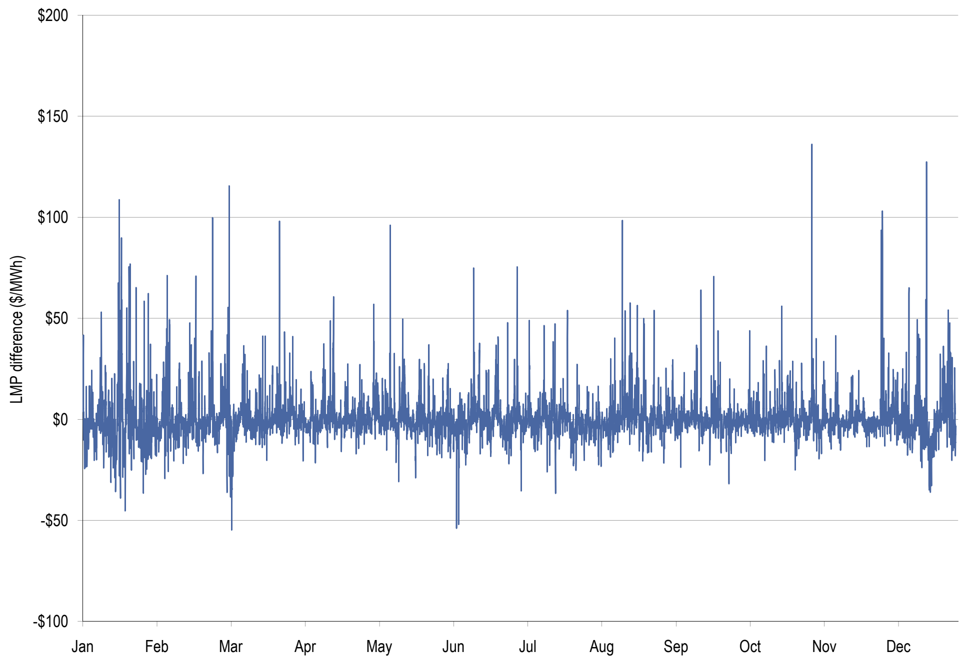


Figure 2-21 shows the monthly simple average differences between the day-ahead and real-time LMP in 2009. The highest monthly difference was in May.

Figure 2-21 Monthly simple average of real-time minus day-ahead LMP: Calendar year 2009

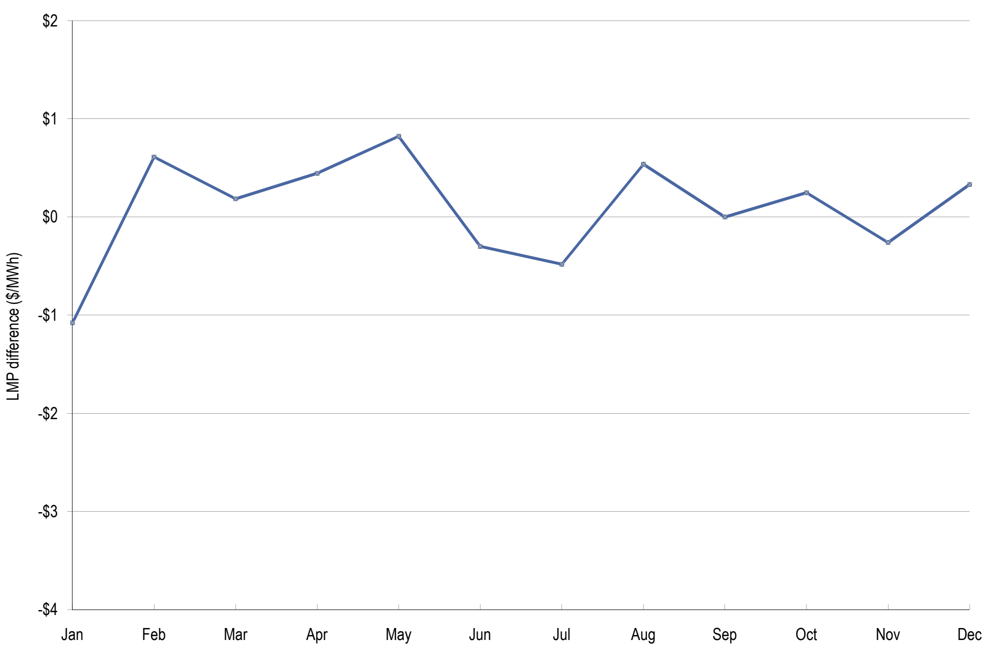
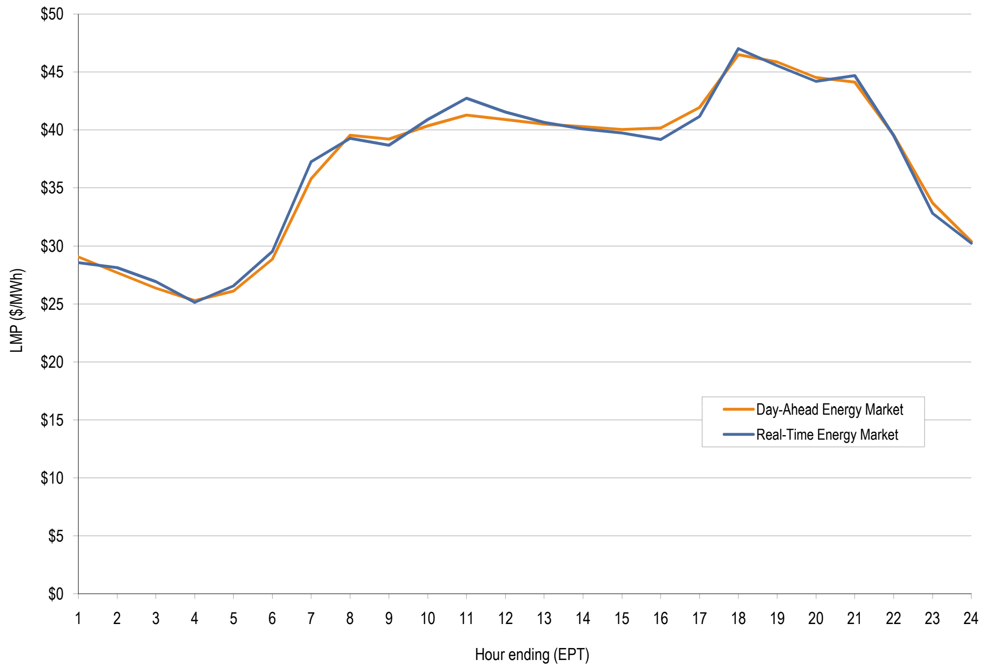


Figure 2-22 shows simple day-ahead and real-time LMP on an average hourly basis. Real-time simple average LMP was greater than day-ahead simple average LMP for 11 out of 24 hours.[55]

Figure 2-22 PJM system simple hourly average LMP: Calendar year 2009



55 See the *2009 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market," for more details on the frequency distribution of prices.

Zonal Price Convergence

Table 2-89 shows 2009 zonal day-ahead and real-time simple annual average LMP. The difference between zonal day-ahead and real-time simple annual average LMP ranged from $0.86 in the BGE Control Zone, where the day-ahead simple annual average LMP was higher than the real-time simple annual average LMP, to $0.56 in the DAY Control Zone, where the day-ahead simple annual average LMP was lower than the real-time simple annual average LMP.

Table 2-89 Zonal day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar year 2009

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$41.44	$40.68	($0.77)	(1.9%)
AEP	$33.44	$33.63	$0.19	0.6%
AP	$37.80	$38.29	$0.49	1.3%
BGE	$42.57	$41.71	($0.86)	(2.1%)
ComEd	$28.94	$29.05	$0.10	0.4%
DAY	$32.94	$33.49	$0.56	1.7%
DLCO	$32.33	$32.73	$0.39	1.2%
Dominion	$40.58	$40.00	($0.58)	(1.5%)
DPL	$41.73	$41.23	($0.50)	(1.2%)
JCPL	$41.36	$40.93	($0.43)	(1.1%)
Met-Ed	$40.35	$39.94	($0.41)	(1.0%)
PECO	$40.79	$40.00	($0.80)	(2.0%)
PENELEC	$37.09	$36.85	($0.24)	(0.7%)
Pepco	$42.54	$41.88	($0.66)	(1.6%)
PPL	$39.90	$39.44	($0.46)	(1.2%)
PSEG	$41.84	$41.27	($0.57)	(1.4%)
RECO	$40.92	$40.36	($0.56)	(1.4%)

Price Convergence by Jurisdiction

Table 2-90 shows the 2009 day-ahead and real-time simple annual average LMPs by jurisdiction. The difference between day-ahead and real-time simple annual average LMP ranged from $0.72 in Maryland, where the day-ahead simple annual average LMP was higher than the real-time simple annual average LMP, to $0.42 in Ohio, where the day-ahead simple annual average LMP was lower than the real-time simple annual average LMP.

Table 2-90 Jurisdiction day-ahead and real-time simple annual average LMP (Dollars per MWh): Calendar year 2009

	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Delaware	$41.15	$40.80	($0.35)	(0.9%)
Illinois	$28.94	$29.05	$0.10	0.4%
Indiana	$32.87	$33.08	$0.20	0.6%
Kentucky	$33.22	$33.48	$0.26	0.8%
Maryland	$42.38	$41.66	($0.72)	(1.7%)
Michigan	$33.94	$34.09	$0.15	0.4%
New Jersey	$41.64	$41.08	($0.56)	(1.4%)
North Carolina	$39.50	$38.92	($0.58)	(1.5%)
Ohio	$32.83	$33.25	$0.42	1.3%
Pennsylvania	$38.80	$38.47	($0.33)	(0.9%)
Tennessee	$33.66	$33.54	($0.13)	(0.4%)
Virginia	$39.88	$39.29	($0.58)	(1.5%)
West Virginia	$34.34	$34.60	$0.26	0.7%
District of Columbia	$43.38	$42.98	($0.40)	(0.9%)

Load and Spot Market

Real-Time Load and Spot Market[56]

Participants in the PJM Real-Time Energy Market can use their own generation to meet load, to sell in the bilateral market or to sell in the spot market in any hour. Participants can both buy and sell via bilateral contracts and buy and sell in the spot market in any hour. If a participant has positive net bilateral transactions in an hour, it is buying energy through bilateral contracts (bilateral purchase). If a participant has negative net bilateral transactions in an hour, it is selling energy through bilateral contracts (bilateral sale). If a participant has positive net spot transactions in an hour, it is buying energy from the spot market (spot purchase). If a participant has negative net spot transactions in an hour, it is selling energy to the spot market (spot sale).

56 The analysis here differs from that presented in the *2007 State of the Market Report* in several respects. The billing organization analysis is not included here because it is not a meaningful representation of the ways in which load is served in PJM. Rather, billing organization data reflects decisions by parent organizations about where to incorporate the load serving obligation. In addition, the transfer of load serving obligations via eSchedule bilateral contracts is treated as a transfer of load serving obligation rather than as a bilateral to serve load.

Real-time load is served by a combination of self-supply, bilateral market purchases and spot market purchases. From the perspective of a parent company of a PJM billing organization 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 addition to directly serving load, load serving entities can also transfer their responsibility to serve load to other parties through eSchedules transactions referred to as wholesale load responsibility (WLR) or retail load responsibility (RLR) transactions. When the responsibility to serve load is transferred via a bilateral contract, the entity to which the responsibility is transferred becomes the load serving entity. Supply from its own generation (self-supply) means that the parent company is generating power from plants that it owns in order to meet demand. Supply from bilateral purchases means that the parent company is purchasing power under bilateral contracts at the same time that it is meeting load. Supply from spot market purchases means that the parent company is not generating enough power from owned plants and/or not purchasing enough power under bilateral contracts to meet load at a defined time and, therefore, is purchasing the required balance from the spot market.

The PJM system's reliance on self-supply, bilateral contracts and spot purchases to meet real-time load is calculated by summing across all PJM parent companies that serve load in the Real-Time Energy Market for each hour. Table 2-91 shows the monthly average share of real-time load served by self-supply, bilateral contract and spot purchase in 2008 and 2009 based on parent company. For 2009, 12.9 percent of real-time load was supplied by bilateral contracts, 17.0 percent by spot market purchase and 70.1 percent by self-supply. Compared with 2008, reliance on bilateral contracts decreased 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.

Table 2-91 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: Calendar years 2008 to 2009

	2008			2009			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	14.3%	17.3%	68.4%	12.6%	15.4%	72.0%	(1.7%)	(1.9%)	3.6%
Feb	15.2%	17.3%	67.5%	13.4%	14.5%	72.1%	(1.7%)	(2.9%)	4.6%
Mar	16.0%	17.1%	66.9%	13.8%	16.7%	69.5%	(2.3%)	(0.4%)	2.6%
Apr	16.6%	18.0%	65.4%	13.5%	17.2%	69.3%	(3.1%)	(0.8%)	3.9%
May	16.0%	18.8%	65.3%	14.6%	18.8%	66.7%	(1.4%)	(0.0%)	1.4%
Jun	13.1%	21.0%	65.9%	12.5%	16.5%	71.0%	(0.6%)	(4.5%)	5.1%
Jul	13.7%	20.6%	65.7%	12.6%	16.9%	70.5%	(1.2%)	(3.7%)	4.8%
Aug	14.9%	22.6%	62.4%	11.7%	16.0%	72.3%	(3.2%)	(6.6%)	9.9%
Sep	14.7%	23.0%	62.2%	12.5%	18.1%	69.4%	(2.3%)	(4.9%)	7.2%
Oct	15.1%	22.7%	62.2%	13.0%	19.8%	67.2%	(2.1%)	(2.9%)	5.0%
Nov	14.8%	22.9%	62.3%	13.2%	19.0%	67.8%	(1.7%)	(4.0%)	5.6%
Dec	12.1%	20.5%	67.4%	11.7%	16.8%	71.5%	(0.4%)	(3.7%)	4.1%
Annual	14.6%	20.1%	65.2%	12.9%	17.0%	70.1%	(1.8%)	(3.1%)	4.9%

Day-Ahead Load and Spot Market

In the PJM Day-Ahead Energy Market, participants can not only use their own generation, bilateral contracts and spot market purchases to supply their load serving obligation, but can also use virtual resources to meet their load serving obligations in any hour. Virtual supply is treated as generation in the day-ahead analysis and virtual demand is treated as demand in the day-ahead analysis.

The PJM system's reliance on self-supply, bilateral contracts, and spot purchases to meet day-ahead load (cleared fixed-demand, price-sensitive load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve load in the Day-Ahead Energy Market for each hour. Table 2-92 shows the monthly average share of day-ahead load served by self-supply, bilateral contracts and spot purchases in 2008 and 2009, based on parent companies. For 2009, 4.9 percent of day-ahead load was supplied by bilateral contracts, 14.9 percent by spot market purchases, and 80.2 percent by self-supply. Compared with 2008, reliance on bilateral contracts decreased by 0.2 percentage points, reliance on spot supply decreased by 3.6 percentage points, and reliance on self-supply increased by 3.7 percentage points.

Table 2-92 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: Calendar Years 2008 to 2009

	2008			2009			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	4.2%	15.6%	80.2%	4.4%	13.7%	81.9%	0.2%	(1.9%)	1.6%
Feb	4.5%	16.0%	79.5%	4.5%	12.3%	83.2%	(0.1%)	(3.7%)	3.7%
Mar	4.7%	16.0%	79.3%	4.3%	12.8%	82.9%	(0.4%)	(3.3%)	3.6%
Apr	5.0%	16.8%	78.2%	4.4%	13.8%	81.7%	(0.5%)	(3.0%)	3.5%
May	5.0%	18.2%	76.8%	4.6%	15.6%	79.8%	(0.4%)	(2.6%)	3.0%
Jun	5.5%	20.2%	74.3%	4.7%	13.9%	81.4%	(0.8%)	(6.3%)	7.2%
Jul	5.6%	20.4%	74.0%	5.6%	16.0%	78.4%	0.0%	(4.4%)	4.4%
Aug	4.9%	20.2%	75.0%	5.2%	15.3%	79.5%	0.3%	(4.9%)	4.6%
Sep	5.4%	19.3%	75.3%	4.8%	16.1%	79.2%	(0.7%)	(3.2%)	3.8%
Oct	5.4%	20.3%	74.3%	5.0%	17.8%	77.2%	(0.4%)	(2.5%)	2.9%
Nov	5.6%	18.9%	75.5%	5.8%	15.9%	78.3%	0.2%	(3.0%)	2.8%
Dec	4.6%	19.1%	76.3%	5.2%	15.6%	79.2%	0.6%	(3.5%)	2.9%
Annual	5.0%	18.4%	76.5%	4.9%	14.9%	80.2%	(0.2%)	(3.6%)	3.7%

Demand-Side Response (DSR)

Markets require both a supply side and a demand side to function effectively. The demand side of wholesale electricity markets is underdeveloped. Wholesale power markets will be more efficient when the demand side of the electricity market becomes fully functional.

A fully functional demand side of the electricity market means that end use customers or their designated intermediaries will have the ability to see real time energy price signals in real time, will have the ability to react to real time prices in real time, and will have the ability to receive the direct benefits or costs of changes in real time energy use. In addition, customers or their designated intermediaries will have the ability to see current capacity prices, will have the ability to react to capacity prices and will have the ability to receive the direct benefits or costs of changes in the demand for capacity. A functional demand side of these markets means that customers will have the ability to make decisions about levels of power consumption based both on the value of the uses of the power and on the actual cost of that power.

Today, most end use customers do not face the market price of energy, that is the locational marginal price of energy (LMP), or the market price of capacity, the locational capacity market clearing price. This results in a market failure because when customers do not know the market price and do not pay the market price, the behavior of those customers is inconsistent with the market value of electricity. When customers pay a price less than the market price, customers will tend to consume more than if they faced the market price and when customers pay a price greater than the market price, customers will tend to consume less than they would if they faced the market price. This market failure is relevant to the wholesale power market because the power used by customers is generated and sold in the wholesale power market. The transition to a more functional demand side requires that the default energy price for all customers be the day ahead or real time hourly locational marginal price (LMP) and the locational clearing price of capacity.

PJM's Economic Load Response Program is designed to address this market failure by attempting to replicate the price signal to customers that would exist if customers were exposed to the real time wholesale price of energy and by providing settlement services to facilitate the participation of third party Curtailment Service Providers (CSPs) in the market. PJM's Load Management (LM) Program in the RPM market also attempts to replicate the price signal to customers that would exist if customers were exposed to the locational market price of capacity. The PJM market design also creates the opportunity for demand resources to participate in ancillary services markets.[57]

PJM's demand side programs, by design, provide a work around for end use customers that are not otherwise exposed to the incremental costs of energy and capacity. They should be understood as one relatively small part of a transition to a fully functional demand side for its markets. The complete transition to a fully functional demand side will require explicit agreement and coordination among the Commission, state public utility commissions and RTOs/ISOs.

57 See the *2009 State of the Market Report for PJM*, Volume II, "Ancillary Service Markets."

PJM Load Response Programs Overview

All load response programs in PJM can be grouped into the Economic and the Emergency Programs. Table 2-93 provides an overview of the key features of PJM load response programs.

Table 2-93 Overview of Demand Side Programs

Emergency Load Response Program			Economic Load Response Program
Load Management (LM)			
Capacity Only	Capacity and Energy	Energy Only	Energy Only
Registered ILR only	DR cleared in RPM; Registered ILR	Not included in RPM	Not included in RPM
Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Voluntary Curtailment
RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA
Capacity payments based on RPM clearing price	Capacity payments based on RPM price	NA	NA
No energy payment	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for mandatory curtailments.	Energy payment based on LMP less generation component of retail rate. Energy payment for hours of voluntary curtailment.

Economic Load Response

In the Economic Load Response Program (ELRP, or the Economic Program), all hours are eligible and all participation is voluntary. The ELRP Program is designed to facilitate the participation of demand response in PJM Energy Markets. Participation in the ELRP takes three forms: submitting a sell offer into the Day-Ahead Market that clears; submitting a sell offer into the Real-Time Market that is dispatched; and self scheduling load reductions while providing notification to PJM. In the first two methods, a load reduction offer is submitted to PJM through the eMkt system specifying the minimum reduction price, including any associated shutdown costs, and the minimum duration of the load reduction.

History

On March 15, 2002, PJM submitted filing amendments to the OATT and to the OA to establish a multiyear Economic Load-Response Program (the Economic Program).[58] On May 31, 2002, the FERC accepted the Economic Program, effective June 1, 2002, but with a December 1, 2004, sunset provision.[59] On October 29, 2004, the FERC extended the Economic Program until December 31, 2007.[60] On February 24, 2006, the FERC approved changes to the PJM Tariff to permit demand-side resources to provide ancillary services and to make the Economic Program

58 *PJM Interconnection, L.L.C.*, Tariff Amendments, Docket No. ER02-1326-000 (March 15, 2002).
59 99 FERC ¶ 61,227 (2002).
60 *PJM Interconnection, L.L.C.*, Letter Order, Docket No. ER04-1193-000 (October 29, 2004).

permanent.[61,62] The same order permitted an increase in the limit on the combined total MW in the Economic and Emergency Programs from 100 MW to 500 MW in the Pilot Program for resources with non-hourly integrated metering.

On November 20, 2007, the PJM Industrial Customer Coalition (PJMICC) filed a complaint with the FERC requesting continuation of Economic Load-Response subsidy payments that, under the existing PJM Tariff, would expire on December 31, 2007.[63] The Commission denied the complaint, stating that, "Even without the subsidy payments, the Economic Program provides customers within PJM the incentive to reduce load based on the wholesale rates they confront."[64,65] On December 31, 2007, the Economic Program incentive payment provisions expired per the PJM OA.

PJM stakeholders continued to discuss the incentive issue during the first half of 2009, but no proposal obtained majority backing. On June 29, 2009, a statement issued on behalf of the PJM Board explained the Board's long term objective to develop the demand side of the market and its short term support for an incentive program, and indicated that PJM would file its own proposal.[66]

On August 24, 2009, PJM filed a proposal. The proposal provided for compensating fixed price demand response customers at LMP less the generation portion of their retail rates (LMP – G) rather than both the generation and transmission portions (LMP - G - T).[67] PJM explained that this change is intended to "(i) alleviate underpayment to the Fixed Price Customer, (ii) result in similar compensation for Fixed Price Customers and LMP-based Customers[footnote omitted] that reduce demand, and (iii) provide Fixed Price Customers the same incentives as LMP-based Customers to reduce demand…"[68] The proposal subjects to debit payments a participant who (i) self-schedules demand reductions or is dispatched for reductions in the Real-Time Energy Market when settlement of its daily activity shows that the participant's credits accumulated for reducing demand are less than accumulated debits for failure to reduce, or (ii) who self-schedules reductions when the applicable zonal LMP drops below the applicable generation charge in the customer's retail rate.[69] PJM proposed to re-introduce incentive payments that would apply to reduced consumption in the nine percent of hours when LMP is at its highest levels and would sunset when there are 1,000 MW of additional price responsive demand capability for small and medium-sized end-use customers.[70]

Numerous stakeholders intervened, many filing protests. Certain intervenors opposed PJM's proposal to pay participants in the Economic Load Response Program LMP – G, arguing instead that participants should be paid full LMP.[71] The MMU filed an answer responding that payment of full LMP was "inconsistent with … fundamental economics" and over compensatory, would "degrade

61 114 FERC ¶ 61,201 (February 24, 2006).
62 See PJM. "Amended and Restated Operating Agreement (OA)," Schedule 1, Section 3.3.A (December 10, 2007).
63 Complaint of the PJM Industrial Coalition in Docket EL08-12-000.
64 121 FERC ¶ 61,315 at P 26 (December 31, 2007).
65 For a discussion of subsidy payments under PJM's Economic Load-Response Program, see "MMU White Paper: PJM Demand Side Response Program" (December 4, 2007) <http://monitoringanalytics.com/reports/Reports/2007/20071204-dsr-whitepaper.pdf> (115 KB).
66 Statement of Terry Boston, President and CEO, on behalf of the PJM Board of Managers (June 26, 2009), which is posted on PJM's website at: <http://www.pjm.com/~/media/about-pjm/newsroom/2009-releases/20090626-pjm-board-statement-regarding-dr-in-pjm-markets.ashx> (104 KB).
67 Supplemental Report and Submittal of PJM Interconnection, L.L.C. in Support of Further Commission Action on Rehearing, initially filed in EL08-12. The FERC determined to initiate a new proceeding with this filing, docketed as EL09-68-000.
68 *Id.* at 6.
69 *Id.*
70 *Id.* at 5–6.
71 Such comments include those filed in Comments and Protest of Demand Response Supporters, including: Comverge, Inc.; EnergyConnect, Inc.; EnerNOC, Inc.; the PJM Industrial Customer Coalition; Viridity Energy, Inc.; WalMart Stores East, L.P.; Protest of the New Jersey Board of Public Utilities and the District of Columbia Public Service Commission ("BPU/DCPSC"); and Comments of the Public Service Commission of Maryland.

the efficient operation of the markets," and "provide no offsetting social benefit.[72] Commission action in this proceeding is pending.

Other proceedings active in 2009 concerning PJM's demand response programs involved approval and measurement of participation.

On July 28, 2009, PJM filed revisions to the metering requirements in PJM's Economic and Emergency Load Response Programs intended to clarify the responsibilities of Curtailment Service Providers (CSPs) in connection with program participants' metering equipment, to account for metering data requirements, to provide uniform terminology and requirements, and to revise certain out-dated requirements included in the Emergency Load Response Program.[73] The Commission approved these revisions, effective September 28, 2009.[74]

In two interrelated proceedings, PJM and the Commission addressed the role of relevant electric retail regulatory authorities (or RERRAs) in approving participation in its Economic and Emergency Load Response Programs.[75] PJM submitted a filing to address the issue, and the Commission concurrently took up the issue in its rulemaking proceeding concerning reform of the organized markets.[76]

On November 20, 2009, PJM submitted a compliance filing pursuant to orders issued in both of these interrelated proceedings.[77] The proposed revisions address the mandate in Order 719-A that RTOs not accept bids from aggregators of retail customers (ARCs) that aggregate the demand response of: (i) the customers of utilities that distributed more than four million MWh in the previous fiscal year, unless the RERRA prohibits an ARC from bidding such customers' demand response, or (ii) the customers of utilities that distributed four million MWh or less in the previous fiscal year, unless the RERRA affirmatively permits an ARC to bid such customers' demand response. Additionally, per the direction in Order 719-A, PJM's proposed revisions describe the mechanism for notifying an affected electric distribution company (EDC) and Load Serving Entity (LSE) when load served by that entity is enrolled to participate in its programs, either individually or through an ARC. The proposed revisions addressed the requirements of the September 14th Order to: (i) recognize a RERRA's ability to condition eligibility to participate in PJM's Demand Side Response Programs; (ii) update obsolete references to "Active Load Management"; (iii) address how RERRA prohibitions will affect existing demand response resource registrations and/or commitments; (iv) clarify that PJM will effectuate such RERRA policies prospectively by precluding affected resources from offering capacity in RPM auctions that are conducted subsequent to the effective date of those policies; (v) clarify that registrations of Economic Load Response Participants will be promptly terminated upon receipt by PJM of evidence of a conflicting prohibition or unsatisfied condition of a RERRA, and that participants will be permitted to submit settlements for the curtailment service already provided; and (vi) commit to posting on PJM's website a list of RERRAs that prohibit or condition retail participation in PJM's programs, and providing annual updates on those programs to PJM's Markets and Reliability Committee. PJM requested that the Commission accept the proposed tariff changes for both proceedings together, and grant a retroactive effective date of August 28, 2009, the effective date of Order 719-A.[78] This filing is currently pending before the Commission.

72 Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM, EL09-68-000 at 1–2 (October 16, 2009).
73 PJM filing in Docket No. ER09-1508.
74 Letter order in Docket No. ER09-1508-000 (September 9, 2009).
75 Dockets Nos. ER09-701-000 and RM07-19-000.
76 *Id.*
77 PJM compliance filing in Dockets Nos. ER09-701-000 & RM07-19-000 (November 20th Filing); 128 FERC ¶ 61,059 (July 16, 2009) ("Order No. 719-A"); 128 FERC ¶ 61,238 (September 14, 2010) ("September 14th Order").
78 November 20th Filing at 12.

Current State

The fundamental purpose of PJM's Economic Load Response Program is, or should be, to address a specific market failure, which is that many retail customers do not pay the market price or LMP. Based on this purpose, the design goal of the Economic Program incentives should be to replicate the price signal to customers that would exist if customers were exposed to the real-time wholesale price. The real-time hourly LMP is the appropriate price signal as it reflects the incremental value of each MWh consumed.[79]

Retail customers pay retail rates including components that reflect the cost of generation (or power purchased from the grid), the cost of transmission and the cost of distribution. Under a rate design consistent with the purpose of the demand-side program, the hourly LMP would replace only the generation component of retail rates in order to provide the appropriate wholesale market price signal to customers. Accordingly, the load reductions in the Economic Program are appropriately compensated at LMP less the generation component of the applicable retail rate per MWh.

The Economic Load Response Program's primary function is to provide a mechanism for fixed rate customers to receive the full market value of savings associated with changes in energy consumption, determined by the hourly Locational Marginal Price (LMP).

The PJM Economic Load-Response Program is a PJM-managed accounting mechanism that provides for payment of the savings that result from load reductions to the load-reducing customer. Such a mechanism is required because of the complex interaction between the wholesale market and the retail incentive and regulatory structures faced by both LSEs and customers. The broader goal of the Economic Program is a transition to a structure where customers do not require mandated payments, but where customers see and react to market prices or enter into contracts with intermediaries to provide that service. Even as currently structured, however, and even with the reintroduction of the defined subsidies, if they exclude previously identified inappropriate components, the Economic Program represents a minimal and relatively efficient intervention into the market.[80]

Emergency Load Response

In the Emergency Load Response Program, only hours in which PJM has declared an Emergency Event are eligible. Participation may be voluntary or mandatory, and payments may include energy payments, capacity payments or both.

History

On February 14, 2002, the PJM Members Committee approved a permanent Emergency Load-Response Program.[81] On March 1, 2002, PJM filed amendments to the OATT and to the OA to

79 This does not mean that every retail customer should be required to pay the real-time LMP, regardless of their risk preferences. However, it would provide the appropriate price signal if every retail customer were obligated to pay the real-time LMP as a default. That risk could be hedged via a contract with an intermediary.

80 One such inappropriate component was the payment of subsidies to customers who were already exposed to hourly LMP pricing.

81 *PJM Interconnection, L.L.C.*, Tariff Amendments, Docket No. ER02-1205-000 (March 1, 2002).

establish a permanent Emergency Load-Response Program (the Emergency Program).[82] By order dated April 30, 2002, the FERC approved the Emergency Program effective June 1, 2002. Like the Economic Program, a sunset date for it was set for December 1, 2004.[83] On October 29, 2004, the FERC extended the program until December 31, 2007, thereby making it coterminous with the Economic Program.[84] On February 24, 2006, the FERC approved changes to the PJM Tariff to make the Emergency Program permanent, including energy only and full emergency options.[85] The Emergency Program was modified in June 2006 to include an Emergency-Capacity Only option.

As a result of Reliability Pricing Model (RPM) implementation on June 1, 2007, the Load Management (LM) Program was introduced as the mechanism for Emergency Program customers and other DR providers to participate in RPM. Customers in the Emergency-Full and Emergency-Capacity Only options of the Emergency Program are committed capacity resources, which receive RPM capacity payments and which are subject to RPM penalties for noncompliance during emergency events. Emergency-Full customers are also eligible for energy payments for reductions during emergency events.[86]

On March 4, 2009, PJM filed with the Commission revisions to the Emergency Load Response Program. The proposed revisions defined Capacity Only resources, revised the way in which actual load reductions by Full Program Option and Capacity Only resources are added back for the purpose of calculating peak load for capacity, and prevented double counting of MWs in the calculation of peak load and normalized peak demand.[87] By order issued May 7, 2009, the Commission accepted PJM's proposed revisions, effective June 1, 2009.[88]

Current State

There are three options for Emergency Load Response registration and participation: energy only; capacity only; and capacity plus energy.

Energy Only

In the Energy Only option, participants submit a minimum dispatch price for load reductions during emergency events, which include shutdown costs and a minimum duration. All participation is voluntary. This option of the Emergency Program is similar to the Economic Program in that it provides only energy payments and all participation is voluntary. However, compensation differs significantly between the two programs as Energy Only participants in the Emergency Program receive the greater of LMP or the value of the submitted minimum dispatch price, including shutdown, for the duration of the emergency reduction.

82 *PJM Interconnection, L.L.C.*, Tariff Amendments, Docket No. ER02-1205-000 (March 1, 2002).
83 99 FERC ¶ 61,139 (2002).
84 *PJM Interconnection, L.L.C.,* Letter Order, Docket No. ER04-1193-000 (October 29, 2004).
85 114 FERC ¶ 61,201 (February 24, 2006).
86 For additional information on RPM provisions for customers in the Emergency Load Response Program, see PJM, "Manual 18: PJM Capacity Market", Revision 8 (January 1, 2010).
87 PJM filing in Docket No. ER09-797-000 (March 4, 2009).
88 Letter Order in ER09-797-000 (May 7, 2010).

Capacity Only

In the Capacity Only Program option, participants are considered a capacity resource, and are obligated to reduce load during emergency events. This option includes only registered Interruptible Load for Reliability (ILR), as Demand Response (DR) offering into RPM Auctions is required to register in the Full Emergency option. Participation during an emergency event or capacity testing is mandatory and failure to reduce will result in a compliance test failure charge. The participant receives capacity payments, however, no energy offers are submitted and no energy payments during emergency events are applicable. This option exists to accommodate registrations in which the Curtailment Service Provider may only provide capacity related services or situations in which the customer is receiving energy payments through another program registration.

Energy and Capacity (Full Emergency Option)

Similar to the Energy Only option, participants in the Full Emergency option submit minimum dispatch prices associated with reductions during emergency events. In addition, they are considered committed capacity resources and receive capacity payments. Participation during an emergency event or capacity testing is mandatory and failure to reduce will result in a compliance test failure charge as well as a daily capacity deficiency charge.

Minimum Dispatch Price

During an emergency event, participants registered in the Full Emergency option and the Emergency Energy Only option will be paid the higher of the submitted minimum dispatch price or the zonal real-time LMP for emergency reductions. The minimum dispatch price, which is submitted by the participant, acts as a floor for energy compensation during an emergency event. Given the current program rules, market participants have an incentive to submit a minimum dispatch price at the maximum threshold for energy bids of $1,000/MWh. For the 2009/2010 delivery year, approximately 88 percent of registered sites representing 71 percent of registered MW in the Emergency Full Capacity option submitted a minimum dispatch price of either $999 or $1,000 per MWh.

There is no relationship between the minimum dispatch price and the locational price of energy or the participant's costs associated with not consuming energy. The minimum dispatch price is also not a meaningful signal from the participant about its willingness to curtail. In the Emergency Full option, end use participants are already contractually obligated to curtail during an emergency event because they are capacity resources and receive capacity payments. Thus, the ability to submit a minimum dispatch price is a guarantee of an energy payment for resources that are already required to curtail, regardless of their minimum dispatch price. The appropriate energy payment for a load reduction during an emergency event is the hourly LMP less any generation component of their retail rate. For customers on a real-time LMP contract, no energy payment is necessary because the customer saves the hourly LMP by not consuming during an emergency event. Any energy payment in excess of the real-time LMP net of generation costs results in an unnecessary and inappropriate subsidy.[89]

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

In the Economic Program, customers also have the opportunity to submit a minimum price at which they will curtail. However, customers in the Economic Program will be dispatched economically and paid the real-time LMP less the generation component of their fixed retail rate only if they are dispatched. Under the Emergency Energy Only option and the Emergency Full option, participants are made whole to a minimum strike price offer regardless of the hourly LMP. 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 the option to specify a minimum dispatch price under the Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. The MMU also recommends that the Emergency Program Energy Only option be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program.

Load Management

As part of the transition to RPM, effective June 1, 2007, the PJM active load management (ALM) program was changed to the load management (LM) program.[90] Load Management generally refers to the integration of load response resources into RPM. It includes the Full and Capacity Only options of the Emergency Load Response Program.

The LM program was, from its inception in June 2007, comprised of two types of resources: Interruptible Load for Reliability (ILR) resources and Demand Resources (DR). Customers offering DR resources submit a capacity sell bid into an RPM Auction and are paid the clearing price. Interruptible load for reliability (ILR) resources must be certified at least three months prior to the delivery year and are paid the final zonal ILR price. The ILR option was eliminated on March 26, 2009 for the delivery year beginning June 1, 2012.[91]

Every DR resource is required to register under the Emergency-Full option of the Emergency Program, and it receives energy payments for load reductions during emergency events equal to the higher of LMP or a submitted minimum dispatch price. It also may be registered in the Economic Program simultaneously. If a customer is determined to be reducing economically during an emergency event, energy payments are paid in accordance with the Economic Load Response Program (ELRP) rules.

The purpose of the Load Management Program is to provide a mechanism for end-use customers to avoid paying the capacity market clearing price in return for agreeing to not use capacity when it is needed by customers who have paid for capacity. The fact that customers in the Load Management Program only have to agree to interrupt ten times per year represents a flaw in the design of the program. There is no reason to believe that the customers who pay for capacity will need the capacity used by participating LM customers only ten times per year. In fact, it can be expected that the probability of needing that capacity will increase with the amount of MW that participating LM customers clear in the RPM auctions.

90 An LM program continues to have three types of products: Direct Load Control, Firm Service Level or Guaranteed Load Drop. Each of the products continues to have two notification periods: short-lead time and long-lead time.

91 126 FERC ¶ 61,275 (2009).

For all RPM Auctions run prior to October 29, 2009, under PJM's interpretation of the tariff, all existing Demand Resources were mitigated to an offer of $0 per MW-day if their sell offer would otherwise affect the Capacity Market clearing price. On September 1, 2009, PJM filed to exempt Demand Resources from market power mitigation provisions in the RPM Auctions, subject to ongoing monitoring, with the support of the MMU and market participants.[92] It was approved by the Commission on October 29, 2009.[93]

Participation

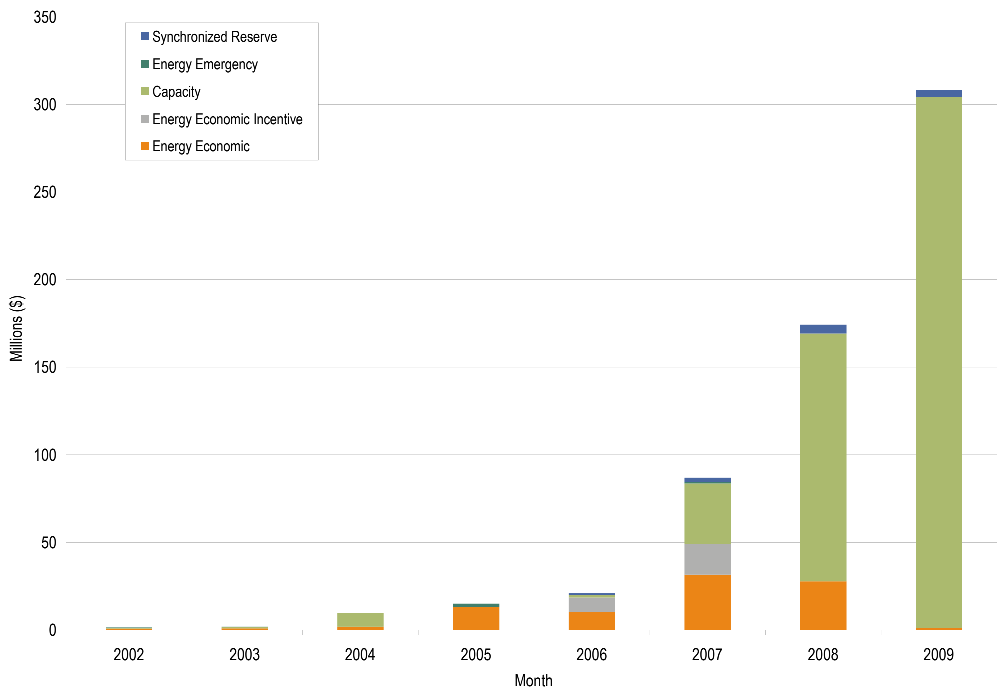
In 2009, in the Economic Program, participation decreased compared to 2008. There were decreases in a range of activity metrics including registrations, settlements submitted, settled MWh and credits. There were many factors contributing to lower levels of participation and lower revenues in the Economic Program, including lower price levels in 2009, lower load levels and improved measurement and verification.

In 2009, the Emergency Program, specifically, the 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.

Figure 2-23 shows all revenue from PJM Demand Side Response Programs by market for the period 2002 through 2009. Since the implementation of the RPM design on June 1, 2007, capacity revenue has become the primary source of revenue to DSR participants. Economic Program revenues declined in 2008 while capacity revenue increased significantly. In 2009, payments from the Economic Program were significantly lower than 2008, decreasing by $26 million or 96 percent, from $27.7 million to $1.2 million, while capacity revenue increased significantly, rising by $161 million or 114 percent, from $141 million to $303 million since 2008. Synchronized Reserve credits decreased by $1.1 million, from approximately $5.1 million to $4.0 million from 2008 to 2009.

92 PJM filing initiating Docket No. ER09-1673-000.
93 129 FERC ¶ 61,081 (2009).

Figure 2-23 Demand Response revenue by market: Calendar years 2002 through 2009



Economic Program

Table 2-94 shows the number of registered sites and MW per peak load day for calendar years 2002 through 2009.[94] On August 10th, 2009, there were 2,486.6 MW registered in the Economic Program compared to the 2,294.7 MW on June 9, 2008, an 8.4 percent increase in peak load day capability. Program totals are subject to monthly and seasonal variation, as registrations begin, expire and renew. Table 2-95 shows registered sites and MW for the last day of each month for the period calendar years 2007 through 2009. Registered sites and MW have generally decreased from the same time period in 2008 since May.[95] Registration in the Economic Program means that customers have been signed up and can participate if they choose. Thus, registrations represent the maximum level of potential participation.

94 Table 2-94 and Table 2-95 reflect distinct registration counts. They do not reflect the number of distinct sites registered for the Economic Program, as multiple sites may be aggregated within a single registration.

95 The site count and registered MW associated with May 2007 are for May 9, 2007. Several new sites registered in May of 2007 overstated their MW capability, and it remains overstated in PJM data.

Table 2-94 Economic Program registration: Within 2002 to 2009

	Sites	Peak-Day, Registered MW
14-Aug-02	96	335.4
22-Aug-03	240	650.6
03-Aug-04	782	875.6
26-Jul-05	2,548	2,210.2
02-Aug-06	253	1,100.7
08-Aug-07	2,897	2,498.0
09-Jun-08	956	2,294.7
10-Aug-09	1,321	2,486.6

Table 2-95 Economic Program registrations on the last day of the month: January 2007 through December 2009

	2007		2008		2009	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	508	1,530	4,906	2,959	4,862	3,303
Feb	953	1,567	4,902	2,961	4,869	3,219
Mar	959	1,578	4,972	3,012	4,867	3,227
Apr	980	1,648	5,016	3,197	2,582	3,242
May	996	3,674	5,069	3,588	1,250	2,860
Jun	2,490	2,168	3,112	3,014	1,265	2,461
Jul	2,872	2,459	4,542	3,165	1,265	2,445
Aug	2,911	2,582	4,815	3,232	1,653	2,650
Sep	4,868	2,915	4,836	3,263	1,879	2,727
Oct	4,873	2,880	4,846	3,266	1,875	2,730
Nov	4,897	2,948	4,851	3,271	1,874	2,730
Dec	4,898	2,944	4,851	3,290	1,853	2,627
Avg.	2,684	2,408	4,727	3,185	2,508	2,852

Table 2-96 shows the zonal distribution of capability in the Economic Program on August 10, 2009. The ComEd Control Zone includes 318 sites or 24 percent of sites and 9 percent of registered MW in the Economic Program. The BGE Control Zone includes 139 sites or 10 percent of sites and 26 percent of registered MW in the Economic Program.

Table 2-96 Distinct registrations and sites in the Economic Program: August 10, 2009[96]

	Registrations	Sites	MW
AECO	38	38	17.7
AEP	15	15	201.7
AP	88	88	212.3
BGE	139	139	645.3
ComEd	318	318	276.4
DAY	5	5	10.6
DLCO	28	28	226.2
Dominion	93	93	131.2
DPL	67	67	71.1
JCPL	38	41	101.3
Met-Ed	41	41	60.9
PECO	160	160	147.0
PENELEC	39	39	31.2
Pepco	22	23	20.3
PPL	136	142	266.6
PSEG	91	92	65.8
RECO	3	3	1.0
Total	1,321	1,332	2,486.6

The total MWh of load reduction and the associated payments under the Economic Program are shown in Table 2-97.[97] Load reduction levels decreased by 425,500 MWh, from 477,212 in 2008 to 51,684 MWh in calendar year 2009, an 89 percent decrease.[98] Total payments in the Economic Program fell $26.5 million, from $27.7 million in 2008 to $1.2 million in 2009, a 96 percent decrease. Payments per MWh were $24 in 2009 compared to $58 in 2008. The Economic Program's actual load reduction per peak-day, registered MW decreased to 20.8 MWh for calendar year 2009, a decrease of 90 percent from 2008.[99] In the calendar year 2009, the maximum hourly load reduction attributable to the Economic Program was 142.3 MW on January 16.

96 Effective July 1, 2009, PJM implemented a new eSuite application, Load Response System (eLRS) to serve as the interface for collecting and storing customer registration and settlement data. With the implementation of the LRS system, more detail is available on customer registrations and, as a result, there is an enhanced ability to capture multiple distinct locations aggregated to a single registration. The second column of reflects the number of registered end-user sites, including sites that are aggregated to a single registration.

97 The "Total MWh" and "Total Payments" for the Economic Program shown here are also subject to subsequent settlement adjustments in 2009.

98 The Economic Program payments and MWh presented in this report do not include all settlement adjustments for 2008 and 2009. The data are provided by PJM's DSR department; Economic Program payments and MWh reductions are based on the January, 2010, PJM billing information and are subject to adjustments.

99 The "Total MWh" and "Total Payments" for calendar year 2008 are different from those reported in the *2008 State of the Market Report for PJM,* as a result of adjusted settlements. The "Total MWh" increased by 24,990 MWh and the "Total Payments" increased by $633,080.

Table 2-97 Performance of PJM Economic Program participants

	Total MWh	Total Payments	$/MWh	Total MWh per Peak-Day, Registered MW
2002	6,727	$801,119	$119	20.1
2003	19,518	$833,530	$43	30.0
2004	58,352	$1,917,202	$33	66.6
2005	157,421	$13,036,482	$83	71.2
2006	258,468	$18,584,013	$72	234.8
2007	714,148	$49,033,576	$74	285.9
2008	477,212	$27,720,575	$58	208.0
2009	51,684	$1,236,416	$24	20.8

Total Payments in Table 2-97 include incentive payments in the Economic Program for the years 2006 and 2007. The economic incentive program expired in November of 2007.[100] Table 2-98 shows total MWh reductions and payments less incentive payments for the years 2002 through 2009.[101]

Table 2-98 Performance of PJM Economic Program participants without incentive payments

	Total MWh	Total Payments	$/MWh	Total MWh per Peak-Day, Registered MW
2002	6,727	$801,119	$119	20.1
2003	19,518	$833,530	$43	30.0
2004	58,352	$1,917,202	$33	66.6
2005	157,421	$13,036,482	$83	71.2
2006	258,468	$10,213,828	$40	234.8
2007	714,148	$31,600,046	$44	285.9
2008	477,212	$27,720,575	$58	208.0
2009	51,684	$1,236,416	$24	20.8

Figure 2-24 shows monthly economic program payments, excluding incentive payments, for 2007 through 2009. Economic Program credits consistently declined in 2008 after June. In 2009, payments were down significantly in every month compared to the same time period in 2007 and 2008.[102] While there are a number of factors that could explain this reduction, declining price levels for energy are the single biggest factor. Energy prices declined significantly in 2008 and again in 2009. Lower prices mean reduced incentives to reduce load and fewer hours eligible for load reductions, given a fixed rate contract. The reduction was also the result in part of the revisions to the Customer Baseline Load (CBL) calculation effective June 12, 2008 and the newly implemented activity review process effective November 3, 2008.

100 In 2006 and 2007, when LMP was greater than, or equal to, $75 per MWh, customers were paid the full LMP and the amount not paid by the LSE, equal to the generation and transmission components of the applicable retail rate (recoverable charges), was charged to all LSEs in the zone of the load reduction. As of December 31, 2007, the incentive payments totaled $17,391,099, an increase of 108 percent from calendar year 2006. No incentive credits were paid in November and December 2007 because the total exceeded the specified cap.

101 Settlement data for 2008 and 2009 including reductions, credits and incentive payments data received from PJM DSR group February 26, 2010.

102 December credits are likely understated due to the lag associated with the submittal and processing of settlements. Settlements may be submitted up to 60 days following an event day. EDC/LSEs have up to 10 business days to approve which could account for a maximum lag of approximately 74 calendar days.

Figure 2-24 Economic Program payments: Calendar years 2007 (without incentive payments), 2008 and 2009

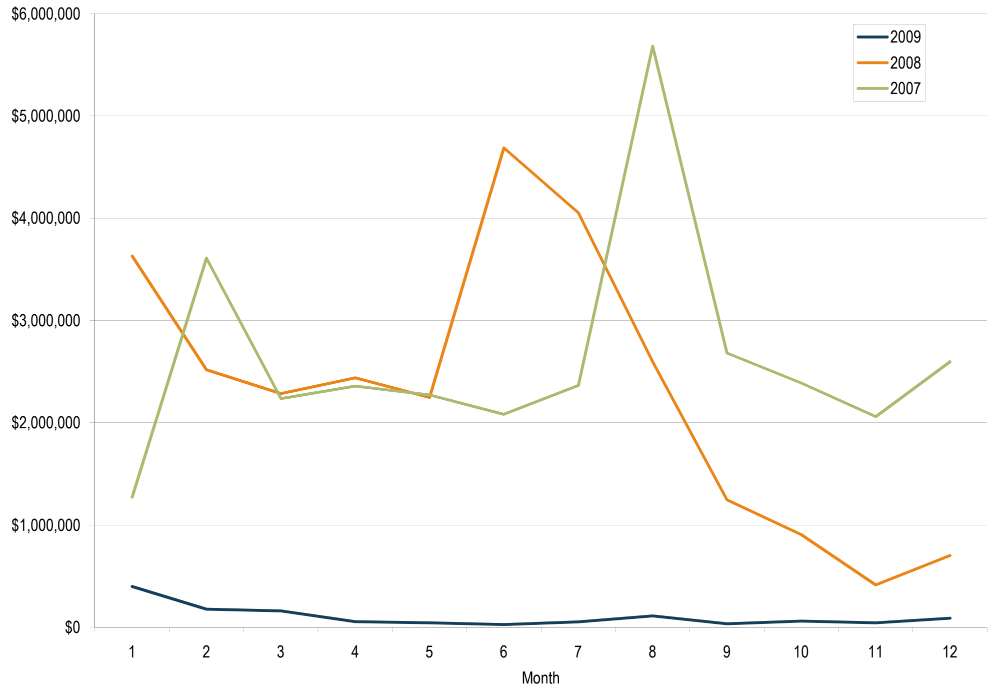


Table 2-99 shows 2009 performance in the Economic Program by control zone and participation type. The total number of curtailed hours for the Economic Program was 31,516 and the total payment amount was $1,236,416.[103] Overall, approximately 90 percent of the MWh reductions, 90 percent of payments and 90 percent of curtailed hours resulted from the real-time, self scheduled option of the Economic Program. Approximately 7 percent of the MWh reductions, 7 percent of payments and 1 percent of curtailed hours resulted from the day-ahead option.[104] Approximately 3 percent of the MWh reductions, 3 percent of the payments and 9 percent of the curtailed hours resulted from the dispatched in real time option of the program. (See Table 2-99) The PPL Control Zone accounted for $480,596 or 39 percent of all Economic Program credits, associated with 18,829 or 36 percent of total program MWh reductions.

103 If two different retail customers curtail during the same hour in the same zone, it is counted as two curtailed hours.

104 On February 2, 2007, PJM proposed to the FERC that customers with day-ahead, LMP-based contracts be eliminated from participation in the day-ahead Economic Program. On June 15, 2007, the Commission issued an order, 119 FERC ¶ 61,280, rejecting PJM's proposed revision to its OATT.

Table 2-99 PJM Economic Program by zonal reduction: Calendar year 2009

	Real Time			Day Ahead			Dispatched in Real Time			Totals		
	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours	MWh	Credits	Hours
AECO	42	$729	144				4	$117	15	46	$846	159
AEP	3,897	$41,796	248	1,317	$23,063	22				5,214	$64,858	270
AP	2,140	$38,555	526				10	$562	11	2,150	$39,117	537
BGE	58	$2,461	210							58	$2,461	210
ComEd	260	$316	102				700	$4,474	806	960	$4,790	908
DAY	3	$104	1							3	$104	1
DLCO	6	$178	13							6	$178	13
Dominion	5,653	$243,316	865	74	$1,549	44	263	$7,257	155	5,989	$252,122	1,064
DPL	15	$557	258							15	$557	258
JCPL	0	$17	1				11	$178	33	11	$195	34
Met-Ed	81	$3,516	135				5	$255	15	86	$3,771	150
PECO	15,005	$280,076	19,347				260	$10,919	1,222	15,265	$290,995	20,569
PENELEC	163	$6,741	52				2	$47	6	166	$6,788	58
Pepco	132	$4,349	88				50	$1,941	89	182	$6,289	177
PPL	18,829	$480,596	6,057	2,182	$66,057	365	209	$11,924	373	21,220	$558,577	6,795
PSEG	304	$4,598	257				5	$158	32	309	$4,756	289
RECO	1	$12	24							1	$12	24
Total	46,589	$1,107,915	28,328	3,573	$90,668	431	1,519	$37,833	2,757	51,681	$1,236,416	31,516
Max	18,829	$480,596	19,347	2,182	$66,057	365	700	$11,924	1,222	21,220	$558,577	20,569
Avg	2,741	$65,171	1,666	1,191	$30,223	144	138	$3,439	251	3,040	$72,730	1,854

Table 2-100 shows total settlements submitted by month for calendar years 2007 through 2009. For January through July of 2008, total monthly settlements were higher than the monthly totals for 2007, despite the recent expiration of the incentive program. In October of 2008, settlement submissions dropped significantly from the prior month and from the same month in 2007, a trend that continued through early 2009. This drop in participation corresponds with the implementation of the PJM daily review process, as well as the lower overall price levels in PJM. April of 2009 showed the lowest level of settlements submitted in the three year period, after which, settlements began to show steady growth. By June of 2009, settlement activity showed signs of stabilization.

Table 2-100 Settlement days submitted by month in the Economic Program: 2007 through 2009

Month	2007	2008	2009
Jan	937	2,916	1,264
Feb	1,170	2,811	654
Mar	1,255	2,818	574
Apr	1,540	3,406	337
May	1,649	3,336	918
Jun	1,856	3,184	2,727
Jul	2,534	3,339	2,879
Aug	3,962	3,848	3,760
Sep	3,388	3,264	2,570
Oct	3,508	1,977	2,361
Nov	2,842	1,105	2,321
Dec	2,675	986	1,240
Total	26,423	32,990	21,605

Table 2-101 shows the number of distinct Curtailment Service Providers (CSPs) and distinct customers actively submitting settlements by month for the period 2007 through 2009. The number of active customers per month decreased in early 2009, reaching a three year low in April. Since then, monthly customer counts vary significantly. However, the number of active customers in calendar year 2009 has increased by 225, or 43 percent, over calendar year 2008.

Table 2-101 Distinct customers and CSPs submitting settlements in the Economic Program by month: Calendar years 2007 through 2009

	2007		2008		2009	
Month	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers
Jan	11	72	13	261	17	257
Feb	10	89	13	243	12	129
Mar	9	87	11	216	11	149
Apr	11	98	12	208	9	76
May	12	109	12	233	9	201
Jun	12	195	17	317	20	231
Jul	15	259	16	295	21	183
Aug	19	321	17	306	15	400
Sep	15	279	17	312	11	181
Oct	11	245	13	226	11	93
Nov	10	204	14	208	9	143
Dec	11	243	13	193	10	160
Total Distinct Active	21	405	24	522	25	747

Table 2-102 shows a frequency distribution of MWh reductions and credits at each hour for calendar year 2009. The period from hour ending 0800 EPT to 2300 EPT accounts for 85 percent of MWh reductions and 86 percent of credits.

Table 2-102 Hourly frequency distribution of Economic Program MWh reductions and credits: Calendar year 2009

	MWh Reductions				Program Credits			
Hour Ending	MWh Reductions	Percent	Cumulative Frequency	Cumulative Percent	Credits	Percent	Cumulative Frequency	Cumulative Percent
1	667	1.29%	667	1.29%	$7,678	0.62%	$7,678	0.62%
2	674	1.30%	1,341	2.59%	$7,930	0.64%	$15,608	1.26%
3	729	1.41%	2,069	4.00%	$9,297	0.75%	$24,904	2.01%
4	818	1.58%	2,887	5.59%	$9,424	0.76%	$34,328	2.78%
5	833	1.61%	3,720	7.20%	$10,249	0.83%	$44,577	3.61%
6	887	1.72%	4,606	8.91%	$14,975	1.21%	$59,552	4.82%
7	2,100	4.06%	6,706	12.98%	$94,378	7.63%	$153,930	12.45%
8	2,603	5.04%	9,310	18.01%	$115,366	9.33%	$269,295	21.78%
9	2,648	5.12%	11,958	23.14%	$76,388	6.18%	$345,684	27.96%
10	2,476	4.79%	14,435	27.93%	$66,820	5.40%	$412,503	33.36%
11	2,517	4.87%	16,952	32.80%	$68,721	5.56%	$481,224	38.92%
12	2,477	4.79%	19,429	37.59%	$54,170	4.38%	$535,394	43.30%
13	2,474	4.79%	21,903	42.38%	$49,943	4.04%	$585,336	47.34%
14	2,717	5.26%	24,620	47.64%	$52,595	4.25%	$637,931	51.60%
15	2,629	5.09%	27,249	52.72%	$49,714	4.02%	$687,646	55.62%
16	2,826	5.47%	30,075	58.19%	$48,496	3.92%	$736,141	59.54%
17	3,185	6.16%	33,260	64.35%	$62,960	5.09%	$799,101	64.63%
18	3,484	6.74%	36,744	71.09%	$106,428	8.61%	$905,530	73.24%
19	3,353	6.49%	40,096	77.58%	$89,845	7.27%	$995,375	80.50%
20	3,428	6.63%	43,524	84.21%	$82,600	6.68%	$1,077,975	87.19%
21	2,936	5.68%	46,460	89.89%	$82,642	6.68%	$1,160,617	93.87%
22	2,259	4.37%	48,719	94.26%	$41,770	3.38%	$1,202,387	97.25%
23	1,684	3.26%	50,402	97.52%	$20,561	1.66%	$1,222,948	98.91%
24	1,281	2.48%	51,684	100.00%	$13,468	1.09%	$1,236,416	100.00%

Table 2-103 shows the frequency distribution of Economic Program MWh reductions and credits by real-time zonal, load-weighted, average LMP in various price ranges. Reductions occurred primarily when zonal, load-weighted, average LMP was between $25 and $100 per MWh. Approximately 91 percent of MWh reductions and 66 percent of program credits are associated with hours when the applicable zonal LMP was less than or equal to $100.

Table 2-103 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): Calendar year 2009

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative Frequency	Cumulative Percent	Credits	Percent	Cumulative Frequency	Cumulative Percent
$0 to $25	723	1.40%	723	1.40%	$511	0.04%	$511	0.04%
$25 to $50	30,468	58.95%	31,191	60.35%	$318,633	25.77%	$319,143	25.81%
$50 to $75	10,891	21.07%	42,082	81.43%	$276,135	22.33%	$595,278	48.15%
$75 to $100	4,877	9.44%	46,958	90.86%	$223,239	18.06%	$818,517	66.20%
$100 to $125	2,227	4.31%	49,185	95.17%	$144,874	11.72%	$963,391	77.92%
$125 to $150	1,287	2.49%	50,472	97.66%	$108,610	8.78%	$1,072,001	86.70%
$150 to $200	813	1.57%	51,285	99.23%	$92,181	7.46%	$1,164,182	94.16%
$200 to $250	326	0.63%	51,611	99.87%	$52,867	4.28%	$1,217,050	98.43%
$250 to $300	11	0.02%	51,622	99.89%	$2,276	0.18%	$1,219,325	98.62%
> $300	59	0.11%	51,681	100.00%	$17,091	1.38%	$1,236,416	100.00%

Emergency Program

The zonal distribution of DSR capability in the Emergency Program option is shown in Table 2-104 by program option. On August 10, 2009, the peak-load day for the year, there were no available resources in the Emergency-Energy Only option of the Emergency Program.[105] There were 6,007 sites accounting for 5,129.8 MW registered in the Emergency Full option and 1,410 sites accounting for 2,164.5 MW registered in Emergency Capacity Only option. The ComEd Control Zone showed the highest number of registered sites in Emergency-Full option at 805 or 13%, while the AEP Control Zone showed the highest MW capability with 1,259.9 MW registered, or 25 percent of MW registered in the option. The ComEd Control Zone showed the highest participation in the Capacity Only option of the Emergency Program with 526 sites, or 37 percent of total sites, and 697.1 MW, or 32 percent of total MW registered in the option. In 2009, there were no days with emergency activity.

105 The number of registered sites and MW levels are measured as a one-day snapshot. The one-day snapshot is used because retail customers may change curtailment service providers (CSP) multiple times within a year and each such change would require a registration. When switching occurs, an annual total of registered sites would count the same sites and MW multiple times.

Table 2-104 Registered sites and MW in the Emergency Program (By zone and option): August 10, 2009

	Energy Only		Full		Capacity Only	
	Sites	MW	Sites	MW	Sites	MW
AECO	0	0.0	131	45.7	12	15.9
AEP	0	0.0	588	1,259.9	99	504.3
AP	0	0.0	524	424.9	42	72.2
BGE	0	0.0	485	615.8	29	26.1
ComEd	0	0.0	805	646.6	526	697.1
DAY	0	0.0	159	147.5	13	57.2
DLCO	0	0.0	160	86.7	34	33.7
Dominion	0	0.0	445	473.4	46	40.6
DPL	0	0.0	168	123.0	15	39.5
JCPL	0	0.0	285	124.3	28	22.4
Met-Ed	0	0.0	174	182.3	42	42.2
PECO	0	0.0	414	136.5	235	215.3
PENELEC	0	0.0	248	192.7	45	27.6
Pepco	0	0.0	269	88.7	32	29.0
PPL	0	0.0	555	292.1	127	315.0
PSEG	0	0.0	582	286.8	79	26.0
RECO	0	0.0	15	3.0	6	0.5
Total	0	0.0	6,007	5,129.8	1,410	2,164.5

Load Management Program

The increase in registrations in the Emergency Program for peak periods in 2009 compared to 2008 is due to increased participation in the Load Management (LM) Program, or increased load response participation in RPM. Table 2-105 shows registered MW in the Load Management Program by program type for delivery years 2007/2008 through 2009/2010.

Table 2-105 Registered MW in the Load Management Program by program type: Delivery years 2007 through 2009

Delivery Year	Total DR MW	Total ILR MW	Total LM MW
2007/2008	560.7	1,584.6	2,145.3
2008/2009	1,017.7	3,480.5	4,498.2
2009/2010	1,020.5	6,273.8	7,294.3

Table 2-106 shows zonal monthly capacity credits that were paid during the calendar year 2009 to ILR and DR resources. Credits from January to May are associated with participation in the 2008/2009 RPM delivery year, while credits from June to December are associated with participation in the 2009/2010 RPM delivery year. The increase in capacity credits after May is the result of a significant increase in both DR and ILR participation in RPM delivery year 2009/2010, as well as increases in RPM clearing prices.

Table 2-106 Zonal monthly capacity credits: January 1, 2009, through December 31, 2009

Zone	January	February	March	April	May	June	July	August	September	October	November	December	Total
AECO	$154,551	$139,595	$154,551	$149,566	$154,551	$375,086	$387,589	$387,589	$375,086	$387,589	$375,086	$387,589	$3,428,428
AEP	$2,578,133	$2,328,636	$2,578,133	$2,494,967	$2,578,133	$3,746,728	$3,871,619	$3,871,619	$3,746,728	$3,871,619	$3,746,728	$3,871,619	$39,284,662
APS	$966,835	$873,270	$966,835	$935,647	$966,835	$2,982,596	$3,082,016	$3,082,016	$2,982,596	$3,082,016	$2,982,596	$3,082,016	$25,985,273
BGE	$2,882,161	$2,603,243	$2,882,161	$2,789,189	$2,882,161	$4,464,694	$4,613,517	$4,613,517	$4,464,694	$4,613,517	$4,464,694	$4,613,517	$45,887,067
ComEd	$3,294,602	$2,975,769	$3,294,602	$3,188,324	$3,294,602	$4,217,299	$4,357,876	$4,357,876	$4,217,299	$4,357,876	$4,217,299	$4,357,876	$46,131,297
DAY	$258,904	$233,849	$258,904	$250,552	$258,904	$646,419	$667,966	$667,966	$646,419	$667,966	$646,419	$667,966	$5,872,235
DLCO	$258,489	$233,474	$258,489	$250,151	$258,489	$375,138	$387,642	$387,642	$375,138	$387,642	$375,138	$387,642	$3,935,073
Dominion	$296,319	$267,643	$296,319	$286,760	$296,319	$1,602,407	$1,655,820	$1,655,820	$1,602,407	$1,655,820	$1,602,407	$1,655,820	$12,873,861
DPL	$665,561	$601,152	$665,561	$644,091	$665,561	$971,656	$1,004,045	$1,004,045	$971,656	$1,004,045	$971,656	$1,004,045	$10,173,074
JCPL	$554,279	$500,639	$554,279	$536,399	$554,279	$868,932	$897,896	$897,896	$868,932	$897,896	$868,932	$897,896	$8,898,256
Met-Ed	$681,734	$615,760	$681,734	$659,743	$681,734	$1,313,605	$1,357,392	$1,357,392	$1,313,605	$1,357,392	$1,313,605	$1,357,392	$12,691,086
PECO	$1,375,581	$1,242,460	$1,375,581	$1,331,207	$1,375,581	$2,052,483	$2,120,899	$2,120,899	$2,052,483	$2,120,899	$2,052,483	$2,120,899	$21,341,456
PENELEC	$283,241	$255,831	$283,241	$274,105	$283,241	$1,282,941	$1,325,705	$1,325,705	$1,282,941	$1,325,705	$1,282,941	$1,325,705	$10,531,303
Pepco	$572,160	$516,789	$572,160	$553,703	$572,160	$788,433	$814,714	$814,714	$788,433	$814,714	$788,433	$814,714	$8,411,124
PPL	$1,200,552	$1,084,370	$1,200,552	$1,161,825	$1,200,552	$3,500,850	$3,617,545	$3,617,545	$3,500,850	$3,617,545	$3,500,850	$3,617,545	$30,820,581
PSEG	$922,290	$833,036	$922,290	$892,538	$922,290	$1,720,276	$1,777,619	$1,777,619	$1,720,276	$1,777,619	$1,720,276	$1,777,619	$16,763,747
RECO	$10,219	$9,230	$10,219	$9,890	$10,219	$17,897	$18,494	$18,494	$17,897	$18,494	$17,897	$18,494	$177,443
Total	$16,955,611	$15,314,746	$16,955,611	$16,408,656	$16,955,611	$30,927,439	$31,958,354	$31,958,354	$30,927,439	$31,958,354	$30,927,439	$31,958,354	$303,205,966

With the elimination of the ILR option on March 26, 2009, effective for the 2012/2013 RPM delivery year, load response participation in RPM will be limited to DR.[106] Table 2-107 shows the amount of DR offered and cleared in each Base Residual Auction (BRA) from delivery year 2007/2008 through 2012/2013. The first auction since the elimination of ILR, for delivery year 2012/2013, showed a significant increase in the amount of DR offered and cleared compared to all prior delivery years.

Table 2-107 Demand Response (DR) offered and cleared in RPM Base Residual Auction: Delivery years 2007/2008 through 2012/2013

Planning Year	DR Offered in BRA	DR Cleared in BRA
2007/2008	123.5	123.5
2008/2009	691.9	518.5
2009/2010	906.9	865.2
2010/2011	935.6	908.1
2011/2012	1,597.3	1,319.5
2012/2013	9,535.4	6,824.3

106 126 FERC ¶ 61,275 (2009).

Load Management Testing

For the 2007/2008 and the 2008/2009 delivery years, Load Management (LM) compliance was assessed only for actual PJM declared events. If no event was declared, no capacity testing was required. On December 12, 2008, PJM filed amendments to the tariff providing for LM testing if no emergency event is called by August 15 of the delivery year. These amendments were approved by the Commission on March 26, 2009 and effective in the 2009/2010 delivery year.[107]

Since there were no emergency events called in the 2009/2010 delivery year, all committed DR and certified ILR resources were required to submit test results. All of a provider's committed DR and certified ILR resources in the same zone are required to test at the same time for a one hour period between 12:00 PM EPT to 8:00 PM EPT on a non-holiday weekday between June 1 and September 30.[108] The resource provider must notify PJM of the intent to test 48 hours in advance.

Depending on initial test results, multiple tests may be conducted. If a Curtailment Service Provider (CSP) shows greater than or equal to 75 percent test compliance across a portfolio of resources, all noncompliant resources are eligible for retesting. However, if the initial test shows less than 75 percent compliance, no associated resources are eligible for a retest.

Results from the 2009/2010 Load Management testing results are shown in Table 2-108. The first column shows the nominal value which represents the reduction capability indicated by the participant at registration. The second column shows Load Management MW commitments, which are used to assess RPM compliance. Differences between these two columns may reflect differences between MW offered and cleared for any partially cleared DR resource. In addition, RPM Commitments consider any RPM transactions, such as capacity replacement sales or purchases for Demand Resources, while the nominal ICAP does not. Overall, test results showed 1,298.5 MW available over RPM Commitments, or 118 percent test compliance. The DPL control zone showed the highest percentage of compliance, with load reductions at 147 percent of RPM Commitments, while the AEP control zone showed the highest level of MW reduction in testing, with load reductions at 1,995.3 MW, or 400.5 MW over RPM Commitments. The DAY control zone showed the lowest level of test compliance, with load reductions at 99 percent of RPM Commitments.

107 126 FERC ¶ 61,275 (2009).

108 For more information, see Manual 18, "PJM Capacity Market", Revision 8 (January 1, 2010), Section 8.6.

Table 2-108 Load Management test results and compliance by zone for the 2009/2010 delivery year

Zone	Nominal ICAP	Committed MW	Load Reduction Test Results	Over/Under Compliance	Percent Test Compliance	Percent of Nominal ICAP
AECO	61.5	61.4	76.0	14.5	124%	123%
AEP	1,764.2	1,594.8	1,995.3	400.5	125%	113%
AP	497.2	495.0	645.7	150.7	130%	130%
BGE	641.9	640.0	666.5	26.5	104%	104%
ComEd	1,343.7	1,342.6	1,552.9	210.3	116%	116%
DAY	204.7	204.4	203.4	(1.1)	99%	99%
DLCO	514.0	507.7	554.7	47.0	109%	108%
Dominion	162.4	160.2	184.6	24.4	115%	114%
DPL	120.4	120.2	177.2	57.0	147%	147%
JCPL	146.7	146.3	184.3	38.0	126%	126%
Met-Ed	224.5	221.5	244.0	22.4	110%	109%
PECO	351.8	351.3	441.6	90.3	126%	126%
PENELEC	220.2	218.4	270.2	51.8	124%	123%
Pepco	117.7	109.9	144.2	34.3	131%	123%
PPL	607.1	601.0	662.3	61.2	110%	109%
PSEG	312.9	310.8	381.4	70.5	123%	122%
RECO	3.5	3.1	3.2	0.1	104%	91%
Total	7,294.3	7,088.8	8,387.4	1,298.5	118%	115%

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.[109] 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.

109 PJM filed for changes to the PJM Tariff and Operating Agreement which state that CSPs are responsible for ensuring that all Emergency Load Response Program participants have metering equipment capable of providing hourly integrated metered load data (see Docket ER09-1508-000). These changes were accepted effective September 28, 2009. However, customers in the non-hourly metered pilot submit test results based on DLC measurement and verification procedures. For more information, see PJM Manual 19, "Load Forecasting and Analysis", Revision 15 (October 1, 2009), Attachment B.

Measurement and Verification

Economic Program

Participants in the Economic Program are paid based upon the reductions in MWh usage that can be attributed to demand side actions and measures. Most participants in the Economic Program measure their reductions by comparing metered load against an estimate of what metered load would have been absent the reduction.[110] The general methodology is to create a base line usage level by calculating the average usage for a set of days that are intended to be representative of a retail customer's typical usage, including separate calculations for weekends/holidays. The extent to which the DSR Program can accurately quantify and compensate actual load reductions is dependent on the Program's ability to establish what a customer's metered load would have been absent any load reduction. This is a very difficult task and the methods used to date have been flawed, resulting in payments for reductions in usage that did not occur.

Customer Base Line (CBL) - History

Since the beginning of the program, there have been significant issues with the approach to measuring demand-side response MW. An inaccurate or unrepresentative CBL can lead to payments when the customer has taken no action to respond to market prices. Substantial improvement in measurement and verification methods must be implemented in order to ensure the credibility of PJM demand-side programs. These could take the form of improvements in the CBL calculation and/or improvements in the verification and customer documentation of load reducing activities. The goal should be to treat the measurement of demand-side resources like the measurement of any other resource in the wholesale power market, including generation and load, that is paid by other participants or makes payments to other participants. Recent changes to the settlement review process represent clear improvements, but do not go far enough.

Prior to recent process revisions, the EDC or LSE was responsible for reviewing a customer's CBL data and could object to the calculations. When an EDC or LSE objected, customers had time to resubmit the data, which were also subject to review. From the beginning of the Economic Program, there were multiple settlement disputes in which an EDC or LSE did not approve CBL calculations and CSPs requested PJM involvement. These disputes were among the factors that led to the creation of the Customer Base Line Subcommittee (CBLS) in January 2007. The subcommittee's mission was to "Evaluate current methodology for PJM economic load response used to determine load reductions done through deliberate customer actions in response to expected day ahead and/or real time prices…[and] propose enhancements and/or changes that will improve the transparency and accuracy of the results which will also help to reduce the number of unanticipated settlement rejections."[111]

In December 2007, proposals to modify CBL business rules were presented to the PJM Market Implementation Committee with a focus on two major issues: the permissible period for selecting a comparable day and the number of days to be used for the CBL calculation; and the definition of

110 On-site generation meter data is the other method used to determine the load reduction, if used only for economic load reduction.
111 "Customer Baseline Committee Charter," February 27, 2007, <http://www.pjm.com/~/media/committees-groups/subcommittees/cbls/postings/20070223-final-charter.ashx> (22.7 KB).

a demand-side curtailment. The key criteria considered by the CBLS were empirical performance, simplicity, eliminating gaming/free-ridership, and overall cost to implement and administer.

On April 14, 2008, PJM filed with the FERC revisions to the Tariff and Operating Agreement to improve the Economic Program.[112] The filing included provisions to: (1) improve the method of establishing CBLs; (2) clarify that eligibility is limited to demand reductions in response to price; (3) establish objective criteria to assist with the identification of inappropriate market activity; and (4) provide PJM the authority to deny participation in the Program. Revisions were approved June 12, 2008.[113]

The revised, current weekday CBL methodology includes the highest four of most recent five weekdays, with a maximum lag on eligible days set at 45. Low usage days (load less than 75 percent of the average) and event days (days with curtailment events or demand reductions) are eliminated and replaced with prior days, unless there are not enough eligible days in the last 45 weekdays. Saturdays are considered separately, as are Sundays and holidays. The elimination of event days means that CBL measurements are not limited to the most recent five weekdays and can include weekdays from as far back as 45 days.

Prior to the revisions, the standard weekday CBL included the highest five weekdays of the most recent 10 weekdays, with no limit on how current CBL days must be. In addition, low usage days were defined as load less than 25 percent of average usage. Submitted settlement days were considered event days in CBL calculations even if they were eventually denied. Saturdays, Sundays and holidays were all considered “like days”.

The effect of the revisions approved June 12, 2008 was to provide for CBL calculations based on more recent and comparable data, which has made CBL calculations more representative of retail customers’ load absent any reduction activities. Additionally, the provision clarifying that participation is limited to reductions in response to real time prices and the establishment of PJM’s authority to deny participation were necessary program changes that are essential components of a rational verification process.

CBL Issues

Even after the revisions, the CBL is still a simple, generic formula applied to nearly every customer’s usage and, as such, is not adequate to serve as the sole or primary basis for determining if an intentional load reduction took place. There are no mandatory CBL enhancements for customers with highly volatile load patterns. If a customer normally has lower load on one particular weekday, that day will appear as a reduction eligible for payment under the current CBL methodology although no deliberate load reducing actions were taken in response to real time price signals. There are no mandatory adjustments to the standard CBL for load levels that are a function of weather. In a mild week following a week of extreme temperatures and high load levels, a customer can submit settlements without taking any load reducing action and it will appear as a reduction eligible for payment because metered load is below CBL. A customer’s CBL calculation is only reviewed in the Economic Program registration process and the review criteria are unclear. In the registration

112 *PJM Interconnection, L.L.C.,* Tariff Amendments, Docket No. ER08-824-000 (April 14, 2008).
113 123 FERC ¶ 61,257 (2008).

process, an alternative CBL may be proposed by the CSP or the relevant LSE/EDC.[114] PJM has developed thirteen alternative CBL calculations, three of which include a weather sensitivity adjustment. While the weather adjusted alternative CBL calculations likely provide a more accurate baseline for all customer consumption, an alternative CBL is an optional program feature rather than a required one, and, as a result, the majority of settlements submitted use an unadjusted standard CBL. Since the implementation of the Load Response System (eLRS) on June 1, there were 17,791 settlements submitted and processed for CBL calculations for calendar year 2009. Of those 17,357 CBL calculations, 14,383 or 83 percent utilized the standard, unadjusted CBL, and 1,468 or 8 percent utilized an alternative CBL adjusted for weather sensitivity.

Determining the accuracy of a CBL is a difficult task. More data is required than the metered load associated with settlement and the CBL used to determine the reduction amount. However, that is the only data currently available to PJM at the time of settlement review. Complete historical data is required in order to determine whether the CBL is representative of normal load patterns.

In the future state, retail markets will reflect hourly wholesale prices and customers will receive direct savings associated with reducing consumption in response to real-time prices. There will not be a need for an RTO Economic Load Response Program, or for extensive measurement and verification protocol. In the transition to that point, there is a need for robust measurement and verification techniques to ensure that transitional programs are incenting the desired behavior. These techniques center on estimating what consumption would have been, absent any load reducing activities, which is a very difficult task.

The MMU has analyzed all settlement data submitted in the Economic Load Response Program from the period January 1 through December 31, 2009, to further assess the revised CBL calculation.[115] While the revised CBL showed significant improvements in representing load patterns, the revised CBL methodology is still inadequate as a basis for defining and determining load reductions which are compensated under the PJM demand side programs. The tariff changes effective June 13, 2008, provide for a thirty day period to review activity in the Economic Load Response Program, after which, "[t]he Office of the Interconnection may refer the matter to the PJM MMU and/or the FERC Office of Enforcement if the review indicates the relevant Economic Load Response Participant and/or relevant electric distribution company or LSE is engaging in activity that is inconsistent with the PJM Interchange Energy Market rules governing Economic Load Response Participants."[116] PJM has not referred any participants or registrations to the MMU.

Analysis of Settlements

The MMU only has access to meter data submitted as part of a settlement day. The revised PJM settlement review process includes screens that result in reduced submissions of excess settlement data.[117] While this is a positive change for the program, it limits the hourly metered load data provided to PJM and thus limits the ability of PJM and the MMU to assess whether a customer's CBL is representative.

114 If, however, agreement cannot be reached, then PJM will determine the alternative CBL.
115 Since behind the meter generation customers do not require a CBL, they were excluded from this analysis.
116 OA Schedule 1 § 3.3A.7(b).
117 Specifically, the normal operations screen and the requirement that notification hours match settlement hours have resulted in a reduction of the submission of excess settlement data.

In the *2008 State of the Market Report for PJM*, the MMU reported that a large number of consecutive hours showing a metered load less than CBL maybe an indication that the CBL is not an adequate method to determine load reductions. If a CBL is accurately modeling load patterns, then a CBL greater than real time load indicates load reducing actions are taking place. If, for any settlement, the number of consecutive hours showing load reduction is beyond a reasonable window for load reducing actions in response to price, it should initiate a CBL review and warrant further substantiation from the customer and CSP.

The MMU screened all settlements submitted for January 1 through December 31, 2009 for any settlement that showed 24 consecutive hours of load reduction. Table 2-109 shows the proportion of 24 hour reduction settlements to total settlements submitted, as well as the proportion of credits associated with these settlements. Table 2-110 shows the same information for July 1, 2008 through December 31, 2008. The proportion of settlements showing 24 hours of reduction has dropped significantly from 19.8 percent in 2008 to 1.5 percent in 2009. The proportion of total credits associated with these settlements has dropped significantly from 40.6 percent to 22.4 percent. However, in 2009, these 314 settlement days still accounts for a disproportionally large percent of total credits for the time period.

Table 2-109 Settlements showing consecutive 24 hour reductions as a percent of total settlements submitted for the period January 1, 2009 through December 31, 2009

	Settlement Days	Percent of Total Settlements	CSP Credits	Percent of Total Credit
24 consecutive hours CBL > metered load	314	1.5%	$273,356	22.4%
All other settlements	20,589	97.4%	$944,544	77.6%
Total	21,133	100.0%	$1,217,900	100.0%

Table 2-110 Settlements showing consecutive 24 hour reductions as a percent of total settlements submitted for the period July 1, 2008 through December 31, 2008

	Settlement Days	Percent of Total Settlements	CSP Credits	Percent of Total Credit
24 consecutive hours CBL > metered load	2,812	19.8%	$3,955,865	40.6%
All other settlements	11,416	80.2%	$5,789,988	59.4%
Total	14,228	100.0%	$9,745,853	100.0%

The PJM Activity Review Process has significantly reduced the occurrence of 24 hour settlement submissions and therefore the frequency of 24 consecutive hours where the CBL is greater than metered load. However, this does not indicate that the CBL is more accurate and there are still instances of requests for settlements passing the daily activity review screen that include 24 consecutive hours of reduction. These settlements are paid without any documentation of load reducing activities in response to real time price signals.

It is extremely implausible that any customer would take load reduction actions for 24 consecutive hours in response to real time price signals. It is also extremely implausible that an accurate CBL would result in metered load less than base line load for every hour of the day. It is more likely that the CBL is biased upward because it is based on usage from prior days with higher load. Under these circumstances, it is impossible to determine whether the customer took any load reducing actions, from the settlement data. 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.

Activity Review Process

Effective November 3, 2008, PJM began a new Activity Review Process for settlements in the Economic Demand Side Response Program.[118] The Activity Review Process includes a daily screen of settlements as well as an ongoing "normal operations" registration review process for identifying inappropriate behavior. The daily settlement screens define specific criteria for the automatic denial of daily settlements. The "normal operations" review process requires identified participants to submit documentation on load reducing actions associated with settlements submitted. With the implementation of the activity review process, PJM specifically defines the acceptable criteria for LSE/EDC denial of settlements. LSE/EDCs can no longer deny settlements based on whether the customer's CBL calculations reasonably represent load or on a determination that a load reduction action was not in response to price. 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 daily screen provides that PJM will deny a daily settlement when any of the following criteria are met: (1) no advanced notification for settlements; (2) settlement hours do not match notification hours; (3) settlement is worth less than $5 in value; or (4) 75 percent or more of settlement hours show a retail generation and transmission rate higher than LMP.

The daily screen does indirectly address an issue with the CBL calculation, the ineligibility of "event days" for inclusion in CBL. When a high CBL results from high load days, a customer or CSP could submit settlements on daily basis to block lower load days from CBL eligibility, creating an upward bias in measured CBL. When a customer submits low value settlements for the purpose of blocking the inclusion of low load days from the CBL, the daily review process will deny them if they fail one of the four identified screens. But, PJM does not review daily settlements to assess responsiveness to price or accuracy of the CBL.

PJM's "normal operations" screen involves a review of all participation when a customer submits settlements for 70 percent (21 days) of available days in a rolling 30 weekday period. The review includes: (1) analysis of notifications and settlements; (2) review of registration contract; (3) required CSP submission of detailed description of load reduction activities; (4) written verification from end-use customer regarding DSR activity on specific days; and (5) optional on-site review. During this review, all new settlement requests will be denied pending the outcome of the review. Depending on the conclusion of the activity review, the registration may be terminated and the CSP may be referred to the FERC Office of Enforcement and/or the MMU, pursuant to the tariff.

118 See PJM. "Economic Demand Side Response: Activity review process and PJM actions" <http://www.pjm.com/~/media/committees-groups/committees/drsc/20081031/20081031-item-04-dsr-activity-review-proc.ashx>

Load Management Program

There are three forms of participation in the Load Management (LM) Program distinguished by their measurement and verification protocol: (1) Direct Load Control (DLC), (2) Firm Service Level (FSL), and (3) Guaranteed Load Drop (GLD). The DLC option accounts for 7 percent of registered MW in the LM Program, while the FSL option accounts for 47 percent and the GLD option accounts for 47 percent.

The DLC method is used for customers in the Pilot Program for non-hourly metered customers. For DLC customers, a CSP will interface directly with customer equipment, sending a communication to cycle when PJM has declared an event. Load reductions are estimated through PJM reported or site surveyed impact studies.

FSL customers are contractually obligated to reduce load to a nominal value. The measurement and verification of load reductions under FSL option for purposes of event compliance is relatively straightforward.

The Guaranteed Load Drop (GLD) program option involves establishing a baseline of consumption absent the emergency event, similar to the measurement and verification procedure in the Economic Program. There are several techniques for estimation available to participants ranging in complexity. The comparable day option determines reductions based on consumption on similar day experience. Another option determines reduction as differences from hourly load immediately prior to or following an event. A third option is the standard CBL calculation used in the Economic Program. Other options include regression analysis and load profile modeling.

The prior section addresses shortfalls of the standard CBL calculation used in the Economic Program, including the potential for an upward bias based on prior days with warmer temperatures. The potential for an upward bias during an actual Emergency Event is minimal, since Emergency Events coincide with peak load conditions in PJM which are highly correlated with peak temperatures. However, this design flaw is an issue when applied to Load Management testing as participants have discretion as to when testing will take place. It is possible for a GLD customer or a group of GLD customers to perform testing directly following a week of high temperatures and higher overall load levels and to show a greater level of reduction capability than would be possible during an emergency event.

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.

Conclusions: Demand Side

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.

Emergency Program

In the 2009/2010 delivery year, all participants in the Emergency Program were capacity resources, integrated into RPM through the Load Management Program. The purpose of the Load Management Program is to provide a mechanism for end-use customers to avoid paying the Capacity Market clearing price in return for agreeing to not use capacity when it is needed by customers who have paid for capacity. The fact that customers in the Load Management Program only have to agree to interrupt ten times per year represents a flaw in the design of the program. There is no reason to believe that the customers who pay for capacity will need the capacity used by participating LM customers only ten times per year. In fact, it can be expected that the probability of needing that capacity will increase with the amount of MW that participating LM customers clear in the RPM auctions.

Under the Emergency Energy Only option and the Emergency Full option, participants are made whole to a minimum strike price offer regardless of the hourly LMP. There is no economic reason to compensate load reductions up to $1,000/MWh during an emergency event regardless of the hourly LMP. Compensation in the Emergency Program should be directly aligned with the RPM market clearing price. The appropriate energy market price signal for load reduction in any hour is the hourly LMP. This means that the appropriate compensation in any PJM Program is the LMP less the generation component of a fixed retail rate, which is already made available through participation in the Economic Program. There is no need for energy payments through the Emergency Program. The current design of the Emergency Program incents resources to seek overcompensation through Emergency Energy payments equal to the greater of LMP or a submitted minimum dispatch price, which, in most cases is set at $1,000/MWh.

The MMU recommends that the option to specify a minimum dispatch price under the Emergency Program Full option be eliminated and that participating resources receive the hourly real-time LMP less any generation component of their retail rate. The MMU also recommends that the Emergency Program Energy Only option should be eliminated because the opportunity to receive the appropriate energy market incentive is already provided in the Economic Program.

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.

Economic Program

In PJM's Economic Load Response Program, the primary tool used to establish what unrestricted load would have been is the standard CBL. The modifications to the CBL calculations effective June, 2008, and the new review process, effective November, 2008, represent significant improvements to the Economic Program, but the review process is not yet adequate to ensure that other customers are receiving the benefit of actual demand reductions when payments are made under the program. The new review process is not yet developed to the point that it can establish that load reductions are the result of identifiable load reducing actions taken in response to price. There is no explicit or implicit screening mechanism in place to verify that CBL calculations are representative of customer load.

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.

The “normal operations” screen defines an explicit threshold for the proportion of available days submitted for settlement, at or above which the CSP and end use customer must substantiate their submitted demand reductions. It is not clear why it is appropriate to require documentation of load reduction activities above a threshold and require no documentation of load reduction activities below that threshold.

The definition of the standard or default CBL should continue to be refined to ensure that it reflects the actual normal use of individual customers including normal daily and hourly fluctuations in usage and usage that is a function of measurable weather conditions.

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 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. This includes: the ongoing evaluation of whether CBL accurately represents customer load for each customer; analysis of settlements to determine responsiveness to price; the required submission of detailed description of load reduction activities on specific days; and review of the contract.

SECTION 3 - ENERGY MARKET, PART 2

The Market Monitoring Unit (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.

Overview

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. (Table 3-10.) 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.

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.[1] 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.

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.

1 126 FERC ¶ 61,251 (2009).

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.

Net Revenue

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 to serve PJM markets. Net revenue quantifies the contribution to capital and avoidable costs received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services. Although generators receive operating reserve payments as a revenue stream, these payments are not included when the analysis is based on perfect dispatch.[2] Operating reserve payments are included, when the analysis is based on the peak-hour, economic dispatch model on any days when a unit operated at a loss and when the analysis is of actual net revenues.[3]

Gross Energy Market revenue is the product of the Energy Market price and generation output. Gross revenues are also received from the Capacity and Ancillary Service Markets. Total gross revenue less variable cost equals net revenue. In other words, net revenue is the amount that remains, after short run variable costs have been subtracted from gross revenue, to cover fixed costs which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Fixed costs, in this sense, include all but short run variable costs.

In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute to the payment of fixed costs. In PJM, the Energy, Capacity and Ancillary Service Markets are all significant sources of revenue to cover fixed costs of generators, as are payments

2 Under the PJM model, operating reserve payments compensate generation owners when units operate at PJM's request when LMP is less than marginal cost over defined hours of operation. Operating reserve does not apply in perfect dispatch because the theoretical unit only operates when LMP is greater than marginal cost.

3 The peak-hour, economic dispatch model is a realistic representation of market outcomes that, in contrast to the perfect dispatch model, considers unit operating limits. The model can result in the dispatch of a unit for a block that yields negative net energy revenue and is made whole by operating reserve payments.

for the provision of black start and reactive services. Thus, in a perfectly competitive market in long-run equilibrium, with energy, capacity and ancillary service payments, net revenue from all sources would be expected to equal the fixed costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate based on actual conditions in all relevant markets.

Theoretical Energy Market Net Revenue

The net revenues presented in this section are theoretical as they are based on explicitly stated assumptions about how a unit would operate, rather than on an analysis of actual net revenues for actual units operating in PJM. Energy Market net revenues were developed separately for both the Real-Time and the Day-Ahead Energy Markets.

The Real-Time Energy Market revenues in Table 3-1 and the Day-Ahead Energy Market revenues in Table 3-2 reflect net Energy Market revenues from all hours during 1999 to 2009 for the Real-Time Energy Market and during 2000 to 2009 for the Day-Ahead Energy Market when the PJM hourly LMP exceeded the identified marginal cost of generation. The tables include the dollars per installed MW-year that would have been received by a unit in PJM if it had operated whenever system price exceeded the identified marginal cost in dollars per MWh, adjusted for unit forced outages.[4] For example, during 2009, if a unit had marginal costs (fuel plus variable operation and maintenance expense) equal to $30 per MWh, it had an incentive to operate whenever the Real-Time Energy Market LMP exceeded $30 per MWh. If such a unit had operated during all profitable hours in 2009, adjusted for forced outages, it would have received $73,039 per installed MW-year in net revenue from the Real-Time Energy Market alone. The same unit would have received $70,736 per installed MW-year in net revenue from the Day-Ahead Energy Market.[5]

Table 3-1 illustrates the relationship between generator marginal cost and net revenue from the PJM Real-Time Energy Market alone for the years 1999 through 2009.

4 Real-Time and Day-Ahead Energy Market net revenue calculations reflect a forced outage rate equal to the actual PJM system forced outage rate for each year. Since these tables include a range of marginal cost from $10 to $200, an outage rate by class cannot be utilized because there is no simple mapping of marginal cost to class of generation, e.g. the $100 marginal cost could include steam-oil, gas–fired CC and efficient gas-fired CTs. Class-specific forced outage rates are used for the class-specific net revenue calculations.

5 This unit would not receive Real-Time Energy Market revenues in addition to Day-Ahead Energy Market revenues as any energy scheduled in the Day-Ahead Energy Market would be credited at the day-ahead energy market-clearing price and would not be eligible for Real-Time Energy Market revenues for the same hour of operation.

Table 3-1 PJM Real-Time Energy Market net revenue (By unit marginal cost (Dollars per MWh)): Calendar years 1999 to 2009

Marginal Cost	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
$10	$152,087	$150,774	$186,887	$153,620	$231,927	$263,115	$394,619	$322,668	$388,984	$459,738	$220,494
$20	$94,690	$89,418	$116,116	$85,661	$159,751	$185,956	$314,917	$242,179	$308,397	$379,750	$141,212
$30	$72,489	$59,776	$78,368	$51,898	$110,126	$121,218	$241,977	$171,735	$235,215	$302,122	$73,039
$40	$62,367	$39,519	$56,055	$31,650	$73,828	$74,920	$184,479	$120,014	$177,918	$233,568	$38,171
$50	$57,080	$25,752	$42,006	$19,776	$47,277	$44,577	$141,078	$83,857	$132,033	$179,669	$21,792
$60	$54,132	$16,888	$33,340	$13,101	$29,566	$25,328	$107,057	$58,812	$95,768	$138,282	$13,197
$70	$52,259	$11,750	$27,926	$9,080	$18,001	$13,624	$80,473	$41,608	$67,644	$106,343	$8,353
$80	$50,959	$8,586	$24,389	$6,623	$10,650	$6,929	$59,903	$29,643	$46,859	$81,666	$5,366
$90	$49,840	$6,700	$22,080	$5,079	$6,273	$3,494	$44,043	$21,585	$32,467	$62,360	$3,479
$100	$48,818	$5,640	$20,521	$4,109	$3,770	$1,784	$32,184	$16,188	$23,110	$47,397	$2,349
$110	$47,863	$4,930	$19,375	$3,507	$2,250	$951	$23,338	$12,653	$16,898	$35,713	$1,588
$120	$46,926	$4,385	$18,480	$3,063	$1,315	$518	$16,831	$10,283	$12,655	$26,971	$1,067
$130	$46,007	$3,958	$17,716	$2,758	$723	$260	$12,070	$8,645	$9,795	$20,281	$731
$140	$45,114	$3,609	$17,030	$2,501	$387	$124	$8,528	$7,466	$7,737	$15,222	$484
$150	$44,228	$3,317	$16,421	$2,287	$218	$51	$5,903	$6,667	$6,302	$11,288	$323
$160	$43,374	$3,102	$15,884	$2,115	$142	$24	$3,946	$6,030	$5,202	$8,351	$205
$170	$42,523	$2,923	$15,395	$1,970	$94	$9	$2,554	$5,508	$4,357	$6,196	$119
$180	$41,685	$2,768	$14,944	$1,828	$51	$0	$1,679	$5,083	$3,722	$4,630	$69
$190	$40,856	$2,623	$14,542	$1,700	$23	$0	$1,113	$4,699	$3,219	$3,464	$41
$200	$40,036	$2,488	$14,162	$1,607	$10	$0	$706	$4,347	$2,831	$2,643	$15

Table 3-2 illustrates the relationship between generator marginal cost and net revenue from the PJM Day-Ahead Energy Market alone for the years 2000 through 2009.[6]

6 The Day-Ahead Energy Market began on June 1, 2000. For the analysis presented in Table 3-2, Real-Time Energy Market LMP was used from January 1, 2000 to May 31, 2000.

Table 3-2 PJM Day-Ahead Energy Market net revenue (By unit marginal cost (Dollars per MWh)): Calendar years 2000 to 2009

Marginal Cost	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
$10	$158,429	$189,366	$154,267	$234,622	$254,455	$392,425	$216,637	$364,734	$456,557	$218,865
$20	$95,823	$115,372	$83,083	$159,572	$176,265	$311,563	$165,614	$283,295	$375,221	$138,961
$30	$61,816	$68,718	$44,916	$102,907	$109,583	$235,006	$117,447	$207,702	$295,084	$70,736
$40	$38,762	$42,283	$25,011	$61,674	$59,650	$173,084	$77,340	$146,320	$221,678	$29,918
$50	$23,141	$27,936	$15,126	$34,891	$27,638	$125,929	$47,954	$97,297	$161,374	$13,695
$60	$14,281	$20,375	$9,894	$19,169	$11,152	$90,176	$29,201	$59,674	$115,287	$6,695
$70	$9,523	$16,304	$6,804	$10,504	$4,039	$63,340	$18,423	$34,135	$80,996	$3,134
$80	$6,840	$13,933	$4,856	$5,858	$1,375	$43,467	$12,613	$19,326	$56,349	$1,433
$90	$5,100	$12,540	$3,522	$3,389	$415	$29,224	$9,180	$11,257	$39,159	$599
$100	$3,927	$11,478	$2,570	$1,954	$121	$19,208	$7,037	$6,530	$27,761	$189
$110	$3,244	$10,705	$1,885	$1,150	$42	$12,186	$5,742	$3,730	$20,157	$38
$120	$2,683	$10,098	$1,385	$620	$14	$7,409	$4,873	$2,081	$14,650	$4
$130	$2,299	$9,579	$1,000	$315	$0	$4,361	$4,203	$1,167	$10,633	$0
$140	$2,056	$9,139	$712	$148	$0	$2,397	$3,628	$703	$7,706	$0
$150	$1,884	$8,708	$494	$34	$0	$1,229	$3,136	$421	$5,594	$0
$160	$1,787	$8,312	$354	$0	$0	$574	$2,703	$241	$4,034	$0
$170	$1,701	$7,926	$243	$0	$0	$234	$2,314	$118	$2,929	$0
$180	$1,616	$7,564	$145	$0	$0	$83	$1,991	$51	$2,173	$0
$190	$1,532	$7,232	$78	$0	$0	$31	$1,717	$11	$1,611	$0
$200	$1,447	$6,908	$30	$0	$0	$11	$1,475	$0	$1,209	$0

Figure 3-1 displays the information from Table 3-1, and Figure 3-2 displays the information from Table 3-2. As Figure 3-1 illustrates, the Real-Time Energy Market net revenue curve was lower in 2009 than in 2008 and in 2007 for every level of unit marginal costs. For units with marginal costs equal to or less than $90, net revenues were lower in 2009 than in any other year since 2003. As Figure 3-2 illustrates, the Day-Ahead Energy Market net revenue curve was lower in 2009 than in 2008 and in 2007 for every marginal cost level. For units with marginal costs equal to, or less than, $80, net revenues were lower in 2009 than in any other year since 2003.

The decrease in 2009 Real-Time Energy Market net revenue compared to 2008 is the result of changes in the frequency distribution of energy prices. In 2009, prices were greater than or equal to $30 per MWh less frequently than in 2008. The 2009 simple average LMP was $37.08 per MWh, a substantial decrease compared to $66.40 per MWh in 2008. In 1999, the Real-Time Energy Market LMP was greater than, or equal to, $30 per MWh during 17 percent of all hours. In 2000, this was 29 percent; in 2001, 34 percent; in 2002, 30 percent; in 2003, 51 percent; in 2004, 68 percent; 81 percent in 2005; 74 percent in 2006; in 2007, 79 percent; in 2008, 92 percent and in 2009, 62 percent.

The decrease in 2009 compared to 2008 Day-Ahead Energy Market net revenue is also the result of changes in the frequency distribution of energy prices. In 2009, prices were greater than, or equal to, $30 less frequently than in 2008 as the simple average LMP was $37.00 per MWh in 2009 compared to $66.12 per MWh in 2008. In 2000, the Day-Ahead Energy Market LMP was greater than or equal to $30 per MWh during 42 percent of all hours. In 2001, this was 42 percent; in 2002, 33 percent; in 2003, 60 percent; in 2004, 72 percent; in 2005, 86 percent; in 2006, 80 percent; in 2007, 84 percent; in 2008, 96 percent and in 2009, 69 percent.

Average price levels in 2009 were significantly lower than in 2008 and, as a result, net revenue levels were lower for specific marginal cost levels, as shown in Figure 3-1 and Figure 3-2. The distribution of prices reflects a number of factors including load levels and fuel costs. Load levels in 2009 were lower compared to those in 2008, and fuel costs decreased significantly. An efficient CT could have produced energy at an average cost of $30 in 1999, compared to $110 in 2008 and $60 in 2009. An efficient CC could have produced energy at an average cost of $20 in 1999, compared to $70 in 2008 and $35 in 2009. An efficient CP could have produced energy at an average cost of $20 in 1999, $45 in 2008 and $30 in 2009. Energy Market net revenues for a new entrant CT, CC and CP were lower in nearly all zones in 2009 due to PJM price levels decreasing more rapidly than the average prices of natural gas and delivered coal. The result is that, while natural gas-fired units and coal-fired units experienced lower marginal costs compared to 2008, the decrease in average PJM prices in 2009 was greater, meaning lower energy net revenue in most control zones for 2009.

Figure 3-1 PJM Real-Time Energy Market net revenue (By unit marginal cost): Calendar years 1999 to 2009

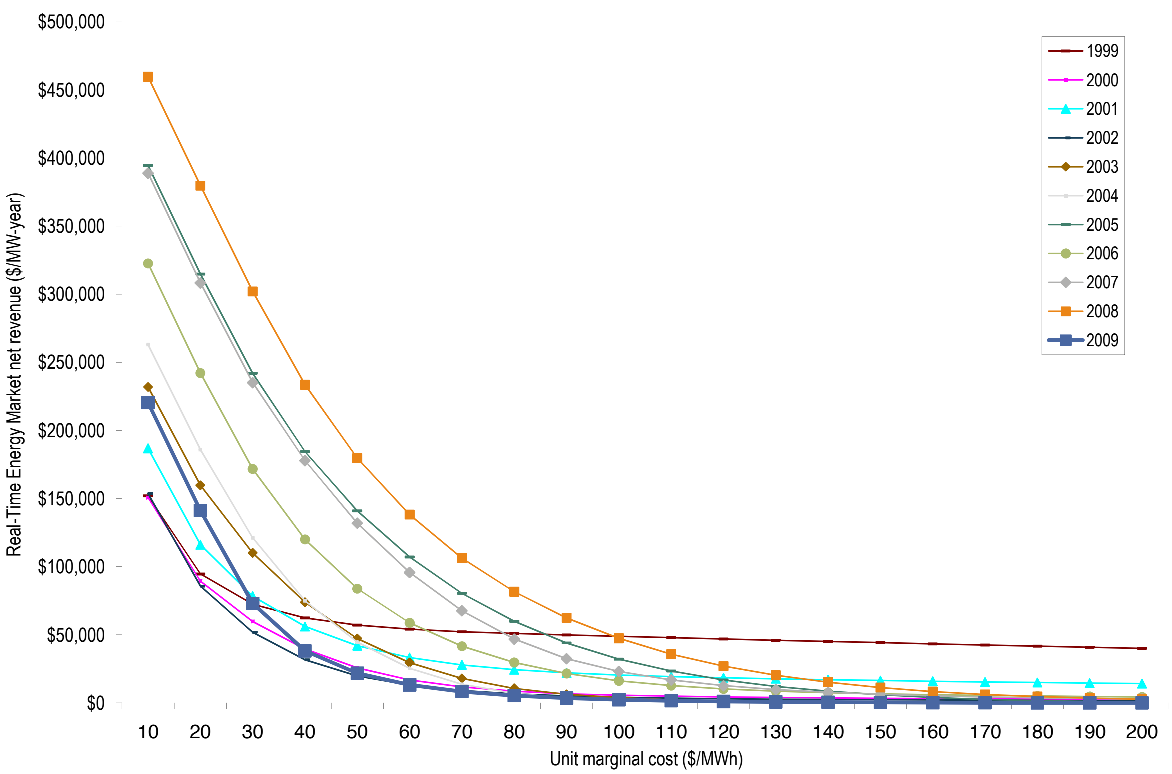
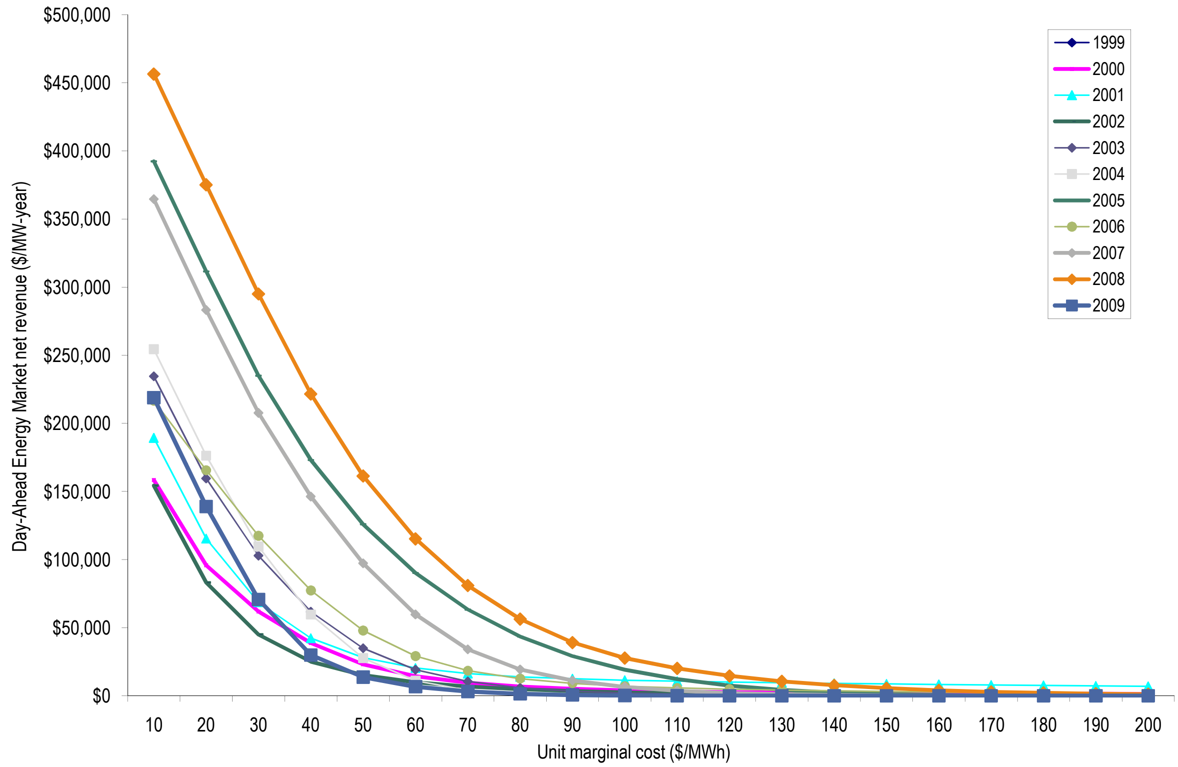


Figure 3-2 PJM Day-Ahead Energy Market net revenue (By unit marginal cost): Calendar years 2000 to 2009



Differences in the shape and position of Real-Time and Day-Ahead Energy Market net revenue curves result from different distributions of Energy Market prices in each year. These differences illustrate, among other things, the significance of a relatively small number of high-priced hours to the profitability of high marginal cost units.[7]

The theoretical net revenues displayed in Table 3-1 and Table 3-2 are calculated under perfect dispatch assumptions and therefore represent an upper bound of the direct contribution to generator fixed costs from the Energy Market. All other things constant, these Energy Market net revenues show how the frequency distribution of price levels in a given year affects the amount of revenue a generator would have received at the specified levels of marginal cost.

The Energy Market net revenues shown in Table 3-1 and Table 3-2 do not consider operating constraints that may affect actual net revenue of an individual plant. Such operating constraints are less likely to affect the net revenue calculations for CTs, given their operational flexibility and the operating reserve revenue guarantee. For a CC plant, a two-hour hot status notification plus startup time for a summer weekday could prevent a unit from running during two positive net revenue hours in the afternoon peak and two more positive net revenue hours in the evening peak separated by two negative net revenue hours, or could result in reduced net revenues from the negative net revenue hours.[8] The actual impact depends on the relationship between LMP and the operating cost of the unit. Similarly, a CP plant with an eight-hour cold status notification plus startup time could run overnight during negative net revenue hours although the lower relative operating costs of

7 See the *2009 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part 1," at "Load and LMP" and Appendix C, "Energy Market" for detailed data on prices and their annual distribution.

8 A two-hour hot start, including a notification period, is consistent with the CC technology.

a steam unit would generally reduce the significance of the issue.[9] Ramp limitations might prevent a CC or steam unit from starting and ramping up to full output in time to operate for all positive net revenue hours.

Conversely, the net revenue measure does not include the potentially significant contribution to fixed cost from the explicit or implicit sale of the option value of physical units or from bilateral agreements to sell output at a price other than the PJM Day-Ahead or Real-Time Energy Market prices, e.g., a forward price.

Capacity Market Net Revenue

Generators receive revenue from the sale of capacity in addition to revenue from the Energy and Ancillary Service Markets. In the PJM market design, the sale of capacity provides an important source of revenues to cover generator fixed costs. The Capacity Credit Market (CCM) design was in effect until June 1, 2007. For the period from January 1 through May 31, 2007, PJM capacity resources received a weighted-average payment from the CCM of $3.21 per MW-day of unforced capacity, a total of $485 per MW for the five-month period, or $1,172 per MW-year on an annualized basis. This was the lowest level of CCM revenues since the opening of the CCM in mid-1999.

On June 1, 2007, with the implementation of the RPM, PJM capacity resources began to receive a daily capacity payment of an amount determined by the first RPM Auction (June 1, 2007, through May 31, 2008) for their corresponding locational delivery area (LDA). The RPM auction clearing prices, applied from June 1, 2008 through May 31, 2009 were: $111.92 per MW-day for RTO, $148.80 per MW-day for EMAAC or $31,843 and $210.11 per MW-day in. The 2009/2010 RPM auction clearing prices, applied from June 1, 2009 through May 31, 2010 were: $102.04 per MW-day for RTO, $191.32 per MW-day for MAAC+APS and $237.33 per MW-day for SWMAAC. Calendar year 2009 capacity revenues are a sum of five months or 151 days at the 2008/2009 Delivery Year Market Clearing Prices and seven months or 214 days at the 2009/2010 Delivery Year Market Clearing Prices. These revenues are shown by zone and LDA in Table 3-3.[10]

9 An eight-hour cold status notification plus startup is consistent with the CP technology.

10 Capacity revenues in Table 3-3 show total potential revenues available through RPM per installed MW-year and are not adjusted with a forced outage rate. Capacity revenues in Table 3-4 do reflect an adjustment for the system forced outage rate.

Table 3-3 2009 PJM RPM auction-clearing capacity price and capacity revenue by LDA and zone: Effective for January 1, through December 31, 2009

		Delivery Year 2008/2009		Delivery Year 2009/2010		
Zone	LDA	$/MW-Day	$/MW in 2009	$/MW-Day	$/MW in 2009	2009 Total
AECO	EMAAC	$148.80	$22,469	$191.32	$40,942	$63,411
AEP	RTO	$111.92	$16,900	$102.04	$21,837	$38,736
AP	RTO	$111.92	$16,900	$191.32	$40,942	$57,842
BGE	SWMAAC	$210.11	$31,727	$237.33	$50,789	$82,515
ComEd	RTO	$111.92	$16,900	$102.04	$21,837	$38,736
DAY	RTO	$111.92	$16,900	$102.04	$21,837	$38,736
DLCO	RTO	$111.92	$16,900	$102.04	$21,837	$38,736
Dominion	RTO	$111.92	$16,900	$102.04	$21,837	$38,736
DPL	EMAAC	$148.80	$22,469	$191.32	$40,942	$63,411
JCPL	EMAAC	$148.80	$22,469	$191.32	$40,942	$63,411
Met-Ed	RTO	$111.92	$16,900	$191.32	$40,942	$57,842
PECO	EMAAC	$148.80	$22,469	$191.32	$40,942	$63,411
PENELEC	RTO	$111.92	$16,900	$191.32	$40,942	$57,842
Pepco	SWMAAC	$210.11	$31,727	$237.33	$50,789	$82,515
PPL	RTO	$111.92	$16,900	$191.32	$40,942	$57,842
PSEG	EMAAC	$148.80	$22,469	$191.32	$40,942	$63,411
RECO	EMAAC	$148.80	$22,469	$191.32	$40,942	$63,411
PJM	N/A	$124.58	$18,812	$138.46	$29,630	$48,441

Table 3-4 shows zonal capacity revenue for the eleven-year period 1999 to 2009.[11] Results for 1999 through 2006 reflect the load-weighted averages from the CCM construct. Results for 2007 combine the CCM values for the January through May period and the RPM Auction values for the June through December period.[12] Capacity revenue for 2009 reflects the second full year under the RPM construct, with five months of the 2008/2009 auction clearing price and seven months of the 2009/2010 auction clearing price.[13] These capacity revenues are adjusted for the yearly, system wide forced outage rate.[14]

11 In tables with zonal net revenues, data for a transmission zone are displayed for all full calendar years following integration into PJM markets.

12 In Table 3-4, the 2007 column represents an average of all revenue associated with the sale of capacity by zone followed by a weighted-average of capacity revenue for the PJM footprint. The zonal results combine load-weighted averages from both daily and monthly CCM prices for January through May as well as the associated LDA-clearing price for the remaining seven months.

13 The 2007 total revenue associated with capacity for PJM in Table 3-4 similarly combines load-weighted CCM and RPM revenues. The RPM revenue for PJM in 2007-2009 is a load-weighted average based on all the LDA-clearing prices in Table 3-3 and the MW associated with each. The result is a load-weighted, average revenue associated with the sale of capacity per MW-year throughout the PJM footprint, not exclusively the RTO LDA.

14 The PJM capacity revenues presented in Table 3-4 differ slightly from those presented in Table 3-9, Table 3-11 and Table 3-13 as capacity revenues by technology type are adjusted for technology-specific outage rates.

Table 3-4 Capacity revenue by PJM zones (Dollars per MW-year): Calendar years 1999 to 2009

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
AECO	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$19,700
AEP	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$27,928	$35,836	$10,131
AP	NA	NA	NA	NA	$7,633	$6,493	$2,089	$1,958	$8,551	$27,928	$53,511	$9,109
BGE	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$37,868	$68,190	$76,336	$20,605
ComEd	NA	NA	NA	NA	NA	NA	$3,607	$1,958	$8,551	$27,928	$35,836	$10,511
DAY	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$27,928	$35,836	$10,131
DLCO	NA	NA	NA	NA	NA	NA	$2,089	$1,958	$8,551	$27,928	$35,836	$10,131
Dominion	NA	NA	NA	NA	NA	NA	NA	$1,958	$8,551	$27,928	$35,836	$12,812
DPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$19,700
JCPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$19,700
Met-Ed	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$27,928	$53,511	$13,647
PECO	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$19,700
PENELEC	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$27,928	$53,511	$13,647
Pepco	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$37,868	$68,190	$76,336	$20,605
PPL	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$8,551	$27,928	$53,511	$13,647
PSEG	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$19,700
RECO	NA	NA	NA	NA	$5,946	$6,493	$2,089	$1,958	$39,680	$57,323	$58,663	$18,915
PJM	$18,124	$20,804	$32,981	$11,600	$5,946	$6,493	$2,089	$1,958	$29,966	$37,095	$44,814	$16,706

New Entrant Net Revenues

In order to provide a more realistic estimate of the net revenues that would result from investment in new generation resources, a peak-hour, economic dispatch scenario was analyzed. In contrast to the perfect dispatch scenario, economic dispatch uses technology-specific operating constraints in the calculation of a new entrant's operations and potential net revenue in PJM markets. All technology specific, zonal net revenue calculations included in the new entrant net revenue analysis in this section are based on the economic dispatch scenario.

Analysis of both the Real-Time and Day-Ahead Energy Market net revenues for a new entrant includes three power plant configurations: a natural gas-fired CT, a two-on-one, natural gas-fired CC and a conventional CP, single reheat steam generation plant. The CT plant consists of two GE Frame 7FA CTs, equipped with full inlet air mechanical refrigeration and selective catalytic reduction (SCR) for NO_x reduction. The CC plant consists of two GE Frame 7FA CTs equipped with evaporative cooling, duct burners, a heat recovery steam generator (HRSG) for each CT with steam reheat and SCR for NO_x reduction with a single steam turbine generator. The coal plant is a western Virginia sub-critical steam CP, equipped with selective catalytic reduction system (SCR) for NO_x control, a Flue Gas Desulphurization (FGD) system with chemical injection for SO_x and mercury control, and a bag-house for particulate control.

All net revenue calculations include the effect of actual hourly local ambient air temperature[15] on plant heat rates[16] and generator output for each of the three plant configurations.[17] Plant heat rates were calculated for each hour to account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.[18] The effect of ambient air conditions on plant generation capability was calculated hourly.

NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost, where applicable. These costs are included in the PJM definition of marginal cost. NO_x and SO_2 emission allowance costs were obtained from actual historical daily spot cash prices.[19] NO_x emission allowance costs were included only during the annual NO_x attainment period from May 1 through September 30. SO_2 emission allowance costs were calculated for every hour of the year.

A forced outage rate for each class of plant was calculated from PJM data.[20] This class-specific outage rate was then incorporated into all revenue calculations. Additionally, each plant was given a continuous 15 day planned, annual outage in the fall season.

Variable operation and maintenance (VOM) expenses were estimated to be $7.09 per MWh for the CT plant, $3.07 per MWh for the CC plant and $2.97 per MWh for the CP plant. These estimates were provided by a consultant to the MMU.[21] The VOM expenses for the CT and CC plants include accrual of anticipated, routine major overhaul expenses.[22] The delivered fuel cost for natural gas is from published commodity daily cash prices, with a basis adjustment for transportation costs.[23] Coal delivered cost was developed from the published prompt-month price, adjusted for rail transportation cost.[24] The average delivered fuel prices are shown in Table 3-5.

Real-time ancillary service revenues for the provision of synchronized reserve service for all three plant types are set to zero. GE Frame 7FA CTs are typically not configured to provide Tier 2 synchronized reserve in PJM. Steam units do provide Tier 1 synchronized reserve, but the 2009 Tier 1 revenues were minimal. Real-time ancillary service revenues for the provision of regulation service for both the CT and CC plant are also set to zero since these plant types typically do not provide regulation service in PJM. Additionally, no black start service capability is assumed for the reference CT plant configuration in either costs or revenues. Real-time ancillary service revenues for the provision of regulation were calculated for the CP plant. The regulation offer price was the sum of the calculated hourly cost to supply regulation service plus an adder of $12 per PJM market rules.[25] This offer price was compared to the hourly clearing price in the PJM Regulation Market. The clearing price includes both the offer price and the lost opportunity cost of the marginal unit in each hour. If the reference CP could provide regulation at a total cost, including the CP opportunity

15 Hourly ambient conditions supplied by Telvent DTN for multiple points in PJM RTO. PJM net revenue calculations include the average of all points in PJM RTO. Zonal net revenue calculations include zone specific ambient air temperatures,

16 These heat rate changes were calculated by Pasteris Energy, Inc., a consultant to the MMU, utilizing GE Energy's GateCycle Power Plant and Simulation Software. Neither GE Energy nor GE has reviewed this report or the calculations and results of the work done by Pasteris Energy, Inc. for the MMU.

17 Pasteris Energy, Inc.

18 All heat rate calculations are expressed in Btu per net kWh. No-load costs are included in the heat rate and subsequently the dispatch price since each unit type is dispatched at full load for every economic hour, but is off for every uneconomic hour. Therefore, there is a single offer point and no offer curve.

19 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.

20 Outage figures obtained from the PJM eGADS database.

21 Pasteris Energy, Inc.

22 Routine combustor inspection, hot gas path and major inspection costs collected through the VOM adder. This figure was established by Pasteris Energy, Inc. and compares favorably with actual operation and maintenance costs from similar PJM generating units.

23 Gas daily cash prices obtained from Platts.

24 Coal prompt prices obtained from Platts.

25 The adder reflects the modifications to the regulation market rules that were effective on December 1, 2008.

cost, that is less than the regulation-clearing price, the regulation service net revenue equals the market price of regulation minus the cost of CP regulation.

Generators receive revenues for the provision of reactive services based on cost-of-service filings with the United States Federal Energy Regulatory Commission (FERC). The actual reactive service payments filed with and approved by the FERC for each generator class were used to determine the reactive revenues. Reactive service revenues are based on the weighted-average reactive service rate per MW-year calculated from the data in the FERC filings. In 2009, for CTs, the calculated rate is $2,384 per installed MW-year; for CCs, the calculated rate is $3,198 per installed MW-year and for CPs, the calculated rate is $1,783 per installed MW-year.[26]

Table 3-5 Average delivered fuel price in PJM (Dollars per MBtu): Calendar years 1999 to 2009

	Natural Gas	Low Sulfur Coal
1999	$2.62	$1.62
2000	$5.18	$1.39
2001	$4.52	$2.14
2002	$3.81	$1.54
2003	$6.45	$1.76
2004	$6.65	$2.74
2005	$9.73	$2.88
2006	$7.40	$2.68
2007	$7.87	$2.53
2008	$9.95	$4.60
2009	$4.73	$3.16

Zonal Real-Time Energy Market net revenue under a peak-hour, economic dispatch scenario for 1999 to 2009 is shown in Table 3-6, Table 3-7 and Table 3-8 for new entrant CT, CC and CP facilities. The difference in net revenue among zones is a direct result of the locational variation in hourly LMP and delivered fuel costs.[27] The difference in net revenue among the generation technologies is a direct result of the variation in marginal cost associated with each.

26 The CT plant reactive revenues are based on 44 recent filings with the FERC for CT reactive costs. The CC plant revenues are based on 27 recent filings with the FERC for CC reactive costs, and the CP plant revenues are based on 18 recent filings with the FERC for CP reactive costs. These figures have been updated from those reported in the *2008 State of the Market Report for PJM* to include new generation filings.

27 Zonal net revenues for 2009 reflect the estimated average delivered fuel costs associated with each zone and increased locational fuel cost detail compared to prior years. As a result, differences in zonal energy net revenue in 2009 compared to prior years may reflect changes in estimated fuel costs in addition to changes in fuel price fundamentals.

Table 3-6 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): Net revenue for calendar years 1999 to 2009

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
AECO	$56,278	$12,077	$40,825	$19,449	$5,274	$6,765	$18,309	$23,165	$41,985	$65,046	$10,735	$27,264
AEP	NA	NA	NA	NA	NA	NA	$641	$4,638	$5,959	$4,458	$3,206	$3,780
AP	NA	NA	NA	NA	$1,069	$864	$5,190	$10,695	$17,726	$17,701	$12,546	$9,399
BGE	$54,770	$7,193	$23,048	$20,049	$4,196	$2,899	$22,293	$31,725	$56,613	$47,525	$14,995	$25,937
ComEd	NA	NA	NA	NA	NA	NA	$1,747	$7,131	$9,271	$4,886	$2,393	$5,086
DAY	NA	NA	NA	NA	NA	NA	$793	$4,342	$5,776	$4,672	$2,981	$3,713
DLCO	NA	NA	NA	NA	NA	NA	$665	$5,408	$9,805	$7,746	$4,704	$5,666
Dominion	NA	NA	NA	NA	NA	NA	NA	$26,830	$43,653	$43,465	$14,319	$32,067
DPL	$57,625	$12,712	$49,833	$22,430	$5,587	$2,881	$14,259	$17,265	$34,151	$35,422	$13,410	$24,143
JCPL	$55,947	$9,803	$37,473	$13,933	$2,982	$14,472	$16,933	$15,932	$37,836	$35,166	$11,622	$22,918
Met-Ed	$54,998	$8,068	$30,697	$17,372	$3,603	$2,271	$15,174	$17,503	$36,393	$25,498	$10,057	$20,149
PECO	$56,510	$11,760	$37,989	$14,761	$4,836	$1,600	$16,114	$15,600	$28,560	$27,081	$9,513	$20,393
PENELEC	$54,997	$7,360	$18,137	$12,117	$1,731	$1,264	$3,117	$6,585	$10,957	$5,953	$6,019	$11,658
Pepco	$54,556	$7,022	$18,108	$22,024	$4,610	$3,915	$25,840	$37,801	$58,816	$54,838	$23,362	$28,263
PPL	$55,305	$7,753	$26,748	$12,589	$2,265	$1,120	$12,403	$13,612	$25,472	$21,531	$8,970	$17,070
PSEG	$56,271	$10,171	$36,818	$13,499	$4,555	$13,163	$16,881	$15,980	$32,405	$28,809	$9,155	$21,610
RECO	NA	NA	NA	NA	$4,213	$3,749	$12,971	$13,606	$32,295	$23,966	$7,846	$14,092
PJM	$55,612	$8,498	$30,254	$14,496	$2,763	$919	$6,141	$10,996	$17,933	$12,442	$5,113	$15,015

Table 3-7 PJM Real-Time Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): Net revenue for calendar years 1999 to 2009

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
AECO	$80,930	$29,354	$68,323	$46,203	$35,658	$52,625	$77,223	$78,489	$107,344	$154,085	$48,544	$70,798
AEP	NA	NA	NA	NA	NA	NA	$12,533	$21,695	$29,990	$29,194	$25,145	$23,711
AP	NA	NA	NA	NA	$19,036	$20,163	$35,748	$41,735	$65,495	$68,874	$52,645	$43,385
BGE	$78,672	$21,290	$42,575	$45,040	$29,165	$33,539	$75,682	$83,645	$131,526	$133,647	$55,496	$66,389
ComEd	NA	NA	NA	NA	NA	NA	$21,779	$30,731	$42,289	$30,764	$18,839	$28,880
DAY	NA	NA	NA	NA	NA	NA	$11,872	$19,706	$30,024	$29,754	$25,301	$23,331
DLCO	NA	NA	NA	NA	NA	NA	$10,781	$18,897	$32,552	$28,813	$26,316	$23,472
Dominion	NA	NA	NA	NA	NA	NA	NA	$78,267	$110,994	$123,330	$53,240	$91,458
DPL	$83,748	$34,057	$79,508	$49,163	$33,913	$39,091	$61,167	$61,072	$99,001	$117,134	$52,338	$64,563
JCPL	$80,716	$25,825	$61,175	$36,979	$26,955	$63,200	$67,269	$56,368	$108,661	$126,738	$50,649	$64,049
Met-Ed	$79,528	$22,995	$53,339	$41,469	$27,374	$31,279	$57,351	$59,317	$102,856	$99,239	$44,671	$56,311
PECO	$81,255	$28,010	$61,526	$38,389	$31,489	$34,570	$61,212	$57,349	$89,797	$102,673	$44,636	$57,355
PENELEC	$79,720	$23,011	$39,473	$42,071	$22,929	$21,460	$26,611	$30,472	$51,289	$44,971	$38,615	$38,238
Pepco	$78,343	$20,865	$36,952	$46,354	$29,914	$36,202	$82,427	$91,120	$133,305	$144,783	$71,539	$70,164
PPL	$79,926	$22,122	$48,045	$34,624	$25,278	$24,688	$51,686	$52,858	$85,950	$92,238	$42,046	$50,860
PSEG	$82,577	$28,650	$62,468	$37,769	$34,549	$63,575	$78,181	$66,446	$105,692	$119,564	$47,113	$66,053
RECO	NA	NA	NA	NA	$33,679	$44,473	$64,071	$61,510	$103,158	$108,670	$43,137	$65,528
PJM	$80,546	$24,794	$54,206	$38,625	$27,155	$27,389	$35,608	$44,692	$66,616	$62,039	$31,581	$44,841

Table 3-8 PJM Real-Time Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Net revenue for calendar years 1999 to 2009

Zone	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
AECO	$92,532	$113,438	$108,787	$105,966	$168,971	$167,610	$301,137	$228,664	$303,350	$337,789	$92,287	$183,685
AEP	NA	NA	NA	NA	NA	NA	$142,931	$122,131	$158,510	$152,316	$29,034	$120,984
AP	NA	NA	NA	NA	$140,178	$114,188	$225,283	$173,387	$243,442	$257,660	$62,730	$173,838
BGE	$90,218	$99,688	$81,733	$103,811	$163,240	$138,798	$297,298	$243,615	$339,865	$309,846	$47,837	$174,177
ComEd	NA	NA	NA	NA	NA	NA	$136,055	$117,135	$152,722	$203,863	$53,680	$132,691
DAY	NA	NA	NA	NA	NA	NA	$132,250	$114,159	$157,981	$130,757	$40,214	$115,072
DLCO	NA	NA	NA	NA	NA	NA	$119,344	$102,923	$145,539	$138,614	$36,538	$108,592
Dominion	NA	NA	NA	NA	NA	NA	NA	$235,662	$316,223	$282,137	$52,969	$221,748
DPL	$96,172	$124,924	$129,746	$109,500	$168,958	$150,777	$280,855	$208,044	$296,729	$320,362	$44,299	$175,488
JCPL	$92,252	$105,657	$99,367	$94,661	$155,564	$177,105	$284,427	$198,595	$310,102	$315,991	$81,687	$174,128
Met-Ed	$91,053	$102,018	$92,371	$99,157	$157,131	$135,061	$269,900	$205,508	$299,833	$282,260	$64,568	$163,533
PECO	$92,923	$112,043	$101,558	$96,113	$163,941	$144,385	$279,306	$203,152	$284,280	$290,745	$82,938	$168,308
PENELEC	$91,889	$109,408	$84,093	$107,445	$154,295	$114,543	$210,236	$156,723	$222,720	$239,391	$84,807	$143,232
Pepco	$89,875	$99,351	$75,464	$105,125	$164,995	$142,377	$307,867	$254,964	$344,407	$328,211	$76,426	$180,824
PPL	$91,447	$100,853	$86,582	$89,955	$152,675	$127,012	$260,567	$196,349	$279,724	$286,355	$78,012	$159,048
PSEG	$95,195	$121,405	$108,158	$96,439	$174,161	$180,518	$309,870	$219,768	$310,978	$248,728	$105,739	$179,178
RECO	NA	NA	NA	NA	$176,678	$159,188	$292,449	$213,850	$304,891	$259,424	$78,553	$212,148
PJM	$92,935	$108,624	$95,361	$96,828	$159,912	$124,497	$222,911	$177,852	$244,419	$179,457	$49,022	$141,074

New Entrant Combustion Turbine

In the peak-hour, economic dispatch analysis, Real-Time Energy Market net revenue was calculated for a CT plant dispatched by PJM operations. For this dispatch scenario, it was assumed that the CT plant could be dispatched by PJM operations in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any block when the real-time, average LMP was greater than, or equal to, the cost to generate, including the cost for a complete startup and shutdown cycle[28] for at least two hours during each four-hour block.[29] The blocks were dispatched independently, and, if there were not at least two economic hours in any given block, then the CT was not dispatched. The startup costs were used in determining the economic hours in each block, but once the CT was dispatched on a particular day, startup costs were not used to evaluate whether to continue to run the unit in the next consecutive four-hour block. The calculations account for operating reserve credits based on PJM rules, as applicable, since the assumed operation is under the direction of PJM operations.[30]

28 Startup and shutdown fuel burns and emission rates were obtained from design data for a new entry plant. Gas daily cash prices were obtained from Platts fuel prices. Emissions allowance costs were included in startup costs where applicable. Per PJM "Manual M-15: Cost Development Guidelines," Revision 11 (December 2, 2009), startup and shutdown station power consumption costs were obtained from the station service rates published quarterly by PJM and netted against the MW produced during startup at the preceding applicable hourly LMP. No-load costs are included in the heat rate.

29 The first block represents the four-hour period starting at hour ending 0800 EPT until hour ending 1100 EPT. The second block represents the four-hour period starting at hour ending 1200 EPT until hour ending 1500 EPT. The third block represents the four-hour period starting at hour ending 1600 EPT until hour ending 1900 EPT, and the fourth block represents the four-hour period starting at hour ending 2000 EPT until the hour ending 2300 EPT.

30 The calculation of operating reserve payments does not reflect changes to operating reserves rules effective December 1, 2008.

Net revenues for the new entrant CT under peak-hour, economic dispatch are shown in Table 3-9 for the years 1999 through 2009. This table shows the contribution of each market individually to the new entrant CT's total net revenue. The increase in capacity revenue is a result of a higher market clearing prices in the 2009/2010 delivery year.

Table 3-9 Real-time PJM-wide net revenue for a CT under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2009

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$55,612	$16,677	$0	$0	$2,248	$74,537
2000	$8,498	$20,200	$0	$0	$2,248	$30,946
2001	$30,254	$30,960	$0	$0	$2,248	$63,462
2002	$14,496	$11,516	$0	$0	$2,248	$28,260
2003	$2,763	$5,554	$0	$0	$2,248	$10,566
2004	$919	$5,376	$0	$0	$2,248	$8,543
2005	$6,141	$2,048	$0	$0	$2,248	$10,437
2006	$10,996	$1,758	$0	$0	$2,194	$14,948
2007	$17,933	$28,442	$0	$0	$2,154	$48,529
2008	$12,442	$35,691	$0	$0	$2,398	$50,532
2009	$5,113	$48,441	$0	$0	$2,384	$55,939

Table 3-10 shows the total net revenue (the Total column in Table 3-9) for the new entrant CT in each zone.[31] For the eleven-year period, the average total net revenue under the peak-hour, economic dispatch scenario was $36,064 per installed MW-year.

Table 3-10 Real-time zonal combined net revenue from all markets for a CT under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2009

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
AECO	$75,203	$34,525	$74,033	$33,213	$13,077	$14,389	$22,605	$27,117	$81,801	$122,598	$70,287	$51,713
AEP	NA	NA	NA	NA	NA	NA	$4,936	$8,590	$16,230	$33,727	$42,852	$21,267
AP	NA	NA	NA	NA	$10,800	$8,487	$9,485	$14,647	$27,996	$46,970	$67,387	$26,539
BGE	$73,695	$29,641	$56,256	$33,813	$11,998	$10,522	$26,589	$35,678	$94,710	$115,532	$99,894	$53,484
ComEd	NA	NA	NA	NA	NA	NA	$7,602	$11,083	$19,542	$34,155	$43,514	$23,179
DAY	NA	NA	NA	NA	NA	NA	$5,089	$8,294	$16,046	$33,941	$44,101	$21,494
DLCO	NA	NA	NA	NA	NA	NA	$4,960	$30,782	$53,923	$37,015	$45,825	$34,501
Dominion	NA	NA	NA	NA	NA	NA	NA	$9,360	$20,075	$72,734	$55,440	$39,402
DPL	$76,550	$35,160	$83,041	$36,193	$13,389	$10,505	$18,554	$21,217	$73,967	$92,974	$79,206	$49,160
JCPL	$74,871	$32,251	$70,681	$27,697	$10,784	$22,096	$21,229	$19,884	$77,652	$92,718	$77,418	$47,935
Met-Ed	$73,923	$30,516	$63,905	$31,136	$11,406	$9,894	$19,469	$21,455	$46,663	$54,767	$70,283	$39,402
PECO	$75,434	$34,208	$71,197	$28,525	$12,638	$9,224	$20,409	$19,552	$68,376	$84,633	$75,308	$45,409
PENELEC	$73,921	$29,808	$51,345	$25,881	$9,533	$8,887	$7,413	$10,537	$21,227	$35,222	$66,246	$30,911
Pepco	$73,480	$29,470	$51,316	$35,788	$12,413	$11,539	$30,135	$41,753	$96,912	$122,845	$108,262	$55,810
PPL	$74,229	$30,201	$59,956	$26,353	$10,068	$8,744	$16,699	$17,564	$35,743	$50,800	$69,197	$36,323
PSEG	$75,196	$32,618	$70,026	$27,263	$12,357	$20,786	$21,177	$19,933	$72,221	$86,361	$74,951	$46,626
RECO	NA	NA	NA	NA	$12,016	$11,373	$17,266	$17,558	$72,112	$81,518	$73,641	$40,783
PJM	$74,537	$30,946	$63,462	$28,260	$10,566	$8,543	$10,437	$14,948	$48,530	$50,532	$55,939	$36,064

31 New entrant CT zonal net revenue for 2009 reflects the estimated zonal, daily delivered price of natural gas.

New Entrant Combined Cycle

Under peak-hour, economic dispatch, Energy Market net revenues were calculated for a CC plant dispatched by PJM operations for continuous output from the peak-hour period beginning with the hour ending 0800 EPT and continuing to the hour ending 2300 EPT for any day when the PJM real-time, average LMP was greater than, or equal to, the cost to generate, including the cost for a complete startup and shutdown cycle for at least eight hours during that time period.[32] If there were not eight economic hours in any given day, then the CC was not dispatched. For every hour the plant is dispatched, the applicable LMP is compared to the incremental costs of duct burner firing, including fuel and, if applicable, emissions allowance credits.[33] If LMP is greater than or equal to the incremental costs of duct-firing for any hour the plant is operating, the duct burner is dispatched. The calculations account for operating reserve payments based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations. This dispatch scenario uses the same variable operation and maintenance cost, outage, fuel cost, emission and plant performance assumptions reflected in the Table 3-7 results.

Net revenues for the new entrant CC under peak-hour, economic dispatch are shown in Table 3-11 for the years 1999 through 2009. This table shows the contribution of each market individually to the new entrant CC's total net revenue. The increase in capacity revenue is a result of a higher market clearing prices in the 2009/2010 delivery year.

Table 3-11 Real-time PJM-wide net revenue for a CC under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2009

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$80,546	$16,999	$0	$0	$3,155	$100,700
2000	$24,794	$19,643	$0	$0	$3,155	$47,592
2001	$54,206	$29,309	$0	$0	$3,155	$86,670
2002	$38,625	$10,492	$0	$0	$3,155	$52,272
2003	$27,155	$5,281	$0	$0	$3,155	$35,591
2004	$27,389	$5,241	$0	$0	$3,155	$35,785
2005	$35,608	$2,054	$0	$0	$3,155	$40,817
2006	$44,692	$1,743	$0	$0	$3,094	$49,529
2007	$66,616	$31,098	$0	$0	$3,094	$100,809
2008	$62,039	$38,691	$0	$0	$3,198	$103,928
2009	$31,581	$46,596	$0	$0	$3,198	$81,376

Table 3-12 shows the total net revenue (the Total column in Table 3-11) for the new entrant CC in each zone. For the eleven-year period, the average total net revenue under the peak-hour, economic dispatch scenario was $66,824 per installed MW-year.

32 Startup and shutdown fuel burns and emission rates were obtained from design data for a new entry plant. Gas daily cash prices were obtained from Platts fuel prices. Emissions allowance costs were included in startup costs where applicable. Per PJM "Manual M-15: Cost Development Guidelines," Revision 11 (December 2, 2009), startup and shutdown station power consumption costs were obtained from the station service rates published quarterly by PJM settlements and netted against the MW produced during startup at the preceding applicable hourly LMP. No-load costs are included in the heat rate.

33 Duct burner firing dispatch rate is developed using same methodology described for unfired dispatch rate, with temperature adjustments to duct burner fired heat rate and output provided by Pasteris Energy, Inc.

Table 3-12 Real-time zonal combined net revenue from all markets for a CC under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2009

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
AECO	$101,084	$52,152	$100,786	$59,850	$44,094	$61,021	$82,432	$83,326	$151,617	$217,072	$112,738	$96,925
AEP	NA	NA	NA	NA	NA	NA	$17,742	$26,533	$41,958	$61,521	$65,604	$42,672
AP	NA	NA	NA	NA	$29,766	$28,560	$40,957	$46,572	$77,463	$101,201	$111,482	$62,286
BGE	$98,827	$44,088	$75,039	$58,688	$37,601	$41,935	$80,891	$88,482	$173,918	$207,969	$138,066	$95,046
ComEd	NA	NA	NA	NA	NA	NA	$28,702	$35,568	$54,257	$63,092	$59,298	$48,183
DAY	NA	NA	NA	NA	NA	NA	$17,081	$24,543	$41,992	$62,081	$65,760	$42,291
DLCO	NA	NA	NA	NA	NA	NA	$15,990	$83,104	$155,267	$61,141	$66,775	$76,455
Dominion	NA	NA	NA	NA	NA	NA	NA	$23,734	$44,520	$155,658	$93,699	$79,403
DPL	$103,903	$56,855	$111,972	$62,811	$42,349	$47,487	$66,376	$65,909	$110,969	$180,121	$116,532	$87,753
JCPL	$100,871	$48,623	$93,639	$50,626	$35,391	$71,596	$72,478	$61,205	$152,934	$189,725	$114,843	$90,176
Met-Ed	$99,682	$45,793	$85,803	$55,117	$35,810	$39,675	$62,560	$64,155	$114,824	$131,566	$103,508	$76,227
PECO	$101,410	$50,808	$93,990	$52,036	$39,925	$42,967	$66,421	$62,187	$134,069	$165,660	$108,830	$83,482
PENELEC	$99,875	$45,809	$71,937	$55,718	$31,365	$29,856	$31,820	$35,309	$63,257	$77,299	$97,452	$58,154
Pepco	$98,497	$43,663	$69,416	$60,001	$38,350	$44,598	$87,636	$95,957	$175,698	$219,105	$154,109	$98,821
PPL	$100,081	$44,920	$80,509	$48,272	$33,714	$33,084	$56,895	$57,695	$97,918	$124,566	$100,883	$70,776
PSEG	$102,731	$51,448	$94,932	$51,416	$42,985	$71,972	$83,390	$71,284	$149,965	$182,551	$111,307	$92,180
RECO	NA	NA	NA	NA	$42,115	$52,870	$69,280	$66,348	$147,431	$171,658	$107,331	$93,862
PJM	$100,700	$47,592	$86,670	$52,272	$35,591	$35,785	$40,817	$49,529	$100,809	$103,928	$81,376	$66,824

New Entrant Coal Plant

The new entrant CP Real-Time Energy Market net revenues were calculated assuming that the plant had a 24-hour minimum run time and was dispatched by PJM operations for all available plant hours, both reasonable assumptions for a large CP. The calculations account for operating reserve payments based on PJM rules, when applicable, since the assumed operation is under the direction of PJM operations.

Net revenues for the new entrant CP under peak-hour, economic dispatch are shown in Table 3-13 for the years 1999 through 2009. This table shows the contribution of each market individually to the new entrant CP's total net revenue. The increase in capacity revenue is a result of the implementation of RPM. Regulation revenue is calculated for any hours in which the new entrant CP's regulation offer is below the regulation-clearing price.

Table 3-13 Real-time PJM-wide net revenue for a CP under peak-hour, economic dispatch by market (Dollars per installed MW-year): Calendar years 1999 to 2009

	Energy	Capacity	Synchronized	Regulation	Reactive	Total
1999	$92,935	$17,798	$0	$5,596	$1,692	$118,022
2000	$108,624	$20,755	$0	$3,492	$1,692	$134,564
2001	$95,361	$30,862	$0	$1,356	$1,692	$129,271
2002	$96,828	$11,493	$0	$2,118	$1,692	$112,131
2003	$159,912	$5,688	$0	$2,218	$1,692	$169,509
2004	$124,497	$5,537	$0	$1,399	$1,692	$133,124
2005	$222,911	$2,100	$0	$1,727	$1,692	$228,430
2006	$177,852	$1,810	$0	$1,107	$1,692	$182,461
2007	$244,419	$29,343	$0	$1,172	$2,350	$277,284
2008	$179,457	$36,107	$0	$796	$1,783	$218,144
2009	$49,022	$43,931	$0	$231	$1,783	$94,968

Table 3-14 shows the total net revenue (the Total column 7 in Table 3-13) for the new entrant CP in each zone.[34] For the eleven-year period, the average total net revenue under the economic dispatch scenario was $163,446 per installed MW-year.

Table 3-14 Real-time zonal combined net revenue from all markets for a CP under peak-hour, economic dispatch (Dollars per installed MW-year): Calendar years 1999 to 2009

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
AECO	$118,254	$137,752	$143,257	$121,785	$179,117	$176,827	$306,995	$233,787	$345,739	$396,564	$151,958	$210,185
AEP	NA	NA	NA	NA	NA	NA	$150,176	$127,588	$170,532	$182,201	$66,176	$139,335
AP	NA	NA	NA	NA	$152,458	$123,620	$231,963	$178,701	$255,474	$288,025	$117,241	$192,497
BGE	$115,926	$124,106	$116,306	$119,714	$173,476	$148,097	$303,218	$248,764	$380,425	$379,157	$124,582	$203,070
ComEd	NA	NA	NA	NA	NA	NA	$144,924	$122,647	$164,740	$234,487	$91,497	$151,659
DAY	NA	NA	NA	NA	NA	NA	$139,572	$119,691	$169,421	$160,462	$77,760	$133,381
DLCO	NA	NA	NA	NA	NA	NA	$125,720	$240,844	$157,544	$168,655	$73,721	$153,297
Dominion	NA	NA	NA	NA	NA	NA	NA	$108,418	$328,069	$312,361	$90,049	$209,724
DPL	$121,871	$149,240	$164,219	$125,338	$179,145	$160,037	$287,243	$213,209	$339,158	$379,198	$103,715	$202,034
JCPL	$117,951	$129,972	$133,840	$110,499	$165,751	$186,365	$290,815	$203,813	$352,520	$374,748	$141,256	$200,685
Met-Ed	$116,776	$126,376	$126,885	$115,061	$167,368	$144,386	$276,296	$210,720	$311,760	$312,370	$119,008	$184,273
PECO	$118,636	$136,379	$136,046	$112,096	$174,147	$153,658	$285,681	$208,382	$326,717	$349,522	$142,528	$194,890
PENELEC	$117,603	$133,724	$118,787	$123,416	$164,692	$123,984	$217,133	$162,124	$234,790	$269,748	$140,148	$164,195
Pepco	$115,585	$123,766	$110,090	$121,020	$175,224	$151,666	$314,137	$260,110	$384,940	$397,620	$153,255	$209,765
PPL	$117,166	$125,227	$121,146	$105,991	$162,900	$136,365	$267,023	$201,584	$291,701	$316,263	$132,526	$179,808
PSEG	$120,910	$145,675	$142,694	$112,410	$184,332	$189,717	$316,131	$224,904	$353,386	$307,268	$165,919	$205,759
RECO	NA	NA	NA	NA	$186,860	$168,414	$298,796	$219,016	$347,309	$318,225	$138,107	$239,532
PJM	$118,022	$134,564	$129,271	$112,131	$169,509	$133,124	$228,430	$182,461	$277,284	$218,144	$94,968	$163,446

34 New Entrant CP zonal net revenue for 2009 incorporates the zone specific, delivered price of coal.

New Entrant Day-Ahead Net Revenues

In order to develop a comprehensive net revenue analysis, Day-Ahead Energy Market net revenues were calculated for the CT, CC and CP technologies for the peak-hour, economic dispatch scenario used for the Real-Time Energy Market analysis. The results for the Day-Ahead Energy Market for each class are presented in Table 3-15, Table 3-16 and Table 3-17, respectively.[35]

Table 3-15 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2009

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
AECO	$12,077	$29,022	$18,894	$2,634	$1,360	$11,975	$13,446	$20,649	$26,001	$6,373	$12,948
AEP	NA	NA	NA	NA	NA	$563	$1,218	$2,267	$1,827	$1,180	$1,411
AP	NA	NA	NA	$595	$0	$3,959	$7,326	$7,244	$6,719	$5,397	$4,463
BGE	$7,193	$14,772	$14,087	$1,779	$42	$9,857	$13,886	$20,904	$27,271	$7,792	$10,689
ComEd	NA	NA	NA	NA	NA	$374	$1,709	$4,392	$1,984	$480	$1,788
DAY	NA	NA	NA	NA	NA	$477	$1,104	$2,003	$1,628	$733	$1,189
Dominion	NA	NA	NA	NA	NA	NA	$10,991	$15,078	$22,582	$7,613	$14,066
DLCO	NA	NA	NA	NA	NA	$308	$854	$1,818	$1,428	$1,098	$1,300
DPL	$12,712	$35,962	$21,844	$2,419	$95	$7,869	$9,733	$12,438	$19,152	$6,840	$11,733
JCPL	$9,803	$24,565	$16,658	$1,531	$489	$7,104	$8,263	$16,080	$14,163	$5,007	$9,424
Met-Ed	$8,068	$19,353	$17,218	$1,273	$50	$8,737	$12,771	$14,559	$12,492	$4,619	$9,013
PECO	$11,760	$26,271	$17,522	$2,089	$0	$10,129	$8,598	$11,330	$12,688	$4,920	$9,573
PENELEC	$7,360	$16,870	$15,415	$537	$0	$1,477	$3,461	$3,736	$4,535	$3,303	$5,154
Pepco	$7,022	$14,469	$13,780	$2,143	$0	$12,988	$18,258	$23,028	$32,677	$15,816	$12,744
PPL	$7,753	$18,174	$15,151	$993	$0	$7,052	$8,259	$9,586	$10,351	$4,345	$7,424
PSEG	$10,171	$25,298	$16,750	$258	$7,332	$7,332	$8,127	$12,718	$13,686	$4,051	$9,611
RECO	NA	NA	NA	$1,346	$11	$5,925	$7,143	$11,711	$11,445	$3,156	$5,820
PJM	$7,418	$20,390	$13,921	$1,282	$1	$2,996	$5,229	$6,751	$6,623	$1,966	$6,658

35 The Day-Ahead Energy Market net revenues were calculated utilizing the same fuel, weather and unit operational assumptions as were used for the Real-Time Energy Market net revenue calculations.

Table 3-16 PJM Day-Ahead Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2009

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
AECO	$29,354	$63,679	$45,357	$31,788	$43,308	$74,855	$62,589	$83,745	$115,974	$51,240	$54,717
AEP	NA	NA	NA	NA	NA	$10,462	$12,393	$19,516	$20,140	$23,139	$17,130
AP	NA	NA	NA	$14,992	$14,077	$29,993	$30,144	$44,880	$50,885	$47,963	$33,276
BGE	$21,290	$37,791	$34,829	$23,003	$23,810	$60,143	$64,078	$94,045	$118,704	$58,133	$48,711
ComEd	NA	NA	NA	NA	NA	$9,888	$12,746	$35,333	$24,163	$14,225	$19,271
DAY	NA	NA	NA	NA	NA	$8,451	$9,671	$19,014	$19,147	$21,226	$15,502
Dominion	NA	NA	NA	NA	NA	NA	$57,718	$80,321	$101,261	$21,270	$65,143
DLCO	NA	NA	NA	NA	NA	$7,709	$8,390	$17,819	$15,605	$21,270	$15,771
DPL	$34,057	$73,455	$48,709	$28,595	$28,534	$59,804	$49,939	$74,526	$101,261	$52,846	$50,157
JCPL	$25,825	$51,367	$39,102	$23,929	$48,514	$56,951	$42,774	$85,349	$112,307	$50,315	$48,767
Met-Ed	$22,995	$44,572	$38,810	$22,806	$22,786	$52,522	$50,581	$75,423	$84,379	$44,189	$41,733
PECO	$28,010	$55,775	$40,411	$27,252	$26,450	$59,822	$47,607	$70,234	$85,673	$46,590	$44,348
PENELEC	$23,011	$43,234	$47,776	$17,460	$13,209	$23,711	$22,590	$35,002	$39,701	$38,970	$27,697
Pepco	$20,865	$37,135	$34,523	$24,379	$26,052	$67,659	$71,755	$99,380	$133,227	$73,603	$53,507
PPL	$22,122	$42,383	$35,750	$19,862	$17,037	$48,895	$43,246	$64,603	$77,511	$41,987	$37,581
PSEG	$28,650	$57,168	$41,945	$27,192	$47,450	$65,167	$51,543	$87,724	$106,457	$47,111	$50,946
RECO	NA	NA	NA	$25,148	$31,204	$54,167	$50,064	$85,050	$96,618	$41,780	$54,862
PJM	$26,132	$48,253	$35,993	$21,865	$18,193	$28,413	$31,670	$44,434	$47,342	$28,360	$30,060

Table 3-17 PJM Day-Ahead Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2009

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Average
AECO	$113,438	$111,272	$108,715	$174,964	$156,185	$302,113	$215,274	$252,783	$323,135	$95,836	$168,520
AEP	NA	NA	NA	NA	NA	$140,898	$111,399	$150,551	$149,397	$23,732	$115,195
AP	NA	NA	NA	$145,314	$108,867	$219,168	$158,105	$223,836	$250,837	$55,868	$165,999
BGE	$99,688	$83,030	$94,034	$161,419	$127,630	$284,669	$223,199	$304,373	$312,579	$48,315	$158,085
ComEd	NA	NA	NA	NA	NA	$133,407	$108,663	$149,353	$210,403	$48,765	$130,118
DAY	NA	NA	NA	NA	NA	$126,886	$98,084	$148,879	$123,738	$33,606	$106,239
Dominion	NA	NA	NA	NA	NA	NA	$215,727	$289,976	$277,629	$51,927	$208,815
DLCO	NA	NA	NA	NA	NA	$121,687	$92,737	$137,774	$139,537	$28,243	$99,573
DPL	$124,924	$128,020	$111,746	$172,871	$141,541	$286,686	$201,807	$278,619	$324,485	$42,395	$164,827
JCPL	$105,657	$94,134	$99,105	$164,028	$161,584	$278,746	$188,852	$289,222	$320,484	$81,671	$162,135
Met-Ed	$102,018	$88,922	$99,331	$161,077	$127,001	$269,696	$199,865	$275,949	$286,549	$63,430	$152,167
PECO	$112,043	$102,119	$101,674	$169,018	$137,889	$284,530	$198,441	$272,984	$297,666	$86,272	$160,240
PENELEC	$109,408	$89,643	$118,915	$157,282	$108,203	$207,894	$147,998	$208,246	$251,168	$86,110	$134,988
Pepco	$99,351	$82,420	$93,756	$163,851	$130,908	$295,462	$233,288	$313,215	$333,200	$76,927	$165,671
PPL	$100,853	$86,022	$93,528	$156,929	$120,447	$263,597	$190,672	$263,141	$291,459	$78,730	$149,580
PSEG	$121,405	$108,221	$106,049	$173,952	$162,402	$295,693	$207,951	$294,953	$250,151	$108,656	$166,312
RECO	NA	NA	NA	$172,622	$143,445	$279,769	$207,438	$291,031	$315,939	$78,117	$212,623
PJM	$116,784	$95,119	$97,493	$162,285	$113,892	$220,824	$167,282	$221,757	$174,191	$45,844	$128,679

For the ten-year period, the average PJM Day-Ahead Energy Market net revenue under the peak-hour, economic dispatch scenario for the CT plant was $6,658 per installed MW-year. For the CC plant, the ten-year average Day-Ahead Energy Market net revenue under the peak-hour, economic dispatch scenario was $30,060 per installed MW-year. For the CP plant, the ten-year average Day-Ahead Energy Market net revenue under the peak-hour, economic dispatch scenario was $128,679 per installed MW-year.

The energy net revenues for both the Real-Time and Day-Ahead Energy Markets are shown in Table 3-18, Table 3-19 and Table 3-20 for the CT, CC and CP plants.

On average, the Real-Time Energy Market net revenue was 39 percent higher than the Day-Ahead Market net revenue for the CT plant, 20 percent higher for the CC plant and 3 percent higher for the CP.[36]

Table 3-18 Real-Time and Day-Ahead Energy Market net revenues for a CT under economic dispatch (Dollars per installed MW-year): Calendar years 2000 to 2009

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$8,498	$7,418	$1,080	13%
2001	$30,254	$20,390	$9,864	33%
2002	$14,496	$13,921	$575	4%
2003	$2,763	$1,282	$1,481	54%
2004	$919	$1	$918	100%
2005	$6,141	$2,996	$3,145	51%
2006	$10,996	$5,229	$5,767	52%
2007	$17,933	$6,751	$11,183	62%
2008	$12,442	$6,623	$5,819	47%
2009	$5,113	$1,966	$3,148	62%
Avg.	$10,956	$6,658	$4,298	39%

Table 3-19 Real-Time and Day-Ahead Energy Market net revenues for a CC under economic dispatch scenario (Dollars per installed MW-year): Calendar years 2000 to 2009

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$24,794	$26,132	($1,338)	(5%)
2001	$54,206	$48,253	$5,953	11%
2002	$38,625	$35,993	$2,631	7%
2003	$27,155	$21,865	$5,290	19%
2004	$27,389	$18,193	$9,196	34%
2005	$35,608	$28,413	$7,196	20%
2006	$44,692	$31,670	$13,023	29%
2007	$66,616	$44,434	$22,183	33%
2008	$62,039	$47,342	$14,697	24%
2009	$31,581	$28,360	$3,221	10%
Avg.	$41,271	$33,066	$8,205	20%

36 The Day-Ahead Energy Market was implemented on June 1, 2000. For the analysis presented in Table 3-18, Table 3-19 and Table 3-20, the Real-Time Energy Market LMP was used from January 1, 2000, to May 31, 2000.

Table 3-20 Real-Time and Day-Ahead Energy Market net revenues for a CP under economic dispatch scenario (Dollars per installed MW-year): Calendar years 2000 to 2009

	Real-Time Economic	Day-Ahead Economic	Actual Difference	Percent Difference
2000	$108,624	$116,784	($8,159)	(8%)
2001	$95,361	$95,119	$242	0%
2002	$96,828	$97,493	($665)	(1%)
2003	$159,912	$162,285	($2,374)	(1%)
2004	$124,497	$113,892	$10,605	9%
2005	$222,911	$220,824	$2,087	1%
2006	$177,852	$167,282	$10,571	6%
2007	$244,419	$221,757	$22,662	9%
2008	$179,457	$174,191	$5,267	3%
2009	$49,022	$45,844	$3,178	6%
Avg.	$145,888	$141,547	$4,341	3%

Net Revenue Adequacy

To put the 2009 net revenue results in perspective, net revenues are compared to the annual, levelized fixed costs for each technology. The MMU reevaluated the fixed costs for all three new entry plant configurations for 2009.[37] The estimated, 20-year levelized fixed costs[38] are $128,705 per installed MW-year for the new entrant CT plant,[39] $173,174 per installed MW-year for the new entrant CC plant and $446,550 per installed MW-year for the new entrant CP plant.[40] Levelized fixed costs increased significantly for all three technologies. Table 3-21 shows the 20-year levelized costs for each technology for the period 2005 through 2009.[41] The increased costs of constructing generation facilities from 2005 through 2008 are the result of a combination of factors, including increased worldwide demand in recent years. The estimated levelized fixed costs for 2009 show a smaller increase than in prior years, indicating a potential reduction in upward pressure on the costs of constructing generation facilities.

In this section, net revenue includes net revenue from the Real-Time Energy Market, from the Capacity Market and from any applicable ancillary service.

Table 3-21 New entrant 20-year levelized fixed costs (By plant type (Dollars per installed MW-year))

	2005 20-Year Levelized Fixed Cost	2006 20-Year Levelized Fixed Cost	2007 20-Year Levelized Fixed Cost	2008 20-Year Levelized Fixed Cost	2009 20-Year Levelized Fixed Cost
CT	$72,207	$80,315	$90,656	$123,640	$128,705
CC	$93,549	$99,230	$143,600	$171,361	$173,174
CP	$208,247	$267,792	$359,750	$492,780	$446,550

37 The MMU began evaluating fixed costs for all three technologies in 2005. In the following tables and figures, the 20-year levelized fixed costs from 2005 are used as a proxy for the preceding years.

38 Annual fixed costs may vary by location. The fixed costs presented here are associated with a location in the EMAAC LDA and are meant to serve as a baseline for comparison.

39 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt-to-equity financing with a target internal rate of return (IRR) of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

40 Installed capacity at an average Philadelphia ambient air temperature of 54 degrees F. during the study period of 1999 to 2009.

41 The figures in Table 3-21 represent the annual cost per MW per year if total costs were levelized over the 20-year life cycle of the plant. These fixed costs of construction are specific to the PJM Mid-Atlantic Region.

In 2009, under the economic dispatch scenario, average net revenue from the PJM Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CT were $55,939 per installed MW-year. The associated operating costs were between $55 and $60 per MWh, based on a design heat rate of 10,500 Btu per kWh, average daily delivered natural gas prices of $4.73 per MBtu and a VOM rate of $7.09 per MWh.[42] The average PJM net revenue in 2009 would not have covered the fixed costs of a new CT. As shown in Table 3-22, the only year when average PJM net revenue was sufficient to cover fixed costs for a new CT was 1999. However, some zonal net revenues were sufficient to cover the fixed costs for a new CT in several prior years.

Table 3-22 CT 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2009

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$72,207	$74,537	103%
2000	$72,207	$30,946	43%
2001	$72,207	$63,462	88%
2002	$72,207	$28,260	39%
2003	$72,207	$10,566	15%
2004	$72,207	$8,543	12%
2005	$72,207	$10,437	14%
2006	$80,315	$14,948	19%
2007	$90,656	$48,530	54%
2008	$123,640	$50,532	41%
2009	$128,705	$55,939	43%
Average	$84,433	$36,064	43%

Table 3-23 includes the 20-year levelized fixed cost in 2009 for a new entrant CT, the economic dispatch net revenue for each zone in 2009 and average net revenue and average fixed costs for the period 1999 to 2009. There are no control zones with net revenue sufficient to cover 100 percent of the 2009 levelized fixed costs. The net revenues in Pepco and in BGE control zones of the SWMAAC LDA show the highest percentage of levelized fixed costs recovery at 84 and 78 percent respectively. Figure 3-3 summarizes the information in Table 3-23, showing the 2009 average net revenue for a new entrant CT, the zonal net revenue for the period 1999 to 2009 and the levelized 2009 fixed cost for a new entrant CT. The extent to which net revenues cover the levelized fixed costs of investment in the CT technology is significantly dependent on location, which affects both energy and, with the locational capacity prices, capacity revenue. Total net revenues in 2009 are higher than the eleven year average for all control zones, and this is largely due to RPM capacity revenue which comprises a significant portion of total revenue for the CT technology. Figure 3-4 shows zonal net revenue for the new entrant CT by LDA with the applicable yearly levelized fixed costs for the period 1999-2009.

42 The analysis used the daily gas costs and associated production costs for CTs and CCs.

Table 3-23 CT 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2009

	2009			11-Year Average (1999-2009)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$70,287	$128,705	55%	$51,713	$84,433	61%
AEP	$42,852	$128,705	33%	$21,267	$84,433	25%
AP	$67,387	$128,705	52%	$26,539	$84,433	31%
BGE	$99,894	$128,705	78%	$53,484	$84,433	63%
ComEd	$43,514	$128,705	34%	$23,179	$84,433	27%
DAY	$44,101	$128,705	34%	$21,494	$84,433	25%
DLCO	$45,825	$128,705	36%	$34,501	$84,433	41%
Dominion	$55,440	$128,705	43%	$39,402	$84,433	47%
DPL	$79,206	$128,705	62%	$49,160	$84,433	58%
JCPL	$77,418	$128,705	60%	$47,935	$84,433	57%
Met-Ed	$70,283	$128,705	55%	$39,402	$84,433	47%
PECO	$75,308	$128,705	59%	$45,409	$84,433	54%
PENELEC	$66,246	$128,705	51%	$30,911	$84,433	37%
Pepco	$108,262	$128,705	84%	$55,810	$84,433	66%
PPL	$69,197	$128,705	54%	$36,323	$84,433	43%
PSEG	$74,951	$128,705	58%	$46,626	$84,433	55%
RECO	$73,641	$128,705	57%	$40,783	$84,433	48%
PJM	$55,939	$128,705	43%	$36,064	$84,433	43%

Figure 3-3 New entrant CT real-time 2009 net revenue, eleven-year average net revenue and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year): Calendar years 1999 to 2009

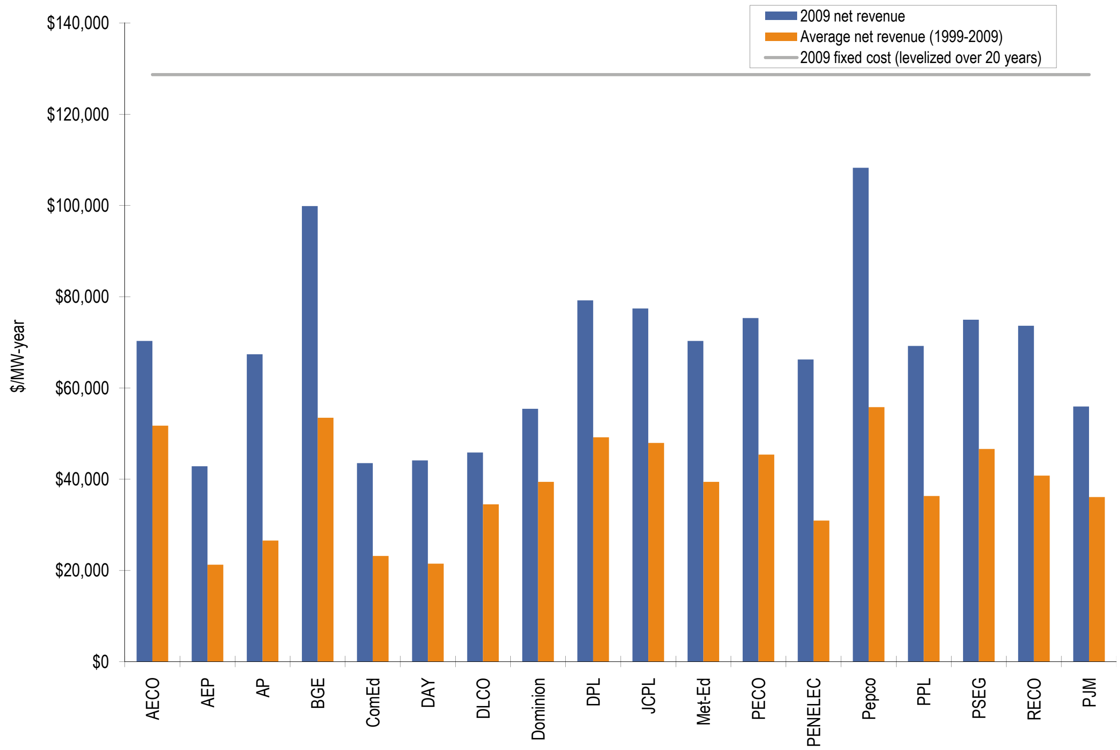


Figure 3-4 New entrant CT real-time net revenue and 20-year levelized fixed cost as of 2009 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2009

In 2009, under the economic dispatch scenario, average net revenue from the PJM Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CC were $81,376 per installed MW-year. The associated operating costs were between $35 and $40 per MWh, based on a design heat rate of 6,900 Btu per kWh, average daily delivered natural gas prices of $4.73 per MBtu and a VOM rate of $3.07 per MWh. The resulting PJM average net revenue is less than the 20-year levelized fixed cost. Table 3-24 shows the PJM average CC net revenue and associated levelized fixed costs for the period 1999 to 2009. The only year when average PJM net revenue was sufficient to cover the associated 20-year levelized fixed costs for a new entrant CC was 1999, but some zonal net revenues were sufficient to cover the fixed costs for a new CC in several prior years.

Table 3-24 CC 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2009

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$93,549	$100,700	108%
2000	$93,549	$47,592	51%
2001	$93,549	$86,670	93%
2002	$93,549	$52,272	56%
2003	$93,549	$35,591	38%
2004	$93,549	$35,785	38%
2005	$93,549	$40,817	44%
2006	$99,230	$49,529	50%
2007	$143,600	$100,809	70%
2008	$171,361	$103,928	61%
2009	$173,174	$81,376	47%
Average	$112,928	$66,824	59%

Table 3-25 compares the 20-year levelized fixed cost in 2009 for a new entrant CC to the economic dispatch net revenue for each zone in 2009, along with average net revenue for the period 1999 to 2009 and average fixed costs. The average PJM net revenue is not enough to cover the levelized fixed costs. There are no control zones with net revenue sufficient to cover 100 percent of the 2009 levelized fixed costs. The net revenues in Pepco and in BGE Control Zones of the SWMAAC LDA show the highest percentage of levelized fixed costs recovery at 89 and 80 percent, respectively. Figure 3-5 summarizes the information in Table 3-25, showing the 2009 net revenue for a new entrant CC, the average net revenue for the period 1999 to 2009 by zone and the levelized 2009 capital cost for a new entrant CC.[43] The extent to which net revenues cover the levelized fixed costs of investment in the CC technology is significantly dependent on location, which affects both energy and, with locational capacity prices, capacity revenue. Total net revenues in 2009 are higher than the eleven year average for all control zones, and this is largely due to RPM capacity revenue which comprises a significant portion of total revenue for the CC technology. Figure 3-6 shows zonal net revenue for the new entrant CC by LDA with the applicable yearly levelized fixed costs for the period 1999-2009.

43 The fixed costs associated with the EMAAC LDA are meant to serve as a baseline for comparison.

Table 3-25 CC 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2009

	2009			11-Year Average (1999-2009)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$112,738	$173,174	65%	$96,925	$112,928	86%
AEP	$65,604	$173,174	38%	$42,672	$112,928	38%
AP	$111,482	$173,174	64%	$62,286	$112,928	55%
BGE	$138,066	$173,174	80%	$95,046	$112,928	84%
ComEd	$59,298	$173,174	34%	$48,183	$112,928	43%
DAY	$65,760	$173,174	38%	$42,291	$112,928	37%
DLCO	$66,775	$173,174	39%	$76,455	$112,928	68%
Dominion	$93,699	$173,174	54%	$79,403	$112,928	70%
DPL	$116,532	$173,174	67%	$87,753	$112,928	78%
JCPL	$114,843	$173,174	66%	$90,176	$112,928	80%
Met-Ed	$103,508	$173,174	60%	$76,227	$112,928	68%
PECO	$108,830	$173,174	63%	$83,482	$112,928	74%
PENELEC	$97,452	$173,174	56%	$58,154	$112,928	51%
Pepco	$154,109	$173,174	89%	$98,821	$112,928	88%
PPL	$100,883	$173,174	58%	$70,776	$112,928	63%
PSEG	$111,307	$173,174	64%	$92,180	$112,928	82%
RECO	$107,331	$173,174	62%	$93,862	$112,928	83%
PJM	$81,376	$173,174	47%	$66,824	$112,928	59%

Figure 3-5 New entrant CC real-time 2009 net revenue, eleven-year average net revenue and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year): Calendar years 1999 to 2009

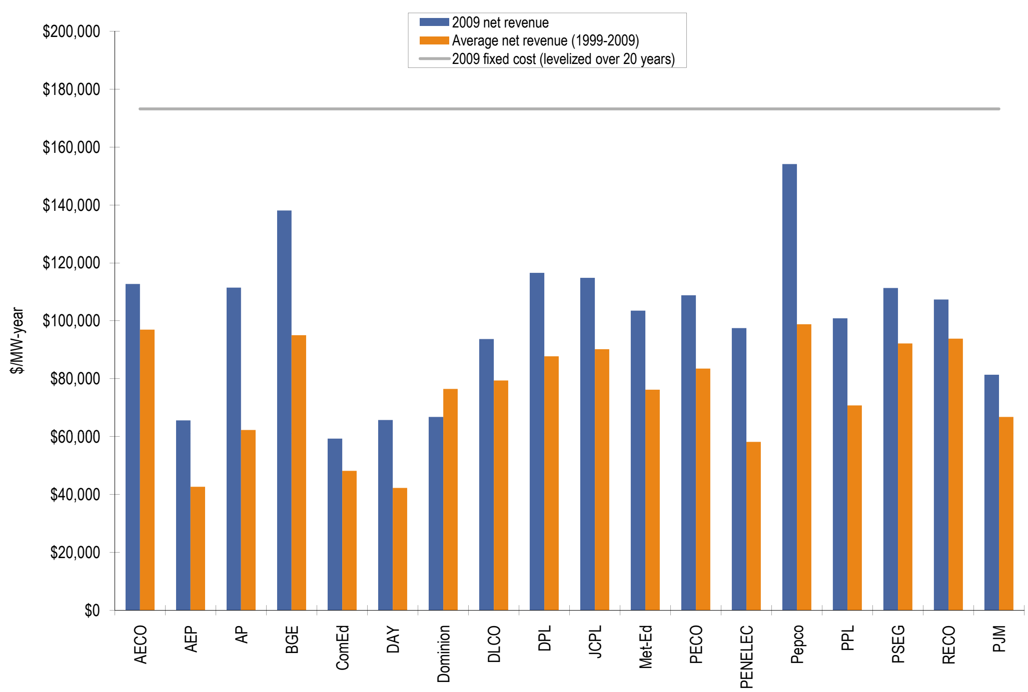
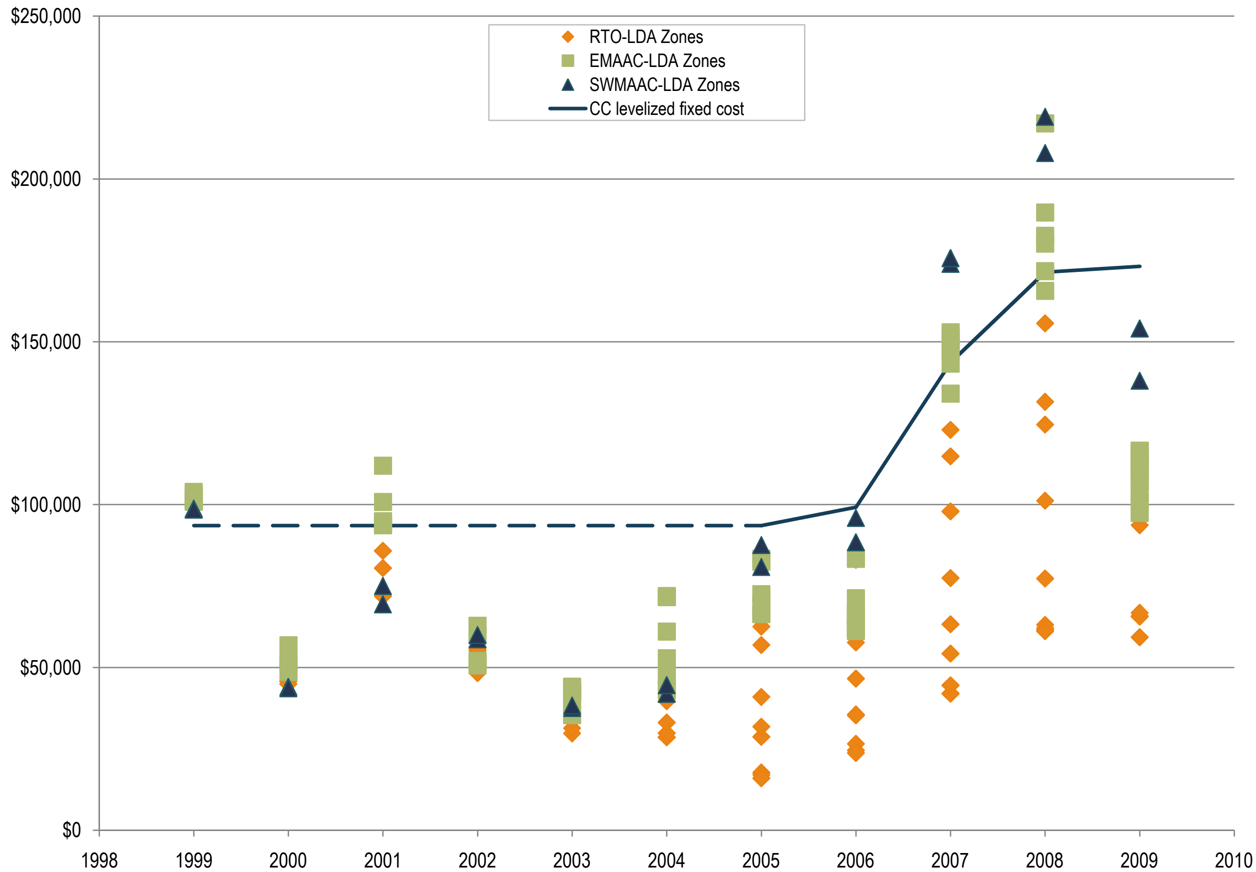


Figure 3-6 New entrant CC real-time net revenue and 20-year levelized fixed cost as of 2009 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2009



In 2009, under the economic dispatch scenario, average PJM net revenue from the Real-Time Energy Market, the Capacity Market and the Ancillary Service Markets for a new entrant CP was $94,968 per installed MW-year. The associated operating costs were between $30 and $35 per MWh, based on a design heat rate of 9,100 Btu per kWh, average delivered coal prices of $3.16 per MBtu and a VOM rate of $2.97 per MWh.[44] Table 3-26 shows the PJM average CP net revenue and associated levelized fixed costs for the period 1999 to 2009. For the period, the resulting PJM average net revenue is less than the 20-year levelized fixed cost. The only year when average PJM net revenue was sufficient to cover the levelized fixed costs for a new entrant CP was 2005. However, several zonal net revenues were sufficient to cover the fixed costs for a new CP in 2007. Average 2009 net revenue for a CP show a significant decrease from 2008 reflecting the lower average energy price levels in PJM and the more substantial impact of energy market net revenues for the CP technology.

44 The analysis used the prompt coal costs and associated production costs for CPs.

Table 3-26 CP 20-year levelized fixed cost vs. real-time economic dispatch net revenue (Dollars per installed MW-year): Calendar years 1999 to 2009

	20-Year Levelized Fixed Cost	Economic Dispatch Net Revenue	Economic Dispatch Percent
1999	$208,247	$118,022	57%
2000	$208,247	$134,564	65%
2001	$208,247	$129,271	62%
2002	$208,247	$112,131	54%
2003	$208,247	$169,509	81%
2004	$208,247	$133,124	64%
2005	$208,247	$228,430	110%
2006	$267,792	$182,461	68%
2007	$359,750	$277,284	77%
2008	$492,780	$218,144	44%
2009	$446,550	$94,968	21%
Average	$274,964	$163,446	59%

Table 3-27 compares the 20-year levelized fixed cost in 2009 for a new entrant CP to the economic dispatch net revenue for each zone in 2009, along with average net revenue for the period 1999 to 2009 and average fixed costs. There were no control zones with sufficient net revenue to cover the 2009 levelized fixed costs. Figure 3-7 summarizes the information in Table 3-27, showing the 2009 net revenue for a new entrant CP, the average net revenue for the period 1999 to 2009 by zone and the levelized 2009 capital cost for a new entrant CP.[45] For every zone, 2009 energy net revenues for a CP are lower than 2008, which is partially offset by higher capacity revenues.[46] The extent to which net revenues cover the levelized fixed costs of investment in the CP technology is significantly dependent on location, which affects both energy and, with locational capacity prices, capacity revenue as well as fuel costs. There is less locational variation in 2009 for the CP technology because locational energy price differences were down substantially in 2009 and the impact of the locational capacity market price differences was attenuated by the smaller relative significance of capacity revenues for the CP technology. Total net revenues in 2009 are lower than the eleven year average for all control zones, and this is driven by lower energy price levels and lower energy net revenues, which comprises a significant portion of total revenue for the CP technology. The Figure 3-8 shows zonal net revenue for the new entrant CP by LDA with the applicable yearly levelized fixed costs for the period 1999-2009.

45 The fixed costs associated with the EMAAC LDA are meant to serve as a baseline for comparison.

46 Average net revenues were taken for all years a zone was fully integrated into PJM.

Table 3-27 CP 20-year levelized fixed cost vs. real-time economic dispatch, zonal net revenue (Dollars per installed MW-year): Calendar years 1999 to 2009

	2009			11-Year Average (1999-2009)		
	Net Revenue	20-Year Levelized Cost	Percent Recovered	Net Revenue	20-Year Levelized Cost	Percent Recovered
AECO	$151,958	$446,550	34%	$210,185	$274,964	76%
AEP	$66,176	$446,550	15%	$139,335	$274,964	51%
AP	$117,241	$446,550	26%	$192,497	$274,964	70%
BGE	$124,582	$446,550	28%	$203,070	$274,964	74%
ComEd	$91,497	$446,550	20%	$151,659	$274,964	55%
DAY	$77,760	$446,550	17%	$133,381	$274,964	49%
DLCO	$73,721	$446,550	17%	$153,297	$274,964	56%
Dominion	$90,049	$446,550	20%	$209,724	$274,964	76%
DPL	$103,715	$446,550	23%	$202,034	$274,964	73%
JCPL	$141,256	$446,550	32%	$200,685	$274,964	73%
Met-Ed	$119,008	$446,550	27%	$184,273	$274,964	67%
PECO	$142,528	$446,550	32%	$194,890	$274,964	71%
PENELEC	$140,148	$446,550	31%	$164,195	$274,964	60%
Pepco	$153,255	$446,550	34%	$209,765	$274,964	76%
PPL	$132,526	$446,550	30%	$179,808	$274,964	65%
PSEG	$165,919	$446,550	37%	$205,759	$274,964	75%
RECO	$138,107	$446,550	31%	$239,532	$274,964	87%
PJM	$94,968	$446,550	21%	$163,446	$274,964	59%

Figure 3-7 New entrant CP real-time 2009 net revenue, eleven-year average net revenue and 20-year levelized fixed cost as of 2009 (Dollars per installed MW-year): Calendar years 1999 to 2009

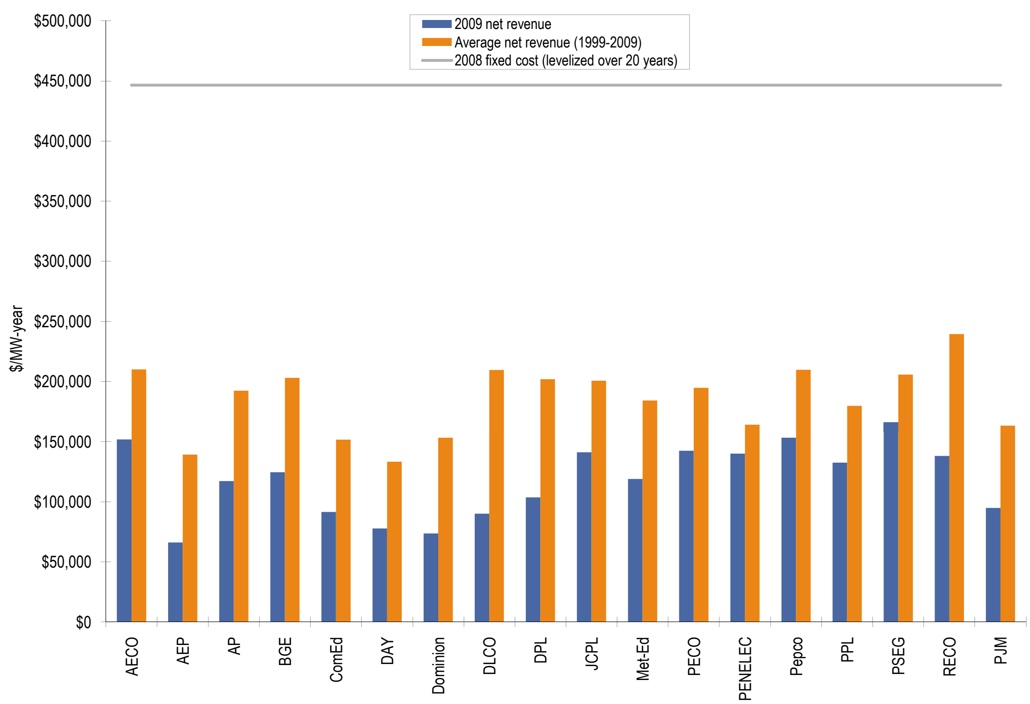
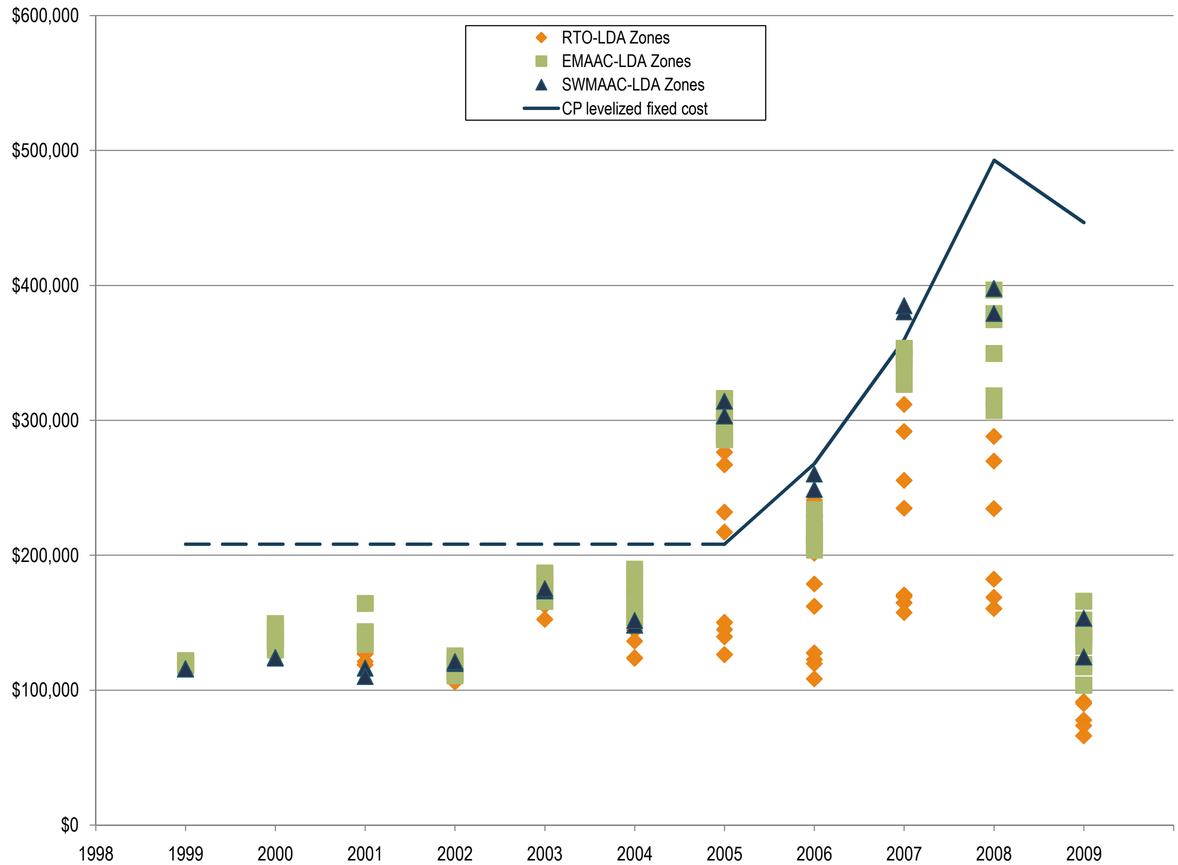


Figure 3-8 New entrant CP real-time net revenue and 20-year levelized fixed cost as of 2009 by LDA (Dollars per installed MW-year): Calendar years 1999 to 2009



Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed costs of investing in new generating resources, 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. Analysis of 2009 net revenue indicates that, in years when energy markets are long and energy prices low, the contribution of capacity revenue from the RPM has a more significant effect on the incentive to invest in a new entrant CT or CC. The profitability of new entrant peaking units, specifically, is substantially impacted by the local capacity market clearing price. Capacity market revenue is a smaller proportion of total net revenue for a new entrant coal plant, thus, the incentive to invest in a new entrant CP is less dependent on capacity revenues and more dependent on energy prices, input costs and energy net revenues.

The net revenue for a new generation resource varied significantly with the input fuel type and the efficiency of the reference technology. The delivered price of natural gas showed a more significant decrease at about 52.4 percent, than did the delivered price of coal, which decreased by about 31.4 percent. [47] As a result, the natural gas fired power plants, particularly the more efficient combined cycle, show lower percentage decreases in energy net revenues from 2008 than the coal-fired power plant. There are no control zones with net revenue sufficient to cover 100 percent of the

47 The calculated increase in delivered cost of coal is based on Central Appalachian, low-sulfur coal used in PJM RTO net revenue calculations.

2009 levelized fixed costs. The net revenues in Pepco and BGE Control Zones of the SWMAAC LDA show the highest percent of the levelized fixed cost recovery for all technologies. Net revenue from the combined cycle technology shows the highest percentage of 20-year levelized fixed cost recovery, while the coal plant technology shows the lowest percentage of levelized fixed cost recovery.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental energy 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 also 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, there may be a lag in Capacity Market prices which either offsets the reduction in energy market revenues or exacerbates the reduction in energy market revenues. Capacity Market prices are a function of a three year historical average net revenue offset which can be an inaccurate estimate of actual net revenues in the current operating year. In 2009 Capacity Market prices and revenues were relatively high but not enough to fully offset the decline in energy revenues for CTs. Energy net revenues decreased significantly in most PJM Control zones, but that decrease is not reflected in higher Capacity Market prices.

The net revenue performance of combined cycle units (CCs) was comparable to that of CTs. CCs, like CTs, burn gas but are more efficient than CTs. Thus, as clearing prices set by CTs decline, net revenues from the Energy Market decline for CCs. However, with lower gas prices in 2009, and with the spread between the delivered price of natural gas and the delivered price of coal decreasing, there are hours in which the CC has lower generating costs than the CP. In these cases, when the CP is marginal, the CC will experience inframarginal energy revenues.

Coal units (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. However, when less efficient coal units are on the margin net revenues are higher for more efficient coal units. Coal units also received higher net revenues as a result of CTs setting prices based on gas costs. But with natural gas prices decreasing more than coal prices, these inframarginal energy revenues were lower than in 2007 and 2008. Similarly, with lower gas prices in 2009, and with the spread between the delivered price of natural gas and the delivered price of coal decreasing, there are hours in which the CC has lower generating costs than the CP. The CP, which has significant operating constraints, may continue running during hours when a CC is marginal and net revenues are negative.

The returns earned by investors in generating units are a direct function of net revenues. Positive returns may be earned at less than the annualized fixed costs, although the returns are less than the target. A sensitivity analysis was performed to determine the impact of changes in net revenue on the return on investment for a new generating unit. The internal rate of return (IRR) was calculated for a range of 20-year levelized net revenue streams, using 20-year levelized fixed costs from Table 3-21. Levelized net revenues were modified and the IRR calculated. A $7,500 per MW-year sensitivity was used for the CT; a $10,000 per MW-year sensitivity was used for the CC; and a $30,000 per MW-year sensitivity was used for the CP generator. The results are shown in Table 3-28.[48]

48 This analysis was performed for the MMU by Pasteris Energy, Inc. The annual costs were based on a 20-year project life, 50/50 debt-to-equity financing with a target IRR of 12 percent and a debt rate of 7 percent. For depreciation, the analysis assumed a 15-year modified accelerated cost-recovery schedule (MACRS) for the CT plant and 20-year MACRS for the CC and CP plants. A general annual rate of cost inflation of 2.5 percent was utilized in all calculations.

Table 3-28 Internal rate of return sensitivity for CT, CC and CP generators

	CT		CC		CP	
	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR	20-Year Levelized Net Revenue	20-Year After Tax IRR
Sensitivity 1	$136,205	13.5%	$183,174	13.5%	$476,550	13.8%
Base Case	$128,705	12.0%	$173,174	12.0%	$446,550	12.0%
Sensitivity 2	$121,205	10.4%	$163,174	10.4%	$416,550	10.2%
Sensitivity 3	$113,705	8.7%	$153,174	8.8%	$386,550	8.3%
Sensitivity 4	$106,205	6.9%	$143,174	7.1%	$356,550	6.2%
Sensitivity 5	$98,705	4.9%	$133,174	5.3%	$326,550	4.0%
Sensitivity 6	$91,205	2.7%	$123,174	3.4%	$296,550	1.6%

Actual Net Revenue

The net revenues presented in this section are based on an analysis of actual net revenues for actual units operating in PJM. Net revenues from energy and capacity markets are compared to avoidable costs to determine the extent to which the revenues from PJM markets provide sufficient incentive for continued operations in PJM Markets. 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 purely 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.

The MMU calculated unit specific energy and ancillary net revenues within several technology classes. These net revenues were compared to avoidable costs to determine the extent to which PJM Energy and Ancillary Service Markets alone provide sufficient incentive for continued operations in PJM Markets. Energy and Ancillary Service revenues were then combined with the applicable capacity revenues, depending on the actual location of the unit, and compared to avoidable costs to determine the extent to which the Reliability Pricing Model covered any shortfall between energy and ancillary net revenues and avoidable costs. The comparison of the two results is an indicator of the significance of the role of the capacity market in maintaining the viability of existing generating units.

Energy net revenues presented in this section include Day-Ahead and balancing energy revenues, less submitted or estimated operating costs, as well as any applicable Day-Ahead or Balancing Operating Reserve Credits. Ancillary revenues include actual unit credits for regulation services, spinning reserves and black start capability, in addition to actual or class average reactive revenues determined by actual FERC filings.

Net revenues were analyzed for six technologies: (1) two on one Frame F combined cycles, (2) third generation aero-derivative combustion turbines, (3) third generation Frame F combustion turbines, (4) nuclear generators, (5) sub-critical coal burning units and (6) super critical coal units.

The underlying analysis is done on a unit specific basis, using individual unit actual net revenues and individual unit avoidable costs. For purposes of reporting the results, the data is aggregated by quartile to ensure that confidential data is not released. Within each technology, quartiles were established based on the distribution of total energy net revenue received per installed MW-year. These quartiles remain constant throughout the analysis. Table 3-29 shows average energy and ancillary service net revenues by quartile, along with the class average, for these technology classes.

Table 3-29 Average energy and ancillary service net revenue by quartile for select technologies for calendar year 2009

Technology	First Quartile Average Energy and Ancillary Net Revenue	Second Quartile Average Energy and Ancillary Net Revenue	Class Average Energy and Ancillary Net Revenue	Third Quartile Average Energy and Ancillary Net Revenue	Fourth Quartile Average Energy and Ancillary Net Revenue
CC - Two on One Frame F Technology	($20,161)	$10,533	$15,386	$26,922	$39,200
CT - Third Generation Aero (GE LM 6000)	$2,294	$3,396	$10,350	$12,546	$21,076
CT - Third Generation Frame F	$44	$2,426	$5,002	$4,084	$13,125
Nuclear	$124,536	$194,122	$229,466	$270,254	$311,418
Sub-Critical Coal	($6,609)	$14,418	$34,361	$36,632	$91,551
Super Critical Coal	$9,435	$21,306	$40,434	$41,086	$84,546

The first quartiles for the combined cycle and sub-critical coal technologies show negative net energy revenues at -$20,161 per MW-year and -$6,609 per MW-year. This does not imply that all units in the first quartile for these technologies show negative net revenues. It does mean, however, that the average energy and ancillary service net revenue for the lowest 25 percent of units is negative and that a proportion of units operate in PJM energy markets at a net loss. This results, for example, when a unit runs during unprofitable hours independent of PJM dispatch. For some older units, this may occur because of an inability to follow PJM dispatch. In other cases, a unit may have an incentive to run during hours when LMP is lower than operating costs because it is receiving revenues from outside PJM markets, via a bilateral agreement.

The MMU calculated average avoidable costs in dollars per MW-year for each quartile based on actual submitted Avoidable Cost Rate (ACR) data for units within a quartile associated with the most recent 2008/2009 and 2009/2010 RPM Auctions.[49] For units that did not submit ACR data, the default ACR was used. Avoidable costs were calculated for calendar year 2009 using the 2008/2009 avoidable cost data for 151 days and the 2009/2010 delivery year avoidable for 214 days.

An estimated annual avoidable cost rate for nuclear units was developed by Pasteris Energy, Inc from publicly available information and used to determine an avoidable cost proxy for all nuclear units.[50] While avoidable costs for the CT, CC and CP technologies are quartile specific averages

49 If a unit submitted updated ACR data for an incremental auction for either the 2008/2009 or the 2009/2010 delivery year, that data was used instead of the ACR data submitted for the associated Base Residual Auction.

50 Data from the Nuclear Energy Institute (NEI) website (http://www.nei.org/) was used to develop an avoidable cost rate based on 2008 information, which was escalated through 2009. The NEI states the "average non-fuel O&M cost for a nuclear power plant in 2008 was 1.37 cents/kWh" which includes costs "related to labor, material & supplies, contractor services, licensing fees, and miscellaneous costs such as employee expenses and regulatory fees." Property tax costs were obtained from public information. Guidelines for the determination of insurance premiums were provided by Moore-McNeil LLC Insurance Consulting of Nashville, TN. Overall labor rates for nuclear plant avoidable costs were escalated at 1 percent annually. Plant O&M was escalated using the Handy-Whitman July 1 Index for "Total Nuclear Production Plant." Property tax expense was not escalated and insurance premiums were escalated at 2.5 percent.

based on unit specific avoidable costs, the nuclear avoidable cost rate represents a class average, consistent for all nuclear units both within and across quartiles.

Table 3-30 shows the percentage recovery of avoidable cost using the quartile average energy and ancillary service net revenue. The average energy net revenues for the first three quartiles are not adequate to recover avoidable costs for either the CT technologies or CP technologies. Although the average energy net revenue is negative for first quartile for the CC, the average energy net revenue for each of the top three quartiles is sufficient to cover avoidable costs. The average energy net revenue for the nuclear technology is greater than the class average avoidable cost rate for each quartile.

Table 3-30 Avoidable cost recovery by quartile from energy and ancillary service net revenue for select technologies for calendar year 2009

Technology	First Quartile Recovery of Class Average Avoidable Costs	Second Quartile Recovery of Class Average Avoidable Costs	Class Average Recovery of Class Average Avoidable Costs	Third Quartile Recovery of Class Average Avoidable Costs	Fourth Quartile Recovery of Avoidable Costs
CC - Two on One Frame F Technology	(209.4%)	105.5%	158.4%	279.6%	407.1%
CT - Third Generation Aero (GE LM 6000)	13.2%	19.5%	60.0%	74.8%	121.1%
CT - Third Generation Frame F	0.6%	32.3%	66.7%	54.0%	174.3%
Nuclear	101.4%	158.1%	186.8%	220.1%	253.6%
Sub-Critical Coal	(12.5%)	25.7%	63.6%	67.7%	172.2%
Super Critical Coal	16.6%	37.6%	72.3%	74.9%	152.6%

The RPM capacity market design provides supplemental signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability. Table 3-31 shows average energy and ancillary service net revenues plus average capacity revenues, along with the class average.[51] Table 3-31 is Table 3-29 plus average capacity revenues for the same units.

Table 3-31 Average total net revenue by quartile for select technologies for calendar year 2009

Technology	First Quartile Average Energy and Ancillary Net Revenue	Second Quartile Average Energy and Ancillary Net Revenue	Class Average Energy and Ancillary Net Revenue	Third Quartile Average Energy and Ancillary Net Revenue	Fourth Quartile Average Energy and Ancillary Net Revenue
CC - Two on One Frame F Technology	$26,764	$56,320	$61,234	$68,743	$88,186
CT - Third Generation Aero (GE LM 6000)	$41,030	$44,875	$59,280	$73,482	$74,061
CT - Third Generation Frame F	$53,051	$50,449	$52,643	$49,029	$58,070
Nuclear	$163,272	$241,842	$279,612	$323,716	$370,352
Sub-Critical Coal	$40,263	$67,171	$84,002	$87,991	$139,139
Super Critical Coal	$59,316	$65,899	$90,884	$89,376	$142,970

51 This analysis does not reflect actual RPM billing dollars, rather, it assumes each unit's installed capacity cleared in the relevant Base Residual Auctions.

Table 3-32 shows the average avoidable cost recovery from all PJM markets by the same quartiles. Capacity payments in calendar year 2009 range from approximately $38,700 in the unconstrained RTO Control zones to $82,500 in the SWMAAC LDA. The result is that for the CC technology and both CT technologies, capacity payments alone lead to full recovery of average avoidable costs. With energy prices and load levels down significantly in 2009, most peaking units, depending on location, will not recover avoidable costs from the energy and ancillary service markets alone. Continued operation of and investment in these generation technologies in periods of low demand and low energy prices is dependent on capacity market revenue.

In some years, for some technologies, capacity payments significantly exceed the avoidable costs of running a power plant. With natural gas prices down significantly, the class average net revenue for the more efficient combined cycle was sufficient to cover avoidable costs before capacity revenues are considered. Thus, the average total net revenues, including capacity, for the third and fourth quartiles for the CC technology are between 7 and 9 times greater than the quartile average avoidable costs.

However, the average total revenue for the lowest quartile of subcritical coal units is not sufficient to cover avoidable costs and the average total revenue for the lowest quartile for supercritical coal units is just sufficient to cover avoidable costs. Avoidable costs for coal plants are considerably higher than for CTs and CCs, and, accordingly, revenues received from the capacity market make up a smaller portion of avoidable costs. As a result, the profitability of coal units is more dependent upon net revenues received in the energy market.

Table 3-32 Avoidable cost recovery by quartile from all PJM Markets for select technologies for calendar year 2009

Technology	First Quartile Recovery of Class Average Avoidable Costs	Second Quartile Recovery of Class Average Avoidable Costs	Class Average Recovery of Class Average Avoidable Costs	Third Quartile Recovery of Class Average Avoidable Costs	Fourth Quartile Recovery of Avoidable Costs
CC - Two on One Frame F Technology	277.9%	564.0%	630.5%	713.9%	915.8%
CT - Third Generation Aero (GE LM 6000)	235.8%	257.9%	343.7%	437.8%	425.7%
CT - Third Generation Frame F	719.0%	671.9%	702.1%	647.8%	771.3%
Nuclear	132.9%	196.9%	227.7%	263.6%	301.6%
Sub-Critical Coal	76.2%	119.6%	155.4%	162.6%	261.7%
Super Critical Coal	104.1%	116.3%	162.4%	163.0%	258.1%

Quartile averages can be greatly affected by outliers, and do not indicate the proportion of actual units in PJM not covering avoidable costs. Table 3-33 shows the proportion of units with full recovery of avoidable costs from energy markets and from all markets for calendar years 2007 through 2009. Capacity revenues from 2007 include actual unit specific experience in the CCM for January 1 through May 31 and zone specific RPM revenue streams for June 1 through December 31. Calendar year 2008 was the first full year of RPM capacity payments. In each year, a portion of units for the CC, CT and sub-critical CP technologies do not achieve full recovery of avoidable costs through energy markets alone.

Table 3-33 Proportion of units recovering avoidable costs from energy and ancillary markets as well as total markets for calendar years 2007 through 2009

	2007		2008		2009	
Technology	Units with full recovery from Energy Markets	Units with full recovery from all markets	Units with full recovery from Energy Markets	Units with full recovery from all markets	Units with full recovery from Energy Markets	Units with full recovery from all markets
CC - Two on One Frame F Technology	74%	90%	74%	100%	63%	93%
CT - Third Generation Aero (GE LM 6000)	45%	79%	41%	100%	28%	100%
CT - Third Generation Frame F	47%	100%	48%	100%	20%	100%
Nuclear	100%	100%	100%	100%	93%	100%
Sub-Critical Coal	93%	95%	85%	95%	25%	75%
Super Critical Coal	98%	100%	100%	100%	23%	86%

For the two CT technologies, less than 50 percent of the units in PJM received sufficient revenue from the energy market to recover avoidable costs in each of the three years analyzed, and RPM capacity revenues were sufficient to cover the shortfall between energy revenues and avoidable costs for 2008 and 2009. For the combined cycle, capacity revenues were sufficient in 2008 to provide full recovery for all units, but in 2009, 7 percent of CCs showed less than full recovery of avoidable costs even with capacity revenues and in 2007 10 percent of CCs showed less than full recovery. However, these units show negative energy net revenues and typically operate during a high number of uneconomic hours independent of PJM dispatch, which suggests it likely that such units have a source of revenue outside of PJM markets. 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. In addition, in 2009, 7 percent of nuclear units did not recover the class average nuclear avoidable cost rate from energy market revenues alone. With significantly higher avoidable costs than CCs and CTs and typically lower operating costs per MWh, the profitability of operating coal and nuclear units relies more heavily on energy market revenues.

Energy market net revenues are a function of energy prices and operating costs, which are a function of the cost of inputs. In 2009, energy prices decreased more significantly than did the delivered price of coal, and, as a result, energy net revenues for coal units were down significantly from 2008. Figure 3-9 shows the frequency of coal units associated with several ranges of energy market net revenue for 2008 and 2009. In 2009, 27 percent of coal units received less than $10,000 per MW-year compared to 3 percent in 2008. In 2008, 70 percent of coal units received greater than $120,000 compared to only 4 percent in 2009. The change in energy market net revenue distributions between 2008 and 2009 is more pronounced for the sub-critical coal technology, which tends to be smaller and less efficient than the supercritical coal (Figure 3-10).

Figure 3-9 Frequency of coal units within energy net revenue ranges as a percentage of total coal units for calendar years 2008 and 2009

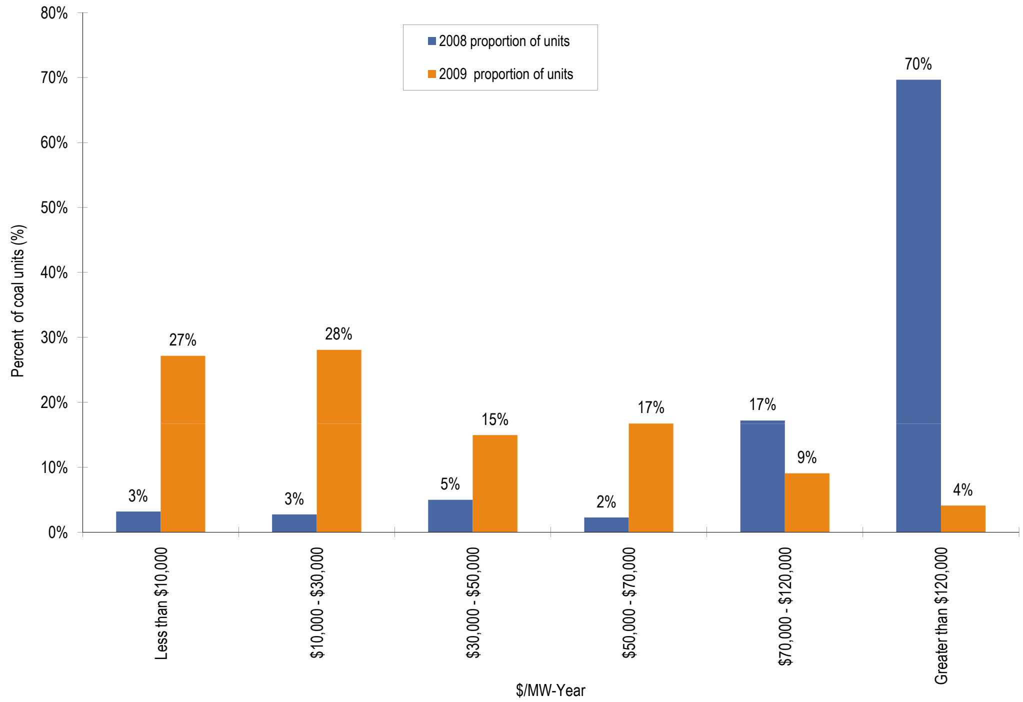


Figure 3-10 Frequency of sub-critical coal units within energy net revenue ranges as a percentage of total sub-critical coal units for calendar years 2008 and 2009

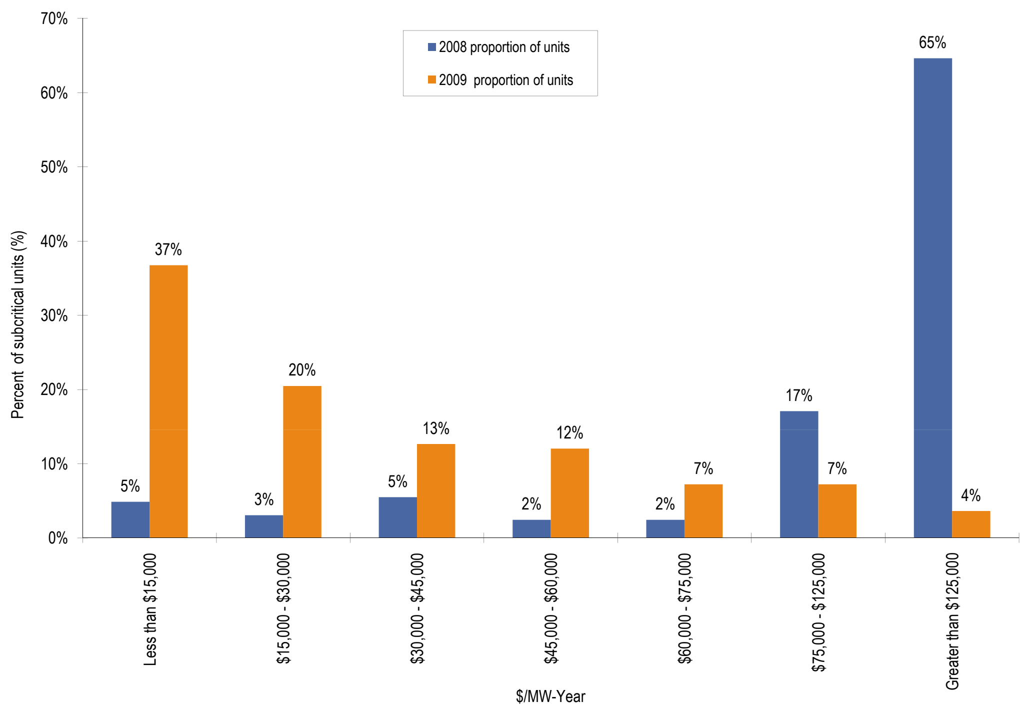


Table 3-34 shows characteristics of the subset of coal units with less than 100 percent recovery of avoidable costs after capacity revenues in 2009, by annual run hours. The total installed capacity associated with coal units that did not cover their avoidable costs in 2009 was 11,250 MW. The largest number of such coal units ran less than 1,000 hours in 2009. These units tended to be significantly smaller than other coal units with an average installed capacity of 73.1 MW and a maximum ICAP of 145 MW. In addition, they tended to incur higher costs of generation, showing a class average heat rate of approximately 10,500 and average operating costs of $54.58/MWh. These units act as mid-merit or even peaking units in the supply stack. They are called on during periods of high LMP and may continue to operate in unprofitable hours due to more severe operating constraints compared to the CT and CC technologies. MMU analysis indicates these units represent the majority of coal units that did not cover their avoidable costs in years 2007 and 2008 as well. 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 their avoidable costs and 52 were close to not covering their avoidable costs. Approximately 16 percent of coal units that did not cover their avoidable costs ran between 1,000 and 3,000 hours for the year, meaning that approximately 38 percent of such coal units ran less than 3,000 hours in 2009. Alternatively, 12 percent operated for more than 7,000 hours in 2009. These units tended to be more efficient and larger units.

Table 3-34 Profile of coal units not recovering avoidable costs from all PJM Market net revenues by hours of operation

Run hours	Proportion of unprofitable units	Average Heat Rate	Average ICAP	Maximum ICAP	Total MW	Average generating costs ($/MWh)
Less than 1,000	22%	10,496.8	73.1	145	804	$54.58
1,000-3,000	16%	9,957.9	185.3	440	1,482	$42.34
3,000-4,000	10%	10,387.8	306.6	500	1,533	$39.69
4,000 - 5,000	10%	10,057.5	211.6	319	1,058	$42.45
5,000 - 6,000	18%	10,070.0	380.4	1,300	3,424	$37.91
6,000 - 7,000	10%	9,702.4	163.2	230	816	$42.89
Greater than 7,000	14%	9,874.6	304.7	800	2,133	$39.10
Total/Average	100%	10,078.1	232.1	533	11,250	$42.71

The profitability of coal units is dependent on a number of factors, including dispatch strategy. It is the case in PJM that some coal units operated as "must-run" units, perhaps to avoid cycling, through periods in which they did not cover costs, independent of PJM dispatch, with the result that the negative net revenues offset positive net revenues earned during higher priced periods.

Location also affects the profitability of coal units. Approximately 85 percent of the coal units that did not cover avoidable costs cleared in the unconstrained RTO LDA for the period, representing the AEP, AP, ComEd, DAY, DLCO and Dominion Control Zones while only 15 percent were located in EMAAC or SWMAAC LDAs.[52] The zones associated with the RTO LDA receive lower capacity revenues and generally lower energy revenues compared to the EMAAC and SWMAAC LDA control zones.

Analysis of 2009 actual net revenues indicates that, for several technologies, there is a significant proportion of units not receiving sufficient net revenue in PJM Energy Markets to cover avoidable

52 A higher proportion of unprofitable units located within the unconstrained RTO Control zones does not alone suggest a cause and effect relationship as the majority of coal units in PJM are located in these control zones. The MMU refers to capacity market clearing prices, average LMPs and the economic dispatch scenario results to demonstrate the relationship between location and profitability of coal units.

costs. For the CT technologies and the CC technology, capacity revenue from the RPM provides a sufficient supplement for units to fully recover avoidable costs. However, 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.

Existing and Planned Generation

Installed Capacity and Fuel Mix

During calendar year 2009, PJM installed capacity rose 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, and the fuel mix also shifted slightly. Installed capacity includes net capacity imports and exports and can vary on a daily basis.

Installed Capacity

On January 1, 2009, PJM installed capacity was 164,898.9 MW.[53] (See Table 3-35) Over the next five months, unit retirements, facility reratings plus import and export shifts resulted in an increase in installed capacity to 165,146.7 MW on May 31, 2009. [54]

Table 3-35 PJM installed capacity (By fuel source): January 1, May 31, June 1, and December 31, 2009

	1-Jan-09		31-May-09		1-Jun-09		31-Dec-09	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	67,064.7	40.7%	67,025.3	40.6%	68,159.0	40.7%	68,137.1	40.7%
Gas	48,333.9	29.3%	48,506.9	29.4%	48,979.3	29.2%	48,838.8	29.2%
Hydroelectric	7,476.3	4.5%	7,550.1	4.6%	7,939.9	4.7%	7,939.9	4.7%
Nuclear	30,478.0	18.5%	30,542.5	18.5%	30,701.5	18.3%	30,731.5	18.4%
Oil	10,714.9	6.5%	10,674.3	6.5%	10,704.3	6.4%	10,700.1	6.4%
Solid waste	664.7	0.4%	664.7	0.4%	672.1	0.4%	672.1	0.4%
Wind	166.4	0.1%	182.9	0.1%	297.8	0.2%	306.9	0.2%
Total	164,898.9	100.0%	165,146.7	100.0%	167,453.9	100.0%	167,326.4	100.0%

At the beginning of the new planning year on June 1, 2009, installed capacity increased by 2,307.2 MW to 167,453.9, a 1.4 percent increase in total PJM capacity over the May 31 level.

On December 31, 2009, PJM installed capacity was 167,326.4 MW.[55]

53 Percents shown in Table 3-35 and Table 3-36 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

54 The capacity described in this section is the capability of all PJM capacity resources, as entered into the eRPM system, regardless of whether the capacity cleared in the RPM auctions.

55 Wind-based resources accounted for 306.9 MW of installed capacity in PJM on December 31, 2009. This value represents approximately 13 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 13 percent of nameplate capacity when determining the system installed capacity because wind resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind resources will be calculated using actual data in place of the 87 percent reduction. There are additional wind resources not reflected in this total because they are energy only resources and do not participate in the PJM Capacity Market.

Energy Production by Fuel Source

In calendar year 2009, coal units provided 50.5 percent, nuclear units 36.0 percent, gas 9.7 percent, oil 0.2 percent, hydroelectric 2.0 percent, waste 0.8 percent and wind 0.8 percent of total generation. (See Table 3-36.)

Table 3-36 PJM generation (By fuel source (GWh)): Calendar year 2009

		GWh	Percent
Coal		349,818.2	50.5%
Nuclear		249,392.3	36.0%
Gas		67,218.9	9.7%
	Natural Gas	65,848.2	9.5%
	Landfill Gas	1,368.5	0.2%
	Biomass Gas	2.2	0.0%
Hydroelectric		14,123.0	2.0%
Waste		5,664.7	0.8%
	Solid Waste	4,147.0	0.6%
	Miscellaneous	1,517.7	0.2%
Wind		5,489.7	0.8%
Oil		1,568.1	0.2%
	Heavy Oil	1,383.7	0.2%
	Light Oil	162.9	0.0%
	Diesel	14.4	0.0%
	Kerosene	7.1	0.0%
	Jet Oil	0.0	0.0%
Solar		3.5	0.0%
Battery		0.3	0.0%
Total		693,278.7	100.0%

Planned Generation Additions

Net revenues provide incentives to build new generation to serve PJM markets. While these incentives operate with a significant lag time and are based on expectations of future net revenue, the amount of planned new generation in PJM reflects the market's perception of the incentives provided by the combination of revenues from the PJM Energy, Capacity and Ancillary Service Markets. At the end of 2009, 76,725 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of approximately 167,000 MW in 2009 and a year-end, installed capacity of 167,326 MW. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000. (See Table 3-37).

Table 3-37 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 to 2009[56]

	MW
2000	505
2001	872
2002	3,841
2003	3,524
2004	1,935
2005	819
2006	471
2007	1,265
2008	2,777
2009	2,516

PJM Generation Queues

Generation request queues are groups of proposed projects. Queue A was open from February 1997 through January 1998; Queue B was open from February 1998 through January 1999; Queue C was open from February 1999 through July 1999 and Queue D opened in August 1999. After Queue D, a new queue was opened every six months. Queue V was active through January 31, 2010.

Capacity in generation request queues for the 10-year period beginning in 2009 and ending in 2018 decreased by 14,081 MW from 90,807 MW in 2008 to 76,725 MW in 2009, or 18 percent. (See Table 3-38.)[57] Queued capacity scheduled for service in 2009 decreased from 16,060 MW to 9,002 MW, or 78 percent. Queued capacity scheduled for service in 2010 decreased from 18,052 MW to 13,732 MW, or 31 percent. The 76,725 MW includes generation with scheduled in-service dates in 2009 and units still active in the queue with in-service dates scheduled before 2009, listed at nameplate capacity, although these units are not yet in service.

Table 3-38 Queue comparison (MW): Calendar years 2009 vs. 2008

	MW in the Queue 2008	MW in the Queue 2009	Year-to-Year Change (MW)	Year-to-Year Change
2009	16,060	9,002	(7,058)	(78.4%)
2010	18,052	13,732	(4,319)	(31.5%)
2011	17,253	15,873	(1,380)	(8.7%)
2012	15,527	11,053	(4,474)	(40.5%)
2013	7,920	6,350	(1,570)	(24.7%)
2014	11,965	13,439	1,474	11.0%
2015	2,436	3,091	655	21.2%
2016	0	950	950	100.0%
2017	0	1,640	1,640	100.0%
2018	1,594	1,594	0	0.0%
Total	90,807	76,725	(14,081)	(18.4%)

56 The capacity described in this table refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.
57 See the *2008 State of the Market Report for PJM* (March 11, 2009), pp. 159-160, for the queues in 2008.

Table 3-39 shows the amount of capacity active, in-service, under construction or withdrawn for each queue since the beginning of the Regional Transmission Expansion Plan (RTEP) Process and the total amount of capacity that had been included in each queue.[58]

Table 3-39 Capacity in PJM queues (MW): At December 31, 2009[59, 60]

Queue	Active	In-Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,121	0	17,347	25,468
B Expired 31-Jan-99	0	4,671	0	15,833	20,503
C Expired 31-Jul-99	0	531	0	4,151	4,682
D Expired 31-Jan-00	0	851	0	7,603	8,454
E Expired 31-Jul-00	0	795	0	16,887	17,682
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	0	486	630	21,986	23,102
H Expired 31-Jan-02	0	603	100	8,422	9,124
I Expired 31-Jul-02	0	103	0	3,738	3,841
J Expired 31-Jan-03	0	40	0	846	886
K Expired 31-Jul-03	0	128	100	2,416	2,643
L Expired 31-Jan-04	20	257	0	4,014	4,290
M Expired 31-Jul-04	0	319	186	3,978	4,482
N Expired 31-Jan-05	1,462	2,133	138	6,663	10,397
O Expired 31-Jul-05	1,978	1,048	570	3,978	7,574
P Expired 31-Jan-06	1,136	989	2,774	3,588	8,486
Q Expired 31-Jul-06	2,976	707	2,889	8,133	14,705
R Expired 31-Jan-07	7,169	566	790	14,192	22,716
S Expired 31-Jul-07	7,606	967	1,241	11,079	20,892
T Expired 31-Jan-08	16,484	164	351	11,469	28,468
U Expired 31-Jan-09	13,332	110	401	21,018	34,861
V Expires 31-Jan-10	14,337	0	56	980	15,372
Total	66,500	23,638	10,225	191,412	291,774

Data presented in Table 3-39 show that through 2009, 54 percent of total in-service capacity from all the queues was from Queues A and B and an additional 9 percent was from Queues C, D and E.[61] As of December 31, 2009, 27.8 percent of the capacity in Queues A and B has been put in service, and 8.1 percent of all queued capacity has been put in service.

The data presented in Table 3-40 show that for successful projects there is an average time of 729 days between entering a queue and the in-service date. The data also show that for withdrawn projects, there is an average time of 520 days between entering a queue and exiting. For each status, there is substantial variability around the average results.

58 Projects listed as active have been entered in the queue and the next phase can be under construction, in-service or withdrawn. At any time, the total number of projects in the queues is the sum of active projects and under-construction projects.

59 The *2009 State of the Market Report for PJM* contains all projects in the queue including reratings of existing generating units and energy only resources.

60 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.

61 The data for Queue V include projects through December 31, 2009.

Table 3-40 Average project queue times: At December 31, 2009

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	1,056	641	0	3,165
In-Service	729	637	0	3,287
Suspended	2,294	865	890	4,172
Under Construction	1,312	845	0	4,370
Withdrawn	520	474	0	2,793

Distribution of Units in the Queues

A more detailed examination of the queue data permits some additional conclusions. The geographic distribution of generation in the queues shows that new capacity is being added disproportionately in the west, and includes a substantial amount of wind capacity.

Table 3-41 shows the RTEP projects under construction or active as of December 31, 2009, by unit type and control zone. Most of the steam projects (predominantly coal) (88.2 percent of the MW), most of the wind projects (96.3 percent of the MW) and most of the combined-cycle projects (60.1 percent of the MW) are outside the Eastern MAAC (EMAAC)[62] and Southwestern MAAC (SWMAAC)[63] locational deliverability areas (LDAs).[64] Of the total capacity additions, only 8,852 MW or 11.5 percent are projected to be in EMAAC; 4,728 MW or 6.2 percent are projected to be constructed in SWMAAC. Overall, 82.3 percent of capacity is being added outside the EMAAC and SWMAAC, and 74.1 percent of capacity is being added outside EMAAC, SWMAAC and MAAC.

Wind projects account for approximately 40,888 MW of capacity or 53 percent of the capacity in the queues and combined-cycle projects account for 14,836 MW of capacity or 19 percent of the capacity in the queues.[65] Wind projects account for 3,067 MW of capacity in MAAC LDAs, or 15.4 percent. While there are no wind projects in the SWMAAC LDA, in the EMAAC LDA wind projects account for 1,516 MW of capacity, or 17.1 percent.

62 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG Control Zones.

63 SWMAAC consists of the BGE and Pepco Control Zones.

64 See the *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.

65 Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent until actual generation data are available. Beginning with Queue U, PJM derates wind resources to 13 percent. Based on the derating of 40,888 MW of wind resources, the 76,725 MW currently active in the queues would be reduced to 41,153 MW.

Table 3-41 Capacity additions in active or under-construction queues by control zone (MW): At December 31, 2009[66]

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Unknown	Total
AECO	0	0	767	4	0	0	201	665	1,066	0	2,702
AEP	0	1,035	594	2	100	84	25	3,726	10,662	73	16,302
AP	0	930	4	0	134	0	20	724	2,052	85	3,948
BGE	0	0	0	5	0	1,640	1	132	0	11	1,789
ComEd	0	1,680	1,044	98	0	392	0	1,366	23,728	0	28,308
DAY	0	0	10	2	112	0	22	12	1,149	0	1,306
DLCO	0	0	0	0	77	91	0	0	0	0	168
DPL	0	0	55	0	0	0	11	43	450	14	573
Dominion	0	3,521	181	25	30	1,944	45	405	230	475	6,855
JCPL	0	1,430	27	33	0	0	80	0	0	0	1,570
Met-Ed	0	1,745	2	26	0	24	30	10	0	675	2,512
PECO	0	1,200	136	6	0	500	1	18	0	575	2,436
PENELEC	0	0	65	18	32	0	0	50	1,372	0	1,537
Pepco	20	2,670	249	0	0	0	0	0	0	0	2,939
PPL	0	0	137	3	143	1,600	26	116	179	5	2,208
PSEG	0	625	767	0	0	0	113	0	0	65	1,570
Total	20	14,836	4,038	223	627	6,275	575	7,266	40,888	1,977	76,725

There are potentially significant implications for future congestion, the role of firm and interruptible gas supply and natural gas supply infrastructure, if older steam units in the EMAAC and SWMAAC LDAs are replaced by units burning natural gas. Table 3-42 shows that in the EMAAC LDA, gas burning unit types account for 56.5 percent of the capacity additions. Steam additions (coal) account for about 8.1 percent of the MW and wind projects account for 17.1 percent of the MW in the queue for the EMAAC LDA. Nuclear and gas capacity comprise 96.4 percent of the MW capacity additions in the SWMAAC LDA. It should be noted that the wind capacity in this section is reported at nameplate capacity and not reduced to 13 percent of nameplate.

Table 3-42 Capacity additions in active or under-construction queues by LDA (MW): At December 31, 2009[67]

	Battery	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Wind	Unknown	Total
EMAAC	0	3,255	1,752	43	0	500	407	726	1,516	654	8,852
SWMAAC	20	2,670	249	5	0	1,640	1	132	0	11	4,728
WMAAC	0	1,745	204	48	175	1,624	56	176	1,551	680	6,257
RTO	0	7,166	1,833	127	453	2,511	112	6,233	37,821	633	56,888
Total	20	14,836	4,038	223	627	6,275	575	7,266	40,888	1,977	76,725

66 In this section, unit type "Unknown" is referred to for units that the RTEP has not yet identified.
67 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.

Table 3-43 shows existing generation by unit type and control zone. Existing steam (mainly coal and residual oil) and nuclear capacity is distributed across control zones.

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 (Table 3-41 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.

Table 3-43 Existing PJM capacity 2009[68] (By zone and unit type (MW))

	Battery	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
AECO	0	0	641	23	0	0	1,274	0	8	1,945
AEP	0	4,355	3,627	57	1,001	2,106	21,255	0	802	33,204
AP	0	1,129	1,140	36	108	0	7,974	0	245	10,632
BGE	0	0	862	7	0	1,735	3,039	0	0	5,643
ComEd	0	1,836	7,217	108	0	10,336	7,094	0	1,762	28,352
DAY	0	0	1,377	53	0	0	3,551	0	0	4,981
DLCO	0	101	188	0	6	1,741	1,259	0	0	3,295
DPL	0	364	2,487	95	0	0	2,016	0	0	4,962
Dominion	0	3,216	3,786	162	3,325	3,425	8,479	0	0	22,393
External	0	974	1,890	0	0	439	9,314	0	185	12,802
JCPL	0	1,196	1,430	25	400	615	318	0	0	3,983
Met-Ed	0	2,000	407	24	20	786	890	0	0	4,127
PECO	1	2,540	833	7	1,642	4,488	2,129	3	0	11,643
PENELEC	0	0	287	47	521	0	6,830	0	447	8,131
Pepco	0	0	1,571	12	0	0	4,707	0	0	6,290
PPL	0	960	1,352	63	571	2,275	5,530	0	217	10,968
PSEG	0	2,921	2,852	0	5	3,553	2,531	0	0	11,862
Total	1	21,592	31,945	720	7,599	31,499	88,188	3	3,665	185,212

Table 3-44 shows the age of PJM generators by unit type. If the age profile of steam units in PJM accurately represents the future age profile, significant and disproportionate retirements of steam units will occur within the next 10 to 20 years. While steam units comprise 47.6 percent of all current MW, steam units 40 years of age and older comprise 84.6 percent of all MW 40 years of age and older and nearly 92.4 percent of such MW if hydroelectric is excluded from the total. Approximately 7,509 MW of steam units 40 years of age and older are located in EMAAC and SWMAAC.

68 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Table 3-44 PJM capacity age (MW)

Age (years)	Battery	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	Solar	Wind	Total
Less than 10	1	17,357	18,851	396	10	0	1,357	3	3,665	41,639
10 to 20	0	3,976	4,767	120	49	0	6,133	0	0	15,044
20 to 30	0	158	437	38	3,207	15,981	9,999	0	0	29,819
30 to 40	0	101	5,296	39	451	14,903	31,316	0	0	52,106
40 to 50	0	0	2,594	123	2,470	615	24,269	0	0	30,071
50 to 60	0	0	0	4	348	0	13,610	0	0	13,962
60 to 70	0	0	0	0	32	0	1,357	0	0	1,389
70 to 80	0	0	0	0	314	0	149	0	0	463
80 to 90	0	0	0	0	486	0	0	0	0	486
90 to 100	0	0	0	0	200	0	0	0	0	200
100 and over	0	0	0	0	32	0	0	0	0	32
Total	1	21,592	31,945	720	7,599	31,499	88,188	3	3,665	185,212

Table 3-45 shows the effect that the new generation in the queues would have on the existing generation mix, assuming that all non-hydroelectric generators in excess of 40 years of age retire by 2018. The expected role of gas-fired generation depends largely on projects in the queues and continued retirement of coal-fired generators. In 2018, CC and CT generators would account for 52.6 percent of EMAAC generation, an increase of 8.3 percentage points from 2009 levels. Accounting for the fact that about 940 MW of steam units over 40 years old are gas-fired, the result would be an increase in the proportion of gas-fired capacity in EMAAC from about 47 percent to about 52 percent. The proportion of gas-fired capacity in EMAAC would increase to 54.4 percent if the 87 percent reduction for wind capacity is taken into account for EMAAC, meaning that the effective capacity additions are 7,533 MW.

Without the planned coal-fired capability in EMAAC, new gas-fired capability would represent 61.6 percent of all new capability in EMAAC and 73.5 percent when the 87 percent reduction for wind capability is included.

There is a planned addition of 1,640 MW of nuclear capacity in SWMAAC. Without the planned nuclear capability in SWMAAC, new gas-fired capability would represent nearly 100 percent of all new capability in the SWMAAC. In 2018 this would mean that CC and CT generators would comprise 37.4 percent of total capability in SWMAAC.

In RTO[69] zones, if older units retire, a substantial amount of coal-fired generation would be replaced by wind generation. In these zones, 92.1 percent of all generation 40 years or older is steam (mostly coal).With the retirement of these units, in 2018, this would mean that wind farms would comprise 28.0 percent of total capacity in RTO zones.

69 RTO zones consist of the AEP, AP, ComEd, DAY, DLCO, and Dominion Control Zones.

Table 3-45 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018[70]

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Additional Capacity through 2018	Estimated Capacity 2018	Percent of Area Total
EMAAC	Battery	0	0.0%	1	0.0%	0	1	0.0%
	Combined Cycle	0	0.0%	7,021	20.4%	3,255	10,276	28.0%
	Combustion Turbine	960	12.1%	8,242	24.0%	1,752	9,034	24.6%
	Diesel	49	0.6%	150	0.4%	43	144	0.4%
	Hydroelectric	2,042	25.8%	2,047	6.0%	0	2,047	5.6%
	Nuclear	615	7.8%	8,656	25.2%	500	8,541	23.3%
	Solar	0	0.0%	3	0.0%	407	410	1.1%
	Steam	4,243	53.6%	8,268	24.0%	726	4,750	12.9%
	Wind	0	0.0%	8	0.0%	1,516	1,524	4.1%
	Unknown	0	0.0%	0	0.0%	654	654	1.8%
	EMAAC Total	7,909	100.0%	34,395	100.0%	8,852	36,727	100.0%
SWMAAC	Battery	0	0.0%	0	0.0%	20	20	0.2%
	Combined Cycle	0	0.0%	0	0.0%	2,670	2,670	20.8%
	Combustion Turbine	556	14.5%	2,433	20.4%	249	2,126	16.6%
	Diesel	0	0.0%	19	0.2%	5	24	0.2%
	Nuclear	0	0.0%	1,735	14.5%	1,640	3,375	26.3%
	Solar	0	0.0%	0	0.0%	1	1	0.0%
	Steam	3,266	85.5%	7,746	64.9%	132	4,612	36.0%
	Unknown	0	0.0%	0	0.0%	11	11	0.1%
	SWMAAC Total	3,822	100.0%	11,932	100.0%	4,728	12,819	100.0%
	Combined Cycle	0	0.0%	2,960	12.7%	1,745	4,705	21.0%
WMAAC	Combustion Turbine	296	4.3%	2,046	8.8%	204	1,954	8.7%
	Diesel	35	0.5%	135	0.6%	48	147	0.7%
	Hydroelectric	444	6.5%	1,112	4.8%	175	1,286	5.7%
	Nuclear	0	0.0%	3,061	13.2%	1,624	4,685	20.9%
	Solar	0	0.0%	0	0.0%	56	56	0.2%
	Steam	6,052	88.6%	13,249	57.0%	176	7,373	32.9%
	Wind	0	0.0%	663	2.9%	1,551	2,214	9.9%
	Unknown	0	0.0%	0	0.0%	680	680	3.0%
	WMAAC Total	6,827	100.0%	23,226	100.0%	6,257	22,420	100.0%
RTO	Combined Cycle	0	0.0%	11,611	10.0%	7,166	18,776	12.9%
	Combustion Turbine	782	2.8%	19,225	16.6%	1,833	20,276	13.9%
	Diesel	43	0.2%	416	0.4%	127	500	0.3%
	Hydroelectric	1,396	5.0%	4,440	3.8%	453	4,893	3.4%
	Nuclear	0	0.0%	18,047	15.6%	2,511	20,558	14.1%
	Solar	0	0.0%	0	0.0%	112	112	0.1%
	Steam	25,824	92.1%	58,926	50.9%	6,233	39,335	27.0%
	Wind	0	0.0%	2,994	2.6%	37,821	40,815	28.0%
	Unknown	0	0.0%	0	0.0%	633	633	0.4%
	RTO Total	28,045	100.0%	115,658	100.0%	56,888	145,897	100.0%
All Areas	Total	46,602		185,212		76,725	217,863	

70 Percents shown in Table 3-44 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Characteristics of Wind Units

Table 3-46 shows the capacity factor of wind units in PJM. During calendar year 2009, the capacity factor of wind units in PJM was 29.1 percent. Wind units that were capacity resources had a capacity factor of 30.6 percent and an installed capacity of 2,393 MW. Wind units that were classified as energy only had a capacity factor of 22.7 percent and an installed capacity of 1,086 MW. Much of this wind capacity does not appear in the RPM market, as wind capacity in RPM is derated to 13 percent of nameplate capacity, and energy only resources are not included.

Table 3-46 Capacity factor of wind units in PJM, Calendar year 2009[71]

Type of Resource	Capacity Factor	Total Hours	Installed Capacity
Energy-Only Resource	22.7%	75,345	1,086
Capacity Resource	30.6%	190,502	2,393
All Units	29.1%	265,847	3,665

Beginning June 1, 2009, units were able to submit negative price offers. Table 3-47 presents data on negative offers by wind units. Wind units were the only unit types to make negative offers. On average, 170.4 MW of wind is offered daily at a negative price. Wind units with negative offers were marginal in 102 separate 5-minute intervals, or 0.10 percent of all intervals. On average, 1,197.2 MW of wind is offered daily. Overall, wind units were marginal in 671 separate 5-minute intervals, or .65 percent of all intervals.

Table 3-47 Wind resources in real time offering at a negative price in PJM, June through December 2009

	Average MW Offered Daily	Intervals Marginal	Percent of All Intervals
At Negative Price	170.4	102	0.10%
All Wind	1,197.2	671	0.65%

Wind output differs from month to month, based on weather conditions. Figure 3-11 shows the average hourly real time generation of wind units in PJM, by month. On average, wind generation was highest in the months of April, October, November and December, and lowest in June, July, August and September. The highest average hour, 1399.5 MW, occurred in December, and the lowest average hour, 185.8 MW, occurred in July. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

71 The corresponding table in the *2009 Quarterly State of the Market Report for PJM: January through June*, reversed the labels for energy only resources and capacity resources data.

Figure 3-11 Average hourly real-time generation of wind units in PJM, Calendar year 2009

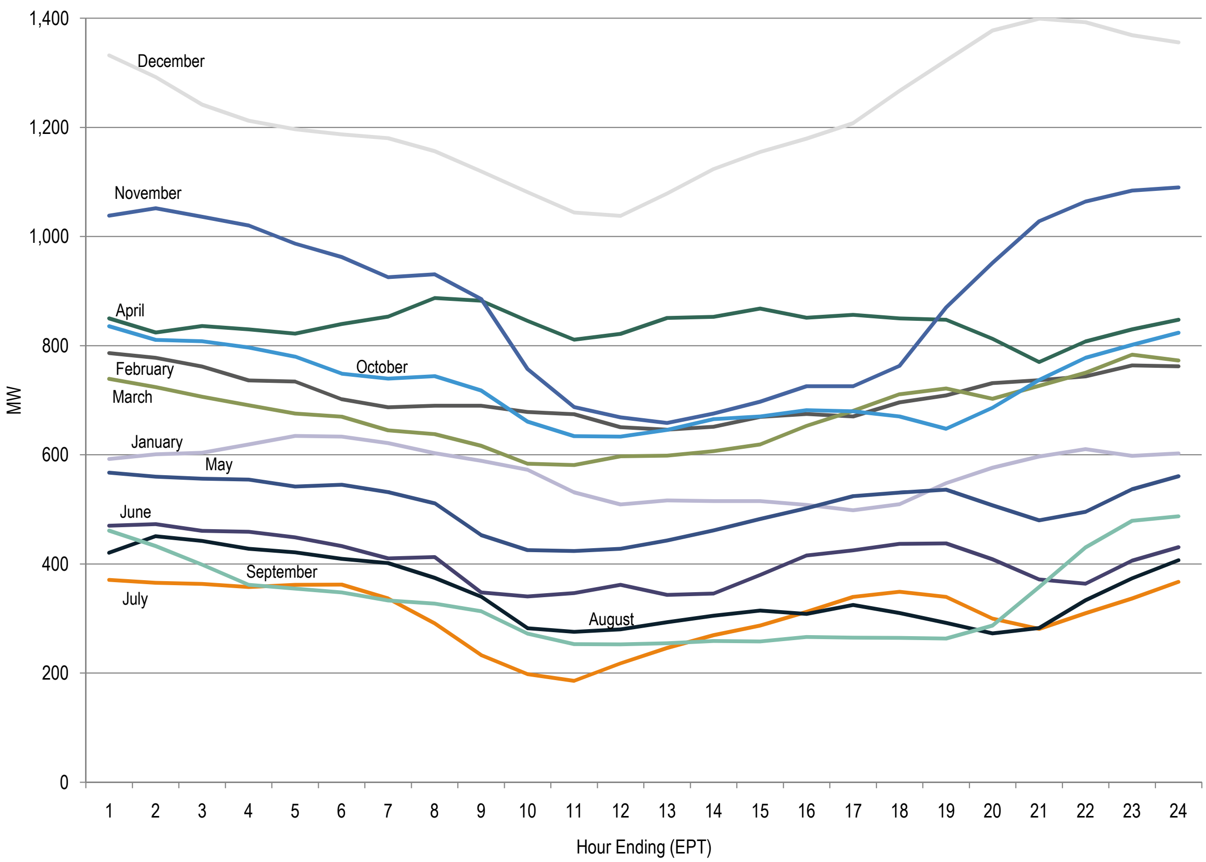


Table 3-48 shows the generation and capacity factor of wind units in each month of 2009. Capacity factors of wind units vary substantially by month. The highest capacity factor of wind units was 45.3 percent in February, and the lowest capacity factor was 14.9 percent in July, a difference of 30.4 percentage points. Overall, the capacity factor in winter months was higher than that of summer months. New wind farms came online throughout 2009, and are included in this analysis as they were added.

Table 3-48 Capacity factor of wind units in PJM by month, Calendar year 2009[72]

Month	Generation (MWh)	Capacity Factor
January	424,885.1	39.6%
February	476,702.8	45.3%
March	501,320.6	35.0%
April	604,480.0	40.6%
May	376,904.6	24.5%
June	291,886.9	19.6%
July	228,850.7	14.9%
August	258,708.4	16.8%
September	239,457.9	16.1%
October	539,353.2	31.5%
November	638,556.4	32.0%
December	908,613.8	38.4%
Annual	5,489,720.3	29.1%

Table 3-49 shows the seasonal capacity factor of wind units in PJM, as well as the seasonal average hourly wind generation and seasonal average hourly load on peak and off peak periods. The on peak winter capacity factor was 39.0 percent while the on peak summer capacity factor was 13.6 percent. The off peak winter capacity factor was 0.4 percentage points lower than during the on peak period, while the off peak summer capacity factor was 5.2 percentage points higher than during the on peak period.

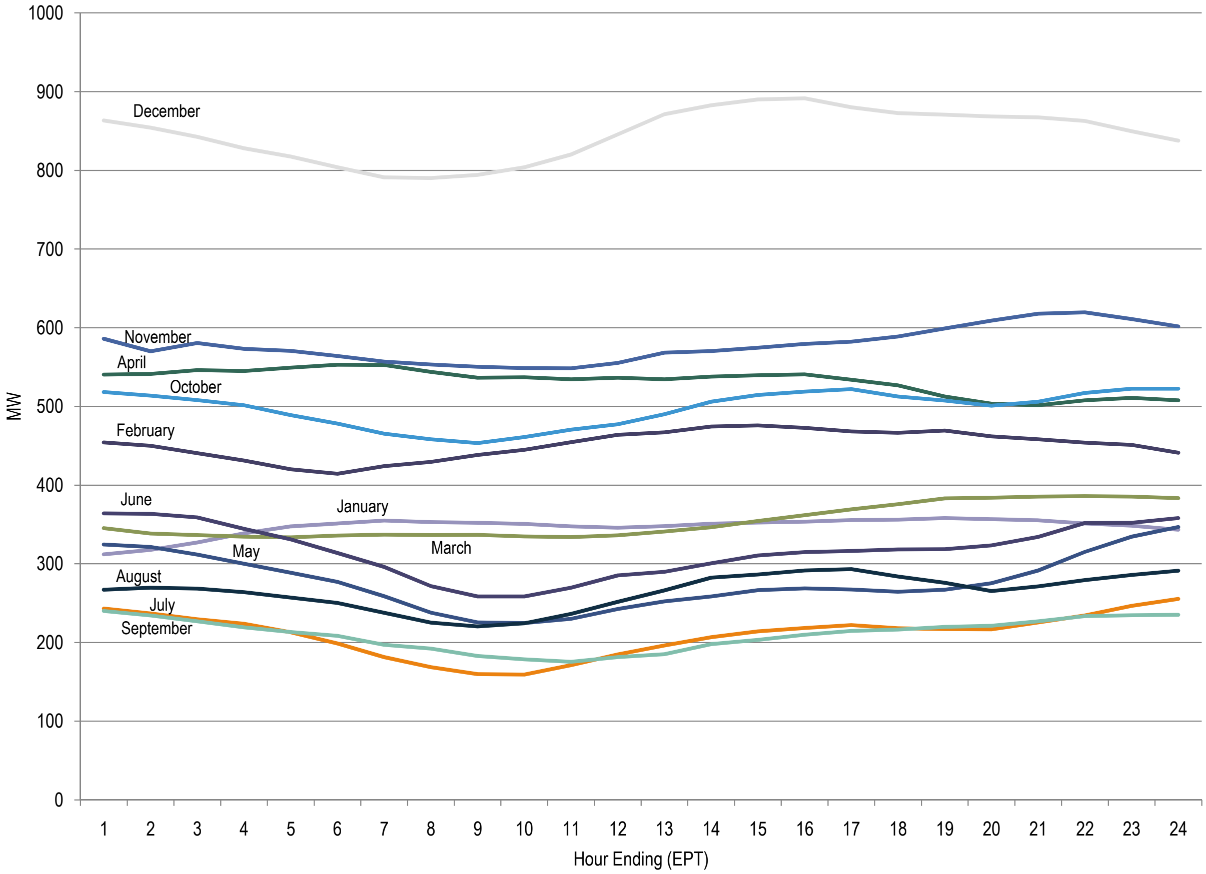
Table 3-49 Peak and off-peak seasonal capacity factor, average wind generation, and PJM load, Calendar year 2009

		Winter	Spring	Summer	Fall	Annual
Peak	Capacity Factor	39.0%	31.6%	13.6%	25.0%	27.1%
	Average Wind Generation	810.0	638.7	282.0	592.5	577.5
	Average Load	90,361.8	77,109.7	91,520.8	77,362.0	84,148.4
Off-Peak	Capacity Factor	38.6%	31.8%	18.8%	27.6%	29.1%
	Average Wind Generation	797.6	642.3	388.8	657.9	622.0
	Average Load	78,247.0	63,339.0	70,548.1	62,493.6	68,588.6

Wind output differs from month to month, based on weather conditions, and is projected by generation owners in the Day-Ahead Market. Figure 3-12 shows the average hourly day-ahead time generation of wind units in PJM, by month.

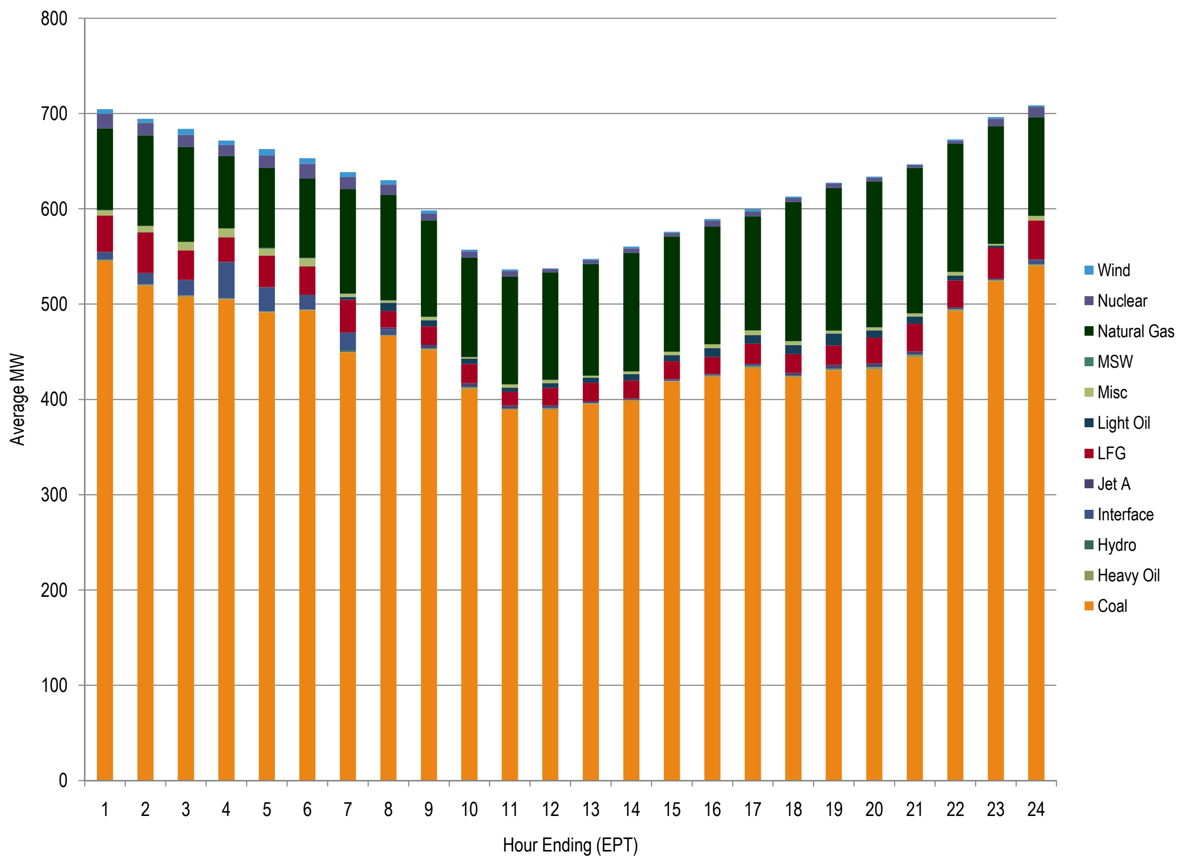
72 Capacity factor shown in Table 3-48 is based on all hours in 2009.

Figure 3-12 Average hourly day-ahead generation of wind units in PJM, Calendar year 2009



Output from wind turbines displaces output from other generation types. This displacement will directly affect the output of marginal units in PJM. The magnitude and type of effect on marginal unit output will depend on the level of the wind turbine output, its location, the time of the output and its duration. Of interest is the type of marginal generation that may be displaced on an average hourly basis by wind turbine output. One measure of this displacement is based on the mix of marginal units when wind is producing output. Figure 3-13 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real time wind generation through 2009. This provides, on an hourly average basis, potentially displaced marginal unit MWs by fuel type in 2009. Wind output varies daily, and on average is about 165 MW lower from peak output (11:00 PM EPT) to lowest output (10:00 AM EPT).

Figure 3-13 Marginal fuel at time of wind generation in PJM, Calendar year 2009



Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, plus reserve requirements, is nearing the limits of the available capacity of the system. Under the current PJM rules, high prices, or scarcity pricing, result from high offers by individual generation owners for specific units when the system is close to its available capacity. These offers give the aggregate energy supply curve its steep upward sloping tail.[73] As demand increases and units with higher markups and higher offers are required to meet demand, prices increase. As a result, positive markups and associated high prices on high-load days may be the result of appropriate scarcity pricing rather than market power.

Scarcity Revenues: The Need for Administrative Mechanisms

While higher prices are expected during scarcity without a specific market mechanism, a wholesale energy market will not consistently result in adequate revenues in the absence of a carefully

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

designed and comprehensive approach to scarcity pricing. This is not the result of the $1,000-per-MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market-clearing prices.

Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards that require wholesale power markets to carry excess capacity means that scarcity conditions in the Energy Market occur with reduced frequency. The mandated reserve margin requires units that are called on only under relatively unusual load conditions, if at all. Resources that do not run for energy, but are needed for reliability, are not supported through an energy only market.

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

For these reasons, the energy market alone frequently does not directly or sufficiently value some of the resources needed to provide for reliability. This provides the rationale for administrative scarcity pricing mechanisms such as PJM's Reliability Pricing Model (RPM) market for capacity and its administrative scarcity pricing mechanism in the energy market. Scarcity revenues to generation owners can come from a combination of energy and capacity markets or they can come entirely from capacity markets.

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

Scarcity Mechanisms

A hybrid market design can provide scarcity revenues both via scarcity pricing in the energy market and via the capacity market. If the scarcity 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. Energy market scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent and verifiable triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power.

Energy market scarcity pricing is part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design, as long as the market rules are designed to ensure that energy market derived scarcity revenues directly offset RPM derived scarcity revenues to prevent double collection of scarcity revenues. This offset must reflect the actual scarcity revenues. The absence of such a mechanism will result in an over collection of scarcity revenues.

The most straightforward way to ensure that such over collection does not occur, and that the forward markets for capacity provide meaningful investment signals, would be to ensure that capacity resources do not receive scarcity revenues from the energy market.

With a settlement process that appropriately offsets scarcity revenues from the energy market against scarcity revenues from the capacity 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. If these design elements are retained, administrative scarcity pricing in the energy market can be a key component in overall market design.

Current Issues with Scarcity Implementation

PJM's current administrative scarcity pricing mechanism is designed to recognize real time scarcity in the energy market and increase prices to reflect the scarcity conditions. Under the current PJM rules, administrative scarcity pricing results when PJM takes identified emergency actions and is based on the highest offer of an operating unit. These emergency actions include emergency energy purchase request events, maximum emergency generation events, manual load dump events and voltage reduction events.[74] The use of any of these measures to maintain system integrity in predefined scarcity pricing regions is an indication that the affected area of the system is in a state of scarcity. When PJM implements any of the identified emergency procedures, any offer capping of units in the affected area is lifted and the LMP of the entire affected area is set equal to the highest-priced offer of a unit dispatched at the time.

While an energy market scarcity pricing mechanism is needed, and PJM's use of specific emergency procedures is a reasonable indicator of scarcity conditions, the MMU's review of market results leads to our recommendation that PJM's scarcity pricing mechanism be reviewed and modified. PJM's stakeholders are discussing ways to improve PJM's current energy market scarcity pricing mechanism.

Proposed Scarcity Pricing Approach

It is the MMU's position that more flexible and locational scarcity signals should be implemented via reserve requirements modeled as constraints for specific transmission constraint defined regions, with administrative reserve scarcity penalty factors, in the security constrained dispatch. Conceptually, incorporating reserve penalty factor curves into the security constrained dispatch

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

internalizes the value of maintaining resources needed for reliability in the centralized dispatch market solution, prior to going into scarcity conditions.

The penalty factors associated with the reserve target constraints would force system dispatch energy prices to reflect the severity level of the scarcity event as the system was redispatched to maintain the reserve requirements. If the reserve requirements were violated, energy prices at the marginal unit buses would be set to a predefined price target. The MMU recommends predefined energy price targets that are consistent with PJM's current offer caps in both the Day Ahead and Real Time energy markets. A price target set at $1,000 at the marginal unit buses in the area with a reserve shortage would provide a clear scarcity signal that is consistent with scarcity, consistent with economic dispatch, consistent with locational pricing, consistent with competitive market outcomes and consistent with PJM's current market design.

Under the MMU's price target approach, the prices for reserves would continue to be determined in forward looking (hour ahead) markets similar to those currently used for regulation and Tier 2 synchronized reserve resources, with real time true up of the opportunity costs payments to generators made at settlement. Resources dispatched for reserves in the hour ahead market during scarcity would clear based on their offers and their opportunity costs. The resulting clearing price for reserves would fully reflect the energy market scarcity price. Resources dispatched within the hour for reserves would be paid their real time opportunity costs for providing reserves.

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.

Transparent and Appropriate Scarcity Pricing Triggers

To work properly in recognizing and internalizing resource scarcity, the reserve constraint requirement mechanism must make use of clearly defined reserve targets and accurate measurement of the resources that are available to meet those requirements. These reserve targets must match defined reserve requirements. The objective should be to create a system that recognizes scarcity in needed reserves; a system that redispatches to maintain needed reserves and a system that provides market signals that are consistent with this redispatch and with any failure to maintain needed reserves. The driver for the determination of scarcity and its reflection in price should be based directly on the level of available 10 minute synchronized reserves relative to the relevant reserve requirement and the progressive use of emergency measures.

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

Accurate measurement of available resources is an essential element of a reserve requirement based scarcity pricing mechanism. Any mechanism that attempts to internalize the dispatch of reserves will only be as good as the measurement of those reserves. Without accurate measurement of available reserves, any mechanism designed to dispatch the system to maintain reserves will be compromised in both efficiency and effectiveness. Based on the direction of the error at any given time, the system could be buying too much reserve or too little, the system could be in a state of unrecognized scarcity or unrecognized surplus. To be effective, operators will need accurate data on unit availability and capabilities at any given moment, including better data on ramp rates and ambient temperature adjustments. PJM does not currently have accurate real time measurements of available operating reserves that are required for an improved approach to scarcity pricing. PJM needs to develop better measurements of available primary reserves prior to implementing a resource constraint based scarcity pricing mechanism.

The reserve requirement penalty factors should be designed to force the system to redispatch resources to maintain system reliability. The objective should be to internalize the cost of maintaining reserve levels needed to maintain reliability, and then sending a clear energy price signal when actual reserve requirements cannot be met. Adding a reserve requirement in addition to what is needed to maintain reliability would be superfluous and wasteful. Requiring, for example, that the system maintain some level of previously undefined level of 30 minute reserves would introduce unnecessary price signals not required for reliable operation. The same is true for using 10 minute non-synchronized reserves as a trigger for scarcity. If maintaining sufficient 10 minute synchronized reserves will maintain reliable operation, there is no reason to use a higher operating reserve threshold.

Mitigating Market Power and Within Hour Reserve Resources

Under the MMU reserve penalty factor curve approach, local market power mitigation in the energy market would remain in force regardless of scarcity conditions. Rather than depending on market power to increase prices during scarcity, the administrative scarcity pricing mechanism results in appropriate prices during a reserve shortage event. This approach eliminates the incentive for participants to make non-competitive energy offers in anticipation of scarcity events.

To avoid market power issues and to provide the correct market signals, the provision of within hour reserves must be based on unit characteristics included in a participant's energy offers, not on the basis of separate offers to provide reserves. Currently market participants provide within-hour reserves on the basis of their energy offer operating parameters including the start time of the unit, the ramp capability of the unit and the total number of MW available from the unit.[75] These parameters also play a direct role in determining how much energy the unit will sell into the PJM market at any given moment in time. As there are no incremental costs for a resource to provide

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

reserves, rather than energy, the within hour reserve availability bid should be zero because the resource is already dispatched and committed to serve energy on the basis of the same set of parameters which determine its reserve capabilities. Allowing for separate energy and within hour reserve offers would force an inefficient allocation of the unit's capability between reserves and energy since this would artificially create inconsistent parameters sets, one for energy and one for reserves, which distort the direct substitutability of unit capacity deployed as either reserves or energy within the hour. Allowing separate offers would create opportunities to withhold reserves.

Scarcity Revenues: The Offset

In the overall market design, scarcity revenues to generation owners can come entirely from energy markets or they can come from a combination of energy and capacity markets. The approach to scarcity must reflect the fact that 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, it would be preferable to include a scarcity pricing mechanism in the energy market because it provides additional direct, market-based incentives to load and generation at the margin, as long as the market rules are designed to ensure that scarcity revenues directly offset RPM revenues to prevent double collection of scarcity revenues. Scarcity revenues are those revenues directly attributable to scarcity price adder contributions to the marginal unit LMPs during a reserve shortage.

The most straightforward way to ensure that such over collection does not occur, and that the forward markets for capacity provide meaningful investment signals, would be to ensure that capacity resources do not receive scarcity revenues. 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. Under this approach generators would retain scarcity revenues from the energy market that exceed, on a cumulative annual, the RPM revenues for the delivery year. For example, if a capacity resource were earning $100 per MW-day from RPM and there were three scarcity event days in the year that generated a cumulative equivalent of $120 per MW-day of scarcity revenues, the capacity resource would collect $20 per MW-day from the cumulative scarcity events over and above its $100 per MW-day capacity market based scarcity payment. This method would prevent double collection of scarcity revenues while recognizing the potential for inadequate scarcity revenues from the RPM market during a particular delivery year.

Accounting for Emergency Procedures and Emergency Actions

The reserve penalty factor curve methodology, regardless of price target, also needs a mechanism to offset the effect of unpriced, non-market administrative measures used during scarcity situations, such as voltage reductions. The offset would increase the reserve requirement by the amount of effective energy provided by the emergency step so as to maintain a market signal consistent with the actual level of scarcity, which is the level of scarcity that would persist in the absence of the administrative action.

A well designed offset will prevent prices from falling as a result of emergency actions during a period of scarcity. In order to implement this, PJM will have to be able to accurately measure the MW impact of the emergency steps. This reserve MW offset mechanism should be used to maintain consistent pricing only for unpriced emergency actions. It should not be applied to emergency resources that have been purchased and have a recognized market value, namely maximum emergency generation and emergency load response. Maximum emergency generation and emergency load resources need to be counted towards reserve targets when available under emergency conditions, as these resources have recognized value in the capacity market and provide their energy, or reduction in demand, at a specified price under emergency conditions.

Maximum emergency and emergency load response resources must be counted as energy, if providing energy (or reduced demand), and must be counted as reserves if capable of providing reserves. Ensuring that generation capacity and demand side capacity, either economic or emergency, is counted as an available resource eliminates the incentive to move capacity from economic to emergency designation during emergency conditions and thereby force scarcity conditions and higher prices.

Any scarcity pricing mechanism should also include an explicit, transparent set of rules governing the recall of energy produced by capacity resources and the defined conditions under which such recalls will occur.

Operating Reserve

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, these 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. These credits are paid by PJM market participants as operating reserve charges.

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.

The level of total operating reserve credits and corresponding charges decreased in 2009 by 24.1 percent compared to 2008, to a total of $325,842,346. This was primarily the result of a large decrease in the amount of balancing operating reserve credits. The decrease in operating reserve credits is the result of a number of factors including the decrease in load, the decline in fuel costs and the related decreases in generator offer prices, LMP and congestion in 2009.

The level of operating reserve credits paid to specific units depends on the level of the unit's energy offer, the unit's operating parameters as well as the decisions of PJM operators. Operating reserve credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, startup and no-load offers. PJM continues internal processes to review and measure daily operating reserve performance, to analyze issues and resolve them in a timely manner, to make better information more readily available to dispatchers and to emphasize the impact of dispatcher decisions on operating reserve charge levels.

New rules governing the payment of operating reserve credits and the allocation of operating reserve charges became effective on December 1, 2008. The new Operating Reserve Construct will be referred to as the new rules and the prior Operating Reserve Construct will be referred to as the old rules.

The following operating reserve business rule changes were made effective on December 1, 2008:

- **Segmented Make Whole Payments.** Resources will be made whole separately for the blocks of hours they operate at PJM direction. There will a maximum of two segments per calendar day, per unit. The first segment will be the greater of the day-ahead schedule or minimum run time (minimum downtime for demand resources); the second segment will be the remainder of the unit run for that calendar day.[76]

- **Parameter Limited Schedules.** When a unit needed for operating reserve has local market power as defined by the three pivotal supplier test or when PJM declares a maximum generation emergency alert, units will be required to use operating parameters consistent with competitive offers. These parameters are defined by unit characteristics and included in a matrix developed by the MMU and included in the PJM OA.[77] PJM also developed business rules approved November 15, 2007, by the Members Committee that, among other things, established a process to evaluate unit-specific exceptions to the values included in the matrix.[78]

- **Generator Deviations.** PJM will use ramp-limited desired MW to determine generator deviations from desired dispatch. Pool-scheduled generators deemed to be following dispatch will not be assessed balancing operating reserve deviations.[79]

- **Netting Generator Deviations.** Generators that deviate from real-time dispatch will be able to offset deviations by using another generator at the same bus. Both generators must be owned or offered by a single PJM market participant and must have identical electrical impacts on the transmission system.[80]

- **Locational Netting of Deviation Calculations.** Demand deviations will be calculated by comparing all day-ahead demand transactions within a single transmission zone, hub, or interface against the real-time demand transactions within that same transmission zone, hub, or interface. Supply deviations will be calculated by comparing all day-ahead transactions within a single transmission zone, hub, or interface against the real-time transactions within that same transmission zone, hub, or interface. Generator deviations will be calculated on a unit-specific basis, except for the netting provisions. Deviations that occur within a single zone will be associated with a region and will be charged the regional balancing operating reserve rate.[81]

76 PJM "Operating Reserve Revised Business Rules v6": *Segmented Make Whole Payments* at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.
77 PJM OA Schedule 1 § 6.6(c).
78 PJM "Operating Reserve Revised Business Rules v6": *Minimum Generator Operating Parameters – Parameter Limited Schedule* at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.
79 PJM "Operating Reserve Revised Business Rules v6": *Ramp-limited RT Desired MW to determine deviations* at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.
80 PJM "Operating Reserve Revised Business Rules v6": *Supplier Netting* at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.
81 PJM "Operating Reserve Revised Business Rules v6": *Netting Deviation Calculations* at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.

- **Balancing Operating Reserve Charge Allocation.** PJM will determine whether operating reserve credits are earned for reasons associated with reliability or with real-time deviations from day-ahead results. PJM will make this determination in both the reliability analysis stage and the real-time stage. Reliability related credits are recovered from charges to real-time load plus exports and deviations related credits are recovered from charges to deviations.[82]

- **Regional Balancing Operating Reserve Charge Allocation.** PJM will identify operating reserves credits that are associated with controlling local constraints, identified as constraints on transmission lines rated at less than or equal to 345kv. Local constraints will be identified as in the Western or the Eastern Region. The resultant operating reserve credits will be allocated as charges to all real-time deviations and real time load within a region, resulting in a Regional Adder rate for Reliability and a Regional Adder rate for Deviations.[83]

Credit and Charge Categories

Operating reserve credits include day-ahead, synchronous condensing and balancing operating reserve categories**.** Total operating reserve credits paid to PJM participants equal the total operating reserve charges paid by PJM participants. Table 3-50 shows the categories of credits and charges and their relationship. The bottom half of this table shows how credits are allocated under the new operating reserve construct. Table 3-51 shows the different types of deviations.

Table 3-50 Operating reserve credits and charges

Credits Received		Charges Paid
Day ahead:		Day-ahead demand
Day-Ahead Energy Market	→	Decrement bids
Day-ahead import transactions		Day-ahead export transactions
Synchronous condensing	→	Real-time load
		Real-time export transactions
Balancing:		
Balancing energy market		Real-time deviations
Lost opportunity cost	→	from day-ahead schedules
Real-time import transactions		
Balancing Energy Market Credits Received		**Balancing Energy Market Charges Paid**
(RTO, Eastern Region, Western Region)		Real-time load
Reliability Credits	→	Real-time export transactions
Deviation Credits	→	Real-time deviations
		from day-ahead schedules

82 PJM "Operating Reserve Revised Business Rules v6": *Balancing Operating Reserve Cost Allocation* at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.

83 PJM "Operating Reserve Revised Business Rules v6": *Regional Balancing Operating Reserve Charge Allocation* at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/operating-reserve-revised-business-rules-v6.ashx>.

Table 3-51 Operating reserve deviations

Deviations		
Day ahead		Real time
Day-ahead decrement bids	Demand (Withdrawal)	Real-time load
Day-ahead load	(RTO, East, West)	Real-time sales
Day-ahead sales		Real-time export transactions
Day-ahead export transactions		
Day-ahead increment offers	Supply (Injection)	Real-time purchases
Day-ahead purchases	(RTO, East, West)	Real-time import transactions
Day-ahead import transactions		
Day-ahead scheduled generation	Generator (Unit)	Real-time generation

Day-Ahead Credits and Charges

Day-ahead operating reserve credits consist of Day-Ahead Energy Market and day-ahead import transaction credits. The rules governing these credits and associated charges were not modified in the new rules.

The day-ahead operating reserve charges that result from paying total day-ahead operating reserve credits are allocated daily to PJM members in proportion to the sum of their cleared day-ahead demand, decrement bids and day-ahead exports. Table 3-54 shows monthly day-ahead operating reserve charges for calendar years 2008 and 2009.

Synchronous Condensing Credits and Charges

Synchronous condensing credits are provided to eligible synchronous condensers for real-time condensing and energy use costs if PJM dispatches them for purposes other than synchronized reserve, post-contingency constraint control or reactive services.[84] The rules governing these credits and associated charges were not modified in the new rules.

The operating reserve charges that result from paying operating reserve credits for synchronous condensing are allocated daily to PJM members in proportion to the sum of their real-time load and real-time export transactions. Table 3-54 shows monthly synchronous condensing charges for calendar years 2008 and 2009.

Balancing Credits and Charges

Balancing operating reserve credits consist of balancing energy market credits, lost opportunity cost credits, and real-time import transaction credits. Balancing operating reserve credits are paid to generation resources that operate at PJM's request if market revenues are less than the resource's offer. Lost opportunity cost credits are paid to generation resources when their output is reduced at

84 PJM. "Manual 28: Operating Agreement Accounting," Revision 42 (July 31, 2009).

PJM's request for reliability purposes from their economic or self-scheduled output level. Balancing operating reserve credits are paid to real-time import transactions, if market revenues are less than the offer. Balancing operating reserve credits are also paid to cancelled pool-scheduled resources, to resources providing quick start reserve and to resources performing annual, scheduled black start tests.

Table 3-52 Balancing operating reserve allocation process

	Reliability Credits	Deviation Credits
RTO	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 500kV & 765kV **2.) Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 500kV & 765kV	**1.) Reliability Analysis:** Load + Reserves and for TX constraints 500kV & 765kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 500kV & 765kV
East	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	**1.) Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV
West	**1.) Reliability Analysis:** Conservative Operations and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is not greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV	**1.) Reliability Analysis:** Load + Reserves and for TX constraints 345kV, 230kV, 115kV, 69kV **2.) Real-Time Market:** LMP is greater than or equal to offer for at least 4 intervals and for TX constraints 345kV, 230kV, 115kV, 69kV

Table 3-52 shows the allocation process for balancing operating reserves. Credits are assigned to units during two periods, the reliability analysis and the Real-Time Market. During PJM's reliability analysis, performed after the Day-Ahead Market is cleared, credits are allocated for conservative operations and to meet real-time load. Conservative operations means that units are committed due to conditions that warrant conservative actions to ensure the maintenance of system reliability. Such conditions include hot and cold weather alerts. The resultant credits are credited as reliability credits and are allocated to real-time load plus exports. Units are committed to operate in real-time to augment the physical units committed in the Day-Ahead Market in order to meet the forecasted real-time load plus the operating reserve requirement. The resultant credits are credited as deviation credits and are allocated to supply, demand, and generator deviations.

In the Real-Time Market, credits are also allocated for reliability or to meet load. Credits are paid to units that are called on by PJM and in which the LMP is not greater than or equal to the unit's offer for at least four five-minute intervals of at least one clock hour while the unit was running at PJM's direction. These are credited as Reliability Credits and are allocated to real-time load plus exports. Balancing operating reserve credits earned by all other units operated at PJM's direction in real time where the LMP is greater than or equal to the unit's offer for at least four five-minute intervals of at least one clock hour will be allocated as deviation credits. These are allocated to real-time supply, demand, and generator deviations from day-ahead schedules.

Credits are allocated regionally based on whether a unit was called on for a transmission constraint and the voltage level of the constraint. Credits associated with transmission constraints that are 500kV or 765kV are assigned to RTO credits while credits associated with all other voltages are assigned to regional credits.

Credit and Charge Results

Overall Results

Table 3-53 shows total operating reserve credits from 1999 through 2009.[85,86] Total operating reserve credits decreased by 24.1 percent in 2009 from 2008. Table 3-53 shows the ratio of total operating reserve credits to the total value of PJM billings.[87] This ratio decreased from 1.3 percent in 2008 to 1.2 percent in 2009. With the exception of 2004, this ratio has decreased every year from 1999 through 2009.

Table 3-53 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 2	NA	0.5346	NA
2001	$290,867,269	34.0%	8.7%	0.2746	(19.5%)	1.0700	100.2%
2002	$237,102,574	(18.5%)	5.0%	0.1635	(40.4%)	0.7873	(26.4%)
2003	$289,510,257	22.1%	4.2%	0.2261	38.2%	1.1971	52.0%
2004	$414,891,790	43.3%	4.8%	0.2300	1.7%	1.2362	3.3%
2005	$682,781,889	64.6%	3.0%	0.0762	(66.9%)	2.7580	123.1%
2006	$322,315,152	(52.8%)	1.5%	0.0781	2.6%	1.3315	(51.7%)
2007	$459,124,502	42.4%	1.5%	0.0570	(27.0%)	2.3310	75.1%
2008	$429,253,836	(6.5%)	1.3%	0.0844	48.0%	2.1132	(9.3%)
2009	$325,842,346	(24.1%)	1.2%	0.1201	42.3%	1.1100*	(47.5%)

Table 3-53 shows the average operating reserve credits per MWh (or the charge rate) for each full year since the introduction of the Day-Ahead Energy Market. The day-ahead operating reserve rate increased $0.0357 per MWh or 42.3 percent from $0.0844 per MWh in 2008 to $0.1201 per MWh in 2009. The balancing operating reserve rate decreased $1.0032 per MWh, or 47.5 percent, from $2.1132 per MWh in 2008 to $1.1100 per MWh in 2009. The balancing rate of $1.1100 per MWh for 2009 is a representation of what the rate would have been if calculated under the old operating construct rules. This was derived by taking all regional reliability and deviation credits for the day and dividing by total PJM supply, demand, and generator deviations. The rates shown in the table are the averages of the daily rates across the year.

85 Table 3-53 includes all categories of credits as defined in Table 3-50 and includes all PJM Settlements billing adjustments. Billing data can be modified by PJM Settlements at any time to reflect changes in the evaluation of operating reserves. The billing data reflected in this report were the current figures on January 19, 2010.

86 An Energy Market that clears based on market-based generator offers was initiated on April 1, 1999. The 1999 total includes Energy Market operating reserve credits for three months based on generators' cost-based offers and for nine months based on generators' market-based offers. The Day-Ahead Energy Market opened on June 1, 2000. Operating reserve credits for 1999 and the first five months of 2000 include only those credits paid in the balancing energy market. Since June 1, 2000, operating reserve credits have included credits for both day-ahead and balancing.

87 See the *2009 State of the Market Report for PJM*, Volume II, Section 7, "Congestion," at Table 7-1, "Total annual PJM congestion (Dollars (Millions)): Calendar years 2003 to 2009," for a description of the value of total annual PJM billings during the period indicated.

Total operating reserve charges in 2009 were $325,842,346, down from the total of $429,253,839 in 2008. Table 3-54 compares monthly operating reserve charges by category for calendar years 2008 and 2009. The overall decrease of 24.1 percent in 2009 is comprised of a 36.4 percent increase in day-ahead operating reserve charges, a 56.6 percent decrease in synchronous condensing charges and a 35.5 percent decrease in balancing operating reserve charges. The share of day-ahead operating reserve charges to total operating reserve charges increased by 12.9 percentage points to 29.1 percent, the share of synchronous condensing charges decreased 0.5 percentage points to 0.8 percent, and the share of balancing charges decreased 12.3 percentage points to 70.1 percent.

Table 3-54 Monthly operating reserve charges: Calendar years 2008 and 2009

	2008 Charges				2009 Charges			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$4,126,221	$456,972	$39,935,491	$44,518,684	$9,260,150	$1,328,814	$30,116,725	$40,705,689
Feb	$3,731,017	$200,456	$23,165,838	$27,097,312	$7,434,068	$839,679	$16,548,988	$24,822,735
Mar	$2,904,498	$249,900	$18,916,241	$22,070,639	$9,549,963	$108,664	$26,025,562	$35,684,189
Apr	$4,213,578	$209,366	$22,559,577	$26,982,522	$6,998,364	$19,929	$13,251,273	$20,269,566
May	$10,873,205	$202,397	$22,970,363	$34,045,964	$6,024,108	$5,543	$15,490,257	$21,519,908
Jun	$7,064,877	$575,927	$65,597,311	$73,238,115	$6,722,329	$0	$19,339,846	$26,062,175
Jul	$7,038,834	$874,234	$48,041,415	$55,954,483	$8,210,636	$38,643	$17,728,976	$25,978,255
Aug	$6,140,554	$143,857	$26,212,547	$32,496,959	$7,697,174	$1	$21,164,586	$28,861,761
Sep	$4,581,147	$405,308	$27,809,898	$32,796,353	$6,057,598	$13,611	$13,471,368	$19,542,577
Oct	$6,705,261	$794,271	$16,054,255	$23,553,788	$7,046,301	$0	$17,026,425	$24,072,727
Nov	$5,069,462	$635,697	$21,097,016	$26,802,175	$8,617,280	$22,639	$12,888,600	$21,528,519
Dec	$7,175,436	$996,292	$21,525,117	$29,696,846	$11,323,263	$117,573	$25,353,409	$36,794,245
Total	$69,624,091	$5,744,678	$353,885,070	$429,253,839	$94,941,235	$2,495,097	$228,406,015	$325,842,346
Share of Annual Charges	16.2%	1.3%	82.4%	100.0%	29.1%	0.8%	70.1%	100.0%

Table 3-55 shows the amount and percentages of regional balancing charge allocations across PJM for 2009. The largest share of charges was paid by RTO demand deviations and the second highest share of charges was paid by RTO supply deviations.

Table 3-55 Regional balancing charges allocation: Calendar year 2009[88]

	Reliability Charges			Deviation Charges				
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total	Total
RTO	$6,802,948 3.9%	$258,555 0.1%	$7,061,503 4.1%	$66,187,248 38.2%	$39,055,422 22.5%	$20,608,021 11.9%	$125,850,691 72.6%	$132,912,194 76.7%
East	$479,731 0.3%	$17,858 0.0%	$497,589 0.3%	$7,162,517 4.1%	$3,805,906 2.2%	$1,935,653 1.1%	$12,904,076 7.4%	$13,401,665 7.7%
West	$22,140,661 12.8%	$926,143 0.5%	$23,066,804 13.3%	$1,948,014 1.1%	$1,317,748 0.8%	$703,058 0.4%	$3,968,820 2.3%	$27,035,624 15.6%
Total	$29,423,340 17.0%	$1,202,556 0.7%	$30,625,896 17.7%	$75,297,778 43.4%	$44,179,076 25.5%	$23,246,732 13.4%	$142,723,586 82.3%	$173,349,483 100%

Deviations

Categories

Under the old rules, all operating reserve charges that resulted from paying balancing operating reserve credits were allocated daily to PJM members in proportion to their real-time hourly deviations from cleared quantities in the Day-Ahead Market. Table 3-54 shows monthly balancing operating reserve charges for calendar years 2008 and 2009. Under the new rules, only credits identified as related to deviations are allocated to deviations. Deviations fall into three categories, demand, supply and generator deviations, and are calculated on an hourly net basis by zone, hub, or interface and summed by organization for the day. Each type of deviation is calculated separately and a PJM member may have deviations in all three categories.

- **Demand.** Hourly deviations in the demand category equal the absolute value of the difference between: a) the sum of cleared decrement bids plus cleared, day-ahead load plus day-ahead exports scheduled through the Enhanced Energy Scheduler (EES);[89] and b) the sum of real-time load plus real-time sales scheduled through eSchedules[90] plus real-time exports scheduled through the EES. Under the old rules, demand deviations were calculated over the entire RTO. Under the new rules, deviations are calculated within a single transmission zone, hub, or interface.

- **Supply.** Hourly deviations in the supply category equal the absolute value of the difference between: a) the sum of the cleared increment offers plus day-ahead imports scheduled through EES; and b) the sum of the real-time bilateral transactions scheduled through eSchedules plus real-time imports scheduled through EES. Under the old rules, demand deviations were calculated over the entire RTO. Under the new rules, deviations are calculated within a single transmission zone, hub, or interface.

88 The total charges shown in Table 3-55 do not equal the total balancing charges shown in Table 3-54 because the totals in Table 3-54 include lost opportunity cost, cancellation, and local charges while the totals in Table 3-55 do not. Only balancing generator charges are allocated regionally using reliability and deviations, while lost opportunity cost, cancellation, and local charges are allocated on an RTO basis, based on demand, supply, and generator deviations.

89 The Enhanced Energy Scheduler is a PJM application used by participants to schedule import and export transactions.

90 PJM's eSchedules is an application used by participants for internal bilateral transactions.

- **Generator.** Hourly deviations in the generator category equal the absolute value of the difference between: a) a unit's cleared, day-ahead generation; and b) a unit's hourly, integrated real-time generation. More specifically, a unit has calculated deviations for an hour if the hourly integrated real-time output is not within 5 percent of the hourly day-ahead schedule; the hourly integrated real-time output is not within 10 percent of the hourly integrated desired output; or the unit is not eligible to set LMP for at least one five-minute interval during an hour. Deviations continue to be calculated for individual units, except where netting at a bus is permitted.

- **Netting.** Demand and supply deviations are netted by zone, hub, or interface in which they occur but not across zones, hubs or interfaces. A negative deviation in a zone can be offset by a positive deviation that occurs in that zone. The sum of the net deviations by zone, hub, or interface is calculated for each region. An organization's total daily balancing operating reserve charges are equal to the sum of the three deviation categories, by region, for the day, multiplied by the regional daily balancing operating reserve rates.

Allocation

Under the old operating reserve construct, balancing operating reserve charges were assigned to total real-time deviations from day-ahead schedules. Under the new rules, only a subset of defined balancing reserve charges are assigned to deviations and deviations are separated into RTO and regional categories. Table 3-55 shows monthly real-time deviations for demand, supply and generator categories for 2008 and 2009. These deviations are the sum of all the regional deviations. Total deviations summed across the demand, supply, and generator categories were higher in 2009 than 2008 by 19,837,959 MWh, primarily as the result of a 31.3 percent increase in supply deviations, although demand deviations increased by 7.2 percent and generator deviations increased by 0.4 percent. From 2008 to 2009, the share of total deviations in the demand category decreased by 2.6 percentage points, the share of supply deviations increased by 4.5 percentage points, and the share of generator deviations decreased by 1.9 percentage points.

Effective December 1, 2008, new rules governing the calculation of generator deviations were implemented. Under the old rules, a generator was considered to deviate if the unit was operating at an actual output that was more than 10 percent from the PJM desired MW, or if they were operating at an output that was 5 percent, or 5 MW from their day-ahead schedule. Under the new rules, the ramp limited desired (RLD) MW is used instead to determine the unit's desired MW. This RLD MW is the achievable MW based on the UDS ramp rate.[91] The goal of this rule change was to further incent generators to follow PJM dispatch instruction, and hence reduce generator deviations. While generator deviations actually increased by 0.4 percent overall for the year 2009 compared to 2008, this includes a spike in generator deviations in December 2009, when PJM experienced high volumes of congestion. Generator deviations for December were 30.0 percent higher than the annual monthly average. Comparing only the months of January through November 2009 to the same months in 2008 shows a 4.5 percent decrease in generator deviations for 2009.

91 See PJM Operating Reserve Revised Business Rules v6 "Ramp-limited RT Desired MW to determine deviations" for more details.

Table 3-56 Monthly balancing operating reserve deviations (MWh): Calendar years 2008 and 2009

	2008 Deviations				2009 Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	8,172,164	3,297,121	2,572,113	14,041,398	9,128,112	5,575,170	2,630,917	17,334,199
Feb	6,728,062	3,046,290	2,546,510	12,320,861	7,044,702	4,153,575	2,107,229	13,305,505
Mar	6,392,821	2,520,387	2,405,061	11,318,269	7,214,090	4,352,550	2,409,507	13,976,146
Apr	5,951,654	3,127,726	2,224,157	11,303,537	6,873,427	3,836,896	2,275,153	12,985,477
May	6,624,696	3,787,650	2,699,616	13,111,962	6,958,699	5,184,983	2,382,351	14,526,033
Jun	8,117,669	3,179,999	2,644,016	13,941,684	8,569,879	4,603,052	2,635,991	15,808,922
Jul	9,237,956	3,914,230	2,213,828	15,366,014	9,233,511	5,129,409	2,243,337	16,606,257
Aug	8,296,485	4,000,974	2,275,294	14,572,753	9,961,944	5,425,344	2,427,539	17,814,827
Sep	7,360,536	3,691,646	2,577,095	13,629,277	7,972,378	4,171,876	2,109,506	14,253,759
Oct	6,792,603	3,538,950	2,404,069	12,735,621	7,028,775	4,543,635	2,203,723	13,776,133
Nov	6,561,634	3,586,432	2,267,083	12,415,148	6,742,675	4,248,221	2,193,013	13,183,910
Dec	8,399,099	4,898,506	1,775,964	15,073,569	8,301,680	4,682,157	3,113,047	16,096,884
Total	88,635,377	42,589,911	28,604,806	159,830,094	95,029,874	55,906,867	28,731,313	179,668,054
Share of Annual Deviations	55.5%	26.6%	17.9%	100.0%	52.9%	31.1%	16.0%	100.0%

A breakdown of real-time load, real-time exports, and deviations in each region is shown in Table 3-57. RTO deviations are classified as the sum of eastern and western deviations, plus deviations from hubs that span multiple regions. Real time load was 365,845,671 MWh in the Eastern Region for 2009, and 300,223,483 in the Western Region. Eastern demand deviations were the highest of all deviation categories (excluding RTO) with 58,407,190 MWh. Total deviations in the Eastern Region were 40.1 percent higher than deviations in the western region in 2009.

Table 3-57 Regional charges determinants (MWh): Calendar year 2009

	Reliability Charge Determinants			Deviation Charge Determinants				
	Real-Time Load (MWh)	Real-Time Exports (MWh)	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total	Total
RTO	666,069,154	26,013,760	692,082,914	95,029,874	55,906,867	28,731,313	179,668,054	871,750,967
East	365,845,671	13,803,483	379,649,154	58,407,190	30,639,519	15,609,547	104,656,256	484,305,410
West	300,223,483	12,210,277	312,433,760	36,377,638	25,195,498	13,121,766	74,694,902	387,128,661

Balancing Operating Reserve Charge Rate

Under the new balancing operating reserve cost allocation construct, PJM calculates six separate balancing rates, a reliability rate for each region, and a deviation rate for each region. The reliability rates are equal to the total reliability credits divided by real-time load plus exports. The deviation rates are calculated as the total deviation credits divided by the sum of the demand, supply, and generation deviations. RTO rates are based on RTO credits, while the regional rates are based on regional credits. See Table 3-52 for how these credits are allocated.

Figure 3-14 shows the daily RTO reliability and deviation rates for 2009. The average daily RTO deviation rate for 2009 was $0.6723 per MWh, while the average daily RTO reliability rate was $0.0092 per MWh. The largest daily rate occurred on March 3, 2009, when the RTO deviation rate was $5.3569 per MWh.[92]

Figure 3-14 Daily RTO reliability and deviation rates ($/MWh): Calendar year 2009

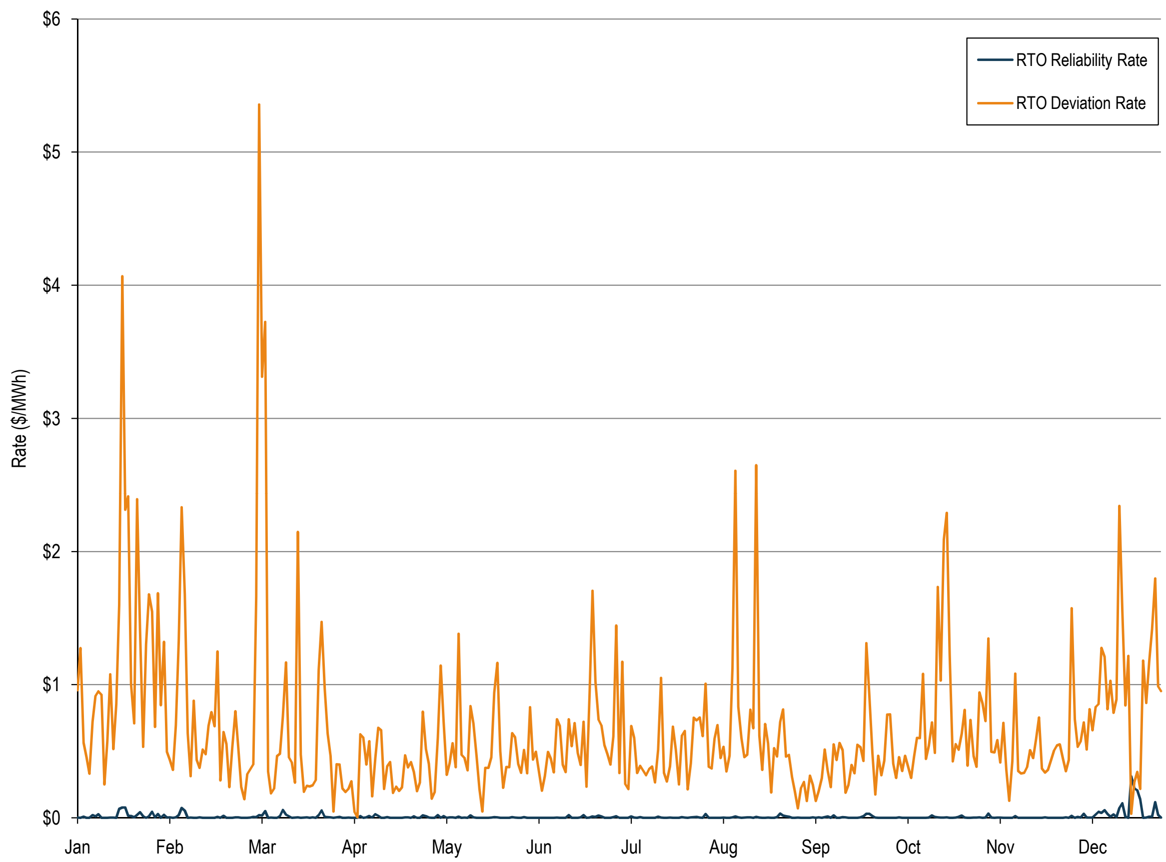


Figure 3-15 shows the daily regional reliability and deviation rates for 2009.

92 For further analysis of March 3, 2009, see *2009 Quarterly State of the Market Report for PJM: January through June*, Section 3, "Energy Market, Part 2".

Figure 3-15 Daily regional reliability and deviation rates ($/MWh): Calendar year 2009

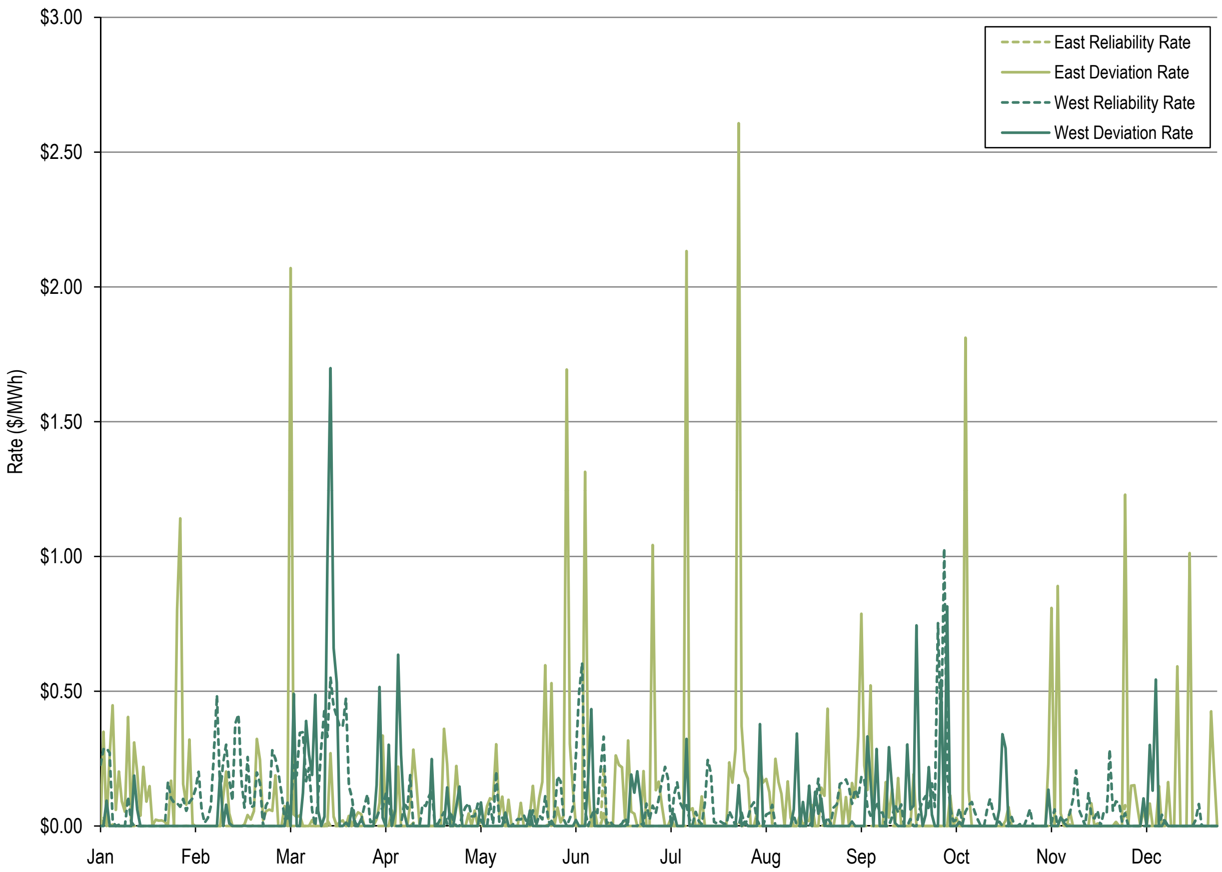


Table 3-58 shows the rates for each region in each category. Regional reliability rates are substantially higher than the RTO reliability rate. The RTO deviation rate is substantially higher than the regional deviation rates.

Table 3-58 Regional balancing operating reserve rates ($/MWh): Calendar year 2009

	Reliability	Deviations
RTO	0.0092	0.6723
East	0.0013	0.1149
West	0.0785	0.0516

Operating Reserve Credits by Category

Figure 3-16 shows that the largest share of total operating reserve credits, 59.6 percent, was paid to resources in the balancing energy market during 2009 and 69.3 percent of total operating reserve credits were in the balancing category, which includes the balancing energy market, real-time transactions, and lost opportunity costs. Figure 3-16 also shows that 29.9 percent of total operating reserve credits were paid to resources in the day-ahead category, which includes the Day-Ahead Energy Market and day-ahead transactions. The remaining 0.8 percent of total credits was paid to resources in the synchronous condensing category. The balancing category share of total operating reserve credits in 2009 is 13.1 percentage points lower in 2009 than the share of 82.5 percent in 2008.

Figure 3-16 Operating reserve credits: Calendar year 2009

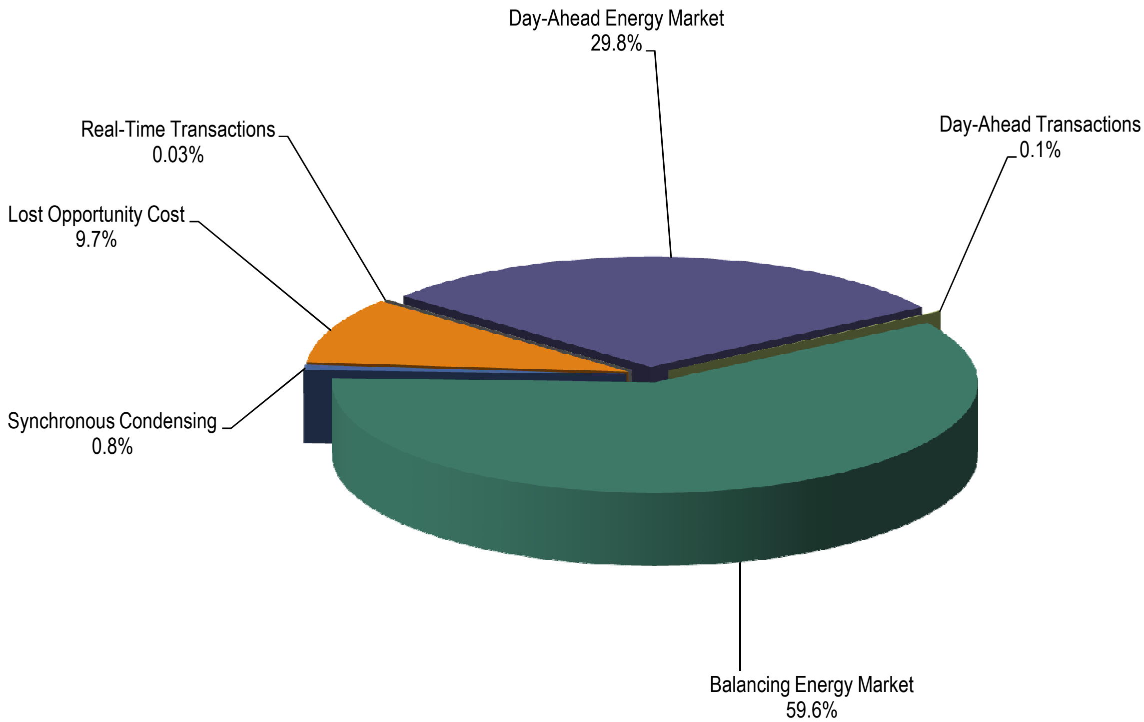


Table 3-59 shows the monthly totals for each type of credit for 2009. The winter months of 2009, which include January, February, November, and December, accounted for 37.3 percent of operating reserve credits, while the summer months, which include May, June, July and August, accounted for 32.0 percent and the shoulder months 30.8 percent. These credits do not equal the total amount of charges paid of $325,842,346. The difference of $7,715,284 was operating reserve billing adjustments made by PJM directly to customers' bills.

Table 3-59 Credits by month (By operating reserve market): Calendar year 2009

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$9,260,150	$0	$1,328,814	$26,534,188	$0	$3,582,536	$40,705,688
Feb	$7,434,068	$0	$839,679	$14,413,879	$31,258	$2,103,852	$24,822,736
Mar	$9,542,383	$7,580	$108,664	$22,307,277	$13,249	$3,557,415	$35,536,568
Apr	$6,998,364	$0	$19,929	$10,751,270	$6,942	$1,833,546	$19,610,052
May	$6,024,108	$0	$5,543	$13,977,804	$0	$1,512,453	$21,519,908
Jun	$6,711,471	$10,858	$0	$16,160,774	$0	$2,540,536	$25,423,640
Jul	$8,183,242	$27,394	$38,643	$15,628,869	$0	$2,100,106	$25,978,255
Aug	$7,636,586	$60,588	$1	$15,630,231	$0	$5,402,076	$28,729,482
Sep	$6,057,599	$0	$13,611	$10,580,172	$0	$2,803,567	$19,454,949
Oct	$6,949,167	$97,135	$0	$14,624,824	$39,844	$1,618,538	$23,329,507
Nov	$8,587,424	$29,855	$22,640	$9,126,338	$0	$1,627,014	$19,393,272
Dec	$11,323,161	$102	$117,573	$20,001,841	$0	$2,180,329	$33,623,006
Total	$94,707,723	$233,512	$2,495,097	$189,737,468	$91,293	$30,861,969	$318,127,062
Share of Credits	29.8%	0.1%	0.8%	59.6%	0.0%	9.7%	100.0%

Characteristics of Credits and Charges

Types of Units

Table 3-60 shows the distribution of credits by unit type and type of operating reserve. (Each row sums to 100 percent.) Steam units received the most operating reserve credits, of which 42.6 percent were received in the Day-Ahead Energy Market and 57.4 percent in the balancing energy market. For combustion turbine units, 95.5 percent of credits were received in the balancing market.

Table 3-60 Credits by unit types (By operating reserve market): Calendar year 2009

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Total
Combined Cycle	41.0%	0.0%	58.1%	0.9%	$103,035,927
Combustion Turbine	1.4%	3.1%	81.8%	13.7%	$80,115,798
Diesel	2.0%	0.0%	82.7%	15.3%	$251,962
Hydro	0.0%	0.4%	99.6%	0.0%	$280,485
Landfill	0.0%	0.0%	0.0%	100.0%	$13,297,176
Nuclear	0.0%	0.0%	0.0%	100.0%	$150,645
Steam	42.6%	0.0%	53.1%	4.3%	$120,319,669
Wind Farm	0.0%	0.0%	1.6%	98.4%	$374,680

Table 3-61 shows the distribution of credits for each type of operating reserves received by each unit type. (Each column sums to 100 percent.) Combined-cycle units and conventional steam units received 98.7 percent of the day-ahead generator credits. Combustion turbines received 100 percent of the synchronous condensing credits.

Table 3-61 Credits by operating reserve market (By unit type): Calendar year 2009

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost
Combined Cycle	44.6%	0.0%	31.5%	2.9%
Combustion Turbine	1.2%	100.0%	34.5%	35.6%
Diesel	0.0%	0.0%	0.1%	0.1%
Hydro	0.0%	0.0%	0.1%	1.2%
Landfill	0.0%	0.0%	0.0%	43.1%
Nuclear	0.0%	0.0%	0.0%	0.5%
Steam	54.1%	0.0%	33.7%	16.6%
Wind Farm	0.0%	0.0%	0.0%	0.0%
Total	$94,707,723	$2,495,097	$189,739,803	$30,883,718

Economic and Noneconomic Generation

Economic generation includes units producing energy at an offer price less than or equal to LMP. Noneconomic generation includes units that are producing energy but at a higher offer price than the LMP. Noneconomic generation includes units assigned by PJM to run and units not assigned by PJM to run or to provide regulation. Regulation generation includes units assigned by PJM to provide regulation. The level of noneconomic generation is an indicator of the level of generation that may require operating reserve credits. However, the data are hourly and some generation that is noneconomic for an hour may receive adequate market revenues during other hours to offset any shortfall.[93]

Table 3-62 shows the percentage of total PJM self-scheduled generation, economic generation, noneconomic generation and regulation generation for 2009.

Table 3-62 PJM self-scheduled, economic, noneconomic and regulation generation receiving operating reserve payments: Calendar year 2009

	All Hours	On Peak	Off Peak
Self-scheduled generation	25.5%	24.0%	29.0%
Economic generation	63.3%	68.7%	50.3%
Noneconomic generation	9.7%	6.5%	17.4%
Regulation generation	1.5%	0.8%	3.3%
Total	100%	100%	100%

Table 3-63 presents the share of self-scheduled, economic, noneconomic and regulation generation by unit type. (Each column adds to 100 percent.) In 2009, steam units represented 92.5 percent of all self-scheduled generation, 89.9 percent of all economic generation and 73.7 percent of noneconomic generation.

93 Self-scheduled units were not included in either economic or noneconomic categories. Self-scheduled units are those units which indicate to PJM that they are self scheduled. Units which are operating, but are not assigned by PJM to run and are not self scheduled, are noneconomic.

Table 3-63 PJM generation by unit type receiving operating reserve payments: Calendar year 2009

	Self-Scheduled Generation	Economic Generation	Noneconomic Generation	Regulation Generation
Combined cycle	3.1%	9.3%	24.3%	31.0%
Combustion turbine	0.2%	0.3%	2.0%	0.0%
Diesel	0.2%	0.0%	0.0%	0.0%
Hydroelectric	3.0%	0.5%	0.0%	0.0%
Steam	92.5%	89.9%	73.7%	69.0%
Wind	1.0%	0.0%	0.0%	0.0%
Total	100%	100%	100%	100%

Table 3-64 presents the share of each unit type by self-scheduled, economic, noneconomic and regulation generation. (Each row adds to 100 percent.) For example, in 2009, 26.5 percent of steam unit generation was self-scheduled, 64.3 percent was economic, 8.1 percent was noneconomic and the remaining 1.2 percent was regulation generation. In 2009, 98.7 percent of wind generation and 71.1 percent of hydroelectric generation was self-scheduled. In 2009, 45.2 percent of combustion turbine generation was noneconomic, which is consistent with Table 3-61 which shows that a large percentage of balancing generator credits was paid to CTs.

Table 3-64 PJM unit type generation distribution (By unit type receiving operating reserve payments): Calendar year 2009

	Self-Scheduled Generation	Economic Generation	Noneconomic Generation	Regulation Generation	Total
Combined cycle	8.4%	62.0%	24.7%	5.0%	100%
Combustion turbine	12.8%	41.8%	45.2%	0.1%	100%
Diesel	80.3%	13.9%	5.8%	0.0%	100%
Hydroelectric	71.1%	28.9%	0.0%	0.0%	100%
Steam	26.5%	64.3%	8.1%	1.2%	100%
Wind	98.7%	1.3%	0.0%	0.0%	100%

Geography of Balancing Credits and Charges

Table 3-65 compares the share of balancing operating reserve charges paid by generators and balancing operating reserve credits paid to generators in the Eastern Region and the Western Region. Generation charges are defined in this table as the allocation of charges paid by generators due to generator deviations from day-ahead schedules or not following PJM dispatch.[94] On average, 53.1 percent of balancing generator charges and 51.4 percent of lost opportunity cost charges were paid by generators deviating in the Eastern Region while these generators received 60.6 percent of balancing generator credits and 79.9 percent of lost opportunity cost credits. Table 3-65 also shows generator credits and charges as shares of total operating reserve credits and charges. On average, generator charges were 8.4 percent of all operating reserve charges and generator credits were 68.7 percent of all operating reserve credits.

94 The Eastern Region contains the BGE, Dominion, PENELEC, Pepco, Met-Ed, PPL, JCPL, PECO, DPL, PSEG, RECO, and AECO Control Zones. The Western Region includes the AEP, AP, ComEd, DLCO, and DAY Control Zones.

Table 3-65 Monthly balancing operating reserve charges and credits to generators (By location): Calendar year 2009

Eastern Region						
	Unit Deviation Charges	Unit Deviation LOC Charges	Total Unit Deviation Charges	Balancing Generator Credit	LOC Credit	Total Balancing Credit
Jan	$2,003,885	$299,205	$2,303,090	$21,129,695	$2,617,930	$23,747,625
Feb	$790,550	$164,106	$954,656	$7,821,619	$1,685,163	$9,506,782
Mar	$1,469,084	$340,198	$1,809,282	$13,211,647	$2,283,617	$15,495,264
Apr	$498,591	$157,780	$656,371	$3,992,645	$1,098,113	$5,090,758
May	$693,618	$113,976	$807,594	$6,823,179	$1,312,397	$8,135,576
Jun	$1,003,287	$199,563	$1,202,850	$8,774,095	$2,017,742	$10,791,837
Jul	$901,022	$153,109	$1,054,130	$10,024,256	$1,855,776	$11,880,032
Aug	$1,079,421	$409,943	$1,489,364	$11,091,698	$4,841,026	$15,932,725
Sep	$572,257	$207,710	$779,966	$5,571,005	$2,602,756	$8,173,762
Oct	$953,675	$132,000	$1,085,676	$9,951,855	$1,333,063	$11,284,918
Nov	$677,193	$141,054	$818,246	$5,956,365	$1,139,586	$7,095,951
Dec	$1,661,238	$211,376	$1,872,614	$16,984,127	$1,625,960	$18,610,087
Average	53.1%	51.4%	52.8%	60.6%	79.9%	63.4%

Western Region								
	Unit Deviation Charges	Unit Deviation LOC Charges	Total Unit Deviation Charges	Balancing Generator Credit	LOC Credit	Total Balancing Credit	Total Unit Deviation Charges Percent of Total Operating Reserve Charges	Total Unit Credits Percent of Total Operating Reserve Credits
Jan	$1,670,026	$279,307	$1,949,334	$5,404,493	$964,606	$6,369,099	10.4%	74.0%
Feb	$726,523	$172,132	$898,655	$6,592,259	$418,689	$7,010,948	7.5%	66.5%
Mar	$1,359,557	$286,649	$1,646,206	$9,095,630	$1,273,798	$10,369,428	9.7%	72.8%
Apr	$530,487	$161,839	$692,326	$6,758,625	$735,433	$7,494,058	6.7%	64.2%
May	$700,650	$132,040	$832,690	$7,154,625	$200,056	$7,354,681	7.6%	72.0%
Jun	$920,146	$224,107	$1,144,253	$7,386,679	$522,794	$7,909,474	9.0%	73.6%
Jul	$635,412	$131,550	$766,962	$5,604,614	$244,330	$5,848,944	7.0%	68.2%
Aug	$866,957	$356,962	$1,223,919	$4,538,533	$561,050	$5,099,583	9.4%	73.2%
Sep	$548,659	$186,125	$734,784	$5,009,167	$200,811	$5,209,978	7.8%	68.8%
Oct	$873,630	$129,657	$1,003,287	$4,672,969	$285,475	$4,958,444	8.6%	69.6%
Nov	$590,510	$129,344	$719,853	$3,169,974	$487,428	$3,657,402	7.1%	55.4%
Dec	$1,516,925	$213,325	$1,730,251	$3,017,714	$554,369	$3,572,083	9.8%	66.0%
Average	46.9%	48.6%	47.2%	39.4%	20.1%	36.6%	8.4%	68.7%

Impacts of Revised Operating Reserve Rules

Review of Impact on Regional Balancing Operating Reserve Charges

The MMU has reviewed and analyzed the net impact of allocating a proportion of balancing operating reserve credits to real-time load and exports. Credits that are received by generators that operate for reliability purposes are now paid as charges by organizations with real-time load and exports. Credits that are received by generators that are operating for deviation purposes are still paid as charges by organizations that have supply, withdrawal, and/or generator deviations. 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. In order to determine the impact of this rule change, the MMU calculated what balancing operating reserve charges would have been under the old rules and compared it to what actually happened in 2009.

Total reliability and deviation balancing operating reserve credits were $173,349,483 in 2009.[95] Table 3-66 shows each category of credits by region.

Table 3-66 Regional balancing operating reserve credits: Calendar year 2009

	Reliability Credits	Deviation Credits	Total Credits
RTO	$7,061,503	$125,850,691	$132,912,194
East	$497,589	$12,904,076	$13,401,665
West	$23,066,804	$3,968,820	$27,035,624
Total	$30,625,896	$142,723,586	$173,349,483

Table 3-67 shows the total amount of deviations in the demand, supply, and generator categories for 2009.

Table 3-67 Total deviations: Calendar year 2009

	Demand Deviations	Supply Deviations	Generator Deviations	Deviations Total
Total (MWh)	95,029,874	55,906,867	28,731,313	179,668,054

Under the old operating reserve construct, total credits for a day would have been calculated using demand, supply, and generator deviations and the resultant balancing rate would have been applied to each organization's demand, supply, and generator deviations to calculate total charges.

For illustrative purposes only, the balancing rate shown in Table 3-68 was calculated as the total credits in Table 3-66 divided by total deviations in Table 3-67, or $173,349,483/179,668,054, for a rate of $0.9648 per MWh. The MMU derived the rates on a daily basis and re-calculated organizational charges.

Table 3-68 Charge allocation under old operating reserve construct: Calendar year 2009

	Demand Deviations	Supply Deviations	Generator Deviations	Total
Total (MWh)	95,029,874	55,906,867	28,731,313	179,668,054
Balancing Rate ($/MWh)	0.9648	0.9648	0.9648	0.9648
Charges ($)	$91,687,861	$53,940,732	$27,720,889	$173,349,483

95 Only balancing generator charges were in this analysis. The charges shown in this section do not include lost opportunity cost, cancellation, or local charges.

Under the new operating reserve construct, rates are calculated separately for reliability and deviation categories in the Eastern, Western, and RTO Regions, resulting in six balancing rates. The Eastern and Western reliability rates are calculated by taking each region's daily reliability credits and dividing by each region's real-time load and exports. These regional rates are then charged to each organization's regional real-time load and exports. The RTO reliability rate is calculated by taking the total RTO reliability rates for the day and dividing it by the sum of eastern and western real-time load and exports. This rate is then charged to the sum of an organization's eastern and western real-time load and exports. Regional deviation credits are charged to the sum of demand, supply, and generator deviations for each region in which they occur (deviations at hubs that span both regions apply to RTO deviations).[96] Total RTO deviations are the sum of the eastern deviations, western deviations, and the deviations at hubs that span both regions.

For 2009, charges were actually allocated as shown in Table 3-69. For illustrative purposes only, the reliability and deviation rates in the table are the annual credits divided by either real-time load and exports or total deviations ($7,061,503 / 692,082,914 = .0102). The charges are calculated based on the actual daily rates.

Table 3-69 Actual regional credits, charges, rates and charge allocation (MWh): Calendar 2009

	Reliability Charges				Deviation Charges				
	Reliability Credits ($)	RT Load and Exports (MWh)	Reliability Rate ($/MWh)	Reliability Charges ($)	Deviation Credits ($)	Deviations (MWh)	Deviation Rate ($/MWh)	Deviation Charges ($)	Total Charges ($)
RTO	$7,061,503	692,082,914	0.0102	$7,061,503	$125,850,691	179,668,054	0.7005	$125,850,691	$132,912,194
East	$497,589	379,649,154	0.0013	$497,589	$12,904,076	104,656,256	0.1233	$12,904,076	$13,401,665
West	$23,066,804	312,433,760	0.0738	$23,066,804	$3,968,820	74,694,902	0.0531	$3,968,820	$27,035,624
Total	$30,625,896	692,082,914	NA	$30,625,896	$142,723,586	179,668,054	NA	$142,723,586	$173,349,483

The difference between the charges based on the old operating reserve construct (Table 3-68) and the actual charges allocated under the current rules is shown in Table 3-70, separated by deviation type. The total amount of charges reallocated from the demand, supply, and generator deviations is equal to the amount of total reliability charges.

Table 3-70 Difference in total charges between old rules and new rules: Calendar year 2009

	Reliability Charges			Deviation Charges			
	Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations	Injection Deviations	Generator Deviations	Deviations Total
Charges (Old)	$0	$0	$0	$91,687,861	$53,940,732	$27,720,889	$173,349,483
Charges (Current)	$29,423,340	$1,202,556	$30,625,896	$75,297,778	$44,179,076	$23,246,732	$142,723,586
Difference	$29,423,340	$1,202,556	$30,625,896	($16,390,083)	($9,761,656)	($4,474,157)	($30,625,896)

An increase of $30,625,896 of charges was assigned to real-time load and exports for 2009. Real-time load paid an additional $29,423,340, while real-time exports paid an additional $1,202,556. 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. Reliability charges accounted for 17.7 percent of total balancing operating reserve charges.

96 Only two hubs span across both the eastern and western regions: the Dominion Hub and the Western Int. Hub.

Impact on decrement bids and incremental offers

The MMU has estimated the impact of the new balancing operating reserve cost allocation construct on virtual activity. The level of virtual activity that was not otherwise netted out was calculated by organization for increment offers and decrement bids. All organizational deviations were grouped into regions. “Total Increment Offers” and “Total Decrement Bids”, shown in Table 3-71, is the sum of cleared virtual activity for 2009. “Adjusted Increment Offer Deviations” and “Adjusted Decrement Bid Deviations” are the net deviations for each type of virtual trade that were not offset. For example, in January 2009, of the 10,407,394 MWh of cleared increment offers, 7,841,756 MWh were netted by other deviations, resulting in 2,565,639 MWh of increment offers being charged balancing operating reserve deviation charges.

Table 3-71 Total virtual bids and amount of virtual bids paying balancing operating charges (MWh): Calendar year 2009

Month	Total Increment Offers (MWh)	Total Decrement Bids (MWh)	Adjusted Increment Offer Deviations (MWh)	Adjusted Decrement Bid Deviations (MWh)
Jan	10,407,394	12,554,252	2,565,639	3,639,601
Feb	9,063,314	10,452,872	2,020,685	2,506,114
Mar	9,929,332	11,282,869	2,114,827	2,444,352
Apr	8,181,571	10,008,029	1,807,709	2,209,075
May	9,562,558	10,395,649	2,753,133	2,358,022
Jun	8,910,238	10,639,623	2,636,356	2,637,496
Jul	9,066,758	10,828,533	2,710,078	3,014,685
Aug	9,186,533	12,370,077	3,006,961	3,913,433
Sep	8,787,276	10,415,029	2,545,261	2,972,666
Oct	9,804,389	11,684,851	2,344,278	2,586,091
Nov	9,311,052	10,797,920	2,286,985	2,498,129
Dec	8,689,316	11,158,575	2,142,485	2,694,103
Total	110,899,732	132,588,277	28,934,395	33,473,766

When multiplied by the regional deviation rates, the total amount of charges paid by these deviations in 2009 was $60,795,622. Total deviation charges using the actual method of including decrement bids in the deviation calculation were $75,297,778, as shown in Table 3-70.

In order to determine what these deviation charges would have been under the old method, balancing operating reserve rates were determined for each day. The rates were calculated using the sum of reliability credits for the RTO, eastern region, western region, and deviation credits for the RTO, eastern region, and western region, and dividing by the total amount of deviations across all regions. Total charges were calculated for each company using this balancing rate and the sum of their adjusted increment offer and decrement bids. The resulting total amount of charges that would have been paid in 2009 was $71,237,186. The monthly differences can be seen in Table 3-72.

Table 3-72 Comparison of balancing operating reserve charges to virtual bids: Calendar year 2009

Month	Charges Under Current Rules	Charges Under Old Rules	Difference
Jan	$9,672,322	$10,738,258	($1,065,936)
Feb	$4,034,001	$5,681,839	($1,647,837)
Mar	$6,745,711	$8,589,442	($1,843,731)
Apr	$2,331,339	$2,736,472	($405,133)
May	$3,602,363	$4,020,105	($417,741)
Jun	$4,827,989	$5,606,584	($778,595)
Jul	$4,792,394	$5,383,784	($591,390)
Aug	$7,234,696	$7,720,394	($485,698)
Sep	$3,973,924	$4,772,689	($798,765)
Oct	$4,664,169	$5,536,136	($871,967)
Nov	$3,380,119	$3,836,906	($456,787)
Dec	$5,536,595	$6,614,578	($1,077,983)
Total	$60,795,622	$71,237,186	($10,441,564)

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. A summary showing this breakdown for each region is shown in Table 3-73.

Table 3-73 Summary of impact on virtual bids under balancing operating reserve allocation: Calendar year 2009

Region	Adjusted Increment Offer Deviations	Adjusted Decrement Bid Deviations	Total Adjusted Virtual Deviations	Balancing Rate Under Current Rules	Balancing Rate Under Old Rules	Charges Under Current Rules	Charges Under Old Rules	Differerence
RTO	28,934,395.37	33,473,765.63	62,408,161.00	0.8629	1.1300	54,696,020.66	71,237,185.54	(16,541,164.88)
East	16,265,449.13	20,838,704.18	37,104,153.30	0.1204	0.0000	4,776,624.74	0.00	4,776,624.74
West	12,597,096.94	12,390,014.85	24,987,111.79	0.0544	0.0000	1,322,976.53	0.00	1,322,976.53

Segmented Make Whole Payments

Under the old operating reserve construct, balancing operating reserves for units were evaluated over the entire 24-hour period of the day. Under the new construct,

> "Balancing Operating Reserve credits are calculated by operating segment within an Operating Day. A resource will be made whole for the duration of the greater of the day-ahead schedule or minimum run time (minimum down time for demand resources) and made whole separately for the block of hours it is operated at PJM's direction in excess of the greater of the day-ahead schedule or minimum run time (minimum down time for demand resources). Startup costs (shut down costs for demand resources), as applicable,

will be included in the segment represented by the longer of the day-ahead schedule or minimum run time (minimum down time for demand resources).“[97]

The primary intent of this rule was to provide incentives for generating units to follow PJM dispatch past their day-ahead schedule or minimum run time. Splitting these credits into two segments was to create compensation which would reimburse resources when it was not economical for them to run, but when they were still needed by PJM. It was also to allow resources to keep their revenues from economical hours, thereby providing incentives to offer flexible schedules and to follow dispatch.

The MMU analyzed the impact of segmented make whole payments on balancing operating reserves since the establishment of the rule. The MMU compared what balancing credits would have been for each unit for each day under the old rules to what the credits were under the new rules. As a result of the introduction of segmented make whole payments in place of 24 hour make whole payments, balancing operating credits were $8,174,406 higher, or 4.10 percent, from December 1, 2008 through December 31, 2009. The total increase for the calendar year 2009 was $7,489,486, or 4.13 percent. Table 3-74 provides a breakdown of monthly differences between the two methods of calculation since December 2008.

Table 3-74 Impact of segmented make whole payments: December 2008 through December 2009

Year	Month	Balancing Credits Under Old Rules	Balancing Credits Under New Rules	Difference
2008	Dec	$17,879,706	$18,564,627	$684,920
2009	Jan	$24,958,891	$26,413,119	$1,454,228
2009	Feb	$13,834,755	$14,391,550	$556,795
2009	Mar	$21,434,893	$22,200,141	$765,248
2009	Apr	$10,532,594	$10,741,260	$208,666
2009	May	$13,499,668	$13,813,209	$313,541
2009	Jun	$15,111,383	$16,058,545	$947,162
2009	Jul	$14,657,498	$15,414,023	$756,525
2009	Aug	$14,467,711	$15,602,754	$1,135,043
2009	Sep	$10,293,949	$10,576,618	$282,669
2009	Oct	$14,337,978	$14,605,878	$267,900
2009	Nov	$8,889,163	$9,091,845	$202,682
2009	Dec	$19,403,859	$20,002,885	$599,026
Total		$199,302,047	$207,476,453	$8,174,406

Table 3-75 shows the effect of segmented make whole payments on each type of unit that received balancing operating reserve credits for the period from December 1, 2008 through December 31, 2009. “Number of Unit-Days” in the table is the count of units that received balancing credits each day, summed across the entire year. For example, it can be said that an average of 4.6 combined-cycle units received credits for each day of the year (1,667 / 365 = 4.6). The average daily amount received in credits for a unit in each method of calculation was analyzed to show the impact of an average day for each type of unit. The last three columns in the table show the total difference in credits for the time period across each unit type.

97 PJM. “Manual 18: Operating Agreement Accounting” Revision 43 (January 20, 2010), Section 5.3.1.

Table 3-75 Impact of segmented make whole payments (By unit type): December 2008 through December 2009

Unit Type	Number of Unit-Days	Average Daily Balancing Credits (Old Rules)	Average Daily Balancing Credits (New Rules)	Average Daily Difference	Total Balancing Credits (Old Rules)	Total Balancing Credits (New Rules)	Total Difference
Combined-Cycle	1,657	$1,865	$4,319	$2,454	$3,090,233	$7,157,021	$4,066,788
Large Frame Combustion Turbine (135 - 180 MW)	386	$5,988	$10,221	$4,233	$2,311,413	$3,945,418	$1,634,005
Medium Frame Combustion Turbine (30 - 65 MW)	2,924	$1,774	$2,063	$289	$5,186,443	$6,032,231	$845,788
Medium-Large Frame Combustion Turbine (65 - 125 MW)	434	$2,959	$4,296	$1,337	$1,284,040	$1,864,256	$580,216
Sub-Critical Coal	570	$299	$998	$699	$170,667	$568,868	$398,201
Petroleum/Gas Steam (Pre-1985)	79	$875	$5,579	$4,704	$69,107	$440,750	$371,643
Petroleum/Gas Steam (Post-1985)	222	$659	$1,600	$941	$146,272	$355,217	$208,945
Small Frame Combustion Turbine (0 - 29 MW)	119	$3,200	$3,538	$338	$380,847	$421,010	$40,164
Hydro	26	$112	$904	$793	$2,900	$23,505	$20,605
Super-Critical Coal	5	$30	$946	$916	$149	$4,729	$4,580
Diesel	26	$610	$743	$133	$15,850	$19,320	$3,470

Combined-cycle units were most affected by the rule change. Under the old rules, these units would have been paid $3,090,233, and with segmented make whole payments, the units received $7,157,021, for a total difference of $4,066,788, or a 131.6 percent increase. This represents 49.8 percent of the total increase of credits. The four types of combustion turbines received a 37.9 percent of the increase, and steam units, which include sub and super-critical coal units, and petroleum and natural gas steam units, received 12.0 percent of the increase. Table 3-76 shows this breakdown.

Table 3-76 Share of balancing operating reserve increases for segmented make whole payments (By unit type): December 2008 through December 2009

Unit Type	Share of Increase
Combined-Cycle	49.8%
Steam	12.0%
Combustion Turbines	37.9%
Diesel	0.0%
Hydro	0.3%

Unit Operating Parameters

The use of restrictive operating parameters to exercise market power and inflate operating reserve credits was addressed, based on the MMU's analysis and positions, in the revised operating reserve rules. The MMU's prior analyses indicated that operating reserve credits may result from the submission of artificially restrictive, unit-specific operating parameters.[98] The MMU also pointed out that restrictive operating parameters can interact with unit-specific markups to increase operating reserve payments to units.

98 See *2008 State of the Market Report for PJM*, Section 3, "Energy Market, Part 2", at "Operating Reserve".

The new operating reserves rules address the parameter issue by establishing a parameter limited schedule (PLS) that helps prevent the use of restrictive operating parameters when units have local market power. Table 3-77 shows the parameter limited matrix for periods that are currently effective.[99]

Table 3-77 Table 37 Unit Parameter Limited Schedule Matrix

Unit Type	Minimum Run Time (Hours)	Minimum Down Time (Hours)	Maximum Daily Starts	Maximum Weekly Starts	Turn Down Ratio
Petroleum/Gas Steam (Pre-1985)	8 or Less	7 or Less	1 or More	7 or More	3 or More
Petroleum/Gas Steam (Post-1985)	5.5 or Less	3.5 or Less	2 or More	11 or More	2 or More
Combined-Cycle	6 or Less	4 or Less	2 or More	11 or More	1.5 or More
Sub-Critical Coal	15 or Less	9 or Less	1 or More	5 or More	2 or More
Super-Critical Coal	24 or Less	84.0	1 or More	2 or More	1.5 or More
Small Frame and Aero Combustion Turbine (0 - 29 MW)	2 or Less	2 or Less	2 or More	14 or More	1 or More
Medium Frame and Aero Combustion Turbine (30 - 125 MW)	3 or Less	2 or Less	2 or More	14 or More	1 or More
Medium-Large Frame Combustion Turbine (65 - 125 MW)	5 or Less	3 or Less	2 or More	14 or More	1 or More
Large Frame Combustion Turbine (135 - 180 MW)	5 or Less	4 or Less	2 or More	14 or More	1 or More

Units may request exceptions to the values in the matrix. The MMU analyzed the impact of these exceptions. The only units included in the analysis were units put on their cost schedule after failing the TPS test.

There were only 216 events, including 44 units, when a unit with a PLS exception was capped and received balancing operating reserve credits. Table 3-78 shows the number of unique units and the number of events that occurred.

Table 3-78 Units receiving credits from a parameter limited schedule: December 2008 through December 2009

Unit Type	Number of Units	Observations
Sub-Critical Coal	23	87
Medium-Large Frame Combustion Turbine (65 - 125 MW)	10	79
Combined-Cycle	4	7
Super-Critical Coal	3	3
Large Frame Combustion Turbine (135 - 180 MW)	2	38
Petroleum/Gas Steam (Post-1985)	1	1
Petroleum/Gas Steam (Pre-1985)	1	1

99 See PJM "Parameter Limited Schedule Matrix," for parameter levels at <http://www.pjm.com/markets-and-operations/energy/~/media/markets-ops/energy/op-reserves/20080916-parameter-limited-schedule-matrix.ashx> (104 KB).

Concentration of Unit Ownership for Operating Reserve Credits

Market Power Issues

The MMU has pointed out that the exercise of market power by units that are paid operating reserve credits has contributed to the level of operating reserve charges paid by PJM members. Such market power was exercised through the use of mark ups by units that were exempt from local market power rules and through the submission of inflexible operating parameters. The mark up issue was resolved by FERC's acting on May 16, 2008, to end the prior exemptions from offer capping.[100] Units that were exempt had, prior to that time, exercised market power by charging substantial mark ups over cost when they had local market power due to PJM's need for the units to supply local operating reserves. As a result, 2009 was the first full year in which there were no exemptions from offer capping. The inflexible operating parameter issue was largely resolved by the introduction of new PJM rules governing parameter limited schedules.

Markup

The MMU analyzed the top 10 units receiving operating reserve credits to determine the contribution that markup makes to operating reserve payments.[101] The markup for the top 10 units averaged -0.7 percent in 2009, the only time it has been negative since 2001. The markup for the top 10 units is a weighted average, weighted by generator output when operating reserve credits are paid.

The generation owner with the largest share of the top 10 units that received operating reserve credits was 67.9 percent, and had a weighted average markup of 0.0 percent in 2009. This generation mix included two combined-cycle units, and a coal-fired steam unit. The second generation owner received 22.5 percent of Energy Market operating reserve payments made to the top 10 units and had a weighted-average markup of -11.8 percent. This includes four coal-fired steam plants. The third generation owner received 3.6 percent of Energy Market operating reserve payments made to the top 10 units and had a weighted-average markup of -22.9 percent in 2009. This was a combined-cycle unit.

Concentration of Operating Reserve Credits

There remains a high degree of concentration in the units and companies receiving operating reserve credits. This concentration appears to result from a combination of unit operating characteristics and PJM's persistent need for operating reserves in particular locations.

The concentration of operating reserve credits is first examined by analyzing the characteristics of the top 10 units receiving operating reserve credits. The focus on the top 10 units is illustrative.

100 123 FERC ¶ 61,169 (May 16, 2008).

101 Markup is calculated as [(Price – Cost)/Cost] where cost represents the cost-based offer as defined in PJM "Manual 15: Cost Development Guidelines," Revision 11 (December 2, 2009). As a result, the markups here are not directly comparable to those calculated as [(Price – Cost)/Price].

Top 10 Units

Despite the fact that the market power issues have been addressed, the concentration of operating reserve credits increased in 2009. As Table 3-79 shows, the top 10 units receiving total operating reserve credits, which makes up less than 1 percent of all units in PJM's footprint, received 37.1 percent of total operating reserve credits in 2009, almost twice as much as 2008. The top 20 units received 46.0 percent of total operating reserve credits in 2009 and 25.8 percent in 2008. In 2009, the top generation owner received 32.8 percent of the total operating reserve credits paid, an increase over 2008, when the top generation owner received 24.9 percent of the total operating reserve credits.

Table 3-79 Top 10 operating reserve revenue units (By percent of total system): Calendar years 2001 to 2009

	Top 10 Units Credit Share	Percent of Total PJM Units
2001	46.7%	1.8%
2002	32.0%	1.5%
2003	39.3%	1.3%
2004	46.3%	0.9%
2005	27.7%	0.8%
2006	29.7%	0.8%
2007	29.7%	0.8%
2008	18.8%	0.8%
2009	37.1%	0.8%

Table 3-80 shows the distribution of operating reserve credits to units by zone. The top three zones accounted for 64.2 percent of the total. The PSEG Control Zone had the largest share of credits with 33.1 percent, the AEP Control Zone was the second highest with 18.7 percent, and the Dominion Control Zone was third with a 12.4 percent share.

Table 3-80 Unit operating reserve credits for units (By zone): Calendar year 2009

Zone	Day Ahead Generator Credit	Synchronous Condensing Credit	Balancing Generator Credit	Lost Opportunity Cost Credit	Total Operating Reserve Credits	Percent of Total Operating Reserve Credits
AECO	$513,710	$944	$791,938	$117,509	$1,424,100	0.4%
AEP	$8,723,238	$5,133	$48,980,822	$1,674,940	$59,384,133	18.7%
AP	$3,747,192	$1,101	$6,805,759	$2,422,733	$12,976,784	4.1%
BGE	$7,007,778	$0	$4,356,403	$42,099	$11,406,280	3.6%
ComEd	$2,435,143	$0	$9,019,152	$2,150,192	$13,604,487	4.3%
DAY	$1,300,875	$4,430	$2,120,856	$31,311	$3,457,472	1.1%
Dominion	$3,291,700	$0	$18,349,168	$17,613,332	$39,254,200	12.4%
DPL	$5,684,241	$173,552	$9,064,286	$609,202	$15,531,281	4.9%
DLCO	$995,576	$0	$1,582,810	$179,765	$2,758,151	0.9%
JCPL	$1,354,488	$0	$3,669,397	$55,396	$5,079,281	1.6%
Met-Ed	$725,864	$0	$2,202,305	$14,948	$2,943,117	0.9%
PECO	$3,212,154	$0	$2,711,564	$501,750	$6,425,468	2.0%
PENELEC	$1,189,888	$79,317	$2,048,576	$1,129,565	$4,447,346	1.4%
Pepco	$7,464,662	$0	$16,003,899	$3,287,739	$26,756,300	8.4%
PPL	$566,776	$0	$5,885,515	$846,691	$7,298,983	2.3%
PSEG	$46,494,438	$2,230,621	$56,147,353	$206,545	$105,078,957	33.1%
Total	$94,707,723	$2,495,097	$189,739,803	$30,883,718	$317,826,341	100.0%

Table 3-81 rank orders the top 10 units receiving total operating reserve credits, and the top 10 organizations receiving total operating reserve credits. The organization ranked number one does not necessarily own the unit that is ranked number one. The unit that received the most total operating reserve credits received $40,271,049 for 2009, or 12.7 percent of the total operating reserve credits paid to all units. The cumulative distribution column shows that the top 10 units had a 37.1 percent share of the total operating reserve credits in 2009. The top organization had a 32.8 percent share of the total credits, or $104,362,793. The top 10 organizations receiving credits had a cumulative share of 85.4 percent.

Table 3-81 Top 10 units and organizations receiving total operating reserve credits: Calendar year 2009

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$40,271,049	12.7%	12.7%	$104,362,793	32.8%	32.8%
2	$26,582,418	8.4%	21.0%	$53,684,600	16.9%	49.7%
3	$13,129,115	4.1%	25.2%	$30,268,335	9.5%	59.3%
4	$8,972,470	2.8%	28.0%	$18,858,384	5.9%	65.2%
5	$7,153,457	2.3%	30.2%	$15,000,057	4.7%	69.9%
6	$6,136,280	1.9%	32.2%	$14,238,849	4.5%	74.4%
7	$4,227,166	1.3%	33.5%	$13,784,436	4.3%	78.7%
8	$4,178,410	1.3%	34.8%	$7,705,847	2.4%	81.1%
9	$3,618,783	1.1%	36.0%	$7,539,983	2.4%	83.5%
10	$3,507,989	1.1%	37.1%	$6,033,195	1.9%	85.4%

Table 3-82 rank orders the top 10 units receiving day-ahead operating reserve credits, and the top 10 organizations receiving day-ahead operating reserve credits. The top unit received $19,581,161, or 20.7 percent of the total day-ahead generator credits, compared to 18.3 percent in 2008. The second unit had a 14.1 percent share, which when combined with the top unit was 34.8 percent of the total credits. The top organization in 2009 received 48.9 percent of the day-ahead credits, compared to 41.8 percent in 2008. The top 10 organizations received 92.1 percent of the day-ahead credits.

Table 3-82 Top 10 units and organizations receiving day-ahead generator credits: Calendar year 2009

	Units			Organizations		
Rank	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution	Day Ahead Generator Credit	Day Ahead Generator Credit Share	Day Ahead Generator Credit Cumulative Distribution
1	$19,581,161	20.7%	20.7%	$46,317,856	48.9%	48.9%
2	$13,367,045	14.1%	34.8%	$8,826,849	9.3%	58.2%
3	$9,844,069	10.4%	45.2%	$7,249,218	7.7%	65.9%
4	$3,204,836	3.4%	48.6%	$6,196,701	6.5%	72.4%
5	$3,183,690	3.4%	51.9%	$3,970,211	4.2%	76.6%
6	$1,441,538	1.5%	53.5%	$3,921,590	4.1%	80.8%
7	$1,235,554	1.3%	54.8%	$3,413,069	3.6%	84.4%
8	$1,079,218	1.1%	55.9%	$2,579,206	2.7%	87.1%
9	$1,074,593	1.1%	57.0%	$2,545,188	2.7%	89.8%
10	$1,034,348	1.1%	58.1%	$2,223,899	2.3%	92.1%

Table 3-83 rank orders the top 10 units receiving synchronous condensing credits, and the top 10 organizations receiving synchronous condensing credits. This market remains even more highly concentrated the operating reserve credits overall, as the top organization received 89.4 percent of synchronous condensing credits, down from 96.7 percent in 2008.

Table 3-83 Top 10 units and organizations receiving synchronous condensing credits: Calendar year 2009

	Units			Organizations		
Rank	Total Credit	Total Credit Share	Total Credit Cumulative Distribution	Total Credit	Total Credit Share	Total Credit Cumulative Distribution
1	$40,271,049	12.7%	12.7%	$104,362,793	32.8%	32.8%
2	$26,582,418	8.4%	21.0%	$53,684,600	16.9%	49.7%
3	$13,129,115	4.1%	25.2%	$30,268,335	9.5%	59.3%
4	$8,972,470	2.8%	28.0%	$18,858,384	5.9%	65.2%
5	$7,153,457	2.3%	30.2%	$15,000,057	4.7%	69.9%
6	$6,136,280	1.9%	32.2%	$14,238,849	4.5%	74.4%
7	$4,227,166	1.3%	33.5%	$13,784,436	4.3%	78.7%
8	$4,178,410	1.3%	34.8%	$7,705,847	2.4%	81.1%
9	$3,618,783	1.1%	36.0%	$7,539,983	2.4%	83.5%
10	$3,507,989	1.1%	37.1%	$6,033,195	1.9%	85.4%

Table 3-84 rank orders the top 10 units receiving balancing generator credits, and the top 10 organizations receiving balancing generator credits. The top organization received 29.3 percent of total credits. The top ten organizations received a total of 86.6 percent of all the balancing generator credits.

Table 3-84 Top 10 units and organizations receiving balancing generator credits: Calendar year 2009

	Units			Organizations		
Rank	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution	Balancing Generator Credit	Balancing Generator Credit Share	Balancing Generator Credit Cumulative Distribution
1	$26,893,531	14.2%	14.2%	$55,607,771	29.3%	29.3%
2	$8,546,543	4.5%	18.7%	$43,713,256	23.0%	52.3%
3	$6,892,404	3.6%	22.3%	$18,496,966	9.7%	62.1%
4	$6,576,909	3.5%	25.8%	$16,010,493	8.4%	70.5%
5	$5,619,044	3.0%	28.7%	$8,803,268	4.6%	75.2%
6	$3,826,633	2.0%	30.8%	$6,733,375	3.5%	78.7%
7	$3,752,008	2.0%	32.7%	$5,100,022	2.7%	81.4%
8	$3,285,046	1.7%	34.5%	$3,576,306	1.9%	83.3%
9	$2,718,638	1.4%	35.9%	$3,421,873	1.8%	85.1%
10	$2,659,577	1.4%	37.3%	$2,816,285	1.5%	86.6%

Table 3-85 rank orders the top 10 units receiving lost opportunity cost credits, and the top 10 organizations receiving lost opportunity cost credits. The top organization received 44.6 percent of the total lost opportunity cost credits and 93.1 percent were received by the top 10 organizations.

Table 3-85 Top 10 units and organizations receiving lost opportunity cost credits: Calendar year 2009

	Units			Organizations		
Rank	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution	LOC Credit	LOC Credit Share	LOC Credit Cumulative Distribution
1	$2,256,939	7.3%	7.3%	$13,777,592	44.6%	44.6%
2	$2,045,331	6.6%	13.9%	$7,800,058	25.3%	69.9%
3	$1,932,260	6.3%	20.2%	$1,439,186	4.7%	74.5%
4	$1,791,713	5.8%	26.0%	$1,323,636	4.3%	78.8%
5	$1,781,744	5.8%	31.8%	$1,314,648	4.3%	83.1%
6	$1,766,793	5.7%	37.5%	$1,144,495	3.7%	86.8%
7	$1,192,543	3.9%	41.3%	$550,608	1.8%	88.6%
8	$909,480	2.9%	44.3%	$521,262	1.7%	90.2%
9	$843,495	2.7%	47.0%	$505,276	1.6%	91.9%
10	$738,101	2.4%	49.4%	$381,926	1.2%	93.1%

SECTION 4 – 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.

Overview

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.[1] Gross monthly import volumes averaged 3,671 GWh while gross monthly exports averaged 3,788 GWh.

- **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.

- **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.[2] 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

1 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.
2 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.

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.

Operating Agreements with Bordering Areas

- **PJM and New York Independent System Operator, Inc. Joint Operating Agreement (JOA).**[3] 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."[4] 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.[5]

- **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

3 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).

4 128 FERC ¶61,049 (Ordering Para. B), *order on clarification*, 128 FERC ¶61,239.

5 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).

management process is reviewed and modified as necessary through the Congestion Management Process (CMP) protocols.[6]

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.[7]

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 United States Federal Energy Regulatory Commission (FERC) mediated settlement process to resolve these issues.

- **PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement.**[8] 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.**[9] 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.**[10] 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.[11]

6 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).

7 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).

8 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).

9 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).

10 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).

11 111 FERC ¶ 61,228 (2005).

- **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.[12] 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.[13] 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.[14] The average hourly flow for 2009 was -136 MW.[15]

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.

12 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).
13 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.
14 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).
15 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.

The southern interfaces have historically experienced significant loop flows.[16] 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.

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.[17] PJM's interface pricing calculations correctly

16 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).

17 See the *2008 State of the Market Report for PJM*, Volume II, "Interchange Transactions."

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."[18]

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.[19]

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 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.*[20]

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

18 128 FERC ¶61,049 (Ordering Para. B), *order on clarification*, 128 FERC ¶61,239.

19 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).

20 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).

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.

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.[21] 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

21 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).

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.[22] 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 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.[23] 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.

22 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).

23 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).

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 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).[24] These options are: the existing SouthIMP/SouthEXP prices; the "Hi/Low" method; and the "Marginal Cost Proxy Method."

24 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).

The proposed tariff revisions were filed with FERC on December 2, 2008, and approved on May 1, 2009.[25] 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.[26] 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.[27] 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.[28] 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 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.

25 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).
26 127 FERC ¶61,101.
27 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).
28 See "WPC White Paper" (April 20, 2007) (Accessed January 15, 2010) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx> (97 KB).

- **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.[29] 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.

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.

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

The MMU analyzed the transactions between PJM and its 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.

Interchange Transaction Activity

Aggregate Imports and Exports

PJM was a monthly 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. (See Figure 4-1, Figure 4-2 and Figure 4-3.)[30] Total net interchange of -1,407 GWh was less than net interchange of -12,124 GWh in 2008. The peak month for net exporting interchange was June in 2009, -1,031 GWh; it had also been June in 2008, -2,388 GWh. The peak month for net importing interchange was January in 2009, 1,715 GWh; it had been December in 2008, 695 GWh. Monthly gross exports averaged 3,788 GWh and monthly gross imports averaged 3,671 GWh, for an average monthly net interchange of -117 GWh.

PJM was a net importer of energy in the Day-Ahead Market in July (182 GWh), and a net exporter of energy in the remaining months. Total net interchange was -9,033 GWh. The peak month for net exporting interchange was October, -2,204 GWh. Monthly gross exports averaged 4,826 GWh and monthly gross imports averaged 4,073 GWh, for an average monthly net interchange of -753 GWh.

While PJM market participants historically imported and exported energy primarily in the Real-Time Energy Market, that is no longer the case. Transactions in the Day-Ahead Market create financial obligations to deliver in the Real-Time Market and to pay operating reserve charges based on differences between the transaction MW in the Day-Ahead and Real-Time Energy Markets. 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 exceeded the net interchange in the Real-Time Energy Market by 642 percent (-1,407 GWh in the Real-Time Market and -9,033 GWh in the Day-Ahead Market).

30 Calculated values shown in Section 4, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Figure 4-1 PJM real-time scheduled imports and exports: Calendar year 2009

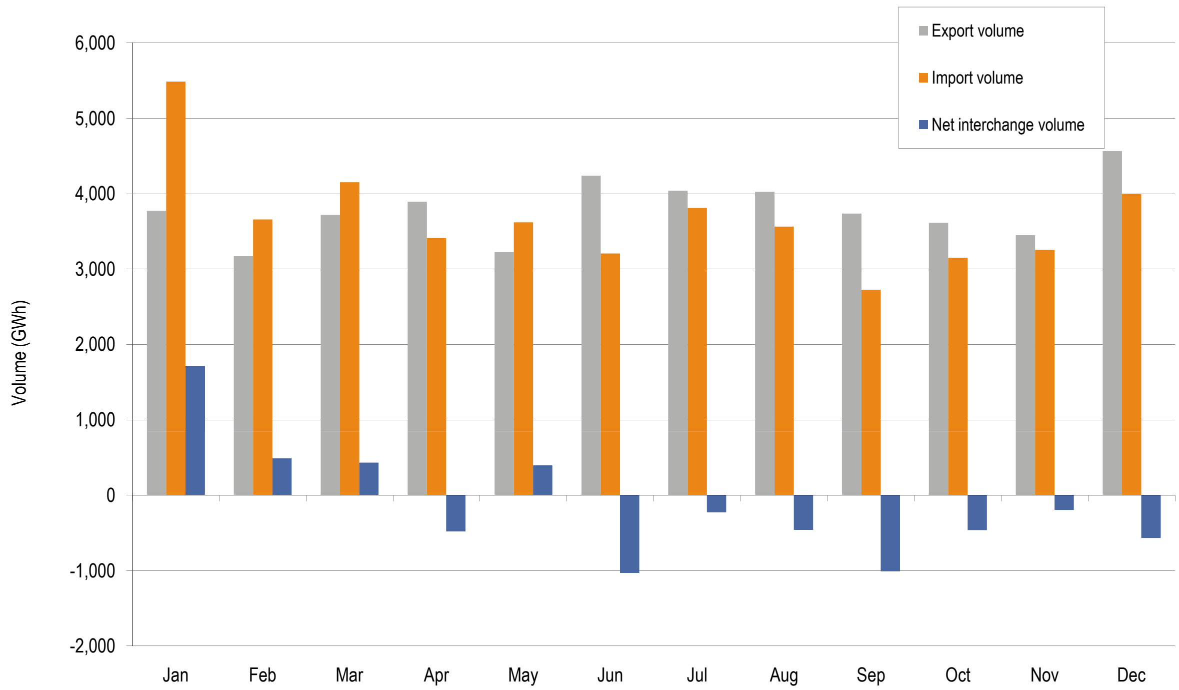


Figure 4-2 PJM day-ahead scheduled imports and exports: Calendar year 2009

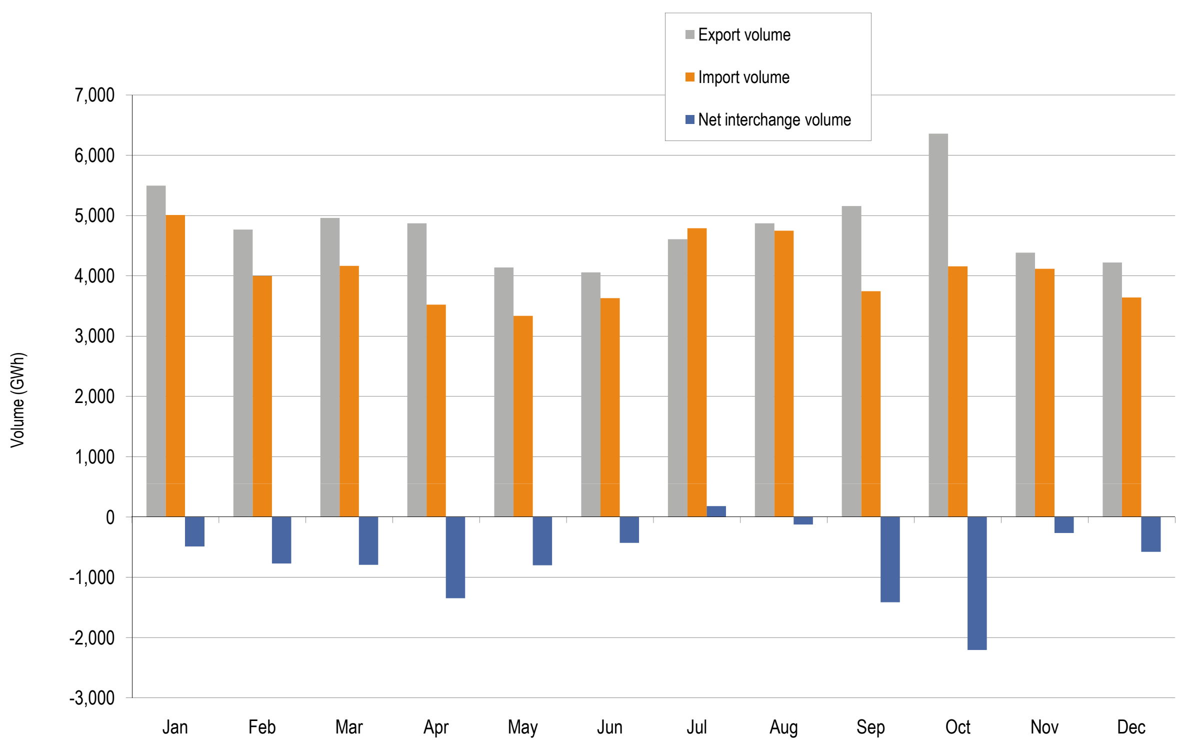
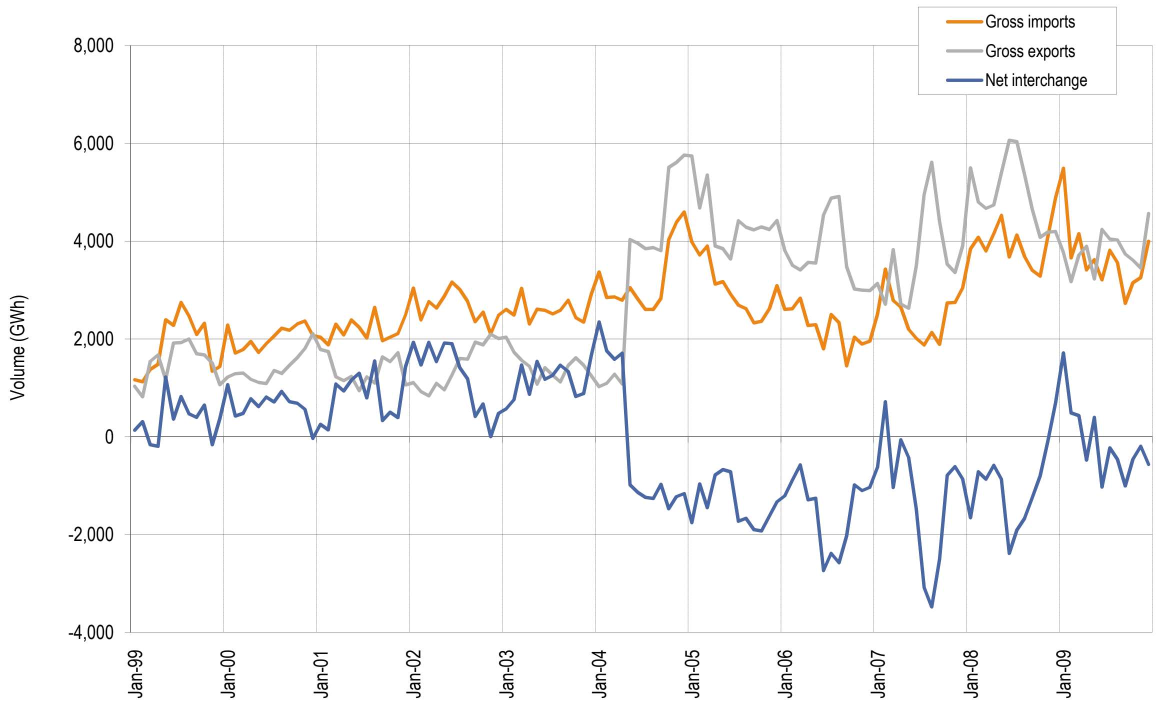


Figure 4-3 shows real-time import and export volume for PJM from 1999 through 2009. PJM became a consistent net exporter of energy in 2004, coincident with the expansion of the PJM footprint, and has continued to be a net exporter in most months since that time.

Figure 4-3 PJM scheduled import and export transaction volume history: 1999 through December 2009



Interface Imports and Exports

In November of 2009, the Linden variable frequency transformer (VFT) facility was placed in service. As a result, a new interface was created, bringing the total number of interfaces between PJM and other balancing authorities to 21. The Linden (LIND) interface and the Neptune (NEPT) Interface are separate from the NYIS Interface. However, all three are between PJM and the NYISO. Table 4-1 through Table 4-6 show the interchange totals at the individual interfaces with the NYISO, as well as with the NYISO as a whole. Similarly, the interchange totals at the individual interfaces between PJM and the Midwest ISO are shown, as well as with the Midwest ISO as a whole.

Total imports and exports are comprised of flows at each PJM interface. Net interchange in the Real-Time Market is shown by interface for 2009 in Table 4-1 while gross imports and exports are shown in Table 4-2 and Table 4-3. Net interchange in the Day-Ahead Market is shown by interface for 2009 in Table 4-4 while gross imports and exports are shown in Table 4-5 and Table 4-6.

In 2009, there were net exports in the Real-Time Market at 12 of PJM's 21 interfaces. (See Table 4-7 for active interfaces during 2009.) The top three exporting interfaces accounted for 62 percent of PJM's total net exports: PJM/NYIS with 28 percent, PJM/NEPT with 25 percent and PJM/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/LIND). Combined, these interfaces made up 55 percent of the total net PJM exports in the Real-Time Market.

Economic fundamentals were the key driver for the net exports through the NYIS Interface in the Real-Time Market. Figure 4-13 shows that PJM's PJM/NYIS average hourly interface price was $1.79 less than the NYISO's NYIS/PJM Interface price, and net exports are consistent with purchasing at a lower price and selling at a higher price. The PJM/NEPT flow averaged approximately -550 MW for each hour through 2009. As with the PJM/NYIS interface, the PJM/NEPT Interface price was, on average lower than the NYIS/NEPT bus price ($41.94 in PJM vs. $49.24 in the NYISO). Similarly, the PJM/LIND Interface price averaged $38.19, while the NYISO/Linden bus price averaged $43.22.

The PJM/CPLE exports are based on economic fundamentals. Figure 4-26 and Figure 4-27 show the correlation between the price available to CPLE imports and exports and their corresponding interchange. As the average hourly price available to CPLE decreases, exports to CPLE increase.

In 2009, there were net exports in the Day-Ahead Market at 14 of PJM's 21 interfaces. The top three exporting interfaces accounted for 58 percent of PJM's total net exports, PJM/ALTW with 24 percent, PJM/ALTE with 17 percent and PJM/NEPT with 17 percent.

There were net imports in the Real-Time Market at nine of PJM's interfaces. Two net importing interfaces accounted for 88 percent of PJM's net import volume, PJM/OVEC with 68 percent and PJM/MECS with 20 percent of the net import volume.

Eleven shareholders own OVEC and share OVEC's generation output. Approximately 70 percent of the shares of ownership belong to load serving entities, or their affiliates, within the PJM footprint. The agreement requires delivery of approximately 70 percent of the generation output into the PJM footprint.[31] OVEC itself does not serve load, and therefore does not import energy. The nature of the ownership of OVEC and the location of its affiliates within the PJM footprint account for the large percentage of PJM's net interchange volume.

The primary reason for the imports at the PJM/MECS Interface is that excess generation from the IESO is often scheduled through the Midwest ISO and into PJM through the PJM/MECS Interface. This is the path with the lowest cost of transmission between the IESO and PJM. While there is an alternate transmission path through the NYISO, transmission charges are higher on this path. This is a result of the fact that the transmission through the Midwest ISO, for transactions sinking in PJM, would be a free service due to the regional through and out rate. The fact that there is an additional transmission charge through the NYISO makes this a more costly transmission path for transactions from the IESO into PJM.

There were net imports in the Day-Ahead Market at seven of PJM's 21 interfaces. The top three net importing interfaces accounted for 85 percent of PJM's total net imports, PJM/OVEC with 53 percent, PJM/WEC with 18 percent and PJM/MECS with 15 percent.

31 See "Ohio Valley Electric Corporation: Company Background." (Accessed January 24, 2010) <http://www.ovec.com/OVECHistory.pdf> (26 KB).

Table 4-1 Real-time scheduled net interchange volume by interface (GWh): Calendar year 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	(62.7)	(161.8)	(208.1)	(281.1)	(113.8)	(293.2)	(317.7)	(242.9)	(241.7)	35.9	3.1	53.2	(1,830.8)
CPLW	(71.4)	(67.4)	(74.3)	(72.0)	(60.3)	(69.8)	(74.6)	(76.7)	(57.6)	0.0	(3.5)	(56.1)	(683.7)
DUK	622.7	67.8	89.9	10.6	60.9	(86.0)	(135.9)	(67.5)	(180.9)	(70.2)	(39.2)	126.6	398.8
EKPC	(173.5)	(78.8)	(88.6)	(57.4)	67.3	(9.7)	(45.0)	(57.3)	(113.1)	(40.8)	(35.6)	(41.8)	(674.3)
LGEE	137.4	90.7	176.3	101.4	169.8	32.6	(3.9)	54.6	43.5	69.4	80.9	62.6	1,015.3
MEC	150.4	302.1	146.1	155.1	(148.4)	(239.8)	(117.9)	(26.8)	(446.6)	(483.0)	(451.8)	(446.7)	(1,607.3)
MISO	388.0	(153.5)	(96.0)	(804.4)	81.0	(277.4)	405.6	(78.5)	9.5	1.9	383.7	349.0	208.9
ALTE	44.4	(41.8)	(86.5)	(147.3)	(117.6)	(143.6)	(136.3)	(94.9)	(39.1)	(27.7)	(9.0)	39.4	(760.0)
ALTW	(65.6)	(69.6)	(74.3)	(97.5)	(66.4)	(175.3)	(230.4)	(151.1)	(92.2)	(70.8)	(29.5)	(4.2)	(1,126.9)
AMIL	126.2	23.7	8.7	(14.9)	28.0	(24.0)	(6.8)	(13.6)	24.6	39.8	17.7	(43.6)	165.8
CIN	102.6	(96.1)	(179.7)	(216.6)	14.7	(91.8)	154.0	133.9	206.5	70.9	109.9	187.2	395.5
CWLP	0.0	0.0	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7
FE	(215.6)	(221.5)	(166.6)	(204.3)	(178.6)	(93.1)	(16.8)	(80.2)	(168.8)	(45.9)	(63.6)	(78.1)	(1,533.1)
IPL	47.1	(17.5)	(88.6)	(79.8)	101.5	(23.9)	173.4	(5.7)	(14.2)	(18.0)	25.3	67.8	167.4
MECS	421.7	361.8	552.3	60.9	341.6	398.7	512.8	258.3	157.3	113.9	276.8	163.6	3,619.7
NIPS	(8.2)	(51.5)	(35.5)	(60.0)	(3.9)	(38.1)	(13.9)	(71.5)	(28.0)	(11.4)	(0.6)	(19.3)	(341.9)
WEC	(64.6)	(41.0)	(26.5)	(44.9)	(38.3)	(86.3)	(30.4)	(53.7)	(36.6)	(48.9)	56.7	36.2	(378.3)
NYISO	(690.9)	(634.2)	(698.4)	(581.7)	(700.0)	(922.9)	(983.5)	(1,068.2)	(844.6)	(970.7)	(1,143.3)	(1,682.4)	(10,920.8)
LIND									(8.9)	(44.5)	(151.8)	(148.8)	(354.0)
NEPT	(294.8)	(402.5)	(445.1)	(400.9)	(434.5)	(456.9)	(493.9)	(484.6)	(382.6)	(265.4)	(426.0)	(473.5)	(4,960.7)
NYIS	(396.1)	(231.7)	(253.3)	(180.8)	(265.5)	(466.0)	(489.6)	(583.6)	(453.1)	(660.8)	(565.5)	(1,060.1)	(5,606.1)
OVEC	1,171.3	994.2	1,018.4	1,012.5	970.4	995.2	1,116.3	1,125.0	865.0	1,015.1	1,041.3	1,198.6	12,523.3
TVA	244.0	128.7	167.6	35.2	69.3	(160.0)	(73.1)	(23.1)	(42.7)	(21.0)	(30.1)	(131.2)	163.6
Total	1,715.3	487.8	432.9	(481.8)	396.2	(1,031.0)	(229.7)	(461.4)	(1,009.2)	(463.4)	(194.5)	(568.2)	(1,407.0)

Table 4-2 Real-time scheduled gross import volume by interface (GWh): Calendar year 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	223.9	69.4	66.8	39.9	115.1	16.8	9.3	17.0	5.2	139.8	115.7	325.2	1,144.1
CPLW	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.1
DUK	737.8	277.9	209.5	154.1	239.2	151.2	101.4	98.5	72.6	155.4	90.9	308.5	2,597.0
EKPC	2.7	6.1	12.9	2.5	90.3	33.2	11.6	4.2	0.9	11.8	9.4	11.8	197.4
LGEE	187.4	125.2	183.6	125.8	172.0	55.7	48.0	72.1	44.3	70.4	84.5	89.5	1,258.5
MEC	337.6	428.2	371.7	361.2	77.8	26.5	113.5	182.9	4.8	15.5	26.4	51.7	1,997.8
MISO	1,529.0	983.6	1,245.6	627.0	1,015.4	1,105.8	1,482.9	1,058.8	909.6	864.9	1,050.8	1,110.4	12,983.8
ALTE	170.4	65.4	18.2	1.7	0.1	0.1	1.7	0.0	2.1	0.0	0.0	44.4	304.1
ALTW	45.7	22.2	1.7	0.0	1.9	3.5	5.1	0.3	4.8	0.0	24.9	14.3	124.4
AMIL	147.3	44.9	38.3	26.8	62.2	48.6	65.8	54.0	46.5	76.9	51.3	66.3	728.9
CIN	382.9	265.0	335.2	209.3	256.2	335.3	332.8	402.7	443.7	315.4	279.0	388.5	3,946.0
CWLP	0.0	0.0	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.7
FE	60.5	32.6	101.6	60.8	73.0	160.0	251.7	180.8	130.3	207.3	185.4	177.1	1,621.1
IPL	107.5	43.8	51.9	63.5	148.6	65.7	199.1	52.0	33.0	34.4	53.7	79.2	932.4
MECS	573.5	500.4	679.7	264.3	458.0	486.8	601.6	368.9	246.7	220.0	355.6	248.8	5,004.3
NIPS	32.5	8.1	0.5	0.0	11.0	0.0	18.2	0.0	0.0	1.3	1.4	0.0	73.0
WEC	8.7	1.2	17.8	0.6	4.4	5.8	6.9	0.1	2.5	9.6	99.5	91.8	248.9
NYISO	1,004.4	589.8	829.7	982.3	795.2	791.0	862.5	915.8	738.0	810.7	763.7	819.8	9,902.9
LIND									0.0	0.5	0.2	0.0	0.7
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	1,004.4	589.8	829.7	982.3	795.2	791.0	862.5	915.8	738.0	810.2	763.5	819.8	9,902.2
OVEC	1,171.3	994.2	1,018.4	1,012.5	970.4	995.2	1,116.3	1,125.0	865.0	1,015.1	1,041.3	1,198.6	12,523.3
TVA	292.8	185.1	214.2	107.1	146.2	31.4	65.9	88.9	86.0	66.6	72.5	83.0	1,439.7
Total	5,489.0	3,659.5	4,152.4	3,412.4	3,621.6	3,206.8	3,811.4	3,563.2	2,726.4	3,150.2	3,255.2	3,998.5	44,046.6

Table 4-3 Real-time scheduled gross export volume by interface (GWh): Calendar year 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	286.6	231.2	274.9	321.0	228.9	310.0	327.0	259.9	246.9	103.9	112.6	272.0	2,974.9
CPLW	73.5	67.4	74.3	72.0	60.3	69.8	74.6	76.7	57.6	0.0	3.5	56.1	685.8
DUK	115.1	210.1	119.6	143.5	178.3	237.2	237.3	166.0	253.5	225.6	130.1	181.9	2,198.2
EKPC	176.2	84.9	101.5	59.9	23.0	42.9	56.6	61.5	114.0	52.6	45.0	53.6	871.7
LGEE	50.0	34.5	7.3	24.4	2.2	23.1	51.9	17.5	0.8	1.0	3.6	26.9	243.2
MEC	187.2	126.1	225.6	206.1	226.2	266.3	231.4	209.7	451.4	498.5	478.2	498.4	3,605.1
MISO	1,141.0	1,137.1	1,341.6	1,431.4	934.4	1,383.2	1,077.3	1,137.3	900.1	863.0	667.1	761.4	12,774.9
ALTE	126.0	107.2	104.7	149.0	117.7	143.7	138.0	94.9	41.2	27.7	9.0	5.0	1,064.1
ALTW	111.3	91.8	76.0	97.5	68.3	178.8	235.5	151.4	97.0	70.8	54.4	18.5	1,251.3
AMIL	21.1	21.2	29.6	41.7	34.2	72.6	72.6	67.6	21.9	37.1	33.6	109.9	563.1
CIN	280.3	361.1	514.9	425.9	241.5	427.1	178.8	268.8	237.2	244.5	169.1	201.3	3,550.5
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	276.1	254.1	268.2	265.1	251.6	253.1	268.5	261.0	299.1	253.2	249.0	255.2	3,154.2
IPL	60.4	61.3	140.5	143.3	47.1	89.6	25.7	57.7	47.2	52.4	28.4	11.4	765.0
MECS	151.8	138.6	127.4	203.4	116.4	88.1	88.8	110.6	89.4	106.1	78.8	85.2	1,384.6
NIPS	40.7	59.6	36.0	60.0	14.9	38.1	32.1	71.5	28.0	12.7	2.0	19.3	414.9
WEC	73.3	42.2	44.3	45.5	42.7	92.1	37.3	53.8	39.1	58.5	42.8	55.6	627.2
NYISO	1,695.3	1,224.0	1,528.1	1,564.0	1,495.2	1,713.9	1,846.0	1,984.0	1,582.6	1,781.4	1,907.0	2,502.2	20,823.7
LIND									8.9	45.0	152.0	148.8	354.7
NEPT	294.8	402.5	445.1	400.9	434.5	456.9	493.9	484.6	382.6	265.4	426.0	473.5	4,960.7
NYIS	1,400.5	821.5	1,083.0	1,163.1	1,060.7	1,257.0	1,352.1	1,499.4	1,191.1	1,471.0	1,329.0	1,879.9	15,508.3
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TVA	48.8	56.4	46.6	71.9	76.9	191.4	139.0	112.0	128.7	87.6	102.6	214.2	1,276.1
Total	3,773.7	3,171.7	3,719.5	3,894.2	3,225.4	4,237.8	4,041.1	4,024.6	3,735.6	3,613.6	3,449.7	4,566.7	45,453.6

Table 4-4 Day-ahead net interchange volume by interface (GWh): Calendar year 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	49.1	(23.0)	(86.0)	(81.0)	(88.1)	(157.1)	(158.8)	(109.9)	(91.0)	(43.0)	(103.0)	(109.6)	(1,001.4)
CPLW	(176.6)	(166.0)	(184.5)	(180.0)	(155.9)	(176.2)	(184.7)	(184.0)	(147.8)	7.7	(5.0)	(165.5)	(1,718.5)
DUK	255.9	26.4	1.1	22.3	120.9	58.7	88.5	45.5	(30.9)	85.8	(6.0)	70.3	738.6
EKPC	(31.1)	(22.8)	(1.1)	0.0	0.0	0.0	0.0	(1.4)	(0.3)	(1.2)	(0.1)	(1.4)	(59.4)
LGEE	(16.5)	(8.9)	23.5	6.9	9.7	39.9	38.0	2.7	46.4	(0.4)	(0.5)	4.2	145.0
MEC	27.3	(90.0)	(173.4)	(185.3)	(209.3)	(252.9)	(216.0)	(207.8)	(448.7)	(497.0)	(482.6)	(491.7)	(3,227.4)
MISO	(1,745.7)	(1,357.3)	(995.7)	(1,356.4)	(870.3)	(275.1)	57.2	(252.5)	(948.0)	(2,141.7)	26.3	130.9	(9,728.3)
ALTE	(142.2)	(61.4)	(518.5)	(673.0)	(779.1)	(521.6)	(340.1)	(409.7)	(542.5)	(573.2)	(321.9)	(26.8)	(4,910.0)
ALTW	(722.6)	(756.0)	(604.5)	(746.7)	(389.5)	(497.7)	(392.8)	(552.0)	(417.7)	(1,261.5)	(320.2)	(246.4)	(6,907.6)
AMIL	52.8	72.3	42.2	86.6	102.4	261.6	153.3	32.6	6.3	33.8	7.7	47.9	899.5
CIN	(225.4)	(96.3)	(47.8)	57.5	(36.7)	55.7	(8.5)	85.2	80.3	23.1	20.5	(97.6)	(190.0)
CWLP	(0.7)	(0.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.8)
FE	(206.7)	(233.8)	(241.4)	(197.3)	(206.0)	(116.4)	(119.4)	(76.8)	(115.4)	(152.1)	53.3	(21.5)	(1,633.5)
IPL	(316.7)	(191.0)	(157.2)	(67.1)	85.2	143.0	254.3	165.3	(34.8)	(35.4)	(1.3)	(46.3)	(202.0)
MECS	101.9	172.9	250.4	261.1	370.6	433.8	548.7	356.0	257.0	9.2	111.6	77.8	2,951.0
NIPS	(233.7)	(320.9)	(71.3)	(194.6)	(286.2)	(62.2)	(81.7)	(287.8)	(591.0)	(828.0)	(341.6)	(77.6)	(3,376.6)
WEC	(52.5)	57.0	352.4	117.2	269.0	28.7	43.4	434.7	409.8	642.4	818.2	521.4	3,641.7
NYISO	(167.7)	(257.3)	(315.6)	(394.7)	(438.4)	(480.5)	(489.0)	(533.8)	(564.7)	(534.1)	(710.3)	(920.5)	(5,806.6)
LIND									(2.7)	(44.0)	(82.8)	(55.1)	(184.6)
NEPT	(326.4)	(403.8)	(446.4)	(402.1)	(436.6)	(472.3)	(496.9)	(491.7)	(408.7)	(262.6)	(440.2)	(476.6)	(5,064.3)
NYIS	158.7	146.5	130.8	7.5	(1.8)	(8.2)	7.9	(42.1)	(153.3)	(227.5)	(187.3)	(388.8)	(557.7)
OVEC	835.6	743.5	786.0	738.6	824.2	857.3	1,028.8	1,038.7	795.4	914.6	1,004.2	938.3	10,505.2
TVA	482.5	384.6	151.7	81.8	5.4	(42.8)	18.0	79.6	(22.7)	5.4	10.6	(33.9)	1,120.2
Total	(487.2)	(770.8)	(794.0)	(1,347.6)	(801.8)	(428.7)	182.0	(122.9)	(1,412.3)	(2,203.9)	(266.4)	(578.9)	(9,032.5)

Table 4-5 Day-ahead gross import volume by interface (GWh): Calendar year 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	187.6	75.8	14.4	21.0	24.0	7.8	7.4	19.8	12.4	40.7	12.4	44.4	467.7
CPLW	9.5	2.1	0.6	0.0	2.8	0.0	2.2	2.0	0.0	9.7	1.4	1.5	31.8
DUK	291.9	102.7	55.9	71.4	138.8	90.0	123.6	66.8	83.6	116.1	28.9	103.9	1,273.6
EKPC	0.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	1.1
LGEE	2.9	0.2	24.9	8.1	11.4	41.0	40.1	5.2	46.4	0.1	0.1	4.2	184.6
MEC	173.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.7	1.5	0.0	6.8	183.2
MISO	2,090.9	2,059.3	2,312.2	1,779.9	1,700.4	1,947.7	2,704.6	2,558.3	2,005.4	2,239.6	2,257.1	1,739.4	25,394.8
ALTE	675.2	674.4	470.1	173.7	52.2	106.5	367.9	191.1	171.6	314.2	285.0	396.0	3,877.9
ALTW	190.8	183.6	33.2	2.3	0.0	12.5	29.9	40.4	15.8	47.7	59.5	20.4	636.1
AMIL	59.4	75.0	44.5	91.5	105.0	261.6	155.7	76.1	17.7	33.8	8.4	48.3	977.0
CIN	103.2	159.2	178.5	247.6	190.5	320.2	273.2	328.9	391.8	316.2	193.2	134.5	2,837.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FE	15.2	44.9	60.0	23.0	10.3	100.7	206.1	227.7	242.0	140.3	341.6	177.1	1,588.9
IPL	246.5	159.9	153.2	254.2	258.7	250.0	389.3	374.6	77.6	126.5	32.6	1.2	2,324.3
MECS	504.9	400.1	488.5	606.8	631.9	626.5	769.8	595.9	390.9	336.1	359.3	285.6	5,996.3
NIPS	284.5	248.4	490.5	208.0	135.6	151.4	338.2	231.6	152.0	72.6	74.6	29.2	2,416.6
WEC	11.2	113.8	393.7	172.7	316.2	118.3	174.5	492.0	546.0	852.2	902.9	647.1	4,740.6
NYISO	890.3	584.5	776.0	776.4	612.0	675.0	840.6	958.6	710.3	748.1	733.2	731.1	9,036.1
LIND									0.0	0.1	0.0	0.0	0.1
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	890.3	584.5	776.0	776.4	612.0	675.0	840.6	958.6	710.3	748.0	733.2	731.1	9,036.0
OVEC	866.7	766.6	810.5	763.1	828.4	858.2	1,032.0	1,043.8	840.5	954.7	1,036.2	981.4	10,782.1
TVA	496.4	407.2	172.8	104.0	20.2	12.0	40.4	96.3	46.0	46.9	50.7	30.7	1,523.6
Total	5,010.2	3,998.4	4,167.3	3,524.0	3,338.0	3,631.7	4,790.9	4,750.8	3,746.3	4,157.7	4,120.0	3,643.4	48,878.7

Table 4-6 Day-ahead gross export volume by interface (GWh): Calendar year 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
CPLE	138.5	98.8	100.4	102.0	112.1	164.9	166.2	129.7	103.4	83.7	115.4	154.0	1,469.1
CPLW	186.1	168.1	185.1	180.0	158.7	176.2	186.9	186.0	147.8	2.0	6.4	167.0	1,750.3
DUK	36.0	76.3	54.8	49.1	17.9	31.3	35.1	21.3	114.5	30.3	34.9	33.6	535.0
EKPC	31.9	22.8	1.1	0.0	0.0	0.0	0.0	1.4	0.3	1.5	0.1	1.4	60.5
LGEE	19.4	9.1	1.4	1.2	1.7	1.1	2.1	2.5	0.0	0.5	0.6	0.0	39.6
MEC	145.9	90.0	173.4	185.3	209.3	252.9	216.0	207.8	450.4	498.5	482.6	498.5	3,410.6
MISO	3,836.6	3,416.6	3,307.9	3,136.3	2,570.7	2,222.8	2,647.4	2,810.8	2,953.4	4,381.3	2,230.8	1,608.5	35,123.1
ALTE	817.4	735.8	988.6	846.7	831.3	628.1	708.0	600.8	714.1	887.4	606.9	422.8	8,787.9
ALTW	913.4	939.6	637.7	749.0	389.5	510.2	422.7	592.4	433.5	1,309.2	379.7	266.8	7,543.7
AMIL	6.6	2.7	2.3	4.9	2.6	0.0	2.4	43.5	11.4	0.0	0.7	0.4	77.5
CIN	328.6	255.5	226.3	190.1	227.2	264.5	281.7	243.7	311.5	293.1	172.7	232.1	3,027.0
CWLP	0.7	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8
FE	221.9	278.7	301.4	220.3	216.3	217.1	325.5	304.5	357.4	292.4	288.3	198.6	3,222.5
IPL	563.2	350.9	310.4	321.3	173.5	107.0	135.0	209.3	112.4	161.9	33.9	47.5	2,526.3
MECS	403.0	227.2	238.1	345.8	261.3	192.7	221.1	239.9	133.9	326.9	247.7	207.8	3,045.3
NIPS	518.2	569.3	561.8	402.6	421.8	213.6	419.9	519.4	743.0	900.6	416.2	106.8	5,793.2
WEC	63.7	56.8	41.3	55.5	47.2	89.6	131.1	57.3	136.2	209.8	84.7	125.7	1,098.9
NYISO	1,058.0	841.8	1,091.6	1,171.1	1,050.4	1,155.5	1,329.6	1,492.4	1,275.0	1,282.2	1,443.5	1,651.6	14,842.7
LIND									2.7	44.1	82.8	55.1	184.7
NEPT	326.4	403.8	446.4	402.1	436.6	472.3	496.9	491.7	408.7	262.6	440.2	476.6	5,064.3
NYIS	731.6	438.0	645.2	768.9	613.8	683.2	832.7	1,000.7	863.6	975.5	920.5	1,119.9	9,593.7
OVEC	31.1	23.1	24.5	24.5	4.2	0.9	3.2	5.1	45.1	40.1	32.0	43.1	276.9
TVA	13.9	22.6	21.1	22.2	14.8	54.8	22.4	16.7	68.7	41.5	40.1	64.6	403.4
Total	5,497.4	4,769.2	4,961.3	4,871.6	4,139.8	4,060.4	4,608.9	4,873.7	5,158.6	6,361.6	4,386.4	4,222.3	57,911.2

Transactions Basics

Interchange Transactions – Real-Time Energy Market

There are three steps required for market participants to enter external interchange transactions in PJM's Real-Time Energy Market. The steps are: acquisition of valid transmission via the Open Access Same Time Information System (OASIS); acquisition of available ramp via PJM's Enhanced Energy Scheduler system (EES); and the creation of a valid NERC Tag. In addition, the interchange request must pass the neighboring balancing authority checkout process in order for the request to be implemented. After a successful implementation of an external energy schedule, the energy will flow between balancing authorities. Such a transaction will continue to flow at its designated energy profile as long as the system can support it, it is deemed economic based on options set at the time of scheduling, or until the market participant chooses to curtail the transaction.

While the OASIS has a path component, this path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the Generation Control Area (GCA) to the Load Control Area (LCA). This complete path is utilized by PJM to determine the interface pricing point which PJM will associate with the transaction.

Interchange Transactions – Day-Ahead Energy Market

Entering external energy transactions in the Day-Ahead Market requires fewer steps than the Real-Time Market. Market participants need to acquire a valid, willing to pay congestion (WPC) OASIS reservation to prove that their day-ahead schedule could be supported in the Real-Time Market. Day-Ahead Market schedules need to be cleared through the Day-Ahead Market process in order to become an approved schedule. The Day-Ahead Market transactions are financially binding but will not physically flow. In the Day-Ahead Market, a market participant is not required to acquire a ramp reservation, a NERC Tag, or to go through a neighboring balancing authority checkout process.

There are three types of day-ahead external energy transactions: Fixed; Up-to congestion; and Dispatchable.

A fixed Day-Ahead Market transaction request means that the market participant agrees to be a price taker for the MW amount of the offer. There is no price associated with the request and the market participant agrees to take the day-ahead LMP at the associated source or sink. If the market participant has met the required deadline and has acquired a valid willing-to-pay congestion OASIS reservation, a fixed day-ahead transaction request will be accepted in the Day-Ahead Market. These approved transactions are a financial obligation. If the market participant does not provide a corresponding transaction in the Real-Time Market, they are subject to the balancing market settlement.

To submit an up-to congestion offer, the market participant is required to submit an energy profile (start time, stop time and MW value) and specify the amount of congestion they are willing to pay. If, in the Day-Ahead Market, congestion on the desired path is less than that specified, the up-to congestion request is approved. Approved up-to congestion offers are financial obligations.

Dispatchable transactions in the Day-Ahead Market are similar to those in the Real-Time Market in that they are evaluated against a floor or ceiling price at the designated import or export pricing point. For import dispatchable transactions, if the LMP at the interface clears higher than the specified bid, the transaction is approved. For export dispatchable transactions, if the LMP at the interface clears lower than the specified bid, the transaction is approved. As with fixed and up-to congestion transactions, cleared dispatchable transactions in the Day-Ahead Market represent a financial obligation. If the market participant does not meet the commitment in the Real-Time Market, they are subject to the balancing market settlement.

Source and Sink in the Real-Time Market

Real-Time Market transaction sources and sinks are determined through a combination of defaulted values and market participant selections.

- **Real-Time Market Imports.** For a real-time import energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, the source defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is DUK and the POD is PJM, the source would initially default to DUK's Interface pricing point (i.e. SouthIMP). At the time the energy is scheduled, if the GCA on the NERC Tag represents physical flow entering PJM at an interface other than the SouthIMP Interface, the source would then default to that new interface. The sink bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated, and does not change.

- **Real-Time Market Exports.** For a real-time export energy transaction, when a market participant selects the POR and POD on their OASIS reservation, the sink defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is PJM and the POD is DUK, the sink would initially default to DUK's Interface pricing point (i.e. SouthEXP). At the time the energy is scheduled, if the LCA on the NERC Tag represents physical flow leaving PJM at an interface other than the SouthEXP Interface, the sink would then default to that new interface. The source bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated, and does not change.

- **Real-Time Market Wheels.** For a real-time wheel through energy transaction, when a market participant selects the POR and POD on their OASIS reservation, both the source and sink default to the associated interface prices as defined by the POR/POD path. For example, if the selected POR is DUK and the POD is NYIS, the source would initially default to DUK's Interface pricing point (i.e. SouthIMP), and the sink would initially default to NYIS's Interface pricing point (i.e. NYIS). At the time the energy is scheduled, if the GCA on the NERC Tag represents physical flow entering PJM at an interface other than the SouthIMP Interface, the source would then default to that new interface. Similarly, if the LCA on the NERC Tag represents physical flow leaving PJM at an interface other than the NYIS Interface, the sink would then default to that new interface.

Source and Sink in the Day-Ahead Market

Day-Ahead Market transaction sources and sinks are determined solely by the market participants.

- **Day-Ahead Market Imports.** For day-ahead import energy transactions, the market participant chooses any import pricing point they wish to have associated with their transaction. This selection is made through the EES user interface. The sink bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated.

- **Day-Ahead Market Exports.** For day-ahead export energy transactions, the market participant chooses any export pricing point they wish to have associated with their transaction. This selection is made through the EES user interface. The source bus is selected by the market participant at the time the OASIS reservation is made, which can be any bus in the PJM footprint where LMPs are calculated.

- **Day-Ahead Market Wheels.** For day-ahead wheel through energy transactions, the market participant chooses any import pricing point and export pricing point they wish to have associated with their transaction. These selections are made through the EES user interface.

Curtailment of Transactions

Once a transaction has been implemented, energy flows between balancing authorities. Transactions can be curtailed under several conditions, including economic and reliability considerations.

There are three types of economic curtailments: curtailments of dispatchable schedules, OASIS designation curtailments (willing to pay congestion or not willing to pay congestion), and market participant self-curtailments. System reliability curtailments are termed TLRs or transmission loading relief.

A dispatchable external energy transaction (also known as "real-time with price") is one in which the market participant designates a floor or ceiling price on their external transaction from which they would like the energy to flow. For example, an import dispatchable schedule specifies that the market participant only wishes to load the transaction if the LMP at the interface where the transaction is entering the PJM footprint reaches a specified limit (the minimum LMP at which they are willing to sell energy into PJM). An export dispatchable schedule specifies the maximum LMP at the interface where the market participant wishes to purchase energy from PJM.

PJM system operators evaluate dispatchable transactions 30 minutes prior to the start of every hour of the energy profile. If the system operator expects the floor (or ceiling) price to be realized over the next hour, they contact the market participant informing them that they are loading the transaction. Once loaded, the dispatchable transaction will run for the next hour. If the system operator does not feel that the transaction will be economic, they will elect to not load the transaction, or to curtail the dispatchable transaction at the top of the next hour if it has already been loaded. Dispatchable schedules can be viewed as a generation offer, with a minimum run time of one hour. If the resulting hourly integrated prices are such that the transaction should not have been loaded, the transaction will be made whole through operating reserve credits.

Not willing to pay congestion transactions should be curtailed if there is realized congestion between the designated source and sink.

Transactions utilizing spot import service will be curtailed if the interface price where the transaction enters PJM reaches zero.

A market participant may curtail their transactions. All self curtailments must be requested on 15 minute intervals. In order for PJM to approve a self curtailment request, there must be available ramp for the modification.

Interface Pricing

Interface pricing points differ from interfaces. (See Table 4-7 for a list of active interfaces in 2009. Figure 4-4 shows the approximate geographic location of the interfaces.)

Transactions can be scheduled to an interface based on a contract transmission path, but pricing points are developed and applied based on the estimated electrical impact of the external power source on PJM tie lines, regardless of contract transmission path.[32] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to individual balancing authorities based on the Generation Control Area and Load Control Area as specified on the NERC Tag. 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. [33] The weighting factors are determined in such a manner that the interface reflects actual system conditions. However, this analysis is an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Transactions between PJM and external balancing authorities need to be priced at the PJM border. The challenge is to create interface prices, composed of external pricing points, that accurately represent flows between PJM and external sources of energy. The result is price signals that embody the underlying economic fundamentals across balancing authority borders.[34] Table 4-8 presents the interface pricing points used during 2009.

Table 4-7 Active interfaces: Calendar year 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
EKPC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
FE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND									Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active	Active

32 See PJM. "LMP Aggregate Definitions" (December 18, 2008) (Accessed January 15, 2010) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (1,369 KB). PJM periodically updates these definitions on its Web site. See <http://www.pjm.com>.

33 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).

34 See the *2007 State of the Market Report*, Volume II, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

Figure 4-4 PJM's footprint and its external interfaces

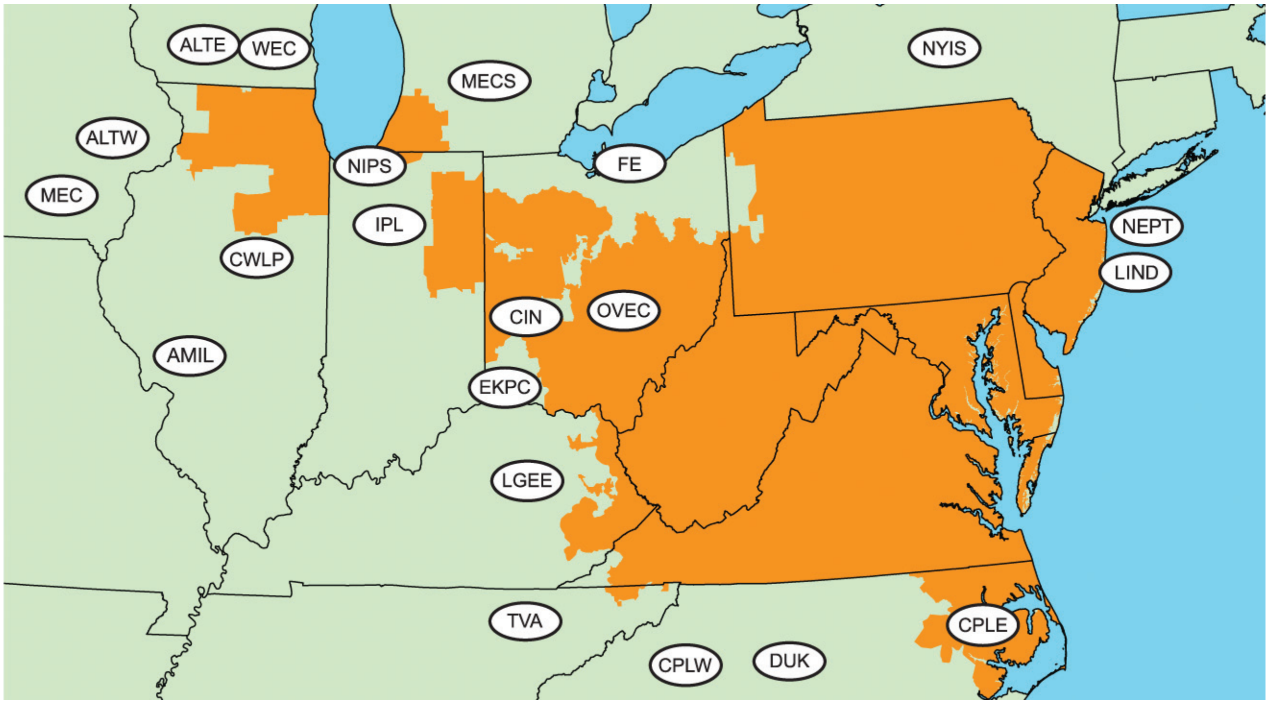


Table 4-8 Active pricing points: 2009

PJM 2009 Pricing Points			
LIND	MICHFE	MISO	NEPT
NIPSCO	Northwest	NYIS	Ontario IESO
OVEC	SOUTHEXP	SOUTHIMP	

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

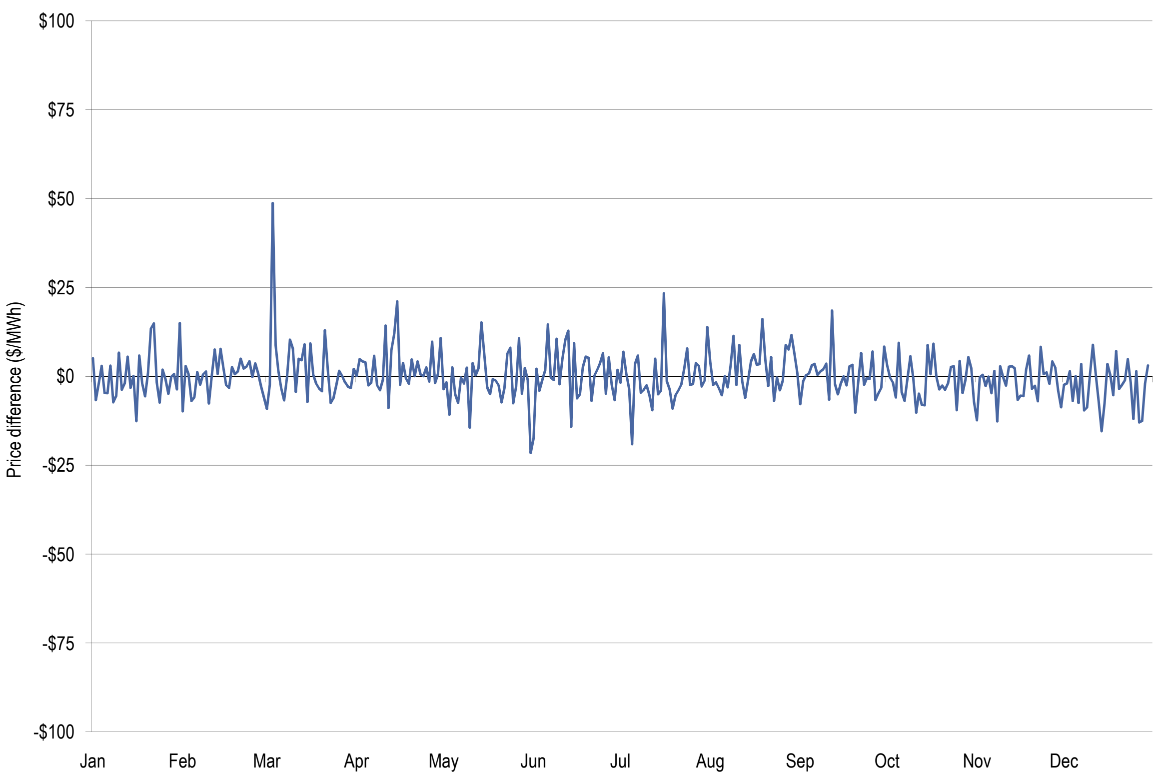
During 2009, Real-Time Market prices at the borders between PJM and the Midwest ISO and between PJM and the NYISO were consistent with competitive forces.

PJM and Midwest ISO Interface Prices

On April 1, 2005, with the introduction of price-based markets, the Midwest ISO created a new interface pricing point with PJM. Both the PJM/MISO and the MISO/PJM Interface pricing points represent the value of power at the relevant border, as determined by each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from the Midwest ISO would receive the PJM/MISO Interface price upon entering PJM, while a transaction into the Midwest ISO from PJM would receive the MISO/PJM Interface price. PJM and the Midwest ISO use network models to determine these prices and to ensure that the prices are consistent with the underlying electrical flows. PJM uses the LMP at nine buses[35] within the Midwest ISO to calculate the PJM/MISO Interface price, while the Midwest ISO uses prices at all of the PJM generator buses to calculate the MISO/PJM Interface price.[36]

The 2009 real-time hourly average interface prices for PJM/MISO and MISO/PJM were $29.67 and $29.68. The simple average difference between the real-time MISO/PJM Interface price and the PJM/MISO Interface price decreased from $1.17 per MWh in 2008 to $0.01 per MWh in 2009.[37] This is consistent with the fact that PJM net exports in 2009 were significantly lower than in 2008, as the price convergence in 2009 did not provide the incentives to purchase power from PJM and export to or through the Midwest ISO. (In the Real-Time Market in 2008, gross exports were 15,890.0 GWh vs. 12,774.9 GWh in 2009.) (See Figure 4-5.)

Figure 4-5 Real-time daily hourly average price difference (Midwest ISO Interface minus PJM/MISO): Calendar year 2009



The simple average interface price difference does not reflect the underlying hourly variability in prices. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

35 See PJM. "LMP Aggregate Definitions" (December 18, 2008) (Accessed January 15, 2010) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (1,369 KB). PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.

36 Based on information obtained from the Midwest ISO Extranet (January 15, 2010) <http://extranet.midwestiso.org>.

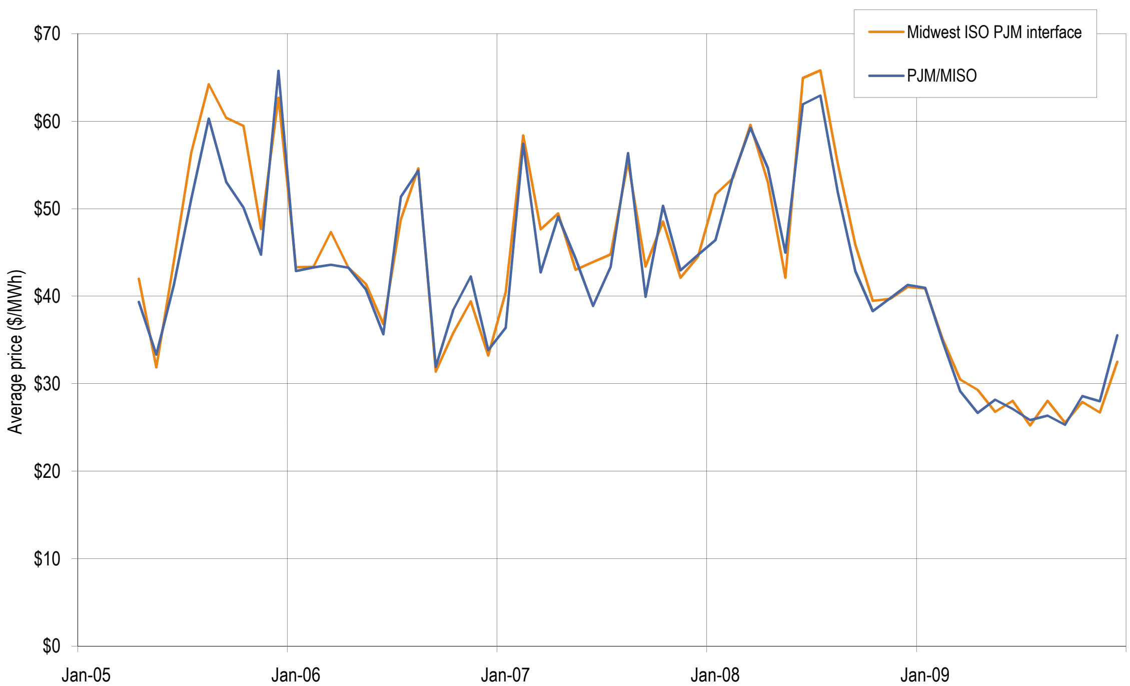
37 Table 4-9 in the *2008 State of the Market Report for PJM* incorrectly shows the simple average difference between the PJM and MISO Interface price as -$0.76. The report and Figure 4-9 correctly indicate that the simple average price difference was -$1.17 for 2008.

During 2009, the difference between the real-time PJM/MISO Interface price and the real-time MISO/PJM Interface price fluctuated between positive and negative about eight times per day. The standard deviation of the hourly price was $13.79 for the PJM/MISO Interface price and $17.83 for the MISO/PJM Interface price. The standard deviation of the difference in interface prices was $17.14. The average of the absolute value of the hourly price difference was $9.94. Absolute values reflect price differences regardless of whether they are positive or negative.

Several factors are responsible for the relationship between interface prices. The simple average interface price difference suggests that competitive forces prevent price deviations from persisting, an observation further supported by the frequency with which price differential switches between positive and negative.

In addition, there is a significant correlation between the real-time monthly average hourly PJM/MISO and MISO/PJM Interface prices during the 2009 period. (See Figure 4-6.)

Figure 4-6 Real-time monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through December 2009



The difference in real-time PJM and MISO Interface prices can also be measured by comparing the LMP for pairs of generating units that are located close together but on opposite sides of the border between PJM and the Midwest ISO and by comparing the LMP for jointly owned units that participate in both markets. The MMU compared two pairs of units and two jointly owned units. The LMP differences were compared over the calendar years 2008 and 2009.

Table 4-9 shows that in 2008 and 2009 both unit pairs and jointly owned units had real-time LMP differences larger than the difference at the PJM/MISO Interface, while the marginal congestion component and the marginal loss components of the total LMP were smaller than the difference at the PJM/MISO Interface. While the sample is not adequate to permit general conclusions, the data from these units indicate that actual price differences at the border between PJM and the Midwest ISO have varied from the interface pricing differences. Price differences at Kincaid reflect actual operational issues that make the price adjustment process less continuous.

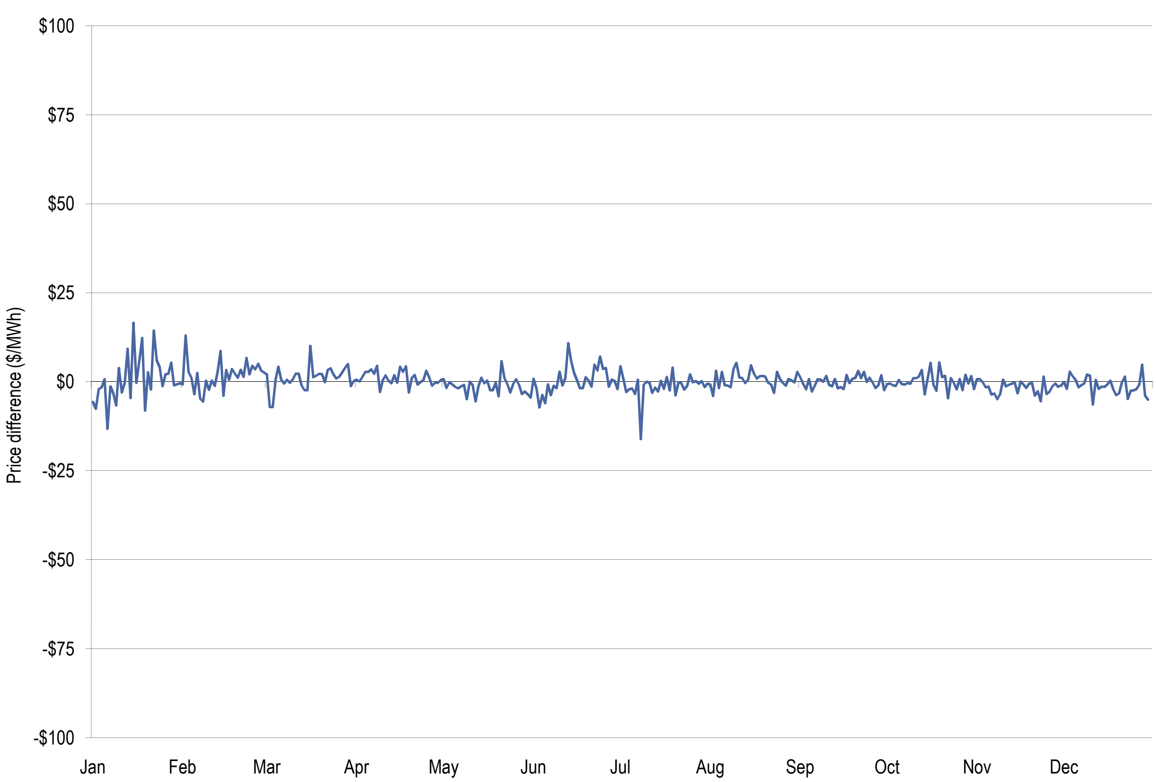
Table 4-9 Average real-time LMP difference (PJM minus Midwest ISO): Calendar years 2008 and 2009

	2008			2009		
	LMP	MCC	MLC	LMP	MCC	MLC
Kincaid (PJM) & Coffeen (MISO)	$8.26	($6.56)	($2.86)	$4.81	($2.65)	($2.06)
Beaver Valley (PJM) & Mansfield (MISO)	$0.89	($14.42)	($2.38)	$3.22	($4.92)	($1.38)
Miami Fort (PJM) & (MISO)	$1.25	($12.27)	($4.16)	$2.20	($4.64)	($2.70)
Stuart (PJM) & (MISO)	$0.87	($12.04)	($4.77)	$1.81	($4.63)	($3.07)
PJM/MISO Interface	($1.16)	($15.34)	($3.51)	$0.01	($6.94)	($2.58)

LMP: Locational Marginal Price, MCC: Marginal Congestion Component, MLC: Marginal Loss Component

The 2009 day-ahead hourly average interface prices for PJM/MISO and MISO/PJM were $29.94 and $29.91. The simple average difference between the day-ahead MISO/PJM Interface price and the PJM/MISO Interface price decreased from $0.62 in 2008 to $0.03 in 2009. (See Figure 4-7.) The day-ahead net gross exports to the Midwest ISO increased from 31,051.9 GWh in 2008 to 35,123.1 GWh in 2009.

Figure 4-7 Day-ahead daily hourly average price difference (Midwest ISO interface minus PJM/MISO): Calendar year 2009



During 2009, the difference between the day-ahead PJM/MISO Interface price and the day-ahead MISO/PJM Interface price fluctuated between positive and negative about five times per day. The standard deviation of the hourly price was $10.73 for the PJM/MISO price and $10.05 for the MISO/PJM Interface price. The standard deviation of the difference in interface prices was $5.05. The average of the absolute value of the hourly price difference was $3.50.

In addition, there is a significant correlation between the day-ahead monthly average hourly PJM and Midwest ISO Interface prices during the 2009 period. Figure 4-8 shows this correlation between hourly PJM and Midwest ISO Interface prices.

Figure 4-8 Day-ahead monthly hourly average Midwest ISO PJM interface price and the PJM/MISO price: April 2005 through December 2009

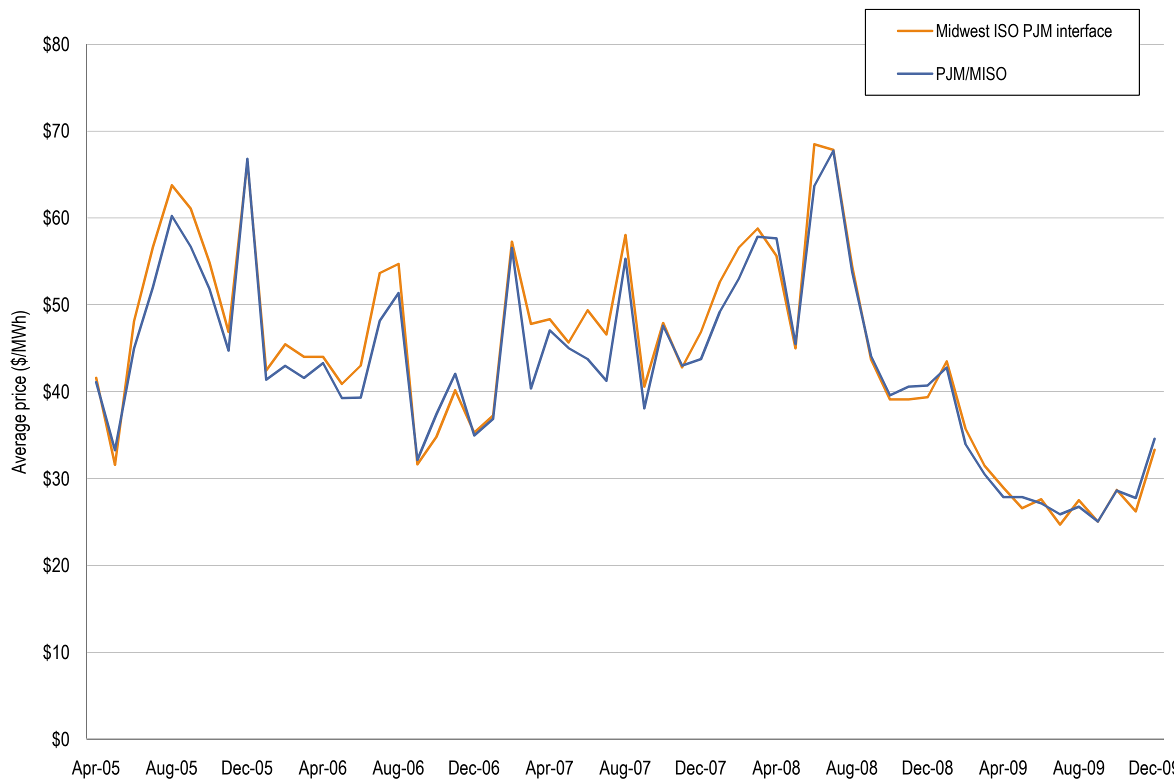


Table 4-10 shows that in 2008 and 2009 both unit pairs and jointly owned units had day-ahead LMP differences larger than the difference at the PJM/MISO Interface, while the marginal congestion component and the marginal loss components of the total LMP were smaller than the difference at the PJM/MISO Interface. While the sample is not adequate to permit general conclusions, the data from these units indicate that actual price differences at the border between PJM and the Midwest ISO have varied from the interface pricing differences. Price differences at Kincaid reflect actual operational issues that make the price adjustment process less continuous.

Table 4-10 Average day-ahead LMP difference (PJM minus Midwest ISO): Calendar years 2008 and 2009

	2008			2009		
	LMP	MCC	MLC	LMP	MCC	MLC
Kincaid (PJM) & Coffeen (MISO)	$9.19	($3.00)	($4.25)	$4.02	($2.06)	($2.80)
Beaver Valley (PJM) & Mansfield (MISO)	$3.40	($9.88)	($3.16)	$2.48	($4.72)	($1.67)
Miami Fort (PJM) & (MISO)	($0.05)	($11.17)	($5.32)	$1.87	($3.85)	($3.16)
Stuart (PJM) & (MISO)	($0.56)	($11.00)	($6.00)	$1.40	($3.87)	($3.61)
PJM/MISO Interface	($0.62)	($12.51)	($4.55)	($0.03)	($5.75)	($3.16)

LMP: Locational Marginal Price, MCC: Marginal Congestion Component, MLC: Marginal Loss Component

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-RTO/ISO power flows, and those price differentials.

PJM operators must verify all requested energy schedules with its neighboring balancing authorities. Only if the neighboring balancing authority agrees with the expected interchange will the transaction flow. If there is a disagreement in the expected interchange for any 15 minute interval, the system operators must work to resolve the difference. It is important that both balancing authorities enter the same values in their Energy Management Systems (EMS) to avoid inadvertent energy from flowing between balancing authorities.

With the exception of the NYISO, all neighboring balancing authorities handle transaction requests the same way as PJM (i.e. via the NERC Tag). This helps facilitate interchange transaction checkouts, as all balancing authorities are receiving the same information. While the NYISO also requires NERC Tags, they utilize their Market Information System (MIS) as their primary scheduling tool. The NYISO's Real-Time Commitment (RTC) tool evaluates all bids and offers each hour, and performs a least cost economic dispatch solution. This evaluation accepts or denies individual transactions in whole or in part. Upon market clearing, the NYISO implements NERC Tag adjustments to match the output of the RTC. PJM and the NYISO can verify interchange transactions once the NYISO Tag adjustments are sent and approved. The results of the adjustments made by the NYISO affect PJM operations, as the adjustments often cause large swings in expected ramp for the next hour (as discussed in the "Ramp" section).

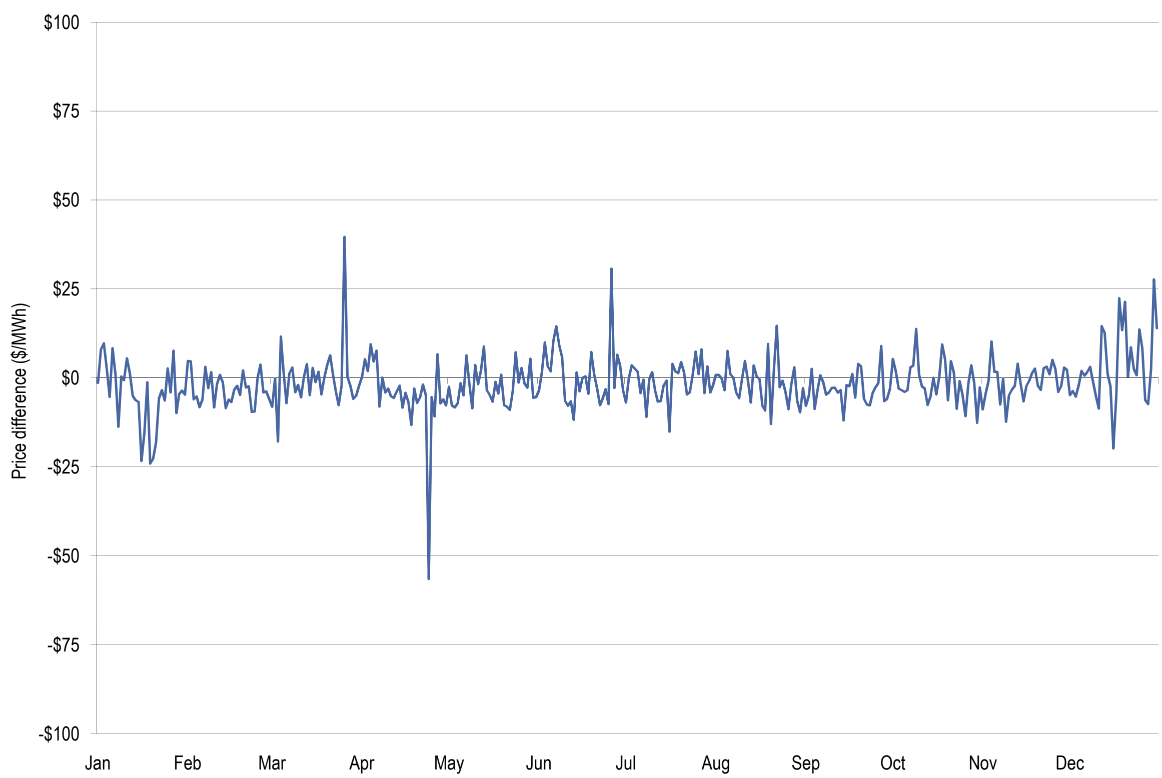
PJM's price for transactions with the NYISO (excluding those transactions across the Neptune and Linden lines), termed the NYIS Interface pricing point by PJM, represents the value of power at the PJM/NYISO border, as determined by the PJM market. PJM defines its NYIS Interface pricing point using two buses.[38] Similarly, the NYISO's price for transactions with PJM, termed the PJM proxy bus by the NYISO, represents the value of power at the NYISO/PJM border, as determined

38 See PJM. "LMP Aggregate Definitions" (December 18, 2008) (Accessed January 15, 2010) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (1,369 KB). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

by the NYISO market. In the NYISO market, transactions are required to have a price associated with them. Import transactions are treated as generator offers at the NYISO/PJM proxy bus. Export transactions are treated as load bids. Competing bids and offers are evaluated along with the other NYISO resources and a proxy bus price is derived.

The 2009 real-time hourly average PJM/NYIS Interface price and the NYISO/PJM proxy bus price were $37.37 and $39.16. The simple average difference between the PJM/NYIS Interface price and the NYISO/PJM proxy bus price increased from $0.86 per MWh in 2008 to $1.79 per MWh in 2009 (See Figure 4-9.) PJM's net export volume to the NYIS Interface for 2009 was significantly higher than in 2008. This is consistent with the fact that the PJM/NYIS price was, on average, lower than the NYISO/PJM price in 2009.

Figure 4-9 Real-time daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2009



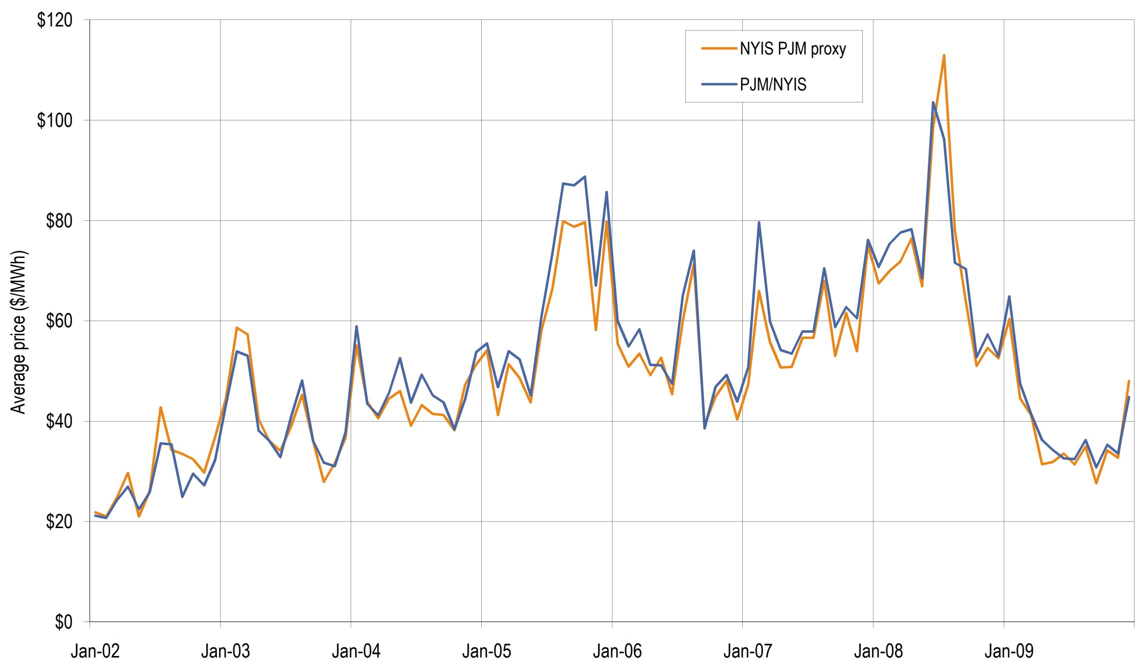
The simple average interface price difference does not reflect the underlying hourly variability in prices. There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences.

The difference between the real-time PJM/NYIS Interface price and the real-time NYISO/PJM proxy bus price continued to fluctuate between positive and negative about eight times per day during 2009 as it has since 2003. The standard deviation of hourly price was $18.69 in 2009 for the PJM/NYIS Interface price and $27.37 in 2009 for the NYISO/PJM proxy bus price. The standard deviation of the difference in interface prices was $25.80 in 2009. The average of the absolute value of the hourly price difference was $11.58 in 2009. Absolute values reflect price differences without regard to whether they are positive or negative.

A number of factors are responsible for the observed relationship between interface prices. The fact that the simple average of interface price differences is relatively small suggests that competitive forces prevent price deviations from persisting. That is further supported by the frequency with which the price differential switches between positive and negative. However, continuing significant variability in interface prices is consistent with the fact that interface prices are defined and established differently, making it difficult for prices to equalize, regardless of other factors.

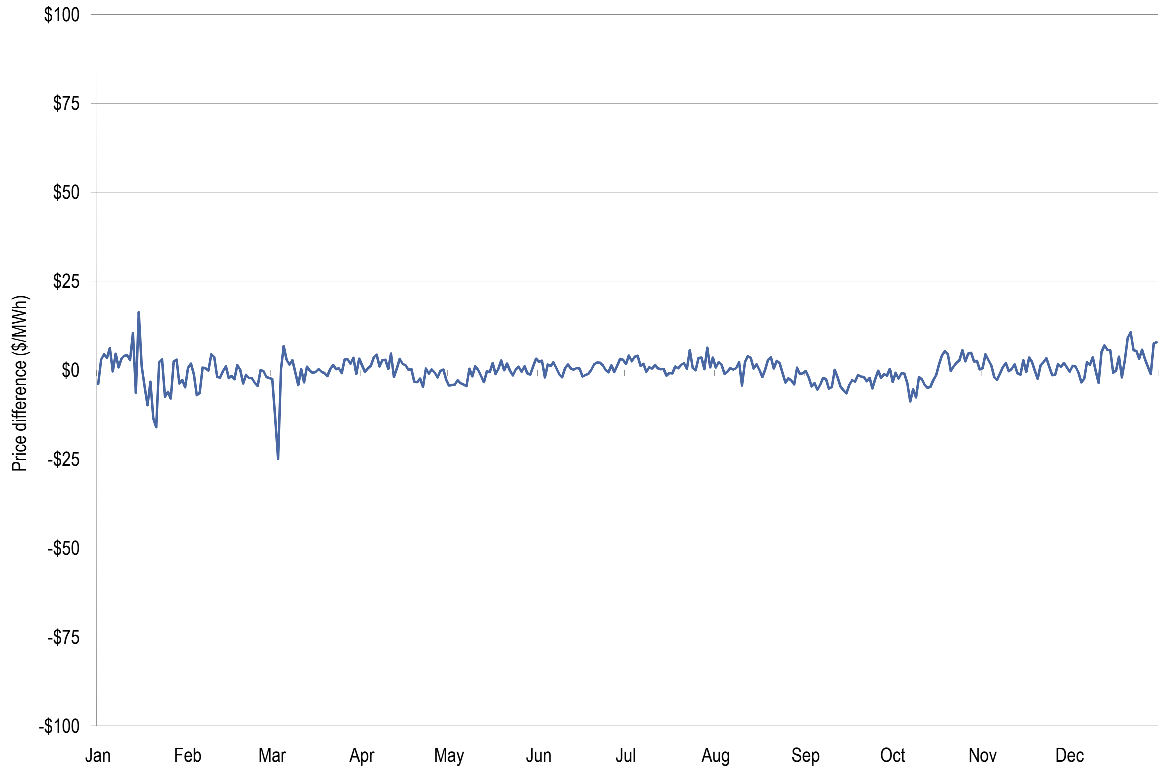
There has been a significant correlation between real-time monthly average hourly PJM/NYIS Interface and NYISO's PJM proxy bus prices during the entire period 2002 to 2009. (See Figure 4-10.)

Figure 4-10 Real-time monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: January 2002 through December 2009



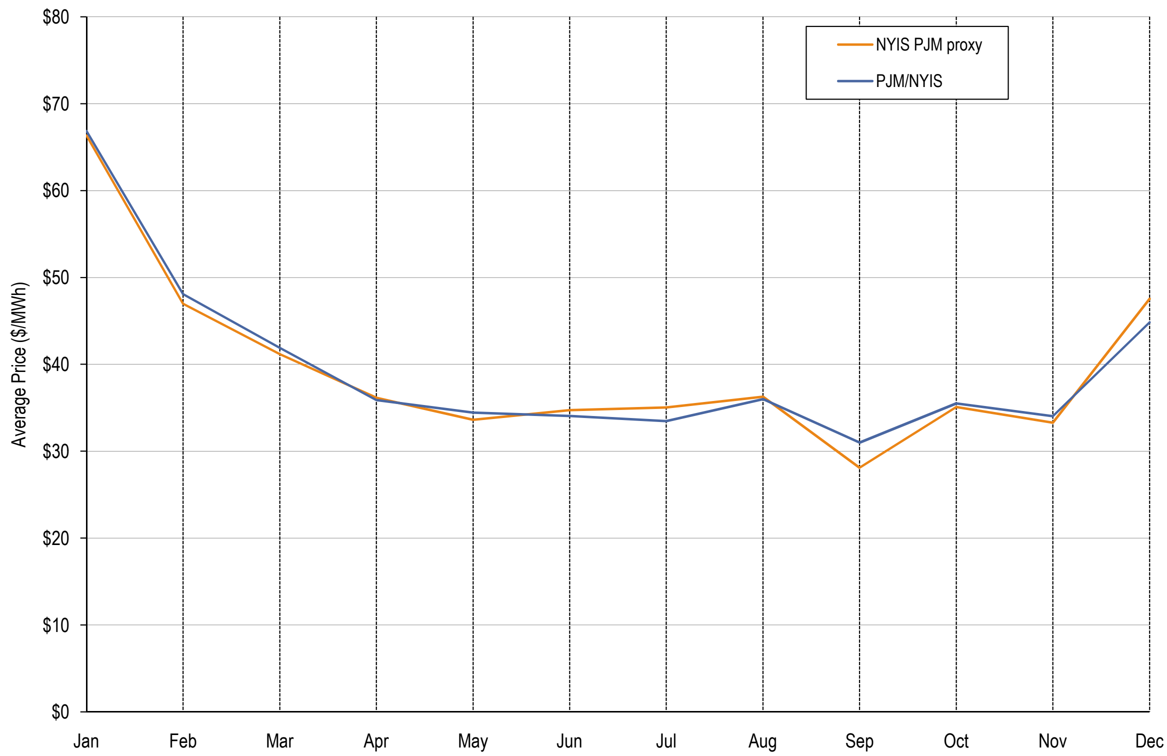
The 2009 day-ahead hourly average PJM/NYIS Interface price and the NYISO/PJM proxy bus price were $39.53 and $39.66. The simple average difference between the day-ahead PJM/NYISO Interface price and the NYISO/PJM proxy bus price decreased from $2.79 in 2008 to $0.13 in 2009. (See Figure 4-11.) The day-ahead net gross exports to the NYISO decreased from 6,500.0 GWh in 2008 to 5,806.6 GWh in 2009.

Figure 4-11 Day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): Calendar year 2009



There has been a significant correlation between day-ahead monthly average hourly PJM/NYIS Interface and NYISO's PJM proxy bus prices during 2009. (See Figure 4-12.)

Figure 4-12 Day-ahead monthly hourly average NYISO/PJM proxy bus price and the PJM/NYIS price: Calendar year 2009



Summary of Interface Prices between PJM and Organized Markets

The key features of the real-time and day-ahead PJM interface pricing with the Midwest ISO and with the NYISO are summarized and compared in Figure 4-13 and Figure 4-14 including average prices and measures of variability.

Figure 4-13 PJM, NYISO and Midwest ISO real-time border price averages: Calendar year 2009

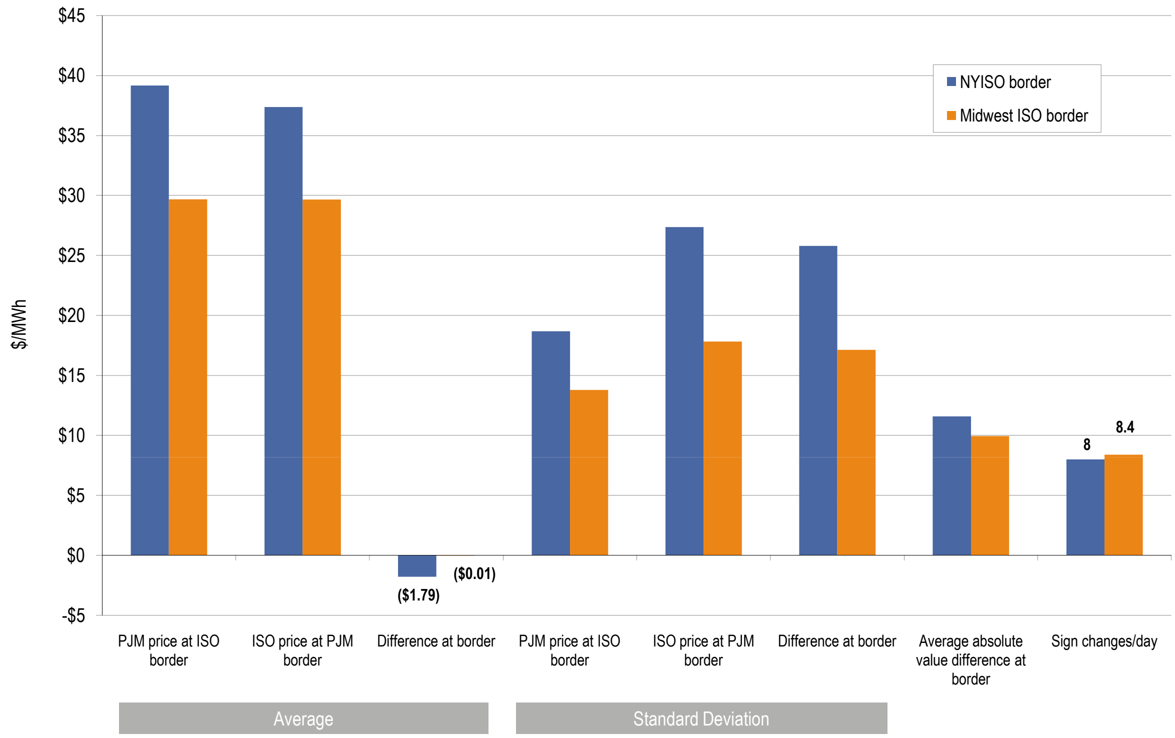
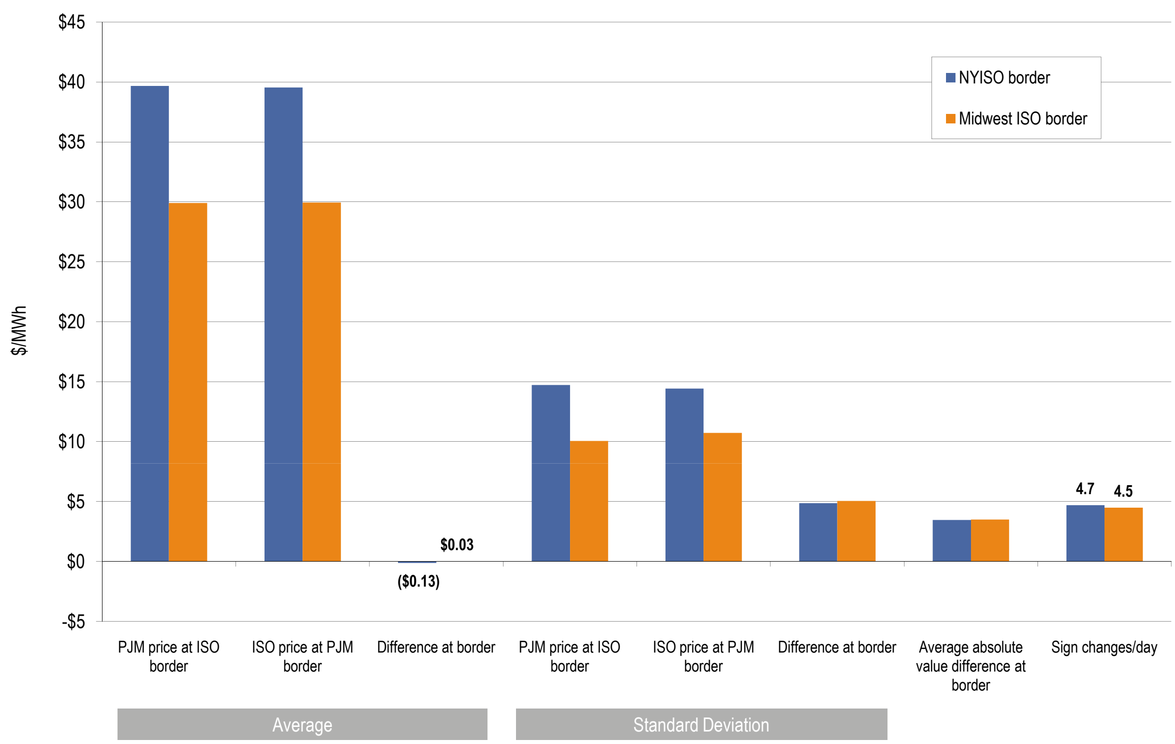


Figure 4-14 PJM, NYISO and Midwest ISO day-ahead border price averages: Calendar year 2009



Operating Agreements with Bordering Areas

To improve reliability and reduce potential competitive seams issues, PJM and its neighbors have developed, and continue to work on, joint operating agreements. These agreements are in various stages of development and include a reliability agreement with the NYISO, an implemented operating agreement with the Midwest ISO, an implemented reliability agreement with TVA, an operating agreement with Progress Energy Carolinas, Inc., that is not yet fully implemented, and a reliability coordination agreement with VACAR South.

PJM and New York Independent System Operator Joint Operating Agreement (JOA)

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." [39] After working in collaboration with PJM, the Midwest ISO and the 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.*[40] The MMU filed comments on November 13, 2009.[41]

PJM and Midwest ISO Joint Operating Agreement

The market to market coordination between PJM and the Midwest ISO continued in 2009. Under the market to market rules, the organizations coordinate pricing at their borders. PJM and the Midwest ISO each calculate an LMP for its interface with the other organization. Both entities calculate LMPs using network models including distribution factor impacts. PJM uses nine buses within the Midwest ISO to calculate the PJM/MISO Interface pricing point LMP while the Midwest ISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM Interface pricing point.

In 2009, the Midwest ISO requested that PJM review the components of the Congestion Management Process (CMP) to verify data accuracy. During this review, it was found that some data inputs to the market flow calculator were incorrect during the 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.[42]

39 128 FERC ¶61,049 (Ordering Para. B), *order on clarification*, 128 FERC ¶61,239.

40 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).

41 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).

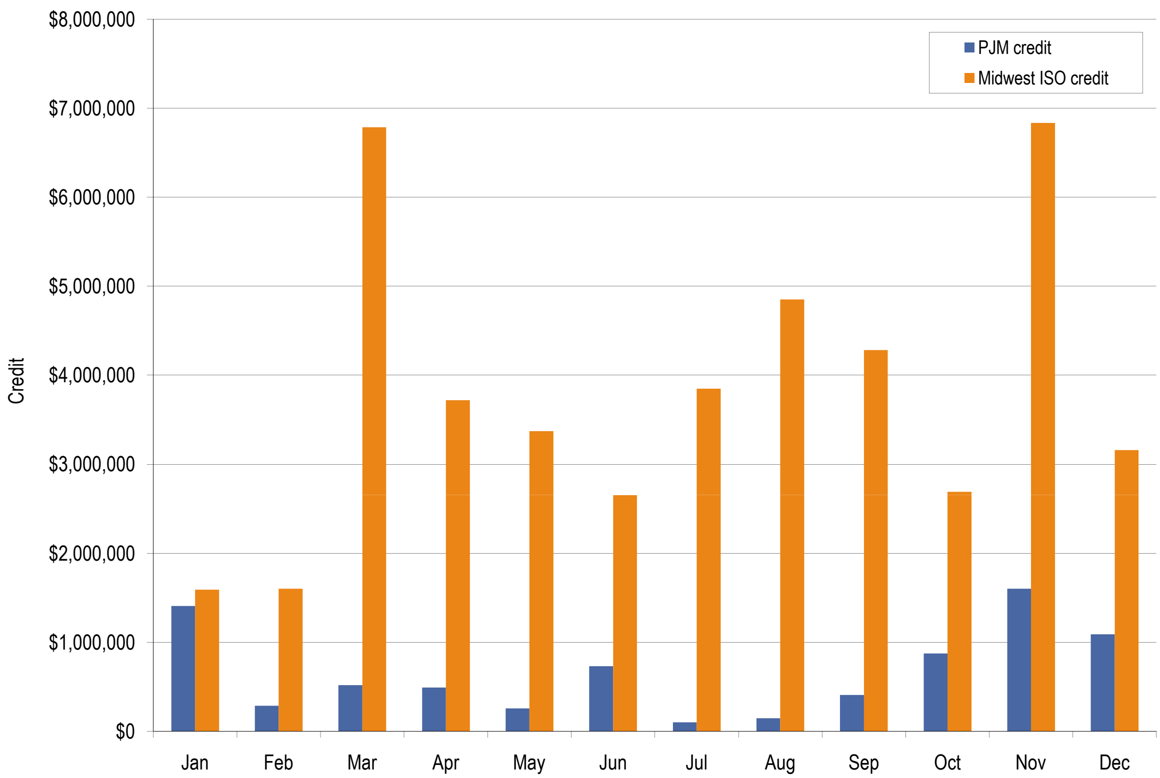
42 See PJM. "PJM/MISO Market Flow Calculation Error" (September 10, 2009) (Accessed January 15, 2010) <http://www.pjm.com/committees-and-groups/committees/~/media/committees-groups/committees/mic/20090910/20090910-item-07-m2m-calculation-error.ashx> (49 KB).

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.

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.

The market to market operations resulted both in the Midwest ISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. The Firm Flow Entitlement (FFE) represents the amount of historic flow that each RTO had created on each reciprocal coordinated flowgate (RCF) used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the non-monitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the non-monitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the non-monitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the non-monitoring RTO for congestion relief provided by the non-monitoring RTO based on the difference between the non-monitoring RTO's market flow and their FFE. Figure 4-15 presents the monthly credits each organization received from redispatching for the other. A PJM credit is a payment by the Midwest ISO to PJM and a Midwest ISO credit is a payment by PJM to the Midwest ISO. The largest payments from PJM to the Midwest ISO during 2009 were the result of redispatch by the Midwest ISO to relieve congestion on the Crete-St Johns Tap 345 kV for the loss of Dumont-Wilton Center 765 kV line. Total PJM payments to the Midwest ISO were $45.4 million, a 23 percent decrease from the 2008 level. The largest payments from the Midwest ISO to PJM during 2009 were the result of redispatch by PJM to relieve congestion on the Paddock-Townline 138 for the loss of Paddock-Blackhawk 138 line. Total Midwest ISO payments to PJM were $7.9 million, a 40 percent decrease from the 2008 level.

Figure 4-15 Credits for coordinated congestion management: Calendar year 2009



PJM, Midwest ISO and TVA Joint Reliability Coordination Agreement (JRCA)

The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management and congestion relief among the wholesale electricity markets of the Midwest ISO and PJM and the service territory of TVA. The agreement continued to be in effect during 2009. Information-sharing among the parties enables each transmission provider to recognize and manage the effects of its operations on the adjoining systems. Additionally, the three organizations conduct joint planning sessions to ensure that improvements to their integrated systems are undertaken in a cost-effective manner and without adverse reliability impacts on any organization's customers.

PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement

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 remains in effect. Since PEC is not a market system, the coordination agreement between PEC and PJM is similar to the agreement that existed between the Midwest ISO and PJM during the first phase of their JOA. The ATC coordination that had been expected to be completed during the first half of 2006 remained under development during 2009. PJM and Progress continued to develop the congestion management process as required by the agreement. A phased approach to development of congestion management is being discussed.

PJM and VACAR South Reliability Coordination Agreement

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), PEC, South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (a part of Alcoa)) entered into a reliability coordination agreement. This agreement was developed to augment and further support reliability. It provides for system and outage coordination, emergency procedures and the exchange of data. This arrangement permits each party to coordinate its plans and operations in the interest of reliability. Provisions are also made for making regional studies and recommendations to improve the reliability of the interconnected bulk power systems. The agreement remained in effect through 2009.

Other Agreements with Bordering Areas

Con Edison and PSE&G Wheeling Contracts

To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using lines controlled by the NYISO. Another path is through northern New Jersey using lines controlled by PJM. This wheeled power creates loop flow across the PJM system. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001. In May 2005, the FERC issued an order setting out a protocol developed by the two companies, PJM and the NYISO.[43] In July 2005, the protocol was implemented. Con Edison filed a protest with the FERC regarding the delivery performance in January 2006.[44] In August 2007, the FERC denied a rehearing request on Con Edison's complaints regarding protocol performance and refunds.[45] PJM continued to operate under the terms of the protocol through 2009.

The contracts provide for the delivery of up to 1,000 MW of power from Con Edison's Ramapo Substation in Rockland County, New York, to PSE&G at its Waldwick Switching Substation in Bergen County, New Jersey. PSE&G wheels the power across its system and delivers it to Con Edison across lines connecting directly into New York City. Two separate contracts cover these wheeling arrangements. A 1975 agreement covers delivery of up to 400 MW through Ramapo (New York) to PSE&G's Waldwick Switching Station (New Jersey) then to the New Milford Switching Station (New Jersey) via the J line and ultimately from the Linden Switching Station (New Jersey) to the Goethals Substation (New York) and from the Hudson Generating Station (New Jersey) to the Farragut Switching Station (New York), via the A and B feeders, respectively. A 1978 agreement covers delivery of up to an additional 600 MW through Ramapo to Waldwick then to Fair Lawn, via the K line, and ultimately through a second Hudson-to-Farragut line, the C feeder. In 2001, Con Edison alleged that PSE&G had under delivered on the agreements and asked the FERC to resolve the issue.

The protocol allows Con Edison to elect up to the flow specified in each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service but less than firm service. These elections obligate PSE&G to pay congestion

43 111 FERC ¶61,228 (2005).
44 Protest of the Consolidated Edison Company of New York, Inc., Protest, Docket No. EL02-23 (January 30, 2006).
45 FERC Order Denying Rehearing, Order, Docket No. EL02-23 (August 15, 2007).

costs associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract. The interface prices for this transaction are not defined PJM interface prices, but are defined in the protocol based on the actual facilities governed by the protocol.

Under the FERC order, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2009, PSE&G's revenues were less than its congestion charges by $5,417 after adjustments. (Revenues exceeded its charges by $13,768 in 2008.) Under the FERC order, Con Edison receives credits on an hourly basis for its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In 2009, Con Edison's congestion credits were $232,744 less than its day-ahead congestion charges. Con Edison also had a day-ahead congestion credit. With appropriate adjustments accounted for, the result was that Con Edison's total charges exceeded its congestion credits by $251,102. (Credits had been $213,535 less than charges in 2008.) (See Table 4-11.)

In effect, Con Edison has been given congestion credits that are the equivalent of a class of FTRs covering positive congestion with subordinated rights to revenue. However, Con Edison is not treated as having an FTR when congestion is negative. An FTR holder in that position would pay the negative congestion credits, but Con Edison does not. The protocol's provisions about congestion payments clearly cover congestion charges and offsetting congestion credits, but are not explicit on the treatment of Con Edison's negative congestion credits, which were -$251,102 in 2009. The parties should address this issue.

Table 4-11 Con Edison and PSE&G wheeling settlement data: Calendar year 2009

	Con Edison			PSE&G		
	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Total Congestion Credit	$1,488,379	$894	$1,489,274	$4,119,216	$0	$4,119,216
Congestion Credit			$1,255,635			$4,099,812
Adjustments			$484,741			$13,987
Net Charge			($251,102)			$5,417

Under the terms of the protocol, Con Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits. This occurred in 2 percent of the hours in 2009.

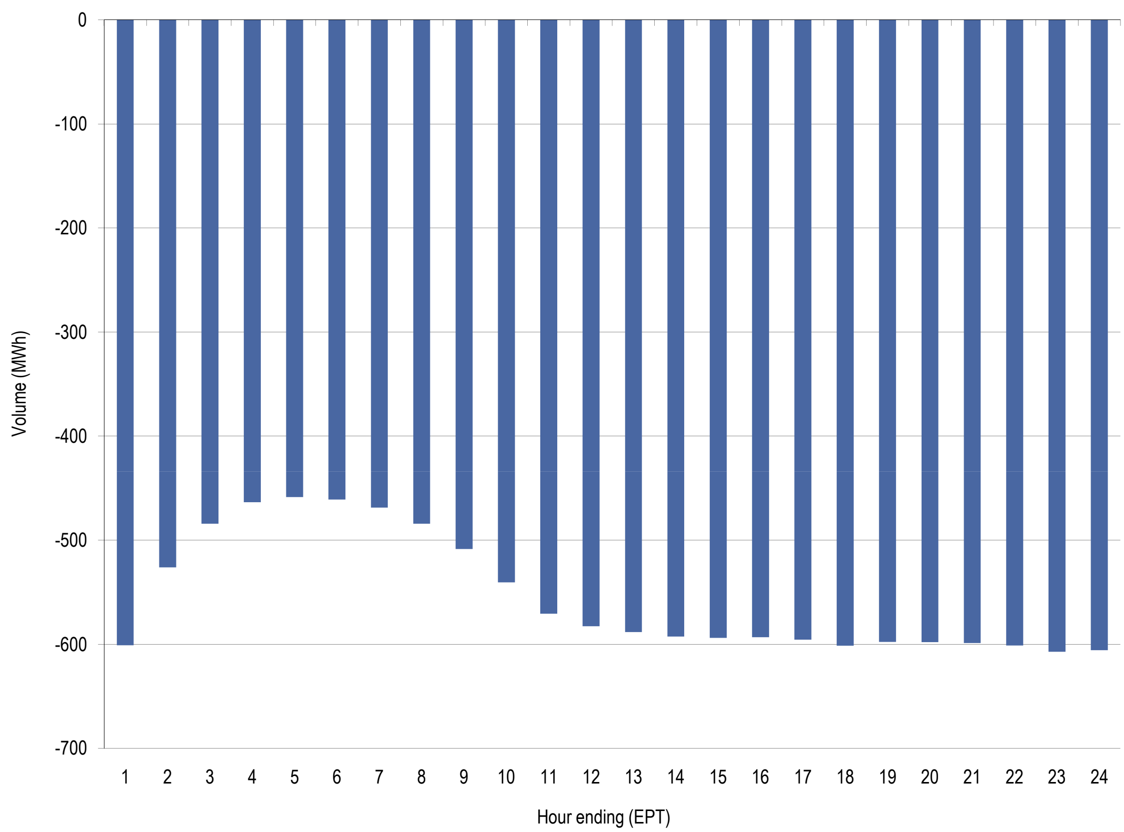
Neptune Underwater Transmission Line to Long Island, New York

On July 1, 2007, a 65-mile, DC transmission line from Sayreville, New Jersey, to Nassau County on Long Island via undersea and underground cable was placed in service, providing an additional connection between PJM and the NYISO. This is a merchant 230 kV transmission line with a capacity of 660 MW. While the Neptune line is a bidirectional facility, Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York.[46] For 2009, the total real-time scheduled net exports on the Neptune line were 4,961 GWh while the day-ahead scheduled net exports were 5,064 GWh. Figure 4-16 shows the average flow, by hour of the day, on the Neptune line for the calendar year 2009. The average hourly flow during 2009 was -555 MWh. For the calendar year 2009, the average hourly PJM/NEPT Interface price was $41.94

46 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).

per MWh, while in the NYISO the Neptune bus average price was $49.24 per MWh. Although the yearly average interface price differentials are consistent with flows from PJM to the NYISO, the PJM/NYIS Interface price was lower than the NYISO Neptune bus price in 37.0 percent of the hours in 2009.

Figure 4-16 Neptune hourly average flow: Calendar year 2009

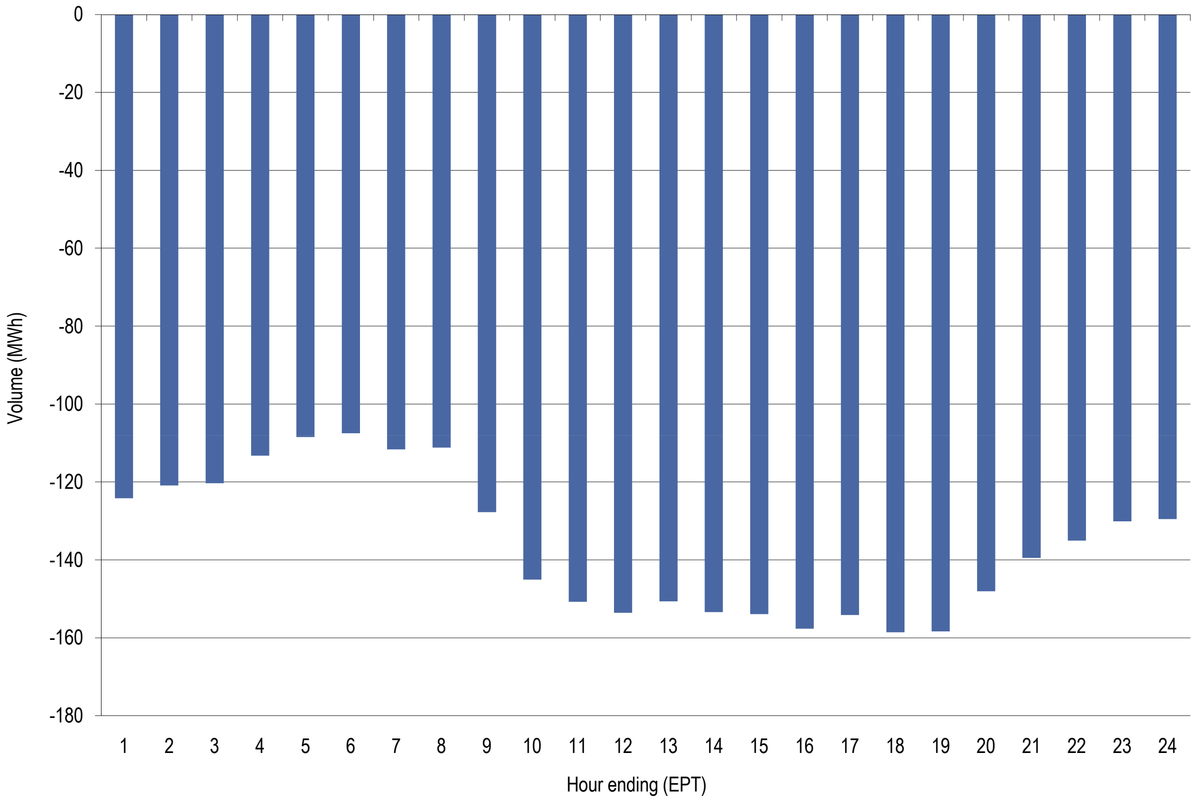


Linden Variable Frequency Transformer (VFT) facility

On November 1, 2009, the Linden VFT facility was placed in service, providing an additional connection between PJM and the NYISO. A variable frequency transformer is a technology which allows for fast responding continuous bidirectional power flow control, similar to that of a PAR. 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.[47] Figure 4-17 shows the average flow, by hour of the day, on the Linden line for the calendar year 2009. The average hourly flow during 2009 was -136 MWh.[48] For the calendar year 2009, the average hourly PJM/LIND Interface price was $38.19 per MWh, while in the NYISO the Linden VFT bus average price was $43.22 per MWh. Although the yearly average interface price differentials are consistent with flows from PJM to the NYISO, the PJM/LIND Interface price was lower than the NYISO Linden VFT bus price in 40.1 percent of the hours in 2009.

47 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).
48 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.

Figure 4-17 Linden hourly average flow: September through December 2009



Interchange Transaction Issues

Loop Flows

Actual flows are the metered flows at an interface for a defined period. Scheduled flows are the flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (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.

Loop flow can arise from transactions scheduled into, out of or around the PJM system 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 exist as a result of transactions within a market based area in the absence of an explicit agreement to price congestion. Loop flows exist because electricity flows on the path of least resistance regardless of the path specified by contractual agreement or regulatory prescription. PJM manages loop flow using a combination of interface price signals, redispatch and TLR procedures.

Loop flows are a significant concern. Loop flows can 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.

The fact that total PJM net actual interface flows were close to net scheduled interface flows, on average for 2009 as a whole, is not a useful measure of loop flow. There were significant differences between scheduled and actual flows for specific individual interfaces. (See Table 4-12.) From an operating perspective, PJM tries to balance overall actual and scheduled interchange, but does not have a mechanism to control the balance between actual and scheduled interchange at individual interfaces because there are free flowing ties with contiguous balancing authorities.

During 2009, for PJM as a whole, net scheduled and actual interchange differed by 2.2 percent. (See Table 4-12.) Actual system net imports were 274 GWh, 6 GWh more than the scheduled total net imports of 268 GWh. Flow balance varied at each individual interface. The PJM/MECS Interface was the most imbalanced, with net actual exports of 10,821 GWh exceeding scheduled imports of 3,620 GWh by 14,441 GWh or 399 percent, an average of 1,649 MW during each hour of the year. At the PJM/CPLE Interface, scheduled flows were exports of 747 GWh and actual flows were imports of 7,664 GWh, creating an imbalance of 8,411 GWh or 1126 percent, an average of 960 MW during each hour of the year.

Table 4-12 Net scheduled and actual PJM interface flows (GWh): Calendar year 2009

	Actual	Net Scheduled	Difference (GWh)	Difference (percent of net scheduled)
CPLE	7,664	(747)	8,411	(1126%)
CPLW	(1,793)	(683)	(1,110)	163%
DUK	(2,728)	398	(3,126)	(785%)
EKPC	550	(674)	1,224	(182%)
LGEE	1,377	1,016	361	36%
MEC	(2,667)	(1,606)	(1,061)	66%
MISO	(6,291)	901	(7,192)	(798%)
ALTE	(5,561)	(760)	(4,801)	632%
ALTW	(2,370)	(1,128)	(1,242)	110%
AMIL	8,198	83	8,115	9777%
CIN	3,117	2,055	1,062	52%
CWLP	(560)	-	(560)	0%
FE	(1,981)	(2,418)	437	(18%)
IPL	2,441	166	2,275	1370%
MECS	(10,821)	3,620	(14,441)	(399%)
NIPS	(2,149)	(342)	(1,807)	528%
WEC	3,395	(375)	3,770	(1005%)
NYISO	(8,331)	(11,035)	2,704	(25%)
LIND	(349)	(349)	-	0%
NEPT	(4,863)	(4,863)	-	0%
NYIS	(3,119)	(5,823)	2,704	(46%)
OVEC	8,493	12,538	(4,045)	(32%)
TVA	4,000	160	3,840	2400%
Total	274	268	6	2.2%

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

Figure 4-18 and Figure 4-19 illustrate the reduction in the previously persistent difference between scheduled and actual power flows at PJM's southern interfaces (PJM/TVA and PJM/EKPC to the west and PJM/CPLE, PJM/CPLW and PJM/DUK to the east) that grew to its largest volumes through the summer of 2006. 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 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.

Despite some improvements, significant loop flows persist. While the SouthIMP and SouthEXP pricing points have replaced the Southeast and Southwest pricing points Figure 4-18 and Figure 4-19 are included for comparison.

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 incur 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).

Figure 4-18 Southwest actual and scheduled flows: January 2006 through December 2009

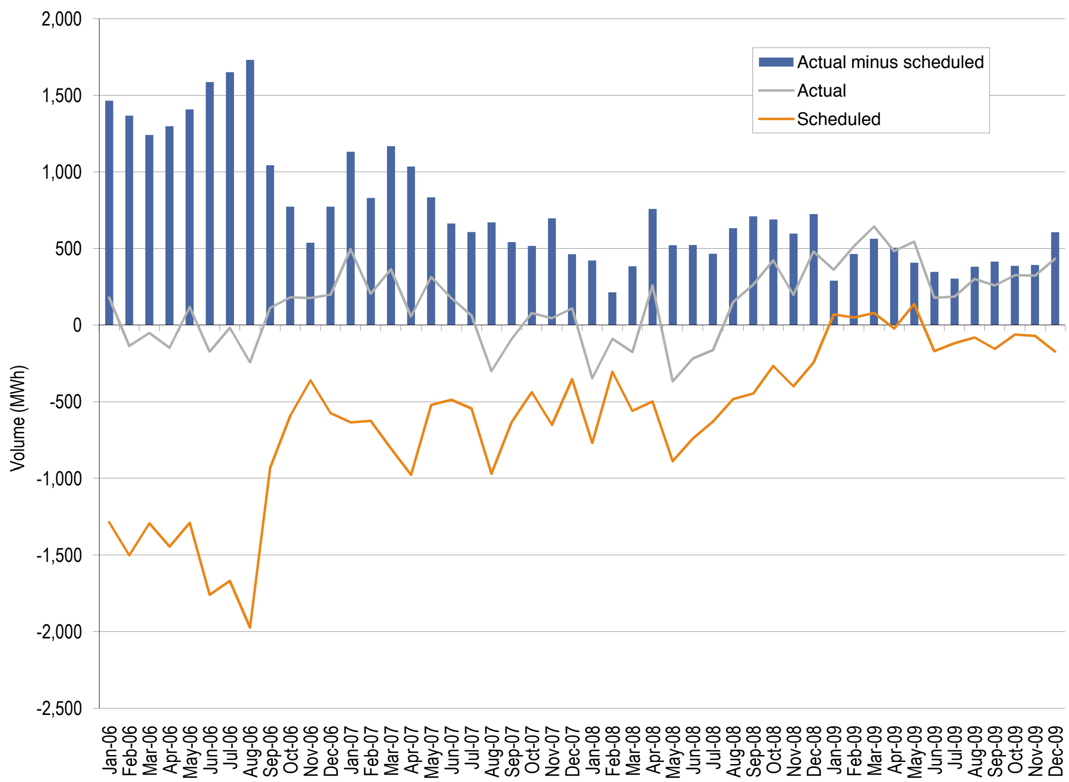
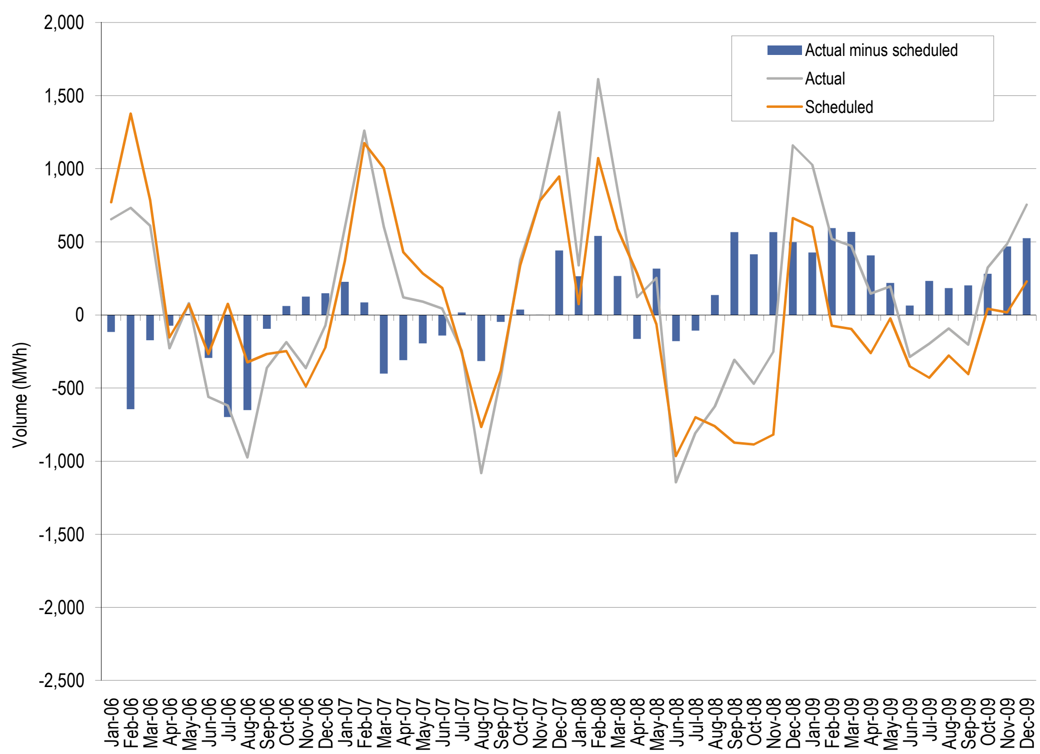


Figure 4-19 Southeast actual and scheduled flows: January 2006 through December 2009



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.[49] 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 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."[50]

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.[51]

The group developed several recommendations, including the use of PARs to control energy flows, a buy-through congestion methodology, the development of a new tool, using existing functionality within NERCs Interchange Distribution Calculator (IDC), to visualize the loop flows and an interregional transaction coordination approach to align business rules across the northeast ISOs/RTOs. On January 12, 2010, in compliance with the Commission's directive, the NYISO submitted its *Report on Broader Regional Markets; Long-Term Solutions to Lake Erie Loop Flow.*[52]

Engineering approaches to address loop flows, such as phase angle regulators 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 to 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 will be allowed to continue to flow their transactions when they would otherwise be curtailed by a TLR, if they were 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.

49 See the *2008 State of the Market Report for PJM*, Volume II, "Section 4, Interchange Transactions"

50 128 FERC ¶61,049 (Ordering Para. B), *order on clarification*, 128 FERC ¶61,239.

51 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).

52 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 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 NERC/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.

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 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 can 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 could provide additional insight that could lead to enhanced overall market efficiency and clarify the interactions 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 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.

- **NERC Tag Data**

  An analysis of loop flow requires knowledge of the scheduled path of energy transactions. NERC Tag Data includes the scheduled path and energy profile of the transactions, including the Generation Control Area (GCA), the intermediate Control Areas, the Load Control Area (LCA) and the energy profile of all transactions. Additionally, complete tag data include the identity of the specific market participants.

  Currently, the MMU has obtained some NERC Tag data via a set of “Tag Dump” files. The existing Tag Dump files include many data items from the overall NERC Tag data. Included in each file are the following data items: Tag Name, Tag Start Date/Time, Tag End Date/Time, Source Security Coordinator, Sink Security Coordinator, Source Control Area, Sink Control Area, Source, sink, Transmission Start Date/Time, Transmission End Date/Time, Transmission Provider Name, Priority, Transmission Product, OASIS Reservation, MW, Point of Receipt, Point of Delivery, Energy Start Date/Time, Energy End Data/Time, Schedule MW and Active MW. Each tag dump file is created hourly, and is in csv format. The files include active tags from the hour in which the data is created and for the next 24 hours.

  The Tag Dump files do not include the following data items: tag type, complete market path, miscellaneous information (token and value fields), tag creation timing, approval timing, denial reasons, denied tags, curtailment reasons, loss provision information, individual request information, and other data items including contact information.

Of the data items not included in the Tag Dump files, the most important elements required for loop flow analysis are the complete market path and the loss provision information. These data items would complete the picture of the scheduled interchange among all balancing authorities.

- **Dynamic Schedule and Pseudo-Tie Data**

  Dynamic schedule and pseudo ties represent another type of interchange transaction between balancing authorities. While dynamic schedules are required to be tagged, the tagged profile is only an estimate of what energy is expected to flow. Dynamic schedules are implemented within each balancing authority's Energy Management System (EMS), with the current values shared over Inter-Control Center Protocol (ICCP) links. By definition, the dynamic schedule scheduled and actual values will always be identical from a balancing authority standpoint, and the tagged profile should be removed from the calculation of loop flows to eliminate double counting of the energy profile. Dynamic schedule data from all balancing authorities are required in order to account for all scheduled and actual flows.

  Pseudo-ties are similar to dynamic schedules in that they represent a transaction between balancing authorities and are handled within the EMS systems and data are shared over the ICCP. Pseudo-ties only differ from dynamic schedules in how the generating resource is modeled within the balancing authorities' ACE equations. Dynamic schedules are modeled as resources located in one area serving load in another, while pseudo-ties are modeled as resources in one area moved to another area. Unlike dynamic schedules, pseudo-tie transactions are not required to be tagged. Pseudo-tie data from all balancing authorities are required in order to account for all scheduled and actual flows.

- **Actual Tie Line Flow Data**

  An analysis of loop flow requires knowledge of the actual path of energy transactions. Currently, a very limited set of tie line data is made available via the NERC IDC and the Central Repository for Curtailments (CRC) website. Additionally, the available tie line data, and the data within the IDC, are presented as information on a screen, which does not permit analysis of the underlying data.

- **Area Control Error (ACE) Data**

  Area Control Error (ACE) data provides information about how well each balancing authority is matching their generation with their load. This information, combined with the scheduled and actual interchange values will show whether an individual balancing authority is pushing on or leaning on the interconnection, contributing to loop flows.

  NERC makes real-time ACE graphs available on their Reliability Coordinator Information System (RCIS) website. This information is presented only in graphical form, and the underlying data is not available for analysis.

- **Market Flow Impact Data**

In addition to interchange transactions, internal dispatch can also affect flows on balancing authorities' tie lines. The impact of internal dispatch on tie lines is called market flow. Market flow data are imported in the IDC, but there is only limited historical data, as only market flow data related to TLR levels 3 or higher are required to be made available via a Congestion Management Report (CMR). The remaining data are deleted.

There is currently a project in development through the NERC Operating Reliability Subcommittee (ORS) called the Market Flow Impact Tool. The purpose of this tool is to make visible the impacts of dispatch on loop flows. The MMU supports the development of this tool, and requests that FERC and NERC ensure that the underlying data are provided in a downloadable format to market monitors and other approved entities.

- **Generation and Load Data**

  Generation data (both real-time scheduled generation and actual output) and load data would permit analysis of the extent to which balancing authorities (or individual generation owners) are meeting their commitments to serve load. If a balancing authority is not meeting its load commitment with adequate generation, the result is unscheduled flows across the interconnections to establish power balance.

  Market areas are transparent in providing real-time load while non market areas are not. For example, PJM posts real-time load via its eDATA application. Most non market balancing authorities provide only the expected peak load on their individual web sites. Data on generation are not made publicly available, as this is considered market sensitive information.

The MMU requests that, in order to permit a complete analysis of loop flow, FERC and NERC ensure that the identified data are made available to market monitors as well as other industry entities determined appropriate by FERC. The MMU has been attempting to obtain access to this data for several years without success. Attempts to obtain the data from NERC or tagging vendors have led to denials or to the option of very expensive subscriptions that would still require obtaining approval from every entity registered in the NERC Transmission System Information Network (TSIN) due to data confidentiality agreements, including Transmission Providers and Market Participants.

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.[53] 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

53 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).

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.

TLRs

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

PJM called fewer TLRs in 2009 than in 2008. One reason for the decrease in TLR activity in 2009 was the result of transmission line outages caused by storms and tornados in 2008. The transmission line outages in 2008 reduced the ability to control power flows via redispatch, creating the need to utilize TLRs more often in 2008. Additionally, the lighter loads seen in 2009, as compared to 2008, likely contributed to a decrease in TLR activity. PJM TLRs decreased by 14 percent, from 150 during 2008 to 129 in 2009. (See Figure 0-20.) In addition, the number of different flowgates for which PJM declared TLRs decreased from 37 during 2008 to 28 in 2009. (See Figure 0-21.) The total MWh of transaction curtailments increased by 80 percent, from 506,617 MWh in 2008 to 912,528 MWh in 2009. (See Figure 0-22.) Of the 129 TLRs called by PJM in 2009, two facilities comprised 53 percent of the total. The two facilities were:

- **15502 Nels-Electric Junction for 15616 Cher-Silv Line.** This line is located in northern Illinois.[54] TLRs were used to control the constraints (41 TLRs in 2009; 11 TLRs in 2008);

- **East Frankfort – Crete 345 kV Line for Loss of Dumont – Wilton Center 765 kV Line.** These lines are located in northern Illinois, close to the border of Indiana. TLRs on this flowgate were generally utilized to control flows across the Illinois-Indiana border through the Northern Indiana Public Service system. While PJM and the Midwest ISO work together to control these flows using the mechanisms prescribed in the JOA, the actions were not always sufficient. This flowgate resulted in the largest amount of market to market settlements in 2009. TLRs on this flowgate were used to control the constraints (28 TLRs in 2009; 35 TLRs in 2008).

The Midwest ISO called significantly fewer TLRs in 2009 than in 2008. The Midwest ISO TLRs decreased by about 36 percent, from 599 during 2008 to 381 in 2009. (See Figure 4-20.)

54 The reasons for the high levels of TLRs on this flowgate are considered confidential.

Figure 4-20 PJM and Midwest ISO TLR procedures: Calendar years 2008 and 2009

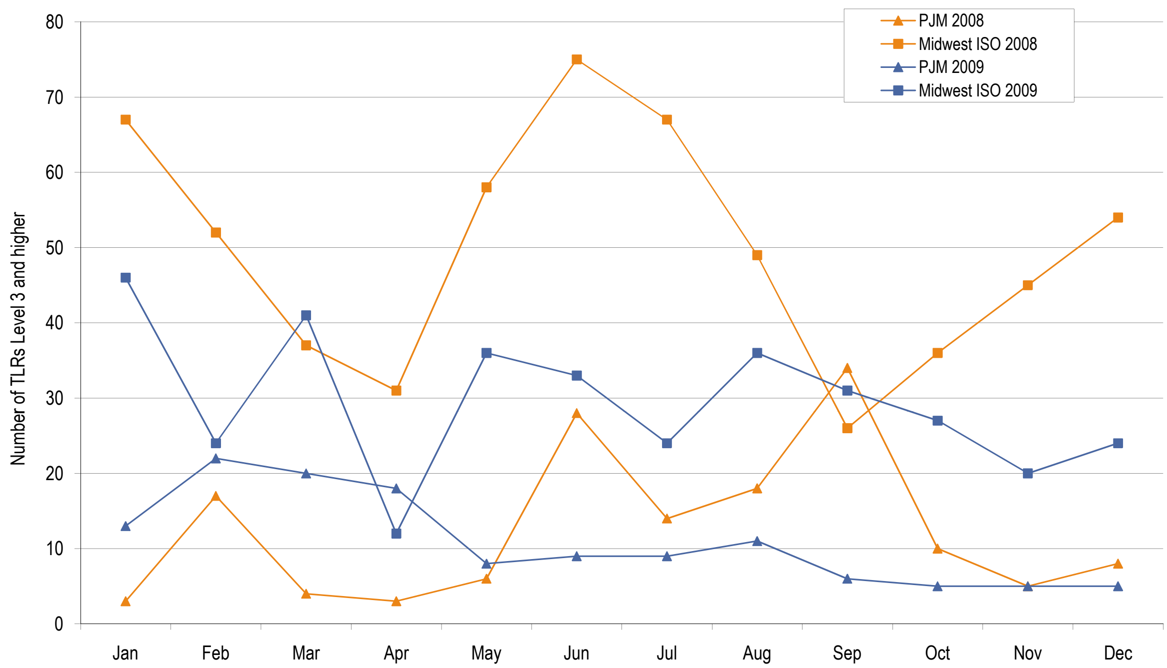


Figure 4-21 Number of different PJM flowgates that experienced TLRs: Calendar years 2008 and 2009

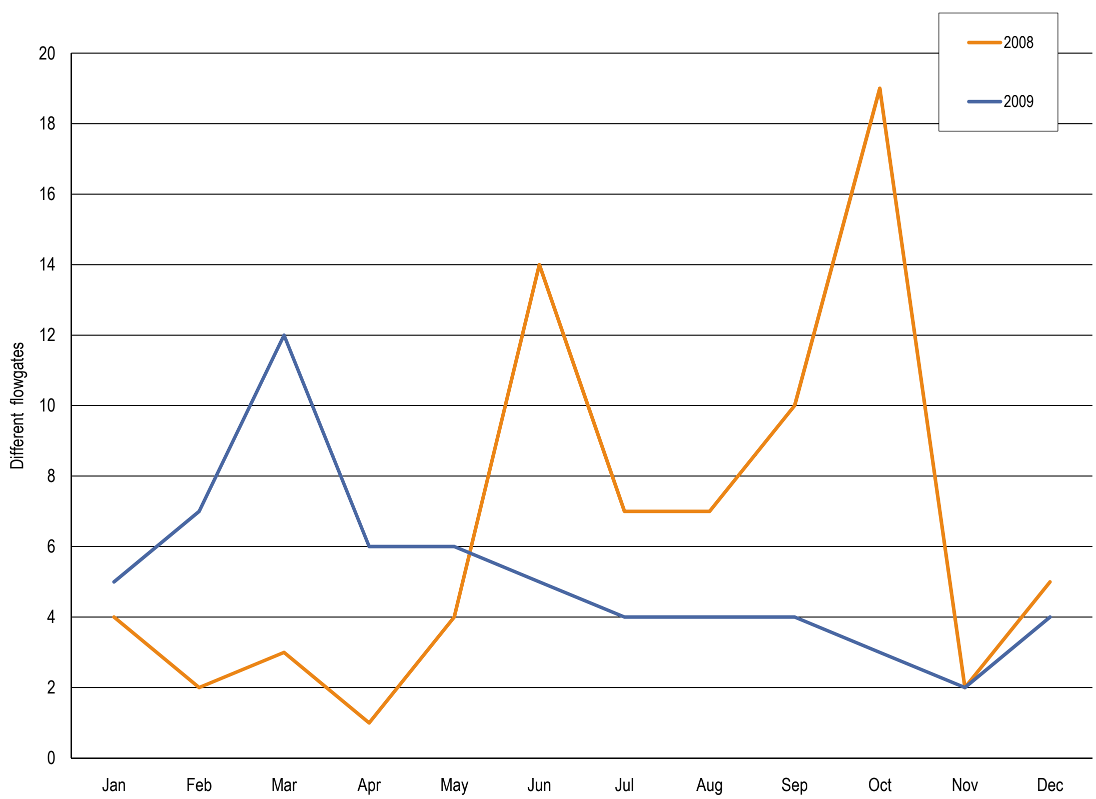


Figure 4-22 Number of PJM TLRs and curtailed volume: Calendar year 2009

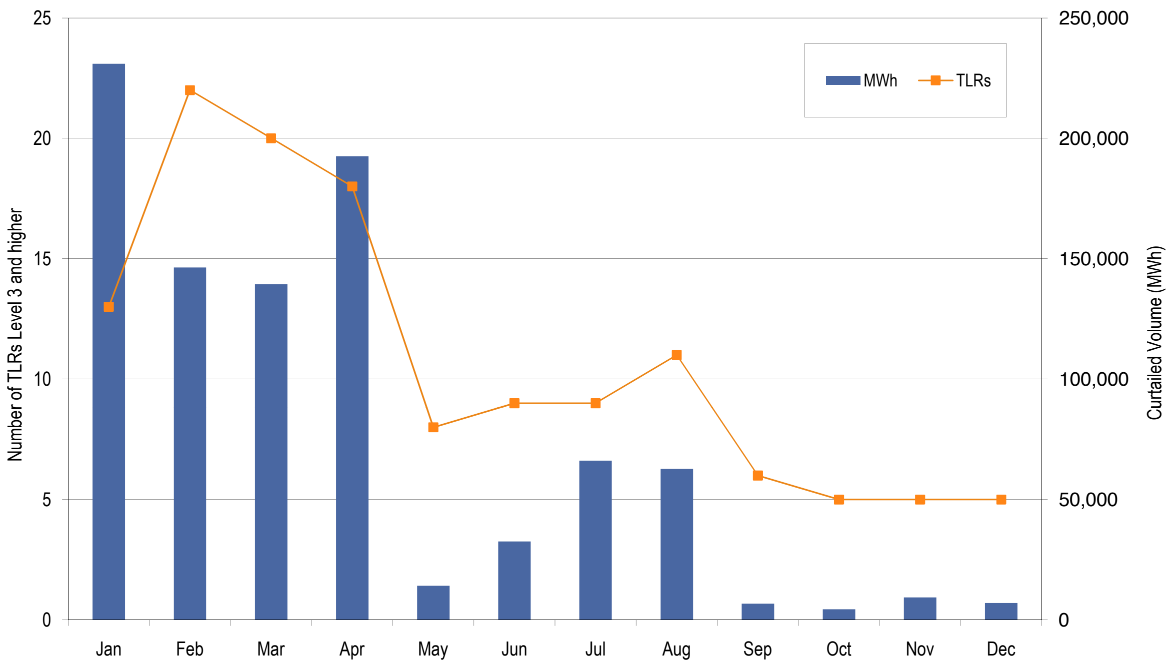


Table 4-13 shows the number of TLRs by TLR level for each reliability coordinator in the Eastern Interconnection. The TLR levels are defined in Appendix D "Interchange Transactions" of this document. During 2009, PJM issued 129 transmission loading relief procedures (TLRs). Of the 129 TLRs issued, the highest levels reached were TLR 3a in 61 instances and TLR 3b in the remaining 68 events (2008 totals were 55 TLR 3a, 92 TLR 3b, 2 TLR 4 and 1 TLR 5b).

Table 4-13 Number of TLRs by TLR level by reliability coordinator: Calendar Year 2009

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2009	ICTE	82	35	55	75	18	1	266
	MISO	199	140	2	15	25	0	381
	NYIS	101	8	0	0	0	0	109
	ONT	169	0	0	0	0	0	169
	PJM	61	68	0	0	0	0	129
	SWPP	383	1,466	33	77	24	0	1,983
	TVA	8	22	29	0	0	0	59
	VACS	0	1	0	0	0	0	1
Total		1,003	1,740	119	167	67	1	3,097

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 per MWh, 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 use to limit or hedge their congestion exposure on scheduled transactions in the Real-Time Market.

In submitting an up-to congestion transaction, the market participant is submitting a transaction equivalent to a matched set of incremental offers (INC) and decrement bids (DEC) that will be evaluated together and approved or denied as a single transaction, subject to a limit on the cleared price difference. For import up-to congestion transactions, the import pricing point specified looks like a DEC bid and the sink specified on the OASIS reservation looks like an INC offer. For export transactions, the specified source on the OASIS reservation looks like a DEC bid, and the export pricing point looks like an INC offer. Similarly, for wheel through up-to congestion transactions, the import pricing point chosen looks like a DEC bid, and the export pricing point specified looks like an INC offer.

While submitting an up-to congestion bid is similar to entering a matched pair of INC offers and DEC bids, there are a number of advantages to using the up-to congestion product rather than using sets of INC and DEC bids. For example, an up-to congestion transaction is approved or denied as a single transaction, will only clear the Day-Ahead Market if the maximum congestion bid criteria is met, and is not subject to day-ahead or balancing operating reserve charges.

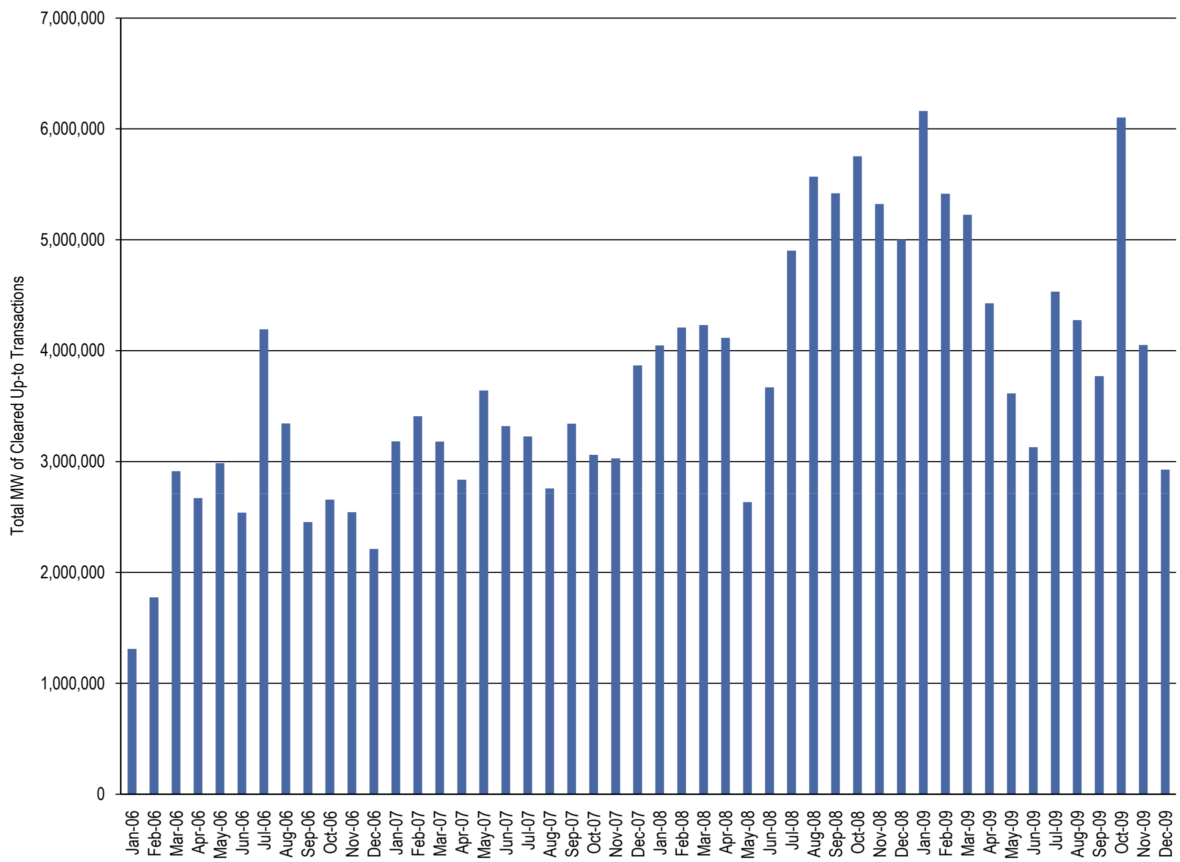
In the Day-Ahead Energy Market, an up-to congestion import transaction is submitted and modeled as an injection at the interface and a withdrawal at a specific PJM node. In real time, the power does not flow to the PJM node specified in the day-ahead transaction. This mismatch results in inaccurate pricing and can provide a gaming opportunity.

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.[55] 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.[56] 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. (See Figure 4-23.)

55 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> (39 KB).

56 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).

Figure 4-23 Monthly up-to congestion bids in MWh: January 2006 through December 2009



The up-to congestion transactions in 2009 were comprised of 45.6 percent imports, 51.7 percent exports and 2.7 percent wheeling transactions. (See Table 4-14.) 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.

Table 4-14 Up-to congestion MW by Import, Export and Wheels: Calendar years 2006 through 2009

	Import MW	Export MW	Wheeling MW	Total MW	Percent Imports	Percent Exports	Percent Wheels
2006	10,730,659	20,398,833	468,648	31,598,141	34.0%	64.6%	1.5%
2007	13,950,514	24,080,803	817,237	38,848,554	35.9%	62.0%	2.1%
2008	20,889,972	32,351,960	1,632,874	54,874,806	38.1%	59.0%	3.0%
2009	24,455,358	27,722,740	1,453,553	53,631,651	45.6%	51.7%	2.7%
Total	70,026,504	104,554,336	4,372,311	178,953,151	39.1%	58.4%	2.4%

Market participants have the opportunity to match the source and sink between the Day-Ahead and Real-Time Markets, but they have not done so. An analysis of the up-to congestion data shows that submitted Real-Time Market transactions match the submitted Day-Ahead Market up-to congestion bid only 0.2 percent of the time. For 99.8 percent of the time, submitted Real-Time

Market transactions do not match the submitted Day-Ahead Market up-to congestion bids being made by participants.

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.

Figure 4-24 and Figure 4-25 show the monthly positive, negative and net gains for matching and non-matching up-to congestion transactions. Figure 4-24 shows the matching transactions on a different scale than Figure 4-25. There is such a small number of matching transactions that the results would not be visible on the scale of Figure 4-25.

Figure 4-24 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Market transaction: Calendar year 2009

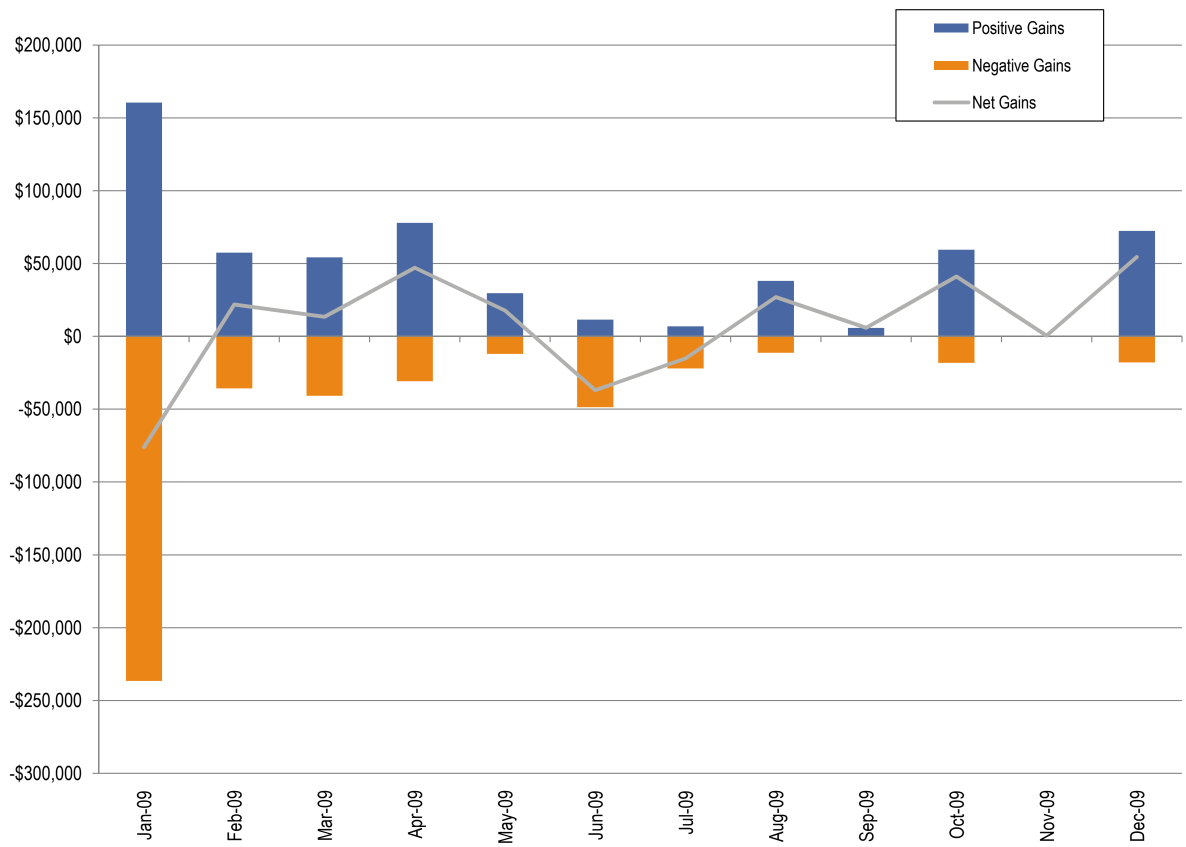
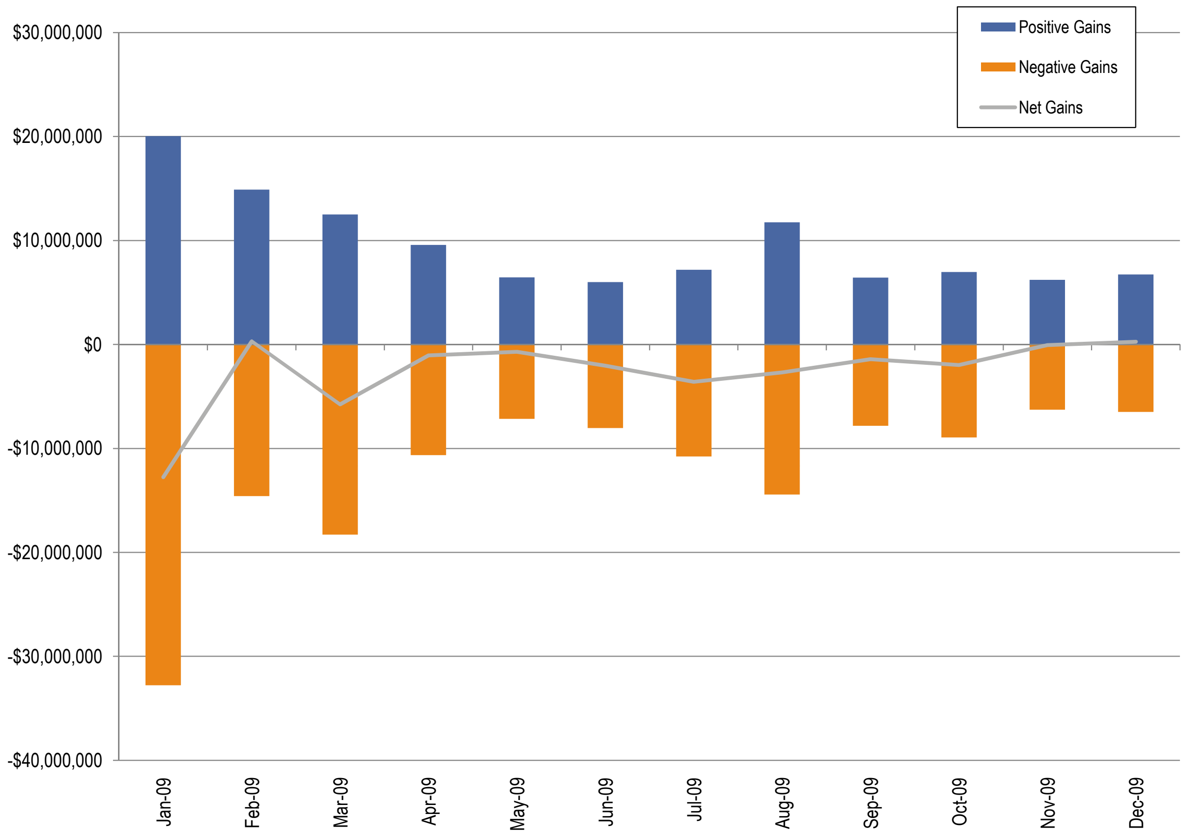


Figure 4-25 Total settlements showing positive, negative and net gains for up-to congestion bids without a matching Real-Time Market transaction: Calendar year 2009



The consistency and volume of the mismatch between day-ahead and real-time sources and sinks in the submitted transactions indicates that this product is not being used as it was intended. The fact that cleared up-to congestion bids that do not have a matching real-time transaction lost approximately $31.5 million in 2009, and that these transactions are repeatedly being scheduled by the same participants is cause for concern. Of all market participants that utilize up-to congestion transactions, the top five participants accounted for 48 percent of all transactions and the top ten participants accounted for 74 percent of all transactions. The top five participants that experience losses accounted for 60 percent of all the losses, and the top ten participants accounted for 77 percent of all the losses on those bids.

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 consolidated the southeast and southwest interface pricing points to a single interface with separate import and export prices (SouthIMP and SouthEXP) on October 31, 2006.[57] Table 4-15 shows the historical differences in LMPs between the southeast, southwest, SouthIMP and SouthEXP Interface prices since the consolidation. The consolidation was based on an analysis which showed that scheduled flows were not consistent with actual power flows. The issue, which has arisen at other interface pricing points, is that the multiple pricing points may create the ability to engage in false arbitrage. False arbitrage occurs when participants schedule transactions in response to interface price differences but the actual power flows associated with the transaction serve to drive prices further apart rather than relieving the underlying congestion. Some market participants complained that their interests were harmed by PJM's consolidation of the southeast and southwest interface pricing points.

Table 4-15 Real-time average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: November 1, 2006 through December 2009

	southeast LMP	southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference southeast LMP - SOUTHIMP	Difference southwest LMP - SOUTHIMP	Difference southeast LMP - SOUTHEXP	Difference southwest LMP - SOUTHEXP
2006	$42.55	$37.89	$38.36	$42.02	$4.20	($0.47)	$0.53	($4.13)
2007	$54.35	$45.48	$49.09	$48.48	$5.26	($3.61)	$5.87	($3.01)
2008	$62.97	$51.43	$55.47	$55.44	$7.50	($4.05)	$7.53	($4.01)
2009	$35.97	$31.94	$33.37	$33.37	$2.61	($1.42)	$2.61	($1.42)

PJM subsequently entered into confidential bilateral locational interface pricing agreements with three companies affected by the revised interface pricing point that provided more advantageous pricing to these companies than the applicable interface pricing rules. The three companies involved and the effective date of their agreements are: Duke Energy Carolinas, January 5, 2007;[58] Progress Energy Carolinas, February 13, 2007;[59] and North Carolina Municipal Power Agency (NCMPA), March 19, 2007.[60] Each of these agreements established a locational price for power purchases and sales between PJM and the individual company that applies under specified conditions. For example, when the company desires to sell into PJM (a PJM import), the rules required that the company cannot have simultaneous scheduled imports from other areas. Similarly, when a company wants to purchase from PJM (a PJM export), the rules require that the company cannot simultaneously have scheduled exports to other areas.

57 PJM posted a copy of its notice, dated August 31, 2006, on its website at: <http://www.pjm.com/~/media/etools/oasis/pricing-information/interface-pricing-point-consolidation.ashx> (66 KB).

58 See "Duke Energy Carolinas Interface Pricing Arrangements" (January 5, 2007) (Accessed January 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/duke-pricing-agreement.ashx> (171 KB).

59 See "Progress Energy Carolinas, Inc. Interface Pricing Arrangements" (February 13, 2007) (Accessed January 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/pec-pricing-agreement.ashx> (210 KB).

60 See "North Carolina Municipal Power Agency Number 1 Interface Pricing Arrangement" (March 19, 2007) (Accessed January 15, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/electricities-pricing-agreement.ashx> (279 KB).

There were a number of issues with these agreements including that they were not made public until specifically requested 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).[61] These pricing point options include the existing SouthIMP/SouthEXP prices, the "Hi/Low" method and the "Marginal Cost Proxy Method."

The default pricing point for transactions between PJM and balancing authorities to the south are the SouthIMP and SouthEXP pricing points. While the SouthIMP and SouthEXP pricing points reflect the physical flows into and out of PJM from the ultimate source or sink, the interface encompasses a large geographic area, and individual neighboring BAs may benefit from providing additional data to take advantage of a more granular pricing mechanism.

Under the "Hi/Low" option, PJM uses the highest generator bus LMP for exports from PJM and the lowest generator bus LMP for imports into PJM to set the interface price. In addition, unit level telemetry can be provided that shows real-time unit status. When a generator is not running, the "high/low" method eliminates the LMP at that bus from the determination of the import or export price. To utilize the "high/low" option, PJM must be able to verify the source for import transactions and the sink for export transactions.

The "marginal cost proxy method" requires the submittal of generator cost data to PJM. This pricing method is based on the incremental production cost of the external supplier's marginal generator. The marginal generator is determined on the basis of the incremental production cost to supply load in the external area, supported by real-time metered output data. For imports to PJM, if the LMP at the unit, calculated by PJM with reference to PJM generation and load, is greater than or equal to the production cost for each unit on line then the interface price is equal to the PJM calculated bus LMP of the marginal unit. If the LMP is less than the production cost for any unit on line, then the interface price is equal to the lowest PJM calculated LMP of any such units. For exports from PJM, if the LMP is greater than or equal to the production cost for each unit on line then the interface price is equal to the PJM calculated LMP of the marginal production unit. If the LMP is greater than the production cost for any unit on line, then the interface price is equal to the highest PJM calculated LMP of any such units.

The proposed tariff revisions were filed with FERC on December 2, 2008[62], and approved on May 1, 2009.[63] 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

61 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).

62 PJM Interconnection, L.L.C., Transmittal Letter, Docket No. ER09-369-000 (December 2, 2008).

63 PJM Interconnection, L.L.C., Letter Order, Docket No. ER09-369-000 (May 1, 2009).

continue the "marginal cost proxy" pricing beyond January 31, 2010), and to file such agreements unexecuted, if requested, after 90 days.[64] 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 July 2009, Duke Energy Carolinas submitted the required data, and PJM had completed the required software modifications to support the "marginal cost proxy method." As of December 31, 2009 neither Progress Energy Carolinas nor the North Carolina Municipal Power Agency has elected to supply the additional data necessary to take advantage of the "high/low" or the "marginal cost proxy method" for interface pricing. Table 4-16 through Table 4-19 show the real-time and day-ahead prices for imports and exports applicable for the interface pricing under the various agreements (January data represents the pricing based on the original agreements, during the period from February 1 through May 3, 2009, the interface pricing was based on the SouthIMP and SouthEXP LMPs as there were no agreements in place, and the data shown for May 3, 2009 through the remainder of the year represents pricing based on the revised agreements).

In September 2009, Progress Energy Carolinas provided an update to the PJM Market Implementation Committee (MIC) on the proposed congestion management agreement.[65] The proposal included three parts: enhanced available transmission capability (ATC) coordination; monitoring of real-time parallel flow impacts; and managing real-time congestion.

On February 2, 2010, PJM filed a revised JOA to include the provisions of the proposed congestion management agreement. On February 23, the MMU provided comments on the filing.[66]

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.

Table 4-16 shows the real-time LMP calculated per the bilateral agreements and, for comparison, the SouthIMP and SouthEXP LMP for January 2009 (the time period when the original agreements were in place). The difference between the LMP under the agreements and PJM's SouthIMP/SouthEXP LMP ranged from $3.29 with Duke to $4.93 with PEC.[67] Table 4-17 shows the real-time LMP calculated per the revised agreements made effective on May 3, 2009 through the remainder of 2009. The difference between the LMP under this agreement and PJM's SouthIMP/SouthEXP LMP ranged from $1.06 with Duke to $1.36 with PEC.

Table 4-16 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January 2009

	LMP	SOUTHIMP	SOUTHEXP	Difference LMP - SOUTHIMP	Difference LMP - SOUTHEXP
Duke	$50.58	$47.29	$47.29	$3.29	$3.29
PEC	$52.21	$47.29	$47.29	$4.93	$4.93
NCMPA	$50.66	$47.29	$47.29	$3.37	$3.37

64 127 FERC ¶61,101.

65 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).

66 (See PJM. "20100202-er10-xxx-000-joa.pdf"(February 2, 2010) (Accessed February 28, 2010) <http://www.pjm.com/~/media/documents/ferc/2010-filings/20100202-er10-xxx-000-joa.ashx> (2,277 KB)). (See Monitoring Analytics. "Corrected Motion to intervene and comments of the independent market monitor for PJM.pdf" (February 23, 2010) (Accessed February 28, 2010) <http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Motion_to_Intervene_and_Comments_ER10-713-000_20100225.pdf> (225 KB)).

67 The Progress Energy Carolinas (PEC) LMP is defined as the Carolina Power and Light (East) (CPLE) pricing point.

Table 4-17 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: May 3, 2009 through December 2009

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$31.87	$32.20	$30.82	$30.81	$1.06	$1.39
PEC	$32.18	$33.50	$30.82	$30.81	$1.36	$2.69
NCMPA	$32.01	$32.08	$30.82	$30.81	$1.19	$1.27

Figure 4-26 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: Calendar year 2009

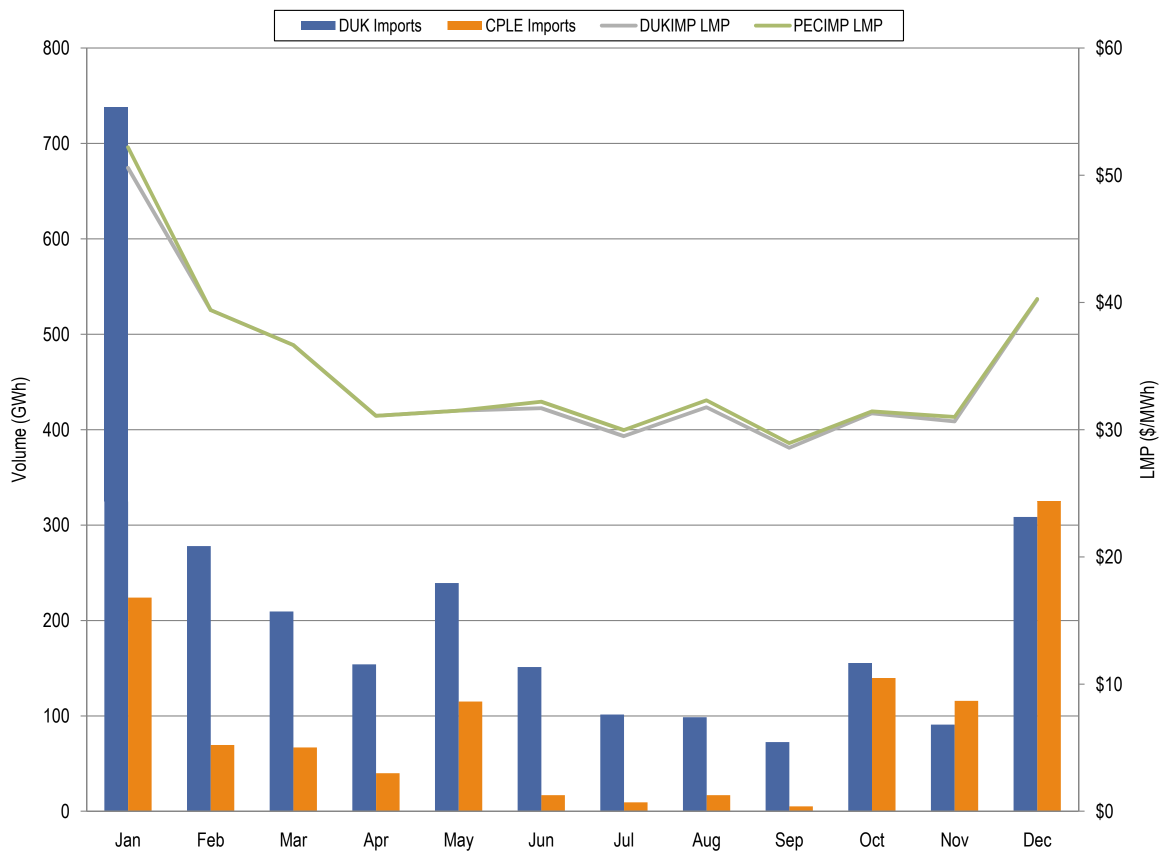


Figure 4-27 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: Calendar year 2009

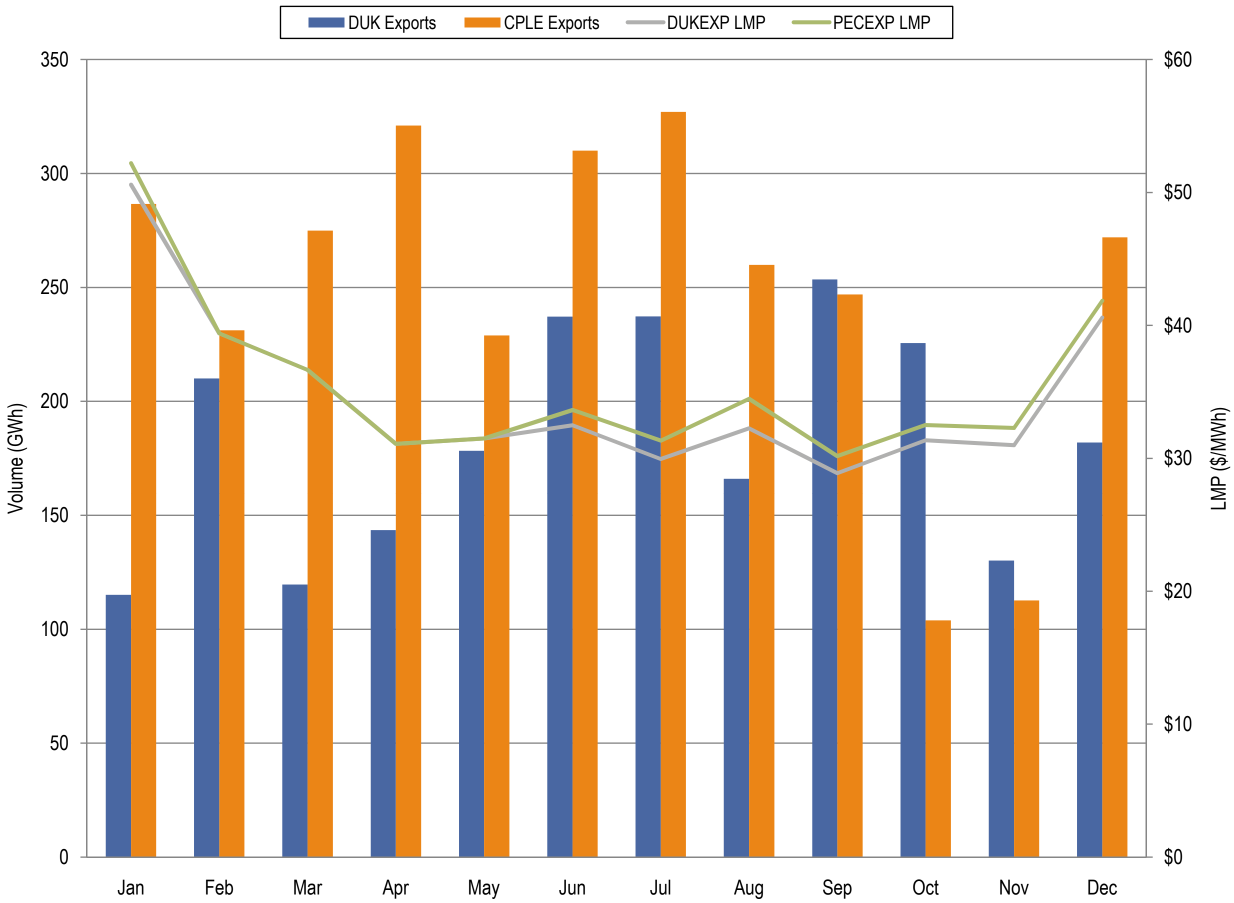


Table 4-18 shows the day-ahead LMP calculated per the bilateral agreements and, for comparison, the SouthIMP and SouthEXP LMP for January 2009 (the time period when the original agreements were in place). The prices available to Duke, CPLE and NCMPA under the agreement were higher than the SouthIMP and SouthEXP Interface prices. The difference between the LMP under the agreements and PJM's SouthIMP/SouthEXP LMP ranged from $3.42 with Duke to $5.82 with PEC. Table 4-19 shows the day-ahead LMP calculated per the revised agreements made effective on May 3, 2009 through the remainder of 2009. The prices available to Duke, CPLE and NCMPA under the revised agreement remained higher than the SouthIMP and SouthEXP Interface prices but the differences were not as large. The difference between the LMP under this agreement and PJM's SouthIMP/SouthEXP LMP ranged from $0.86 with Duke to $1.35 with PEC.

Table 4-18 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January 2009

	LMP	SOUTHIMP	SOUTHEXP	Difference LMP - SOUTHIMP	Difference LMP - SOUTHEXP
Duke	$52.01	$48.59	$48.59	$3.42	$3.42
PEC	$54.41	$48.59	$48.59	$5.82	$5.82
NCMPA	$52.10	$48.59	$48.59	$3.51	$3.51

Table 4-19 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: May 3, 2009 through September 2009

	IMPORT LMP	EXPORT LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$31.91	$32.51	$31.04	$31.04	$0.86	$1.47
PEC	$32.39	$33.86	$31.04	$31.04	$1.35	$2.81
NCMPA	$32.18	$32.25	$31.04	$31.04	$1.13	$1.20

Figure 4-28 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: Calendar year 2009

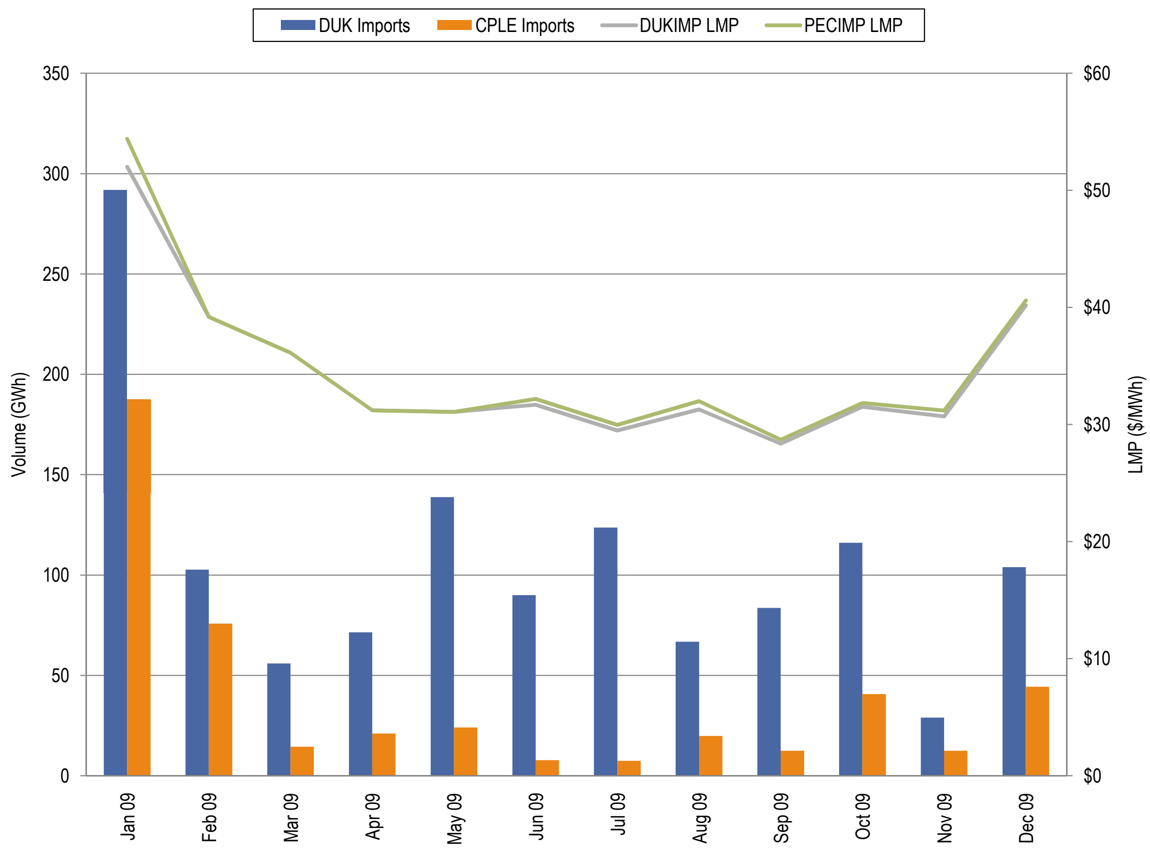
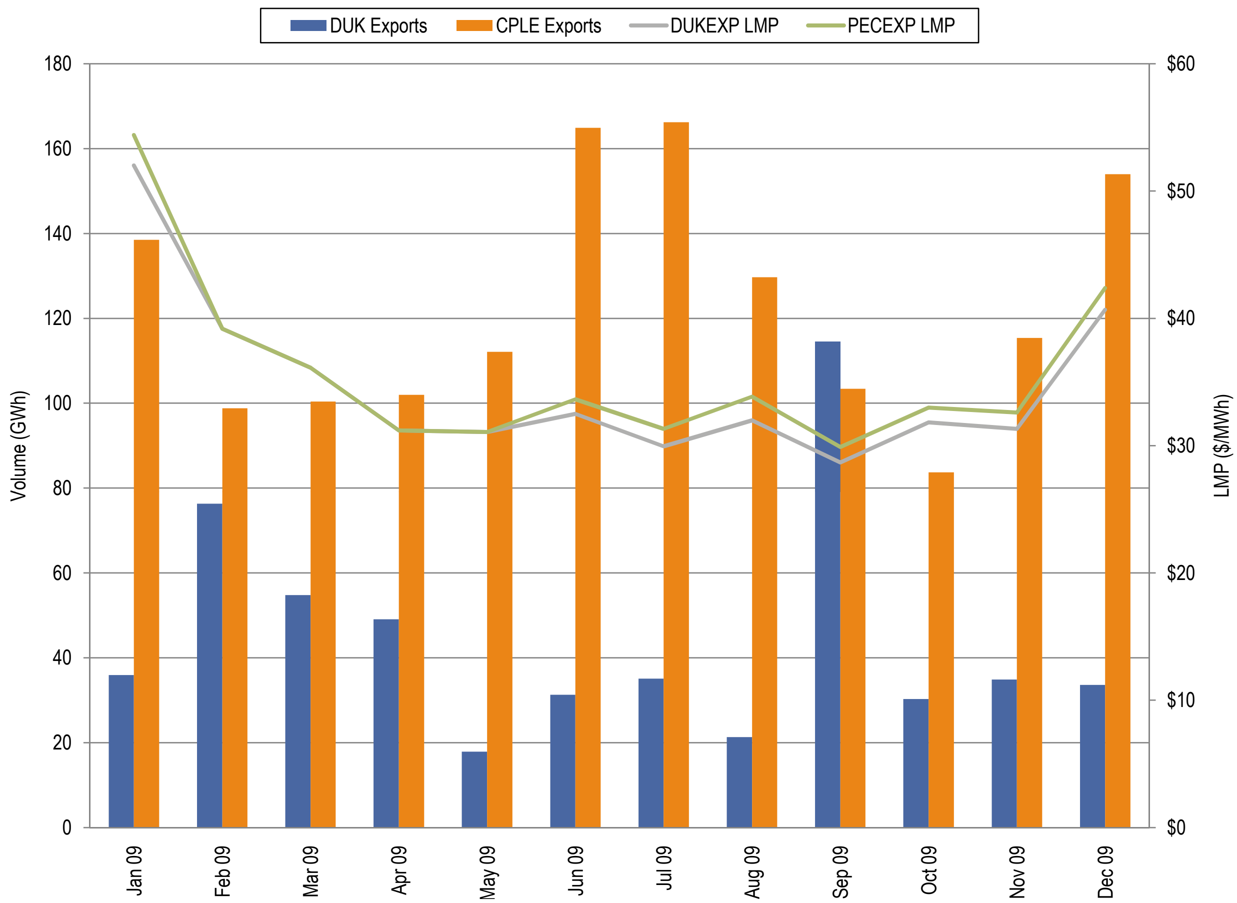


Figure 4-29 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: Calendar year 2009



Spot Import

Spot market imports, non-firm point-to-point and network services that are willing to pay congestion, collectively Willing to Pay Congestion (WPC), were part of the PJM LMP energy market design implemented on April 1, 1998. WPC provided market participants the ability to offer energy into or bid to buy from the PJM spot market at the border/interface as price takers without restrictions based on estimated available transmission capability (ATC). Price and PJM system conditions, rather than ATC, effectively limited interchange.

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.[68] 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 to customers. Unlike non-firm point-to-point

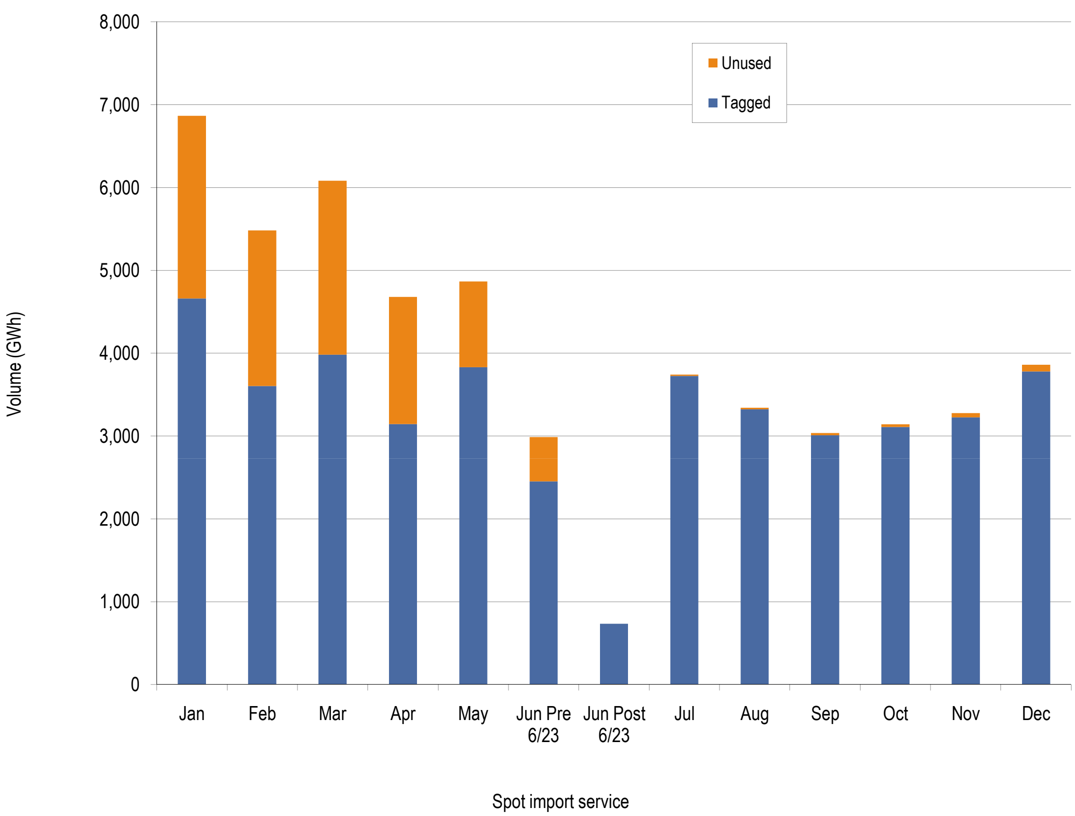
68 See "WPC White Paper" (April 20, 2007) (Accessed January 15, 2010) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx> (97 KB).

WPC service, spot import (a network service) is provided at no charge to the market participant offering into the PJM spot market.

In response to market participant complaints regarding the inability to acquire spot import service after this rule change on April 1, 2007, changes were made to the spot import service effective May 1, 2008.[69] These changes limited spot imports to only hourly reservations and caused spot import service to expire if not associated with a valid NERC Tag within 2 hours when reserved the day prior to the scheduled flow or within 30 minutes when reserved on the day of the scheduled flow.

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 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 two hours 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. (See Figure 4-30.) The MMU will continue to monitor participant use of spot import service.

Figure 4-30 Spot import service utilization: Calendar year 2009



69 See "Regional Transmission and Energy Scheduling Practices" (May 1, 2008) (Accessed January 15, 2010) <http://www.pjm.com/~/media/etools/oasis/20090131-regional-practices-redline.ashx> (450 KB).

Willing to Pay Congestion and Not Willing to Pay Congestion

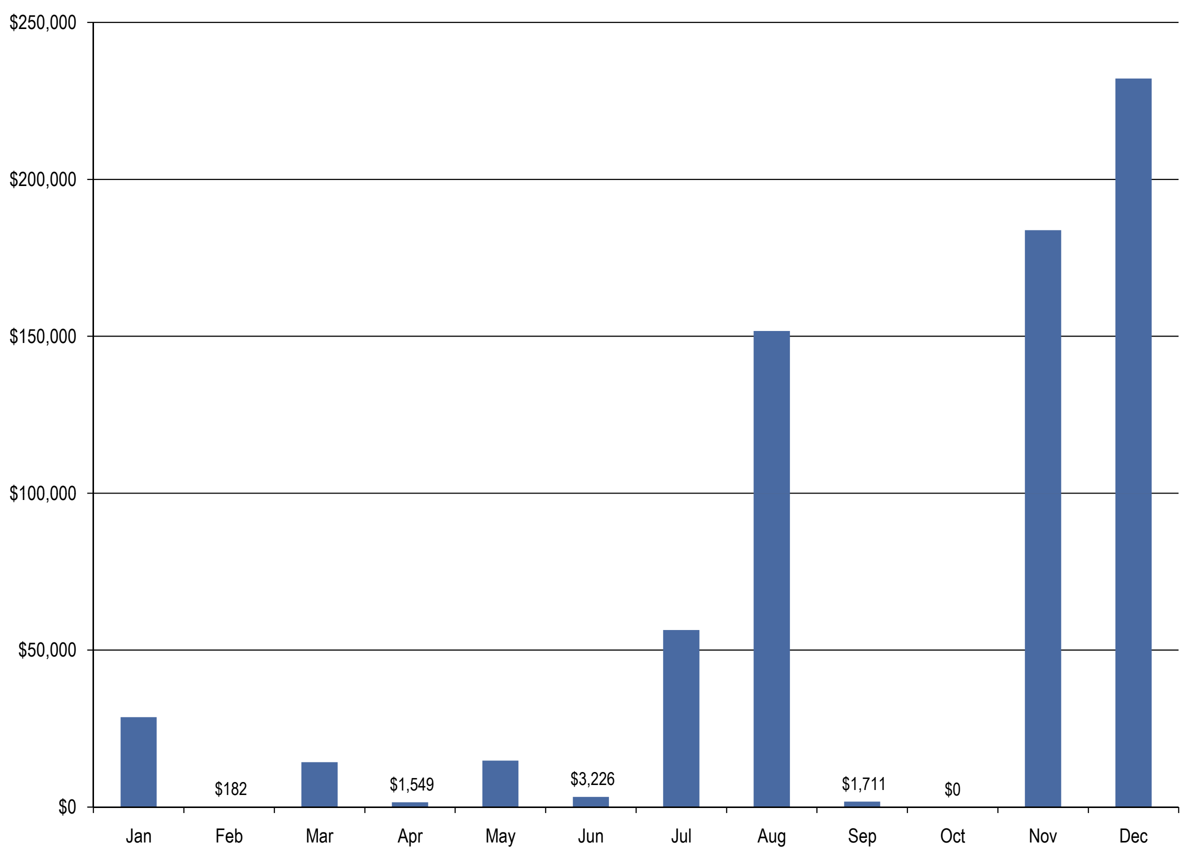
When reserving non-firm transmission, the market participant has the option to choose whether or not they are willing to pay congestion. When the market participant elects to pay congestion, PJM operators redispatch the system, if necessary, to allow the energy transaction to continue to flow.

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.

Figure 4-31 shows the monthly uncollected congestion charges for 2009. 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 transaction is not permitted to flow in the presence of congestion.

Figure 4-31 Monthly uncollected congestion charges: Calendar year 2009



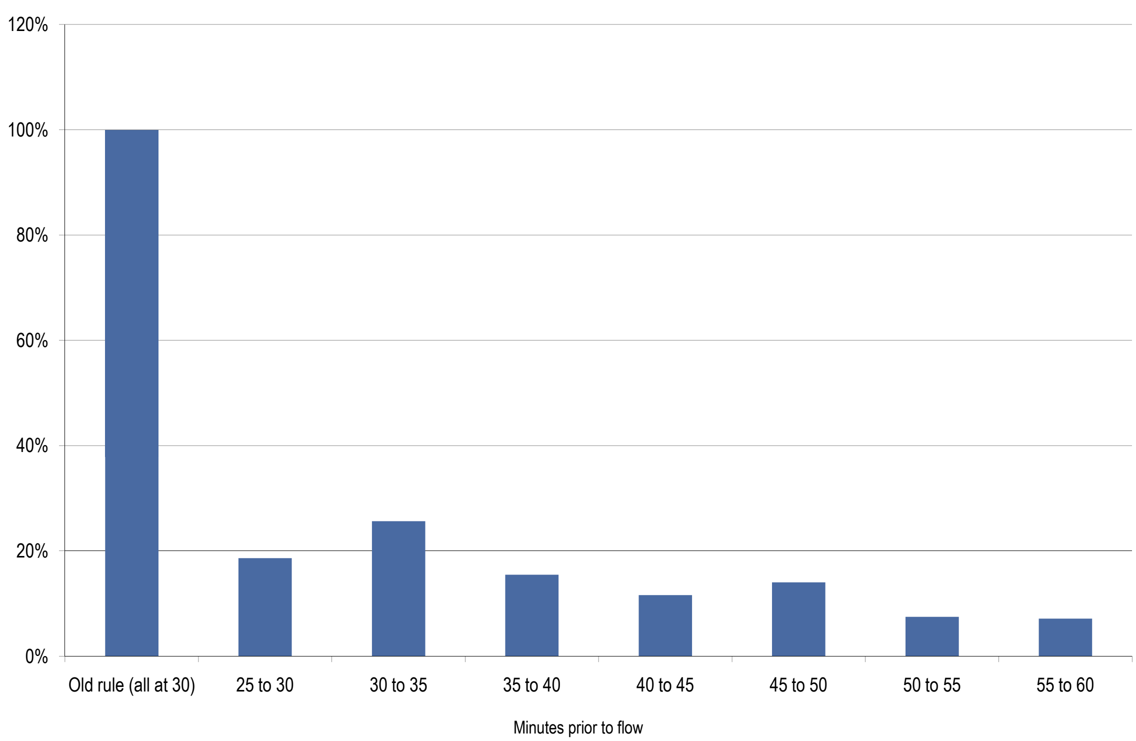
Ramp Availability

PJM limits the amount of change in net interchange within 15 minute intervals in order to ensure compliance with NERC performance standards. Changes in net interchange affect PJM operations and markets as they require increases or decreases in generation to meet load. The change in net interchange is referred to as ramp. Any market participant wishing to initiate (or to change) a transaction must obtain a ramp reservation. PJM issues reservations, on a first-come, first-served basis, up to the ramp limit.

While ramp limits may be modified by PJM depending on system conditions, the default limit is ± 1,000 MW within a 15 minute interval. For example, if at 0800 Eastern Prevailing Time (EPT) the sum of all external transactions were -3,000 MW (negative sign indicates net exporting), the limit for 0815 would be -2,000 MW to -4,000 MW. In other words, the starting or ending of transactions would be limited so that the overall change from the previous 15 minute period would not exceed 1,000 MW in either direction.

Figure 4-32 shows the ongoing results of the ramp rule change that became effective on August 7, 2006. Under the new rule, unused ramp reservations expire at the conclusion of a defined time interval that starts when a reservation is approved. The goal was to prevent large swings in ramp 30 minutes prior to flow, and to spread automatic ramp reservation expirations over a longer period to permit other participants to use them. The actual distribution pattern of expirations since the rule change is compared to when reservations would have expired under the old rule in Figure 4-32. Under the old rule, all unused reservations had expired at the same time, 30 minutes prior to flow or just 10 minutes prior to the deadline for scheduling a transaction (20 minutes prior to flow).

Figure 4-32 Distribution of expired ramp reservations in the hour prior to flow (Old rules (Theoretical) and new rules (Actual)) October 2006 through December 2009



The artificial creation of ramp room is an ongoing issue. For example, a market participant who wishes to initiate an import transaction when there is no available import ramp, requests a ramp reservation in the exporting direction. When accepted, this reservation creates apparent import ramp, which permits the participant to obtain an import reservation. The import transaction flows and the export reservation expires after its time limit. In 2007, PJM modified its business rules to permit PJM to curtail such a participant's transaction(s) prior to using the normal, last-in-first-out method of ordering curtailments, if PJM determines that a participant has scheduled an offsetting reservation that is unused.[70] Although the rule has been added, the mechanism for automatically performing this task has not yet been developed. System operators may apply this rule manually.

Large swings in PJM's ramp availability have continued to be regularly observed at the NYISO Interface. The NYISO rules for its hourly market require transaction bids to be placed at least 75 minutes prior to flow. For each potential import or export transaction that is bid into the NYISO market, a PJM ramp reservation is required. During the time between the bid submission to the NYISO and the time the NYISO market results are posted, all ramp reservations associated with all the bids are in PJM's system, often leaving no ramp available, awaiting the outcome of the NYISO market clearing. When the NYISO market results are posted, the ramp reservations for any unsuccessful bids are returned to the PJM system. The result is a large swing in ramp observed at approximately 20 minutes after the hour. The difference between transaction rules in the NYISO and PJM create incentives to obtain ramp that will not be needed. There is also the potential for gaming by submitting out-of-market bids and offers for import or export transactions to the NYISO, thus limiting ramp availability to competitors. Additionally, market participants can extend their NYISO market bids to cover multiple hours to acquire ramp by submitting out-of-merit bids and offers. For example, if ramp is not available at the end time of the desired hour, the market participant can submit a NYISO schedule to cover two hours, thus having no effect at the time when ramp is not available. When the NYISO evaluates the second hour, it will not pass their market (as it is out-of-merit) and they will deny the transaction. PJM will have no choice but to remove the transaction from the second hour, thus causing a ramp violation at the end of the first hour where ramp was initially not available.

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.[71] On May 1, 2008, the Enhanced Energy Scheduler (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.

70 PJM. "Manual 41: Managing Interchange," Revision 03 (November 24, 2008), p. 9.
71 PJM. "Manual 41: Managing Interchange," Revision 03 (November 24, 2008), p. 5.

SECTION 5 – 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.

Overview

The Market Monitoring Unit (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.[1] 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.[2] 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.[3] 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.

1 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.
2 126 FERC ¶61,275 (2009).
3 Docket No. ER10-366-000.

RPM prices are locational and may vary depending on transmission constraints.[4] 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. 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.[5] 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 resource 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).

4 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.

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

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), 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).

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).[6] 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).

- **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 Electricity distribution companies (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.

6 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.

- **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).[7] 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.

- **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.

7 124 FERC ¶ 61,140 (2008).

- **2012/2013 RPM Base Residual Auction.**[8] 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.**[9] 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.[10] 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.

  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.

8 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>.

9 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.

10 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 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.

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.[11] 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.[12] 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.

11 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.

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

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.[13]

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 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

13 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.

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.

RPM Capacity Market

Market Design

The RPM Capacity Market, implemented June 1, 2007 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.

Annual base auctions are held in May for delivery years that are three years in the future. Prior to January 22, 2010, First, Second and Third Incremental RPM Auctions were conducted 23, 13 and four months prior to the delivery year. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[14] In 2009, the 2012/2013 BRA was held in May.[15] A Third Incremental Auction was held in January 2009 for the delivery year 2009/2010, and a First Incremental Auction was held in June for the delivery year 2011/2012.[16]

14 Letter Order in Docket No. ER10-366-000 (January 22, 2010).

15 Delivery years are from June 1 through May 31. The 2009/2010 delivery year runs from June 1, 2009, through May 31, 2010.

16 For more detailed analysis of the RPM Auctions, see: "Analysis of the 2007/2008 RPM Auction" (August 16, 2007); "Analysis of the 2008/2009 RPM Auction" (November 30, 2007); "Analysis of the 2008/2009 Third Incremental RPM Auction" (June 23, 2008); "Analysis of the 2009/2010 RPM Auction" (November 30, 2007); "Analysis of the 2010/2011 RPM Auction" (May 6, 2008); "Analysis of the 2011/2012 RPM Auction" (September 12, 2008); "Analysis of the 2012/2013 RPM Base Residual Auction" (August 6, 2009) <http://www.monitoringanalytics.com/reports/Reports.shtml>.

Market Structure

Supply

As shown in Table 5-1, 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. This increase was the result of 439.2 MW of new generation, and 74.1 MW from generation uprates. DR offers increased 220.6 MW. The net EFORd effect was -383.7 MW. The EFORd effect is the measure of the net internal capacity change attributable to EFORd changes and not capacity modifications.

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.

As also shown in Table 5-1 and Table 5-7, in the 2009/2010 RPM Auction, the increase of 17 RPM generation resources 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). There were 38 DR resources offered compared to 23 DR resources offered in the 2008/2009 RPM Auction.

As shown in Table 5-1 and Table 5-8, in the 2010/2011 auction, the increase of 11 RPM generation resources consisted of 15 new resources (406.9 MW), four reactivated resources (161.7 MW), 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). There were 23 demand resources (DR) offered compared to 38 DR resources offered in the 2009/2010 RPM auction.

As also shown in Table 5-1 and Table 5-8, in the 2011/2012 auction, the increase of 21 generation resources 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). There were 37 demand resources (DR) offered compared to 23 DR resources offered in the 2010/2011 RPM auction.

As shown in Table 5-1 and Table 5-8, in the 2012/2013 auction, the increase of eight generation 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).[17] 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 resources 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). There were 233 demand resources (DR) offered compared to 37 DR resources offered in the 2011/2012 RPM Base Residual Auction. There were 53 Energy Efficiency (EE) resources offered as a new resource type for the 2012/2013 planning year.

17 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.

Table 5-1 Internal capacity: June 1, 2008, through May 31, 2012[18,19]

	UCAP (MW)						
	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL South	PSEG North
Total internal capacity @ 01-Jun-08	156,968.0	72,889.5			10,777.1		
New generation	439.2	109.9			0.0		
Units out of retirement	0.0	0.0			0.0		
Generation capmods	74.1	(149.7)			(298.2)		
DR mods	220.6	163.2			42.3		
Net EFORd effect	(383.7)	0.0			(176.0)		
Total internal capacity @ 01-Jun-09	157,318.2	73,012.9			10,345.2	1,587.0	
New generation	406.9					0.0	
Units out of retirement	165.0					0.0	
Generation capmods	1,085.8					(85.5)	
DR mods	43.7					15.7	
Net EFORd effect	11.3					28.9	
Total internal capacity @ 01-Jun-10	159,030.9					1,546.1	
New generation	2,203.7						
Units out of retirement	486.9						
Generation capmods	(2,567.6)						
DR mods	684.4						
Net EFORd effect	44.4						
Total internal capacity @ 01-Jun-11	159,882.7		66,329.7	32,733.0		1,460.3	4,167.5
Reclassification of Duquesne resources	3,187.2		0.0	0.0		0.0	0.0
Adjusted internal capacity @ 01-Jun-11	163,069.9		66,329.7	32,733.0		1,460.3	4,167.5
New generation	661.3		61.9	59.7		0.0	0.0
Units out of retirement	0.0		0.0	0.0		0.0	0.0
Generation capmods	(1,513.1)		(901.3)	(444.9)		(31.8)	(509.0)
DR mods	8,028.7		3,829.7	1,480.9		64.6	67.6
EE mods	652.5		186.9	24.4		0.0	0.9
Net EFORd effect	(946.0)		(503.0)	(185.6)		5.8	18.3
Total internal capacity @ 01-Jun-12	169,953.3		69,003.9	33,667.5		1,498.9	3,745.3

18 The RTO includes MAAC+APS, EMAAC and SWMAAC. MAAC+APS and MAAC include EMAAC and SWMAAC. EMAAC includes DPL South and PSEG North. Results for only constrained LDAs are shown. Maps of the LDAs can be found in the *2009 State of the Market Report for PJM*, Appendix A, "PJM Geography."

19 The UCAP MW value attributed to the reclassification of Duquesne units differs from the value reported in the *2008 State of the Market Report for PJM* as a result of generation cap mods, DR and EE mods, and EFORd changes.

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. This increase resulted from a higher peak-load forecast.

The MMU analyzed market sectors in the PJM Capacity Market to determine how they met their load obligations. The Capacity Market was divided into the following sectors:

- **PJM EDC.** EDCs with a franchise service territory within the PJM footprint. This sector includes traditional utilities, electric cooperatives, municipalities and power agencies.
- **PJM EDC Generating Affiliate.** Affiliate companies of PJM EDCs that own generating resources.
- **PJM EDC Marketing Affiliate.** Affiliate companies of PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-PJM EDC.** EDCs with franchise service territories outside the PJM footprint.
- **Non-PJM EDC Generating Affiliate.** Affiliate companies of non-PJM EDCs that own generating resources.
- **Non-PJM EDC Marketing Affiliate.** Affiliate companies of non-PJM EDCs that sell power and have load obligations in PJM, but do not own generating resources.
- **Non-EDC Generating Affiliate.** Affiliate companies of non-EDCs that own generating resources.
- **Non-EDC Marketing Affiliate.** Affiliate companies of non-EDCs that sell power and have load obligations in PJM, but do not own generating resources.

On June 1, 2009, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 79.6 percent (Table 5-2), down slightly from 80.1 percent on June 1, 2008. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 20.4 percent, up from 19.9 percent on June 1, 2008. Obligation is defined as cleared MW plus ILR forecast obligations.

Table 5-2 PJM Capacity Market load obligation served: June 1, 2009

	Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Obligation	68,587.1	11,994.4	26,027.0	1,056.0	10,452.7	517.3	15,252.5	133,887.0
Percent of total obligation	51.2%	9.0%	19.4%	0.8%	7.8%	0.4%	11.4%	100.0%

Market Concentration

Preliminary Market Structure Screen

Under the terms of the PJM Tariff, the MMU is required to apply the PMSS prior to RPM Base Residual Auctions.[20] The results of the PMSS are applicable for the First, Second, and Third Incremental Auctions for a given delivery year.[21] The purpose of the PMSS is to determine whether additional data are needed from owners of capacity resources in the defined areas in order to permit the MMU to apply the market structure tests defined in the Tariff.

An LDA or the RTO Region fails the PMSS if any one of the following three screens is failed: the market share of any capacity resource owner exceeds 20 percent; the HHI for all capacity resource owners is 1800 or higher; or there are not more than three jointly pivotal suppliers.[22]

As shown in Table 5-3, all defined markets failed the PMSS. As a result, capacity resource owners were required to submit avoidable cost rate (ACR) data to the MMU for resources for which they intended to submit nonzero sell offers unless certain other conditions were met.[23]

20 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," Substitute Original Sheet No. 605 (Effective June 1, 2007), section 6.3 (a) i.
21 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," Second Revised Sheet No. 593 (Effective November 1, 2009), section 5.11 (b).
22 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," Original Sheet No. 605A (Effective June 1, 2007), section 6.3 (a) ii.
23 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," First Revised Sheet No. 610 (Effective November 1, 2009), section 6.7 (b).

Table 5-3 Preliminary market structure screen results: 2009/2010 through 2012/2013 RPM Auctions

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
2009/2010				
RTO	18.4%	853	1	Fail
SWMAAC	51.1%	4229	1	Fail
MAAC+APS	26.9%	1627	1	Fail
2010/2011				
RTO	18.4%	853	1	Fail
EMAAC	31.3%	2053	1	Fail
SWMAAC	51.1%	4229	1	Fail
MAAC+APS	26.9%	1627	1	Fail
2011/2012				
RTO	18.0%	855	1	Fail
2012/2013				
RTO	17.4%	853	1	Fail
MAAC	17.6%	1071	1	Fail
EMAAC	32.8%	2057	1	Fail
SWMAAC	50.7%	4338	1	Fail
PSEG	84.3%	7188	1	Fail
PSEG North	90.9%	8287	1	Fail
DPL South	55.0%	3828	1	Fail

Auction Market Structure

As shown in Table 5-4, all participants in the total PJM market as well as the LDA RPM markets failed the TPS test in the 2009/2010 BRA, the 2009/2010 Third Incremental Auction, the 2010/2011 BRA, the 2011/2012 BRA, and the 2011/2012 First IA.[24] The result was that offer caps were applied to all sell offers. In the 2012/2013 BRA, all participants included in the incremental supply of EMAAC passed the test. The result was that offer caps were applied to all sell offers of participants that did not pass the test, excluding sell offers for new units. In applying the market structure test, the relevant supply for the RTO market includes all offers less than or equal to 150% of the cost-based clearing price, and the relevant demand includes cleared MW at or below the unconstrained clearing price. The constrained LDA markets include the incremental supply inside the constrained LDAs which was offered at a price higher than 150% of the unconstrained clearing price for the parent LDA market. The incremental demand consists of the MW needed inside the LDA to relieve the constraint.

24 The market definition used for the TPS test includes all offers with costs less than or equal to 1.50 times the clearing price. See the *2009 State of the Market Report for PJM*, Appendix L, "Three Pivotal Supplier Test" for additional discussion.

Table 5-4 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity. The results of the TPS are measured by the Residual Supply Index (RSI_x). The RSI_x is a general measure that can be used with any number of pivotal suppliers. The subscript denotes the number of pivotal suppliers included in the test. If the RSI_x is less than or equal to 1.0, the supply owned by the specific generation owner, or owners, is needed to meet market demand and the generation owners are pivotal suppliers with a significant ability to influence market prices. If the RSI_x is greater than 1.0, the supply of the specific generation owner or owners is not needed to meet market demand and those generation owners have a reduced ability to unilaterally influence market price.

Table 5-4 RSI results: 2009/2010 through 2012/2013 RPM Auctions[25]

RPM Markets	RSI_3	Total Participants	Failed RSI_3 Participants
2009/2010 BRA			
RTO	0.60	66	66
MAAC+APS	0.37	21	21
SWMAAC	0.00	3	3
2009/2010 Third IA			
RTO	0.64	40	40
MAAC+APS	0.14	8	8
2010/2011 BRA			
RTO	0.60	68	68
DPL South	0.00	2	2
2011/2012 BRA			
RTO	0.63	76	76
2011/2012 First IA			
RTO	0.62	30	30
2012/2013 BRA			
RTO	0.63	98	98
MAAC/SWMAAC	0.54	15	15
EMAAC/PSEG	7.03	6	0
PSEG North	0.00	2	2
DPL South	0.00	3	3

25 The RSI shown is the lowest RSI in the market.

Imports and Exports

As shown in Table 5-5, 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 a decrease in exports of 1,643.2 MW and an increase in imports of 45.1 MW.

Table 5-5 PJM capacity summary (MW): June 1, 2007 through May 31, 2012[26,27]

	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

Demand-Side Resources

Under the PJM load management (LM) program, qualifying load management resources can be offered into RPM Auctions as capacity resources and receive the clearing price, or, prior to the 2012/2013 delivery year, they can be offered outside of the auction and receive the final, zonal ILR price.

The LM program introduced two RPM-related products. DR resources are load resources that are offered into an RPM Auction as capacity and receive the relevant LDA or RTO clearing price. ILR resources are load resources that are not offered into the RPM Auction, but receive the final, zonal ILR price determined after the close of the second incremental auction.

Under RPM, DR resources must be offered into the auction for the delivery year during which they will participate while ILR resources must be certified by a published deadline which is after the Base Residual Auction for the delivery year but at least three months prior to the delivery year during

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

27 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.

which they will participate. Beginning with the 2012/2013 delivery year, the load management product ILR was eliminated. It was replaced by the Short-Term Resource Procurement Target.

The Energy Efficiency (EE) resource type is eligible to be offered in RPM auctions starting with the 2012/2013 delivery year and also for incremental auctions in the 2011/2012 delivery year.[28] An EE Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak periods) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such delivery year, without any requirement of notice, dispatch, or operator intervention.[29]

As shown in Table 5-6, capacity in the RPM load management programs, which prior to the 2012/2013 delivery year is a combination of DR cleared in the RPM Auctions and certified/forecast ILR, increased by 3,206.9 MW from 4,167.5 MW on June 1, 2008 to 7,374.4 MW on June 1, 2009. Final ILR is certified three months before the delivery year and it may differ from the ILR forecast.

Table 5-6 RPM load management statistics: June 1, 2008 through May 31, 2012[30]

	UCAP (MW)						
	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL South	PSEG North
DR cleared	559.4			169.0	309.2		
ILR certified	3,608.1			622.6	219.7		
RPM load management @ 01-June-2008	4,167.5			791.6	528.9		
DR cleared	892.9	813.9			356.3		
ILR certified	6,481.5	1,055.7			345.7		
RPM load management @ 01-June-2009	7,374.4	1,869.6			702.0		
DR cleared	939.0					14.9	
ILR forecast - FRR DR	1,657.6					22.2	
RPM load management @ 01-June-2010	2,596.6					37.1	
DR cleared	1,364.9						
ILR forecast	1,593.8						
RPM load management @ 01-June-2011	2,958.7						
DR cleared	7,047.2		4,723.7	1,638.4		64.6	67.6
EE cleared	568.9		179.9	20.0		0.0	0.9
RPM load management @ 01-June-2012	7,616.1		4,903.6			64.6	68.5

28 Letter Order in Docket No. ER10-366-000 (January 22, 2010).

29 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," First Revised Sheet No. 35C (Effective March 27, 2009), Section M.

30 PJM used forecast ILR, including FRR DR, for the first four base residual auctions. For 2008/2009 and 2009/2010, certified ILR data were used in the calculation here because the certified ILR data are now available. For 2010/2011, forecast ILR less FRR DR is used and will continue to be used until certified ILR data are available. PJM used forecast ILR, excluding FRR DR, for the 2011/2012 BRA. Therefore, FRR DR is not subtracted in the calculation here for the 2011/2012 auction. Effective the 2012/2013 delivery year, ILR was eliminated and the Energy Efficiency (EE) resource type was eligible to be offered in RPM auctions.

Market Conduct

Offer Caps

If a capacity resource owner failed the market power test for the auction, avoidable costs were used to calculate offer caps for that owner's resources. Avoidable costs are the costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year.[31] In effect, avoidable costs are the costs that a generation owner would not incur if the generating unit were mothballed for the year. In the calculation of avoidable costs, there is no presumption that the unit would retire as the alternative to operating, although that possibility could be reflected if the owner documented that retirement was the alternative. Avoidable costs also include annual capital recovery associated with investments required to maintain a unit as a capacity resource. This component of avoidable costs is termed the avoidable project investment recovery rate (APIR). Avoidable costs are the defined costs less net revenues from all other PJM markets and from unit-specific bilateral contracts. The specific components of avoidable costs are defined in the PJM Tariff.

Capacity resource owners could provide ACR data by providing their own unit-specific data, by selecting the default ACR values calculated by the MMU, by submitting an opportunity cost for a possible export, by inputting a transition adder or by using combinations of these options. The opportunity cost option for exports allows resource owners to input a documented export price as the opportunity cost offer for the unit. If the relevant RPM market clears above the opportunity cost, the unit's capacity is sold in the RPM market. If the opportunity cost is greater than the clearing price, the unit's capacity does not clear in the RPM market and it is available for export. The transition adder was added to the offer cap, if appropriate, regardless of the offer-cap calculation method.[32]

31 See PJM. "Open Access Transmission Tariff (OATT)," "Attachment DD: Reliability Pricing Model," First Revised Sheet No. 617 (Effective January 19, 2008), section 6.8 (b).

32 The transition adder, which is added to the calculated offer cap, is $10.00 per MW-day for delivery years 2007/2008 and 2008/2009 and $7.50 per MW-day for delivery year 2009/2010. It can be applied only up to 3,000 MW of unforced capacity per owner, only in unconstrained markets and only by those parent companies which own no more than 10,000 MW of unforced capacity in PJM.

Table 5-7 ACR statistics: 2009/2010 RPM Auctions

	2009/2010 BRA		2009/2010 Third IA	
Calculation Type	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered
Default ACR selected	377	34.5%	1	0.4%
ACR data input (non-APIR)	22	2.0%	0	0.0%
ACR data input (APIR)	129	11.8%	2	0.7%
Opportunity cost input	10	0.9%	2	0.7%
Transition adder only	12	1.1%	0	0.0%
Offer caps calculated	550	50.3%	5	1.9%
Uncapped new units	3	0.3%	6	2.2%
Generators capped at 1.1 times BRA clearing price	NA		255	95.5%
Generator price takers	540	49.4%	1	0.4%
Generating units offered	1,093	100.0%	267	100.0%
Demand resources offered	38		13	
Total capacity resources offered	1,131		280	

Table 5-8 ACR statistics: 2010/2011 through 2012/2013 RPM Auctions

	2010/2011 BRA		2011/2012 BRA		2011/2012 First IA		2012/2013 BRA	
Calculation Type	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered	Number of Resources	Percent of Generating Resources Offered
Default ACR selected	370	33.5%	301	26.8%	47	36.4%	476	42.0%
ACR data input (non-APIR)	20	1.8%	12	1.1%	18	14.0%	118	10.4%
ACR data input (APIR)	134	12.1%	133	11.8%	1	0.8%	2	0.2%
Opportunity cost input	8	0.7%	24	2.1%	2	1.6%	8	0.7%
Default ACR and opportunity cost input	0	0.0%	2	0.2%	0	0.0%	3	0.3%
Offer caps calculated	532	48.1%	472	42.0%	68	52.8%	607	53.6%
Uncapped new units	15	1.4%	20	1.8%	1	0.8%	11	1.0%
Generator price takers	557	50.5%	633	56.2%	60	46.4%	515	45.4%
Generating units offered	1,104	100.0%	1,125	100.0%	129	100.0%	1,133	100.0%
Demand resources offered	23		37		0		233	
Energy efficiency resources offered	0		0		0		53	
Total capacity resources offered	1,127		1,162		129		1,419	

Table 5-9 APIR statistics: 2009/2010 through 2012/2013 RPM Auctions[33,34,35]

		Weighted-Average ($ per MW-day UCAP)						
		Combined Cycle	Combustion Turbine	Oil or Gas Steam	SubCritical/ SuperCritical Coal	Other	Opportunity Costs	Total
2009/2010 BRA								
Non-APIR units	ACR	$37.74	$26.07	$80.09	$159.26	$84.07		$82.66
	Net revenues	$61.97	$23.08	$31.92	$321.88	$516.72		$162.48
	Offer caps	$14.76	$13.51	$49.81	$11.44	$1.36	$123.60	$26.32
APIR units	ACR	$58.12	$43.83	$129.59	$525.98	$30.71		$285.17
	Net revenues	$97.94	$16.10	$19.71	$322.91	$15.75		$172.57
	Offer caps	$17.93	$30.45	$109.88	$164.31	$22.45		$102.07
	APIR	$0.24	$22.86	$43.79	$386.13	$18.96		$195.85
	Maximum APIR effect							$383.79
2010/2011 BRA								
Non-APIR units	ACR	$34.39	$27.10	$67.57	$167.08	$82.55		$80.86
	Net revenues	$96.75	$18.81	$15.19	$302.79	$391.00		$151.31
	Offer caps	$10.13	$14.12	$52.38	$9.67	$4.53	$124.60	$20.98
APIR units	ACR	$61.61	$49.26	$152.09	$654.18	$34.62		$360.27
	Net revenues	$26.84	$10.32	$20.94	$525.48	$2.07		$263.27
	Offer caps	$37.30	$39.41	$131.15	$155.39	$32.55		$110.25
	APIR	$9.87	$30.93	$60.54	$521.16	$22.42		$272.18
	Maximum APIR effect							$577.03
2011/2012 BRA								
Non-APIR units	ACR	$39.52	$30.17	$72.20	$181.52	$62.54		$75.86
	Net revenues	$69.04	$20.16	$17.27	$466.41	$322.78		$173.54
	Offer caps	$11.76	$16.42	$62.13	$7.88	$11.50	$182.41	$45.80
APIR units	ACR	$61.66	$56.28	$184.34	$723.65	$36.03		$424.49
	Net revenues	$78.17	$10.35	$19.81	$531.93	$2.06		$286.80
	Offer caps	$34.69	$46.18	$164.54	$203.41	$33.97		$147.77
	APIR	$11.82	$37.28	$91.30	$578.47	$24.68		$324.58
	Maximum APIR effect							$523.26
2011/2012 First IA								
Non-APIR units	ACR	$54.15	$29.43	$71.79	$284.63	$30.04		$169.77
	Net revenues	$220.31	$44.98	$10.25	$298.96	$0.07		$195.83
	Offer caps	$2.66	$2.64	$61.54	$150.63	$29.97	$136.01	$78.56
APIR units	ACR	$220.20	$152.28	$194.25	$583.59			$326.57
	Net revenues	$81.72	$6.94	$23.64	$328.71			$128.90
	Offer caps	$138.48	$145.34	$170.62	$254.88			$197.67
	APIR	$220.19	$120.84	$82.87	$324.31			$170.61
	Maximum APIR effect							$468.26
2012/2013 BRA								
Non-APIR units	ACR	$41.84	$32.61	$75.47	$207.54	$57.18		$110.84
	Net revenues	$91.67	$35.29	$7.51	$396.82	$257.96		$208.65
	Offer caps	$5.28	$14.40	$67.96	$11.31	$15.63	$136.48	$21.55
APIR units	ACR	$218.10	$49.83	$177.52	$715.10	NA		$464.65
	Net revenues	$98.97	$15.62	$3.62	$508.00	NA		$302.04
	Offer caps	$119.12	$34.96	$173.89	$215.38	NA		$167.62
	APIR	$218.10	$26.59	$89.08	$559.97	NA		$351.74
	Maximum APIR effect							$1,155.57

33 The weighted-average offer cap can still be positive even when the weighted-average net revenues are higher than the weighted-average ACR due to the offer-cap minimum being zero. On a unit basis, if net revenues are greater than ACR, net revenues in an amount equal to the ACR are used in the calculation and the offer cap is zero.

34 This table has been updated since the MMU RPM Auction reports were posted. The 2010/2011 and 2011/2012 BRA values for Oil and Gas Steam and Sub Critical/Super Critical Coal for resources with an APIR component were updated due to a prior misclassification.

35 Statistics for the 2009/2010 Third IA are not included as 95.5 percent of the resources chose the offer cap option of 1.1 times the BRA clearing price.

2009/2010 RPM Base Residual Auction

As shown in Table 5-7, 1,093 generating resources submitted offers in the 2009/2010 RPM Auction as compared to 1,076 generating resources offered in the 2008/2009 RPM Auction. 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 posted by the MMU. Three new generation resources had uncapped offers while the remaining 540 generation resources were price takers, of which the offers for 514 resources were zero and the offers for 26 resources were set to zero because no data were submitted.[36] The transition adder was part of the offers on 206 resources, of which offers on 12 resources included only the transition adder. The transition adder had no impact on the clearing prices.

Of the 1,093 generating resources which submitted offers, 129 (11.8 percent) included an APIR component. (See Table 5-7.) As shown in Table 5-9, the weighted-averages for resources with APIR for ACR ($285.17 per MW-day) and offer caps ($102.07 per MW-day) were higher than the ACR ($82.66 per MW-day) and offer caps ($26.32 per MW-day) for resources without an APIR component, including resources for which the default value was selected. The APIR component added $195.85 per MW-day to the ACR value of the APIR resources.[37] The default ACR values include an average APIR of $0.91 per MW-day. The highest APIR for a technology ($386.13 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($383.79 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2009/2010 RPM Third Incremental Auction

As shown in Table 5-7, 267 generating resources submitted offers in the 2009/2010 RPM Third Incremental Auction. 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 posted by the MMU. 255 generation resources (95.6 percent) chose the option of 1.1 times the BRA clearing price as an offer cap, of which 160 resources submitted nonzero sell offers. Of the 267 generating units, the remaining six (2.2 percent) resources were uncapped new units while one (0.4 percent) resource did not elect the 1.1 times the BRA clearing price offer cap option.

2010/2011 RPM Base Residual Auction

As shown in Table 5-8, 1,104 generating resources submitted offers in the 2010/2011 RPM Auction as compared to 1,093 generating resources offered in the 2009/2010 RPM Auction. Unit-specific offer caps were calculated for 154 resources (13.9 percent) including 134 resources (12.1 percent) with an APIR component and 20 resources (1.8 percent) without an APIR component. Offer caps of all kinds were calculated for 532 resources (48.1 percent), of which 370 (33.5 percent) were based on the technology specific default (proxy) ACR posted by the MMU. There were 15 new generation resources with uncapped offers while the remaining 557 generation resources were price takers,

36 Generally, planned units are not subject to mitigation. The seven other planned units submitted zero price offers. See PJM “Open Access Transmission Tariff (OATT),” “Attachment DD: Reliability Pricing Model,” Substitute Second Revised Sheet No. 607 (Effective March 27, 2009), section 6.5 (a) ii.

37 Of the 129 units which had an APIR component, 109 units had current year capital dollars submitted of $2.5 billion on 14,519.2 MW UCAP. Twenty units had APIR based on the inclusion of 2007/2008 and 2008/2009 capital projects.

of which the offers for 546 resources were zero and the offers for 11 resources were set to zero because no data were submitted.[38]

Of the 1,104 generating resources which submitted offers, 134 (12.1 percent) included an APIR component. (See Table 5-8.) As shown in Table 5-9, the weighted-averages for resources with APIR for ACR ($360.27 per MW-day) and offer caps ($110.25 per MW-day) were higher than the ACR ($80.86 per MW-day) and offer caps ($20.98 per MW-day) for resources without an APIR component, including resources for which the default value was selected. The APIR component added $272.18 per MW-day to the ACR value of the APIR resources.[39] The default ACR values include an average APIR of $0.91 per MW-day. The highest APIR for a technology ($521.16 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($577.03 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2011/2012 RPM Base Residual Auction

As shown in Table 5-8, 1,125 generating resources submitted offers in the 2011/2012 RPM Auction as compared to 1,104 generating resources offered in the 2010/2011 RPM Auction. Unit-specific offer caps were calculated for 145 resources (12.9 percent of all generating resources offered) including 133 resources (11.8 percent) with an APIR component and 12 resources (1.1 percent) without an APIR component. Offer caps of all kinds were calculated for 472 resources (42.0 percent), of which 301 (26.8 percent) were based on the technology specific default (proxy) ACR posted by the MMU. There were 20 new generation resources with uncapped offers while the remaining 633 generation resources were price takers, of which the offers for 578 resources were zero and the offers for 55 resources were set to zero because no data were submitted.[40]

Of the 1,125 generating resources which submitted offers, 133 (11.8 percent) included an APIR component. (See Table 5-8.) As shown in Table 5-9, the weighted-averages for resources with APIR for ACR ($424.49 per MW-day) and offer caps ($147.77 per MW-day) were higher than the ACR ($75.86 per MW-day) and offer caps ($45.80 per MW-day) for resources without an APIR component, including resources for which the defaults ACR value was selected. The APIR component added $324.58 per MW-day to the ACR value of the APIR resources.[41] The default ACR values include an average APIR of $0.91 per MW-day. The highest APIR for a technology ($578.47 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($523.26 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

2012/2013 RPM Base Residual Auction

As shown in Table 5-8, 1,133 generating resources submitted offers in the 2012/2013 RPM Auction as compared to 1,125 generating resources offered in the 2011/2012 RPM Auction. Unit-specific offer caps were calculated for 120 resources (10.6 percent of all generating resources offered) including 118 resources (10.4 percent) with an APIR component and 2 resources (0.2 percent) without an APIR component. Offer caps of all kinds were calculated for 607 resources (53.6 percent),

38 Planned units are subject to mitigation only under specific circumstances defined in the tariff. Some of the uncapped planned units submitted zero price offers.
39 The 134 units which had an APIR component submitted $1.5 billion for capital projects associated with 12,645.3 MW UCAP.
40 Planned units are subject to mitigation only under specific circumstances defined in the tariff. Some of the 20 uncapped planned units submitted zero price offers.
41 The 133 units which had an APIR component submitted $613.8 million for capital projects associated with 8,813.7 MW UCAP.

of which 476 (42.0 percent) were based on the technology specific default (proxy) ACR posted by the MMU. There were 11 new generation resources with uncapped offers while the remaining 515 generation resources were price takers, of which the offers for 512 resources were zero and the offers for three resources were set to zero because no data were submitted.[42]

Of the 1,133 generating resources which submitted offers, 118 (10.4 percent) included an APIR component. (See Table 5-8.) As shown in Table 5-9, the weighted-averages for resources with APIR for ACR ($464.65 per MW-day) and offer caps ($167.62 per MW-day) were higher than the ACR ($110.84 per MW-day) and offer caps ($21.55 per MW-day) for resources without an APIR component, including resources for which the defaults ACR value was selected. The APIR component added $351.74 per MW-day to the ACR value of the APIR resources.[43] The default ACR values include an average APIR of $1.31 per MW-day. The highest APIR for a technology ($559.97 per MW-day) was for subcritical/supercritical coal resources. The maximum APIR effect ($1,155.57 per MW-day) is the maximum amount by which an offer cap was increased by APIR.

Market Performance

Prices for capacity decreased from $111.92 per MW-day for the RTO for the 2008/2009 BRA to $102.04 per MW-day for the 2009/2010 BRA. (See Table 5-10.)

Annual weighted average capacity prices increased from a CCM/RPM combined, weighted average price of $5.73 per MW-day in 2006 to an RPM weighted-average price of $173.15 per MW-day in 2010 and then declined to $90.08 per MW-day in 2012. Figure 5-1 presents capacity market prices on a calendar year basis for the entire history of the PJM capacity markets.

As Table 5-5 shows, 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, because of a 2,873.4 MW increase in ILR and a 2,634.2 MW increase in cleared capacity, offset by an increase in the reliability requirement of 2,253.2 MW.[44] The increase in unforced capacity of 2,038.5 MW was the result of a decrease in exports of 1,643.2 MW, a 350.2 MW growth in total internal capacity, plus an increase in imports of 45.1 MW.[45] (See Table 5-5.)

42 Planned units are subject to mitigation only under specific circumstances defined in the tariff. Some of the 11 uncapped planned units submitted zero price offers.

43 The 118 units which had an APIR component submitted $567.2 million for capital projects associated with 11,124.8 MW of UCAP.

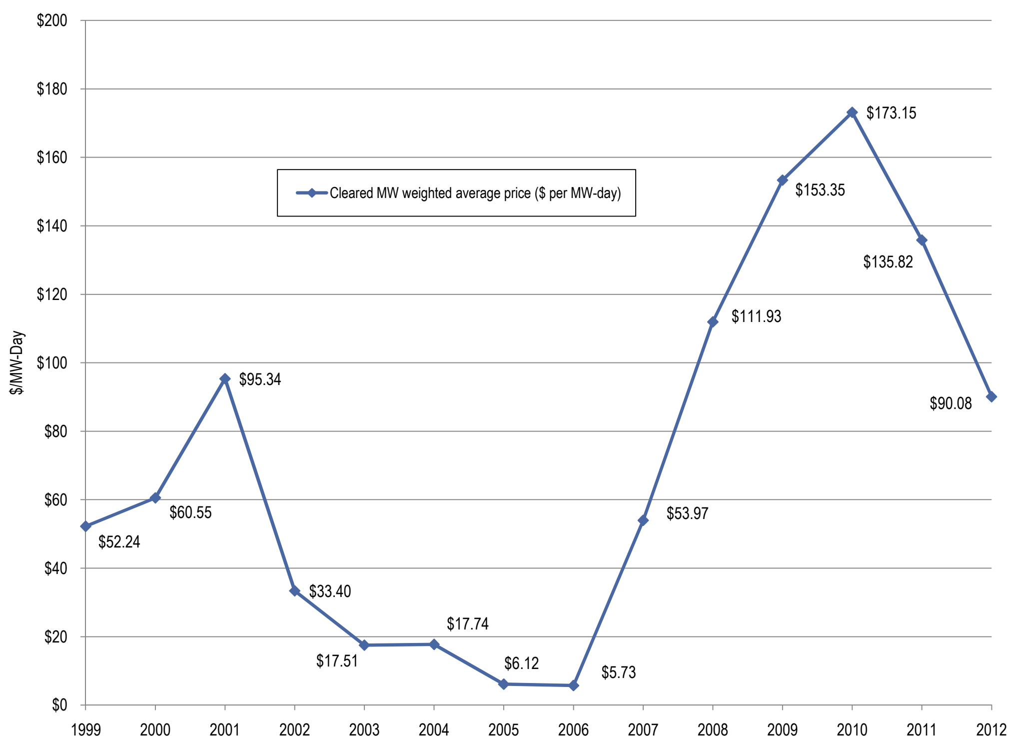
44 Prior to the 2012/2013 delivery year, net excess under RPM was calculated as cleared capacity less the reliability requirement plus ILR. For 2008/2009 and 2009/2010, certified ILR was used in the calculation. For 2010/2011, forecast ILR less FRR DR is used in the calculation because PJM forecast ILR 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.

45 Unforced capacity is defined as the UCAP value of iron in the ground plus the UCAP value of imports less the UCAP value of exports.

Table 5-10 Capacity prices: 2007/2008 through 2012/2013 RPM Auctions

	RPM Clearing Price ($ per MW-day)						
	RTO	MAAC+APS	MAAC	EMAAC	SWMAAC	DPL South	PSEG North
2007/2008 BRA	$40.80			$197.67	$188.54		
2008/2009 BRA	$111.92			$148.80	$210.11		
2008/2009 Third IA	$10.00				$223.85		
2009/2010 BRA	$102.04	$191.32			$237.33		
2009/2010 Third IA	$40.00	$86.00					
2010/2011 BRA	$174.29					$178.27	
2011/2012 BRA	$110.00						
2011/2012 First IA	$55.00						
2012/2013 BRA	$16.46		$133.37	$139.73		$222.30	$185.00

Figure 5-1 History of capacity prices: Calendar year 1999 through 2012[46]



46 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.

Table 5-11 RPM cost to load: 2009/2010 through 2012/2013 RPM Auctions[47,48,49]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2009/2010 BRA			
RTO	$104.82	56,696.9	$2,169,117,837
MAAC+APS	$193.78	60,984.3	$4,313,445,473
SWMAAC	$224.86	16,205.7	$1,330,043,812
2010/2011 BRA			
RTO	$174.29	129,340.6	$8,228,112,710
DPL	$178.27	4,507.5	$293,295,977
2011/2012 BRA			
RTO	$110.04	133,815.3	$5,389,363,034
2012/2013 BRA			
RTO	$16.46	69,648.3	$418,440,022
MAAC	$129.63	31,338.7	$1,482,789,024
EMAAC	$135.18	21,171.5	$1,044,616,630
DPL	$162.99	4,685.6	$278,752,670
PSEG	$149.65	12,642.7	$690,572,720

Table 5-11 shows the RPM annual charges to load. For the 2009/2010 planning year, annual charges totaled approximately $7.8 billion.

2009/2010 RPM Base Residual Auction

Cleared capacity 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 BRA.

RTO

Table 5-12 shows total RTO offer data for the 2009/2010 RPM Auction, which includes the MAAC+APS and SWMAAC LDAs. 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

47 The annual charges are calculated using the rounded, net load prices as posted in the PJM Base Residual Auction results.

48 There is no separate obligation for DPL South as the DPL South LDA is completely contained within the DPL Zone. There is no separate obligation for PSEG North as the PSEG North LDA is completely contained within the PSEG Zone.

49 Prior to the 2009/2010 delivery year, the Final UCAP Obligation is determined after the clearing of the Second IA. For the 2009/2010 through 2011/2012 delivery years, the Final UCAP Obligations are determined after the clearing of the Third IA. Effective with the 2012/2013 delivery year, the Final UCAP Obligation is determined after the clearing of the final incremental auction. Prior to the 2012/2013 delivery year, the Final Zonal Capacity Prices are determined after certification of ILR. Effective with the 2012/2013 delivery year, the Final Zonal Capacity Prices are determined after the final incremental auction. The 2010/2011 Net Load Prices are not finalized. The 2011/2012 and 2012/2013 Net Load Prices and Obligation MW are not finalized.

Auction, excluding external units, and also includes owners' modifications to installed capacity ratings which are permitted under the PJM Reliability Assurance Agreement (RAA) and associated manuals.[50]

After accounting for FRR committed resources and for imports, RPM capacity was 136,300.4 MW.[51] This amount was reduced by exports of 2,194.9 MW[52] and 104.3 MW which were excused from the RPM must-offer requirement as a result of non-utility generator (NUG) ownership questions (57.2 MW), planned reductions due to environmental regulations (33.5 MW), planned capacity withdrawals (5.5 MW), generation moving behind the meter (4.0 MW) and other factors (4.1 MW). Subtracting 450.2 MW of FRR optional volumes not offered, resulted in 133,551.0 MW that were available to be offered into the auction.[53] Offered volumes included 1,151.3 MW of EFORd offer segments. All capacity resources were offered into the RPM Auction. Eight new CT units (380.2 MW), one new diesel unit (7.5 MW) and one new steam unit (49.8 MW) were offered into the auction.

The downward sloping demand curve resulted in more capacity cleared in the market than the reliability requirement. The 132,231.8 unforced 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 (IRM of 15.0 percent).[54,55,56] As shown in Figure 5-2, the downward sloping demand curve resulted in a price of $102.04 per MW-day. Net excess was 8,265.5 MW, which was an increase of 3,254.4 MW from the net excess of 5,011.1 MW in the 2008/2009 RPM Auction. (See Table 5-5.) This increase was mainly because of an increase in ILR from 3,608.1 MW to 6,481.5 MW. Certified ILR was 6,481.5 MW.

As shown in Table 5-12, the net load price that LSEs will pay is $104.82 per MW-day in the RTO area not included in the constrained LDAs. This value is the final zonal capacity price. The final zonal capacity price is the resource-clearing price adjusted for differences between the certified ILR for the delivery year and the forecasted RTO ILR obligation.

50 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region" (June 1, 2007) (Accessed January 20, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/raa.ashx> (882.99 KB).

51 The FRR alternative allows an LSE, subject to certain conditions, to avoid direct participation in the RPM Auctions. The LSE is required to submit an FRR capacity plan to satisfy the unforced capacity obligation for all load in its service area.

52 If all of the exports had been offered into the auction at $0.00 per MW-day, the clearing price would have been approximately $82.00 per MW-day.

53 FRR entities are allowed to offer into the RPM Auction excess volumes above their FRR quantities, subject to a sales' cap amount. The 450.2 MW are excess volumes included in the sales' cap amount which were not offered into the auction.

54 Both the reserve margin calculation and IRM include FRR resources and FRR load and are on an ICAP basis.

55 The RTO reliability requirement, which is after FRR adjustments, is plotted on the variable resource requirement (VRR) curve as the reliability requirement less the ILR forecast obligation adjusted for any FRR DR.

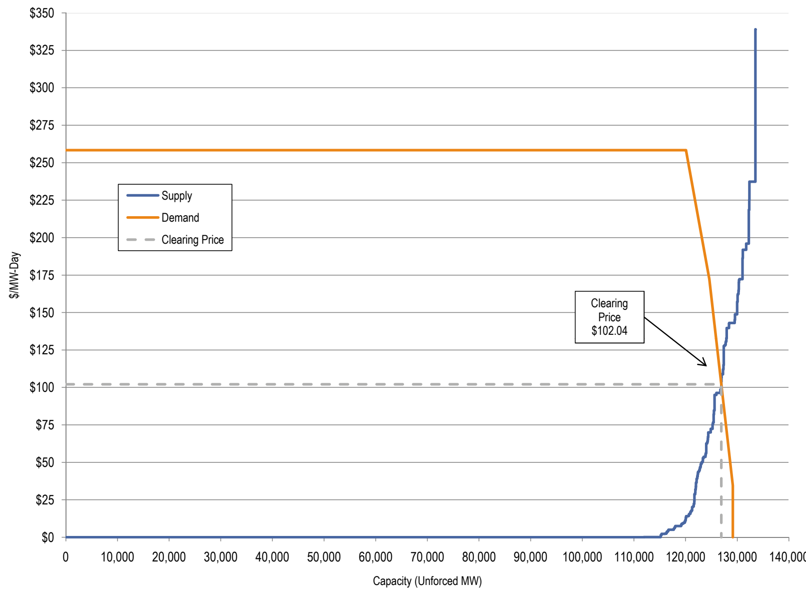
56 The demand curve UCAP quantities are based on three points, which are ratios of the installed reserve margin (IRM=15.0 percent) times the reliability requirement, less the forecast RTO ILR obligation. For the three points, the ratios are 1.12/1.15, 1.16/1.15 and 1.20/1.15. For these three points the UCAP prices are based on factors multiplied by net cost of net entry (CONE) divided by one minus the pool-wide EFORd. Net CONE is defined as CONE minus the energy and ancillary service revenue offset (E&AS). For the three points, the factors are 1.5, 1.0 and 0.2. For 2009/2010, CONE was $197.83 per MW-day and E&AS was $36.12 MW-day.

Table 5-12 RTO offer statistics: 2009/2010 RPM Base Residual Auction[57]

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total Internal RTO Capacity (Gen and DR)	166,639.7	157,318.2		
FRR	(25,316.2)	(23,523.2)		
Imports	2,652.5	2,505.4		
RPM Capacity	143,976.0	136,300.4		
Exports	(2,376.2)	(2,194.9)		
FRR Optional	(552.5)	(450.2)		
Excused	(136.8)	(104.3)		
Available	140,910.5	133,551.0	100.0%	100.0%
Generation Offered	140,003.6	132,614.2	99.4%	99.3%
DR Offered	906.9	936.8	0.6%	0.7%
Total Offered	140,910.5	133,551.0	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	133,859.0	126,917.1	95.0%	95.0%
Cleared in LDAs	5,594.4	5,314.7	4.0%	4.0%
Total Cleared	139,453.4	132,231.8	99.0%	99.0%
Uncleared in RTO	895.5	869.0	0.6%	0.7%
Uncleared in LDAs	561.6	450.2	0.4%	0.3%
Total Uncleared	1,457.1	1,319.2	1.0%	1.0%
Reliability Requirement		130,447.8		
Total Cleared		132,231.8		
ILR Certified		6,481.5		
RPM Net Excess/(Deficit)		8,265.5		
Resource Clearing Price ($ per MW-day)		$102.04	A	
Final Zonal Capacity Price ($ per MW-day)		$104.82	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$0.00	C	
Final Zonal ILR Price ($ per MW-day)		$102.04	A-C	
Net Load Price ($ per MW-day)		$104.82	B-C	

57 Prices are only for those generating units outside of MAAC+APS and SWMAAC.

Figure 5-2 RTO market supply/demand curves: 2009/2010 RPM Base Residual Auction[58]



MAAC+APS

Table 5-13 shows total MAAC+APS offer data for the 2009/2010 RPM Auction. Total internal MAAC+APS unforced capacity of 73,012.9 MW includes all generating units and DR that qualified as a PJM capacity resource, excluding external units, and also includes owners' modifications to ICAP ratings. Including imports of 89.3 MW into MAAC+APS, RPM unforced capacity was 73,102.2 MW.[59] This amount was reduced by 104.3 MW which were excused from the RPM must-offer requirement as a result of non-utility (NUG) ownership questions (57.2 MW), planned reductions due to environmental regulations (33.5 MW), planned capacity withdrawals (5.5 MW) generation moving behind the meter (4.0 MW) and other factors (4.1 MW), resulting in 72,997.9 MW that were available to be offered into the auction. All capacity resources were offered into the RPM Auction.

Of the 72,547.7 MW cleared in MAAC+APS, 67,233.0 MW were cleared in the RTO before MAAC+APS became constrained. Once the constraint was binding, based on the 4,941.0 MW CETL value, only the incremental supply located in MAAC+APS was available to meet the incremental demand in the LDA. 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, as shown in Figure 5-3. The price was determined by the intersection of the incremental supply and demand curves. The uncleared MW were the result of offer prices which exceeded the demand curve.

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.

58 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve excludes incremental demand which cleared in MAAC+APS and SWMAAC.

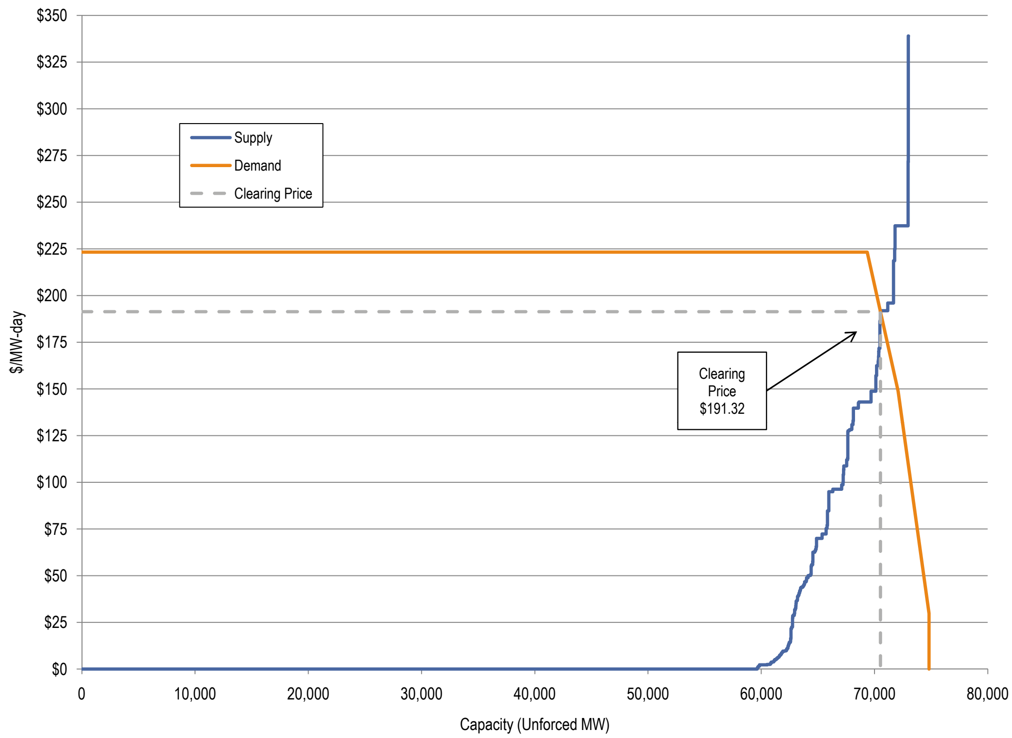
59 Rules for RPM auctions state that imports are modeled in the unconstrained region of the RTO. See PJM. "Manual 18: PJM Capacity Market," Revision 8 (Effective January 1, 2010), p. 24, <http://www.pjm.com/documents/~/media/documents/manuals/m18.ashx> (1.27 MB). The import MW into MAAC+APS consist of MW under a grandfathered agreement related to Rural Electric Cooperatives (RECs) generation.

As shown in Table 5-13, the net load price that LSEs will pay is $193.77 per MW-day. This value is the final zonal capacity price ($196.54 per MW-day) less the final CTR credit rate ($2.77 per MW-day). The CTR MW value allocated to load in an LDA is the LDA UCAP obligation less the cleared generation internal to the LDA less the ILR forecast for the LDA. This MW value is multiplied by the locational price adder for the LDA to arrive at the economic value of the CTRs allocated to the load in the LDA. This value is then divided by the LDA UCAP obligation to arrive at the final CTR credit rate for the LDA. The final CTR credit rate is an allocation of the economic value of transmission import capability that exists in constrained LDAs and serves to offset a portion of the locational price adder charged to load in constrained LDAs.

Table 5-13 MAAC+APS offer statistics: 2009/2010 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total Internal MAAC+APS Capacity (Gen and DR)	77,870.6	73,012.9		
Imports	89.3	89.3		
RPM Capacity	77,959.9	73,102.2		
Exports	0.0	0.0		
Excused	(136.8)	(104.3)		
Available	77,823.1	72,997.9	100.0%	100.0%
Generation Offered	77,028.6	72,177.3	99.0%	98.9%
DR Offered	794.5	820.6	1.0%	1.1%
Total Offered	77,823.1	72,997.9	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	71,667.1	67,233.0	92.1%	92.1%
Cleared in LDAs	5,594.4	5,314.7	7.2%	7.3%
Total Cleared	77,261.5	72,547.7	99.3%	99.4%
Uncleared	561.6	450.2	0.7%	0.6%
Reliability Requirement		77,902.9		
Total Cleared		72,547.7		
CETL		4,941.0		
Total Resources		77,488.7		
ILR Certified		3,081.0		
RPM Net Excess/(Deficit)		2,666.8		
Resource Clearing Price ($ per MW-day)		$191.32	A	
Final Zonal Capacity Price ($ per MW-day)		$196.54	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$2.77	C	
Final Zonal ILR Price ($ per MW-day)		$188.55	A-C	
Net Load Price ($ per MW-day)		$193.77	B-C	

Figure 5-3 MAAC+APS supply/demand curves: 2009/2010 RPM Base Residual Auction[60]



SWMAAC

Table 5-14 shows total SWMAAC offer data for the 2009/2010 RPM Auction. Total internal SWMAAC unforced capacity of 10,345.2 MW includes all generating units and DR that qualified as a PJM capacity resource, excluding external units, and also includes owners' modifications to ICAP ratings. Since there were no imports from outside PJM into SWMAAC, RPM unforced capacity was 10,345.2 MW. This amount was reduced by 33.5 MW which were excused from the RPM must-offer requirement as a result of planned reductions due to environmental regulations, resulting in 10,311.7 MW that were available to be offered into the auction. All capacity resources were offered into the RPM Auction.

Of the 9,914.6 MW cleared in SWMAAC, 6,202.3 MW had cleared in the RTO before SWMAAC became constrained. Once the constraint was binding, based on the 6,391.0 CETL value, only the incremental supply in SWMAAC was available to meet incremental demand in the LDA. Of the 2,413.7 MW of incremental supply, 2,016.6 MW cleared, which resulted in a resource clearing price of $237.33 per MW-day. (See Figure 5-4)

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.

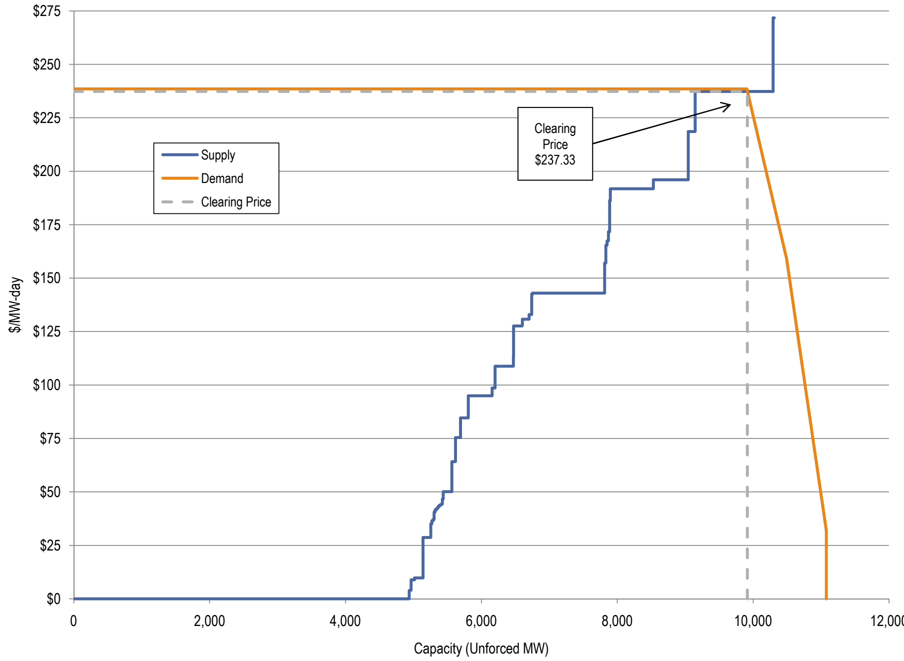
60 The supply curve includes all supply offers at the lower of offer price or offer cap. The demand curve excludes incremental demand which cleared in SWMAAC.

As shown in Table 5-14, the net load price that LSEs will pay is $224.59 per MW-day. This value is the final zonal capacity price ($243.80 per MW-day) less the final CTR credit rate ($19.21 per MW-day).

Table 5-14 SWMAAC offer statistics: 2009/2010 RPM Base Residual Auction

	ICAP (MW)	UCAP (MW)	Percent of Available ICAP	Percent of Available UCAP
Total Internal SWMAAC Capacity (Gen and DR)	11,448.6	10,345.2		
Imports	0.0	0.0		
RPM Capacity	11,448.6	10,345.2		
Exports	0.0	0.0		
Excused	(37.0)	(33.5)		
Available	11,411.6	10,311.7	100.0%	100.0%
Generation Offered	11,066.7	9,955.4	97.0%	96.5%
DR Offered	344.9	356.3	3.0%	3.5%
Total Offered	11,411.6	10,311.7	100.0%	100.0%
Unoffered	0.0	0.0	0.0%	0.0%
Cleared in RTO	7,001.2	6,202.3	61.4%	60.1%
Cleared in MAAC+APS	1,784.3	1,695.7	15.6%	16.4%
Cleared in LDA	2,146.2	2,016.6	18.8%	19.6%
Total Cleared	10,931.7	9,914.6	95.8%	96.1%
Uncleared	479.9	397.1	4.2%	3.9%
Reliability Requirement		16,318.8		
Total Cleared		9,914.6		
CETL		6,391.0		
Total Resources		16,305.6		
ILR Certified		519.3		
RPM Net Excess/(Deficit)		506.1		
Resource Clearing Price ($ per MW-day)		$237.33	A	
Final Zonal Capacity Price ($ per MW-day)		$243.80	B	
Final Zonal CTR Credit Rate ($ per MW-day)		$19.21	C	
Final Zonal ILR Price ($ per MW-day)		$218.12	A-C	
Final Net Load Price ($ per MW-day)		$224.59	B-C	

Figure 5-4 SWMAAC supply/demand curves: 2009/2010 RPM Base Residual Auction



2009/2010 RPM Third Incremental Auction

Under RPM, the Third Incremental Auction, which is held in January prior to the start of the delivery year, allows capacity resource owners to buy and sell capacity to accommodate adjustments to participants' resource positions as a result of resource retirements, cancellations, delays or changes in a resource's EFORd. Prior to the 2012/2013 delivery year, the demand curve in the Third Incremental Auction is entirely a function of demand bids, and there is no administrative market demand curve.

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.

RTO

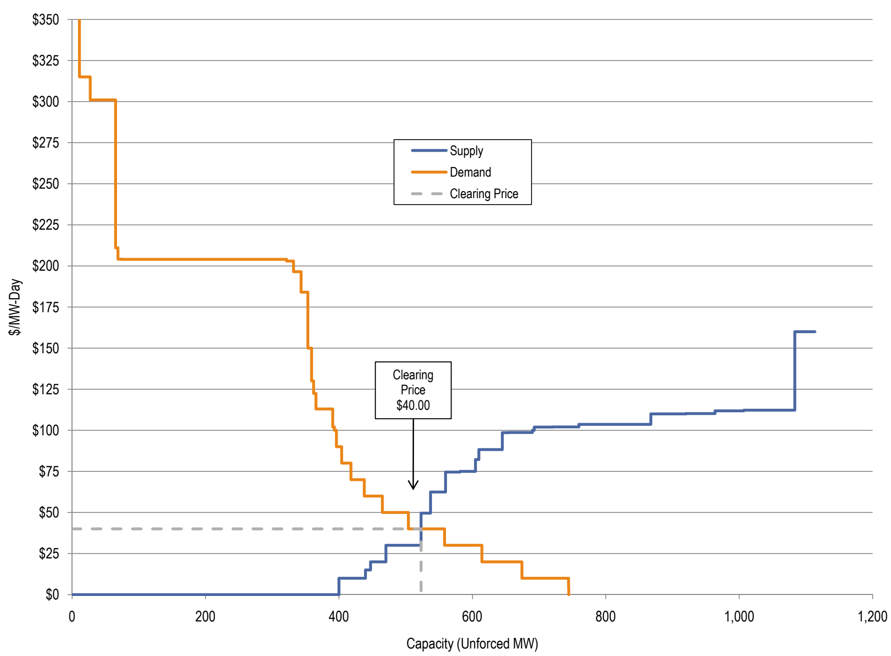
Table 5-15 shows total RTO offer and bid data for the 2009/2010 RPM Third Incremental Auction. There were 3,255.8 MW offered into the incremental auction while buy bids totaled 2,697.6 MW. The offered volumes came from uncleared offers from the 2009/2010 BRA, capacity and DR modifications to existing capacity resources, additional capacity from resources that were not previously capacity resources, and additional UCAP due to improved EFORds. Buy bids were submitted to cover short positions due to deratings and EFORd increases or because participants wished to purchase additional capacity. No EFORd offer segments were permitted in this auction because the delivery year EFORds were known for this auction and the EFORd risk was therefore zero. Cleared volumes in the RTO were 1,798.4 MW, resulting in an RTO clearing price of $40.00

per MW-day (See Figure 5-5.) The price was set by a demand bid. The RTO clearing price in the 2009/2010 BRA was $102.04 per MW-day. The 1,457.4 MW of uncleared volumes can be used as replacement volumes or traded bilaterally.

Table 5-15 RTO offer statistics: 2009/2010 RPM Third Incremental Auction

	Offered (Supply)		Bid (Demand)
	ICAP (MW)	UCAP (MW)	UCAP (MW)
Generation	2,918.7	2,724.4	
DR	514.6	531.4	
Total	3,433.3	3,255.8	2,697.6
Cleared in RTO	539.9	523.1	523.1
Cleared in MAAC+APS	1,364.1	1,275.3	1,275.3
Total cleared	1,904.0	1,798.4	1,798.4
Uncleared in RTO	589.6	590.4	221.3
Uncleared in MAAC+APS	939.7	867.0	677.9
Total uncleared	1,529.3	1,457.4	899.2
Resource clearing price ($ per MW-day)	$40.00		

Figure 5-5 RTO supply/demand curves: 2009/2010 RPM Third Incremental Auction[61,62]



61 The supply curve includes all supply offers at the lower of offer price or offer cap.
62 For ease of viewing, the graph was truncated at $350 per MW-day and does not show a buy bid of approximately $1,000 per MW-day.

MAAC+APS

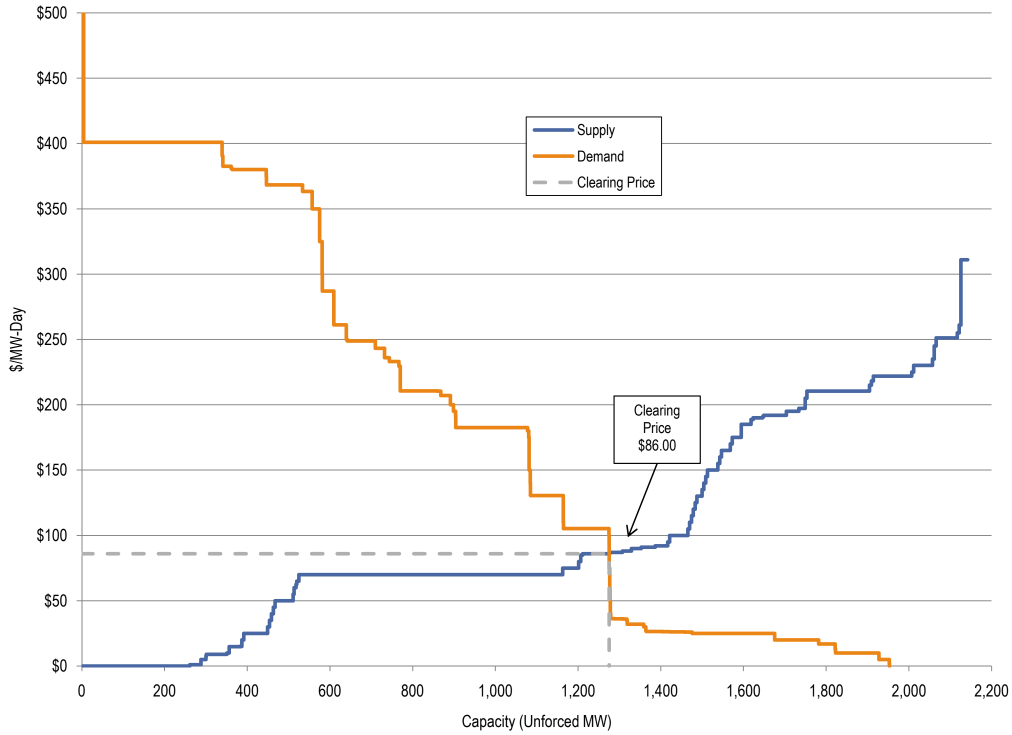
Table 5-16 shows total MAAC+APS offer and bid data for the 2009/2010 RPM Third Incremental Auction. There were 2,142.3 MW in MAAC+APS offered into the auction while buy bids in MAAC+APS totaled 1,953.2 MW. The offered volumes came from uncleared offers from the 2009/2010 BRA, capacity and DR modifications to existing capacity resources, additional capacity from resources that were not previously capacity resources, and additional UCAP due to improved EFORds. Cleared volumes in MAAC+APS were 1,275.3 MW, resulting in a MAAC+APS clearing price of $86.00 per MW-day. (See Figure 5-6) The MAAC+APS clearing price in the 2009/2010 BRA was $191.32 per MW-day.

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

Table 5-16 MAAC+APS offer statistics: 2009/2010 RPM Third Incremental Auction

	Offered (Supply)		Bid (Demand)
	ICAP (MW)	UCAP (MW)	UCAP (MW)
Generation	2,043.3	1,873.3	
DR	260.5	269.0	
Total	2,303.8	2,142.3	1,953.2
Cleared in RTO	487.3	462.9	
Cleared in MAAC+APS	876.8	812.4	
Total cleared	1,364.1	1,275.3	1,275.3
Uncleared	939.7	867.0	677.9
Resource clearing price ($ per MW-day)	$86.00		

Figure 5-6 MAAC+APS supply/demand curves: 2009/2010 RPM Third Incremental Auction[63]



Generator Performance

Generator performance results from the interaction between the physical nature of the units and the level of expenditures made to maintain the capability of the units, which in turn is a function of incentives from energy, ancillary services and capacity markets. Generator performance can be measured using indices calculated from historical data. Generator performance indices include those based on total hours in a period (generator performance factors) and those based on hours when units are needed to operate by the system operator (generator forced outage rates).[64]

Generator Performance Factors

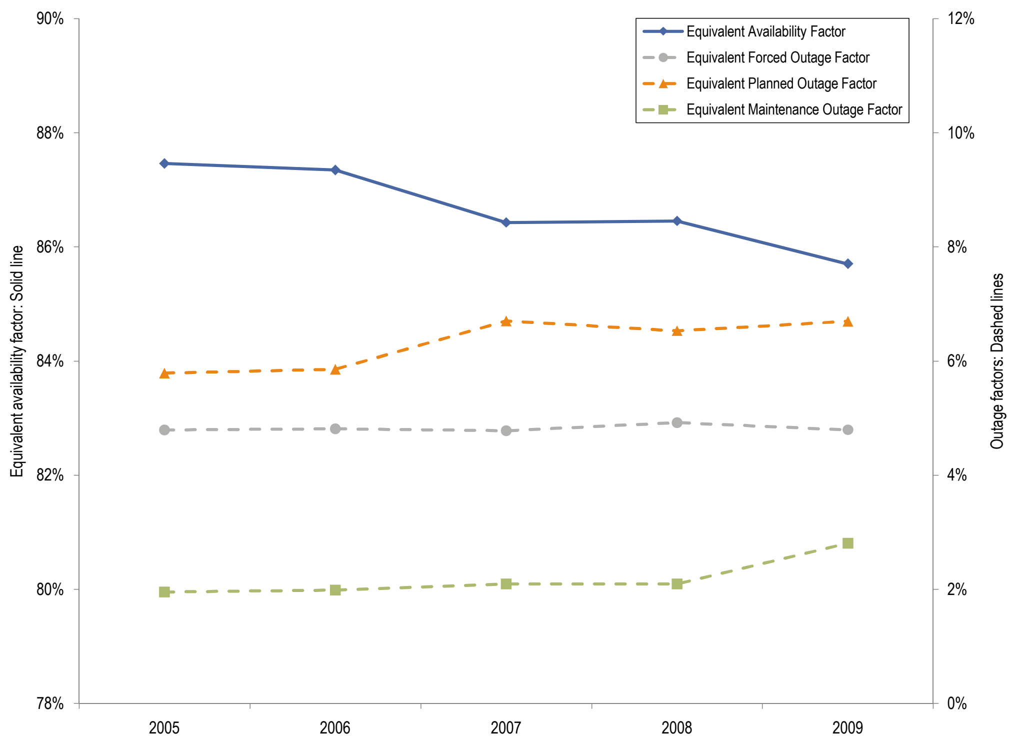
Generator performance factors are based on a defined period, usually a year, and are directly comparable.[65] Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the

63 The supply curve includes all supply offers at the lower of offer price or offer cap.
64 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM GADS database. This set of capacity resources may include generators in addition to those in the set of generators committed as resources in the RPM.
65 Data from all PJM capacity resources for the years 2005 through 2009 were analyzed.

three outage factors include all the hours when a unit is unavailable. The EMOF is the proportion of hours in a year when a unit is unavailable because of maintenance outages and maintenance deratings. The EPOF is the proportion of hours in a year when a unit is unavailable because of planned outages and planned deratings. The EFOF is the proportion of hours in a year when a unit is unavailable because of forced outages and forced deratings.

The PJM aggregate EAF decreased from 86.5 percent in 2008 to 85.7 percent in 2009. The EFOF decreased 0.126 percentage points from 2008 to 4.796 percent in 2009, while the EPOF increased by 0.165 percentage points to 6.694 and the EMOF increased 0.714 percentage points to 2.808.[66] (See Figure 5-7)

Figure 5-7 PJM equivalent outage and availability factors: Calendar years 2005 to 2009



Generator Forced Outage Rates

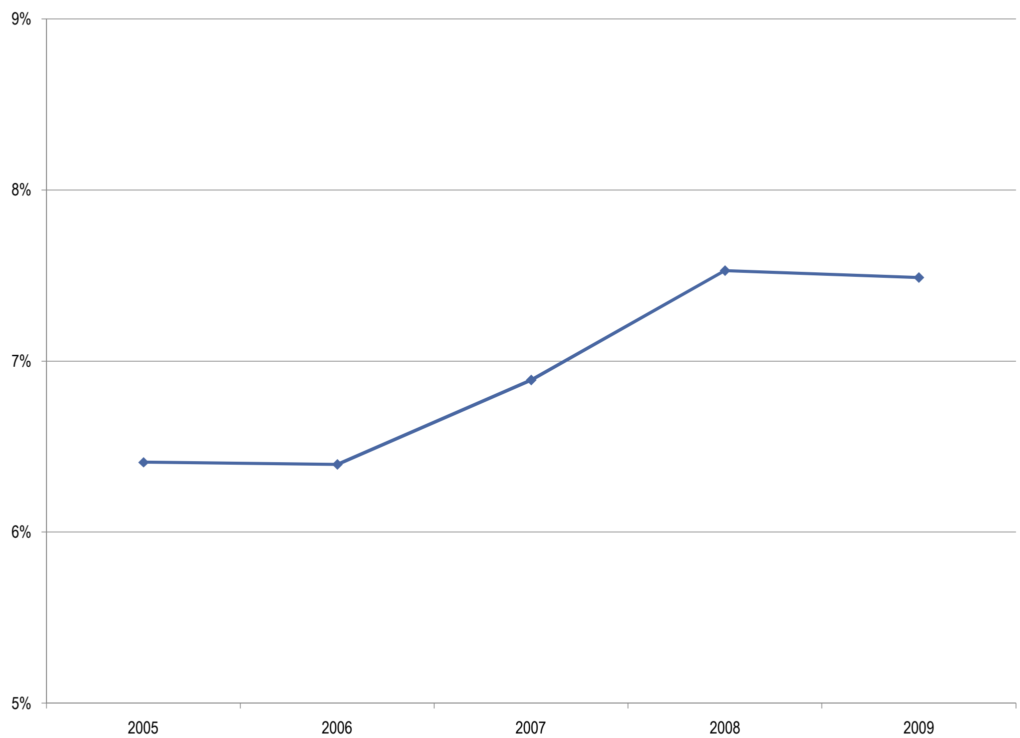
The equivalent demand forced outage rate (EFORd) (generally referred to as the forced outage rate) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd is calculated using historical performance data. PJM systemwide EFORd is a capacity-weighted average of individual unit EFORd. Unforced capacity in the PJM Capacity Market for any individual generating unit is equal to one minus the EFORd adjusted to exclude Outside Management Control (OMC) events multiplied by the unit's

66 The performance factor data include all units from PJM. Results for prior years may be different from previous reports as corrections can be made at any time with permission from the PJM GADS administrators. Data are for the year ending December 31, 2009, as downloaded from the PJM GADS database on February 23, 2010.

net dependable summer capability. The PJM Capacity Market creates an incentive to minimize the forced outage rate because the amount of capacity resources available to sell from a unit (unforced capacity) is inversely related to the forced outage rate.

EFORd calculations use historical data, including equivalent forced outage hours,[67] service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[68] The average PJM EFORd changed from 6.4 percent in 2005 and 2006 to 6.9 percent in 2007 and to 7.5 percent in 2008 and 2009.[3] 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.[69] If this unit were excluded from the results, 2009 EFORd would decrease to 6.9 percent. Figure 5-8 shows the average EFORd since 2005 for all units in PJM.

Figure 5-8 Trends in the PJM equivalent demand forced outage rate (EFORd): Calendar years 2005 to 2009



Distribution of EFORd

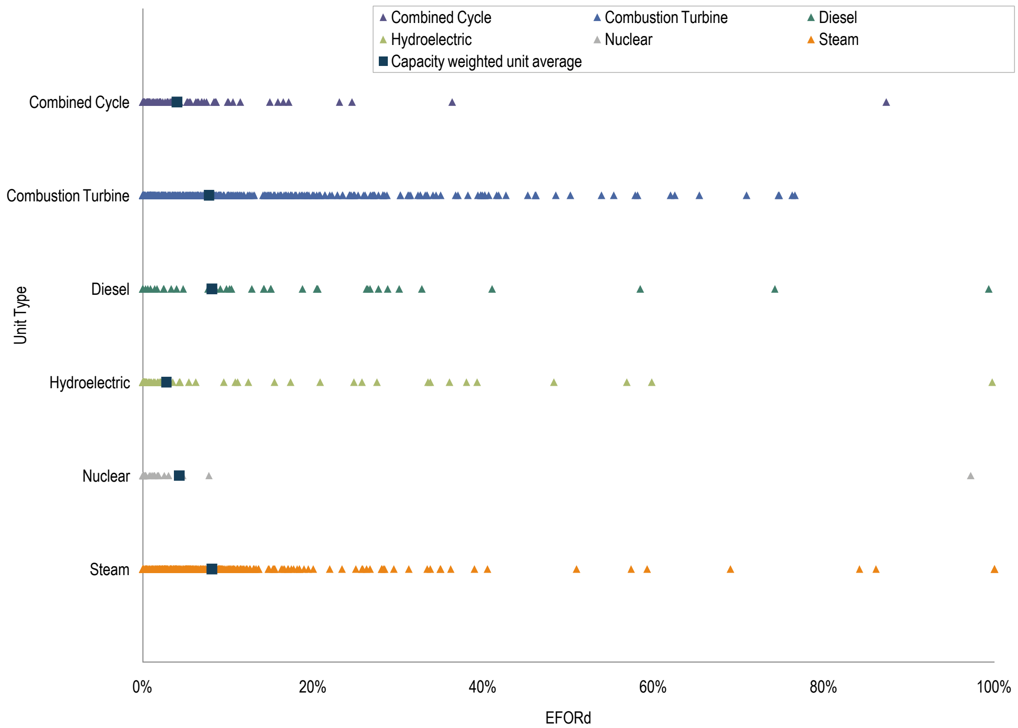
The average EFORd results do not show the actual underlying pattern of EFORd rates by unit type. The distribution of EFORd by unit type is shown in Figure 5-9. Each generating unit is represented by a single point, and the capacity weighted unit average is represented by a solid square.

67 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.

68 See PJM. "Manual 22: Generator Resource Performance Indices," Revision 15 (June 1, 2007), Equations 2 through 5.

69 "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 5-9 PJM 2009 Distribution of EFORd data by unit type



Components of EFORd

Table 5-17 compares PJM EFORd data by unit type to the five-year North American Electric Reliability Council (NERC) average EFORd data for corresponding unit types. The 2009 PJM forced outage rates for combined cycle, diesel and hydroelectric units were below the NERC five-year averages. The 2009 PJM EFORd for combustion turbine, nuclear and fossil steam units exceeded the NERC averages.[70]

Table 5-17 Five-year PJM EFORd data comparison to NERC five-year average for different unit types: Calendar years 2005 to 2009

	2005	2006	2007	2008	2009	NERC EFORd 2004 to 2008 Average
Combined Cycle	5.0%	4.3%	3.4%	3.4%	3.8%	6.1%
Combustion Turbine	8.9%	9.4%	11.0%	11.0%	9.8%	8.5%/8.3%
Diesel	14.0%	13.2%	12.0%	11.4%	10.2%	10.5%
Hydroelectric	2.5%	1.9%	2.1%	2.0%	3.2%	4.7%
Nuclear	1.6%	1.4%	1.4%	1.9%	4.1%	3.2%
Steam	8.1%	8.2%	9.1%	10.1%	9.3%	6.9%
Total	6.4%	6.4%	6.9%	7.5%	7.5%	NA

70 NERC defines combustion turbines in two categories: jet engines and gas turbines. The EFORd for the 2004 to 2008 period are 8.5 percent for jet engines and 8.3 percent for gas turbines per NERC's GADS "2004-2008 Generating Availability Report"<http://www.nerc.com/files/gar2008.zip>(2.46 MB). Also, the NERC average for fossil steam units is a unit-year-weighted value for all units reporting. The PJM values are weighted by capability for each calendar year.

Table 5-18 shows the contribution of each unit type to the system EFORd, calculated as the total forced MW for the unit type divided by the total capacity of the system.[71] Forced MW for a unit type is the EFORd multiplied by the generator's net dependable summer capability.

Table 5-18 Contribution to EFORd for specific unit types (Percentage points): Calendar years 2005 to 2009[72]

	2005	2006	2007	2008	2009	Change in 2009 from 2008
Combined Cycle	0.6	0.5	0.4	0.5	0.5	0.0
Combustion Turbine	1.3	1.4	1.6	1.7	1.5	(0.1)
Diesel	0.0	0.0	0.0	0.0	0.0	(0.0)
Hydroelectric	0.1	0.1	0.1	0.1	0.1	0.1
Nuclear	0.3	0.3	0.2	0.4	0.8	0.4
Steam	4.1	4.1	4.2	5.0	4.6	(0.4)
Total	6.4	6.4	6.9	7.5	7.5	(0.0)

Steam units continue to be the largest contributor to overall PJM EFORd. The decrease in contribution to EFORd across most unit types with the exception of nuclear is due to a significant increase in the contribution of nuclear EFORd to overall EFORd.

Duty Cycle and EFORd

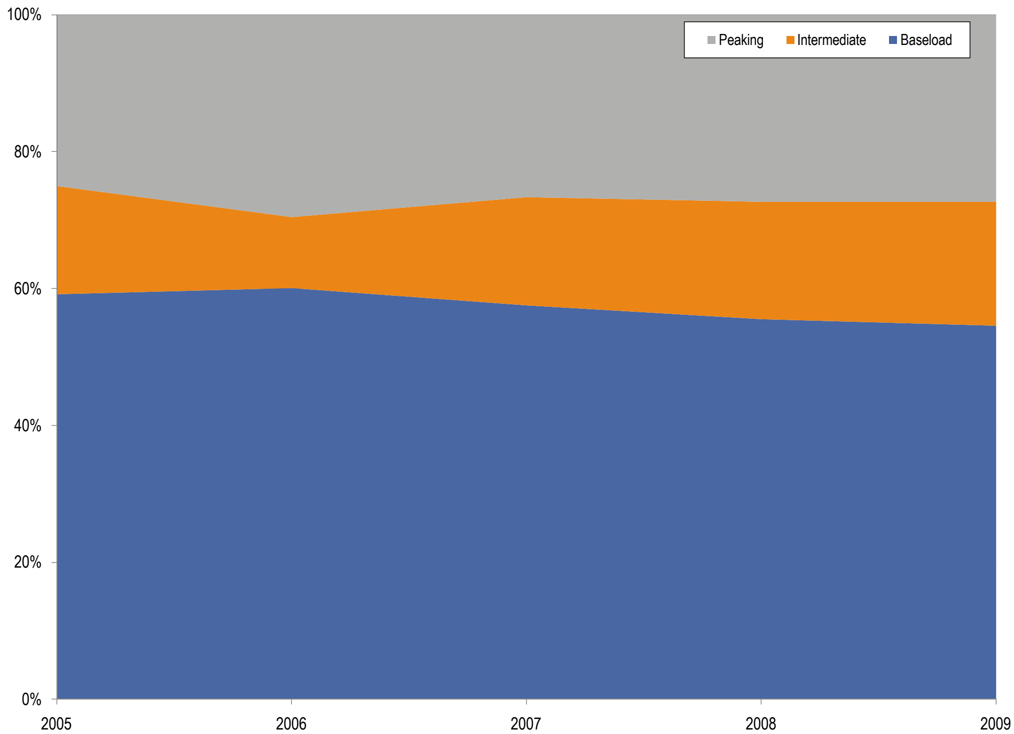
In addition to disaggregating system EFORd by unit type, units were categorized by actual duty cycles as baseload, intermediate or peaking to determine the relationship between type of operation and forced outage rates.[73] Figure 5-10 shows the contribution of unit types to system average EFORd. Total capacity in 2009 consists of 65.0 percent baseload capacity, 13.8 percent intermediate capacity, and 21.2 percent peak capacity.

71 The generating unit types are: steam, nuclear, diesel, combustion turbine, combined-cycle and hydroelectric. For all tables, run of river and pumped storage hydroelectric are combined into a single hydroelectric category.

72 Calculated values presented in Section 5, "Capacity Market" at "Generator Performance" are based on unrounded, underlying data and may differ from those derived from the rounded values shown in the tables.

73 Duty cycle is the time the unit is generating divided by the time the unit is available to generate. A baseload unit is defined here as a unit that generates during 50 percent or more of its available hours. An intermediate unit is defined here as a unit that generates during from 10 percent to 50 percent of its available hours. A peaking unit is defined here as a unit that generates during less than 10 percent of its available hours.

Figure 5-10 Contribution to EFORd by duty cycle: Calendar years 2005 to 2009



Forced Outage Analysis

The MMU analyzed the causes of forced outages for the entire PJM system. The metric used was lost generation, which is the product of the duration of the outage and the size of the outage reduction. Lost generation can be converted into lost system equivalent availability.[74] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor.

The PJM EAF for 2009 was 85.7 percent; the corresponding EMOF and EPOF were 2.8 percent and 6.7 percent, respectively. As a result, the 2009 PJM EFOF was 4.8 percent. This means 4.8 percent lost availability because of forced outages.

The major reasons for this lost equivalent availability are listed in Table 5-19.

74 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a systemwide basis.

Table 5-19 Outage cause contribution to PJM EFOF: Calendar year 2009

	Percentage Point Contribution to EFOF	Contribution to EFOF
Boiler Tube Leaks	0.84	17.6%
Low Pressure Turbine	0.75	15.6%
Economic	0.47	9.7%
Electrical	0.32	6.7%
Boiler Air and Gas Systems	0.20	4.2%
Generator	0.18	3.9%
Boiler Fuel Supply from Bunkers to Boiler	0.13	2.6%
Fuel Quality	0.12	2.6%
Stack Emission	0.10	2.1%
Boiler Piping System	0.10	2.0%
Controls	0.09	1.8%
High Pressure Turbine	0.08	1.7%
Feedwater System	0.08	1.7%
Performance	0.08	1.7%
Condensing System	0.07	1.4%
Inlet Air System and Compressors	0.07	1.4%
Boiler Tube Fireside Slagging or Fouling	0.07	1.4%
Valve	0.07	1.4%
Miscellaneous (Generator)	0.06	1.2%
All Other Causes	0.92	19.2%
Total	4.80	100.0%

Table 5-19 shows that boiler tube leaks, at 17.6 percent of the systemwide EFOF, were the largest single contributor to EFOF. Forced outages because of boiler tube leaks reduced system equivalent availability by 0.84 percentage points. Forced outages because of low pressure turbine problems caused the second largest reduction to equivalent availability by 0.75 percentage points. Economic reasons caused the third largest reduction to equivalent availability by 0.47 percentage points, or 9.7 percent of the systemwide EFOF.

Table 5-20 shows the categories which are included in the economic category.[75] Lack of fuel that is considered Outside Management Control accounted for 87.6 percent of all economic reasons while lack of fuel that was not Outside Management Control accounted for only 6.5 percent.

75 The classification and definitions of these outages are defined by NERC GADS.

Table 5-20 Contributions to Economic Outages: 2009

	Contribution to Economic Reasons
Lack of Fuel (OMC)	87.6%
Lack of Fuel (Non-OMC)	6.5%
Other Economic Problems	5.4%
Lack of Water (Hydro)	0.4%
Fuel Conservation	0.1%
Problems with Primary Fuel for Units with Secondary Fuel Operation	0.0%
Total	100.0%

Table 5-21 Contribution to EFOF by unit type for the most prevalent causes: Calendar year 2009

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	1.2%	0.0%	0.0%	0.0%	0.0%	24.8%	17.6%
Low Pressure Turbine	0.1%	0.0%	0.0%	0.0%	78.7%	5.5%	15.6%
Economic	3.5%	13.9%	1.5%	1.3%	0.0%	12.3%	9.7%
Electrical	11.6%	16.5%	0.5%	25.5%	6.1%	5.1%	6.7%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	5.9%	4.2%
Generator	9.8%	1.7%	0.7%	42.2%	0.0%	3.2%	3.9%
Boiler Fuel Supply from Bunkers to Boiler	0.2%	0.0%	0.0%	0.0%	0.0%	3.7%	2.6%
Fuel Quality	0.0%	0.0%	13.4%	0.0%	0.0%	3.6%	2.6%
Stack Emission	0.0%	0.3%	0.2%	0.0%	0.0%	3.0%	2.1%
Boiler Piping System	0.9%	0.0%	0.0%	0.0%	0.0%	2.7%	2.0%
Controls	1.2%	1.1%	0.5%	0.5%	0.7%	2.2%	1.8%
High Pressure Turbine	0.0%	0.0%	0.0%	0.0%	0.0%	2.4%	1.7%
Feedwater System	4.1%	0.0%	0.0%	0.0%	0.0%	2.0%	1.7%
Performance	1.9%	10.2%	5.8%	2.2%	0.6%	1.3%	1.7%
Condensing System	0.1%	0.0%	0.0%	0.0%	0.4%	2.0%	1.4%
Inlet Air System and Compressors	9.0%	14.8%	0.0%	0.0%	0.0%	0.0%	1.4%
Boiler Tube Fireside Slagging or Fouling	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%	1.4%
Valve	1.3%	0.0%	0.0%	0.0%	1.1%	1.6%	1.4%
Miscellaneous (Generator)	7.8%	1.7%	0.1%	0.6%	0.0%	0.8%	1.2%
All Other Causes	47.1%	39.8%	77.2%	27.6%	12.5%	15.8%	19.2%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-21 shows the major causes of EFOF by unit type. Boiler tube leaks caused 24.8 percent of the EFOF for fossil steam units. Low pressure turbine problems caused 78.7 percent of the EFOF for nuclear units. Generator outages caused 42.2 percent of the EFOF for hydroelectric units. Some generator outages include outages caused by problems with the stator windings, bushings, and terminals and the bearing cooling system.[12]

Table 5-22 Contribution to EFOF by unit type: Calendar year 2009

	EFOF	Contribution to EFOF
Combined Cycle	2.6%	6.8%
Combustion Turbine	1.8%	5.6%
Diesel	7.5%	0.3%
Hydroelectric	2.3%	1.9%
Nuclear	4.1%	14.9%
Steam	6.8%	70.5%
Total	4.8%	100.0%

The contribution to systemwide EFOF by a generator or group of generators is a function of duty cycle, EFORd and share of the systemwide capacity mix. For example, fossil steam units have the largest share (about 49.1 percent) of the capacity mix, have a high duty cycle and in 2009 had an EFORd of 9.3 percent which yields a 69.8 percent contribution to PJM systemwide EFOF. Nuclear units also have a high duty cycle; their share of the PJM systemwide capacity mix is about 18.3 percent and in 2009 they had a 4.1 percent EFORd which yields a 14.9 percent contribution to PJM systemwide EFOF. By using the values in Table 5-22 and Table 5-21 one can determine how much the individual unit types' causes contributed to PJM systemwide EFOF. For instance the value for boiler tube leaks in Table 5-21 multiplied by the contribution value in Table 5-22 for the same unit type will yield the percent contribution to the PJM systemwide EFOF for that outage cause.

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages to be deemed Outside Management Control (OMC) in response to the system disturbance of August 14, 2003.[76] NERC specified, in its January 2006 update to the "Generator Availability Data System Data Reporting Instructions,"[77] in Appendix K,[78] that each OMC outage must be carefully considered as to its cause and nature. An outage can 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. Appendix K of the "Generator Availability Data Systems Data Reporting Instructions" lists specific cause codes (i.e., codes that are standardized for specific outage causes) that would be considered OMC outages.[79] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, fuel quality issues (i.e., codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered per the NERC directive. In 2007, PJM removed the OMC designation from all of the fuel quality codes with the exception of 9250, "low Btu coal" since only that code had both an OMC and non-OMC code (i.e., 9250, OMC code for "low Btu coal"; 9251, non-OMC code for "low Btu coal"). After analyzing the data for these outages types, it was found that in 2006, of 17 companies that used either of these cause codes, only three had used both the OMC and non-OMC cause codes. In other words, 14 companies exclusively used the

76 NERC had always provided cause codes for outages that were caused by external forces. However, as a result of the system disturbance on August 14, 2003, NERC specifically created outage specifications for outages that were "outside management control."

77 The "Generator Availability Data System Data Reporting Instructions" can be found on the NERC website: <http://www.nerc.com/files/2009_GADS_DRI_Complete_Set.pdf> (4.9 MB).

78 The "Generator Availability Data System Data Reporting Instructions," Appendix K can be found on the NERC website: <http://www.nerc.com/files/Appendix_K_Outside_Plant_Management_Control.pdf> (161 KB).

79 For a list of these cause codes, see the *2009 State of the Market Report for PJM*, Volume II, Appendix E, "Capacity Market."

OMC cause code. In 2007, however, of 39 companies that used either of the OMC and non-OMC fuel quality cause codes, only one company exclusively used the OMC cause code. In 2008 and 2009, no company exclusively used the OMC cause code. In 2006, approximately 51 percent of the lost generation because of “low Btu coal” was deemed OMC by the generation owners. In 2007, 6 percent of the lost generation because of “low Btu coal” was deemed OMC, in 2008, 12 percent of the lost generation because of “low Btu coal” was deemed OMC, and in 2009, 2.3 percent of the lost generation because of “low Btu coal” was deemed OMC. It is not clear why some companies exclusively used the OMC cause codes and did not use the non-OMC cause code for “low Btu coal” in 2006. It is a reasonable expectation that companies would monitor coal quality stringently and reject noncompliant shipments. It is also possible that these outages are a function of issues with generating plant equipment. Neither reason is necessarily the basis for designating a related outage as an OMC event.

All outages, including OMC outages, are included in the EFORd that is used for planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations used to determine the level of unforced capacity for specific units and thus the amount of unforced capacity that must be offered in PJM Capacity Markets. This modified EFORd is termed the XEFORd. All submitted OMC outages are reviewed by PJM’s Resource Adequacy Department. Table 5-23 shows the impact of OMC outages on EFORd for 2009. The difference is especially noticeable for steam units and combustion turbine units. For steam units, the OMC outage reason that resulted in the highest total MW loss in 2009 was lack of fuel. Combustion turbine units have natural gas fuel curtailment outages that were also classified as OMC. If companies’ natural gas fuel supply is curtailed because of pipeline issues, the event can be deemed OMC. However, natural gas curtailments caused by lack of firm transportation contracts or arbitraging transportation reservations should not be classified as OMC. In 2009, steam XEFORd was 1.3 percentage points less than EFORd, which translates into a 1,057 MW difference in unforced capacity.

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

Table 5-23 PJM EFORd vs. XEFORd: Calendar year 2009

	2009 EFORd	2009 XEFORd	Difference
Combined Cycle	3.8%	3.6%	0.2%
Combustion Turbine	9.8%	8.3%	1.5%
Diesel	10.2%	8.0%	2.2%
Hydroelectric	3.2%	3.0%	0.2%
Nuclear	4.1%	4.1%	0.0%
Steam	9.3%	8.0%	1.3%
Total	7.5%	6.6%	0.9%

Components of EFORp

The equivalent forced outage rate during peak hours (EFORp) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate during the peak hours of the day in the peak months of January, February, June, July and August. EFORp is calculated using historical performance data and is designed to measure if a unit would have run had the unit not been forced out. EFORp excludes OMC outages. PJM systemwide EFORp is a capacity-weighted average of individual unit EFORp.

Table 5-24 shows the contribution of each unit type to the system EFORp, calculated as the total forced MW for the unit type divided by the total capacity of the system. Forced MW for a unit type is the EFORp multiplied by the generator's net dependable summer capability.

Table 5-24 Contribution to EFORp by unit type (Percentage points): Calendar years 2008 to 2009

	2008	2009
Combined Cycle	0.3	0.4
Combustion Turbine	0.5	0.4
Diesel	0.0	0.0
Hydroelectric	0.1	0.1
Nuclear	0.2	0.8
Steam	3.5	2.3
Total	4.5	4.0

In Table 5-25, note that EFORp for nuclear units in 2009 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.

Table 5-25 PJM EFORp data by unit type: Calendar years 2008 to 2009

	2008	2009
Combined Cycle	2.5%	2.9%
Combustion Turbine	3.4%	2.5%
Diesel	5.8%	5.3%
Hydroelectric	1.3%	2.9%
Nuclear	0.9%	4.3%
Steam	7.1%	4.7%
Total	4.5%	4.0%

EFORd, XEFORd and EFORp

EFORd, XEFORd and EFORp are designed to measure the rate of forced outages, which are defined as outages that cannot be postponed beyond the end of the next weekend.[80] It is reasonable to expect that units have some degree of control over when to take a forced outage, depending on the underlying cause of the forced outage. If units had no control over the timing of forced outages, outages during peak hours of the peak months would be expected to occur at roughly the same rate as outages during periods of demand throughout the rest of the year. With the exception of nuclear units, EFORp is lower than both EFORd and XEFORd, suggesting that units elect to take forced outages during off-peak hours, as much as it is within their control to do so. That is consistent with

80 See PJM. "Manual 22: Generator Resource Performance Indices," Revision 15 (June 1, 2007), Definitions.

the incentives created by the PJM Capacity Market. EFORp of nuclear units is slightly higher than EFORd and XEFORd, suggesting that nuclear units have a slightly higher rate of forced outages during the peak months of January, February, June, July and August.

Table 5-26 shows the contribution of each unit type to the system EFORd, XEFORd and EFORp, calculated as the total forced MW for the unit type divided by the total capacity of the system. Table 5-27 shows the capacity-weighted class average of EFORd, XEFORd and EFORp.

Table 5-26 Contribution to PJM EFORd, XEFORd and EFORp by unit type: Calendar year 2009

	EFORd	XEFORd	EFORp
Combined Cycle	0.5	0.5	0.4
Combustion Turbine	1.5	1.3	0.4
Diesel	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.1
Nuclear	0.8	0.7	0.8
Steam	4.6	4.0	2.3
Total	7.5	6.6	4.0

Table 5-27 PJM EFORd, XEFORd and EFORp data by unit type: Calendar year 2009

	EFORd	XEFORd	EFORp
Combined Cycle	3.8%	3.6%	2.9%
Combustion Turbine	9.8%	8.3%	2.5%
Diesel	10.2%	8.0%	5.3%
Hydroelectric	3.2%	3.0%	2.9%
Nuclear	4.1%	4.1%	4.3%
Steam	9.3%	8.0%	4.7%
Total	7.5%	6.6%	4.0%

Comparison of Expected and Actual Performance

If the EFORd based planning assumptions were consistent with actual unit performance, the distribution of actual performance would be identical to a hypothetical normal distribution based on average EFORd performance.

This analysis was performed based on resource-specific EFORd and Summer Net Capability capacity values for the year ending December 31, 2009.[81] These values were used to estimate a

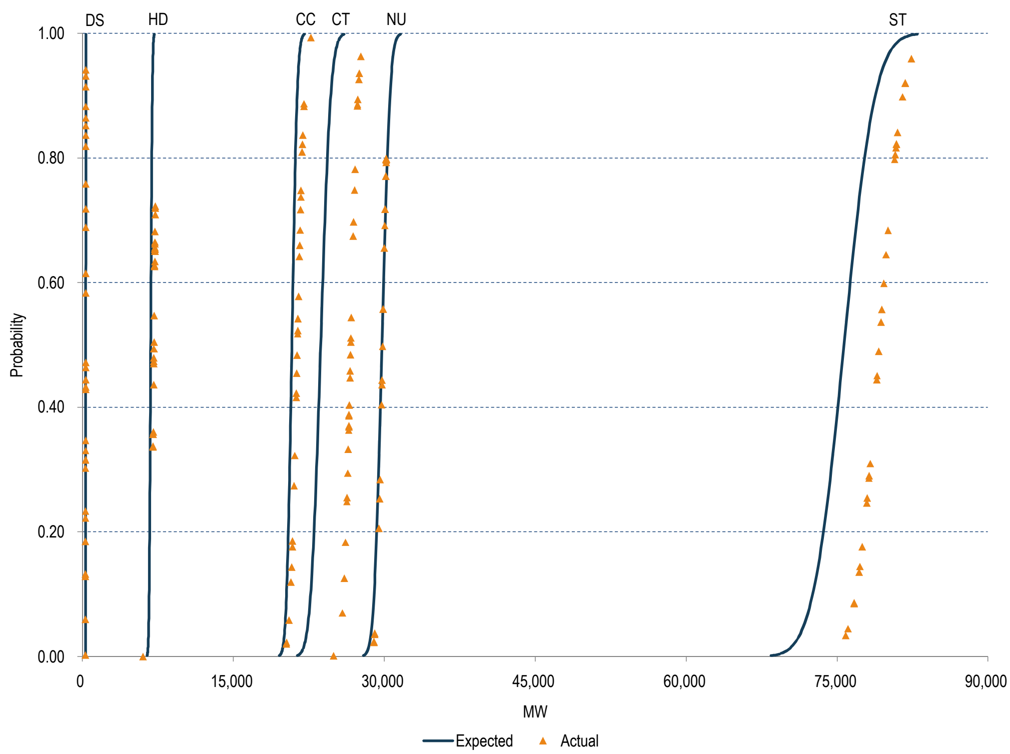
81 See PJM. "Manual 21: Rules and Procedures for Determination of Generating Capability," Revision 08 (January 1, 2010), Summer Net Capability.

normal distribution for each unit type,[82] which was superimposed on a distribution of actual historical availability for the same resources for the year ending December 31, 2009.[83] The top thirty load days were selected for each year and the performance of the resources was evaluated for the peak hour of those days, a sample of 30 peak load hours.

Figure 5-11 compares the normal distribution to the actual distribution based on the defined sample.

Overall, generating units performed better during the selected peak hours than would have been expected based on the EFORd statistic. In particular, CT and ST units tend to have more capacity available during the sampled hours than implied by the EFORd statistic.

Figure 5-11 PJM 2009 distribution of EFORd data by unit type



82 The formulas used to approximate the parameters of the normal distribution are defined as:

$$\text{Mean} = \sum_i \left[\text{MW}_i * (1 - \text{EFORd}_i)\right]$$

$$\text{Variance} = \sum_i \left[\text{MW}_i * \text{MW}_i * (1 - \text{EFORd}_i) * \text{EFORd}_i\right]$$

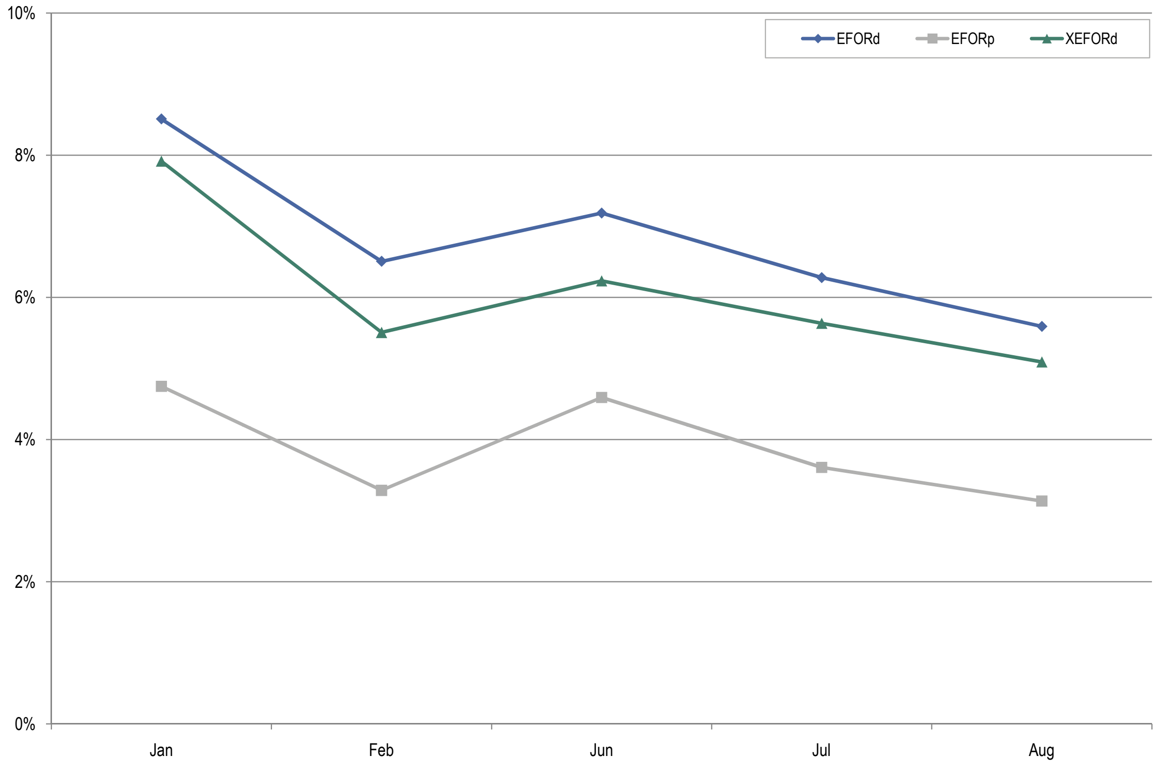
$$\text{Standard Deviation} = \sqrt{\text{Variance}}$$

83 Availability calculated as net dependable capacity affected only by forced outage and forced derating events. Planned and maintenance events were excluded from this analysis.

Performance During Peak Months

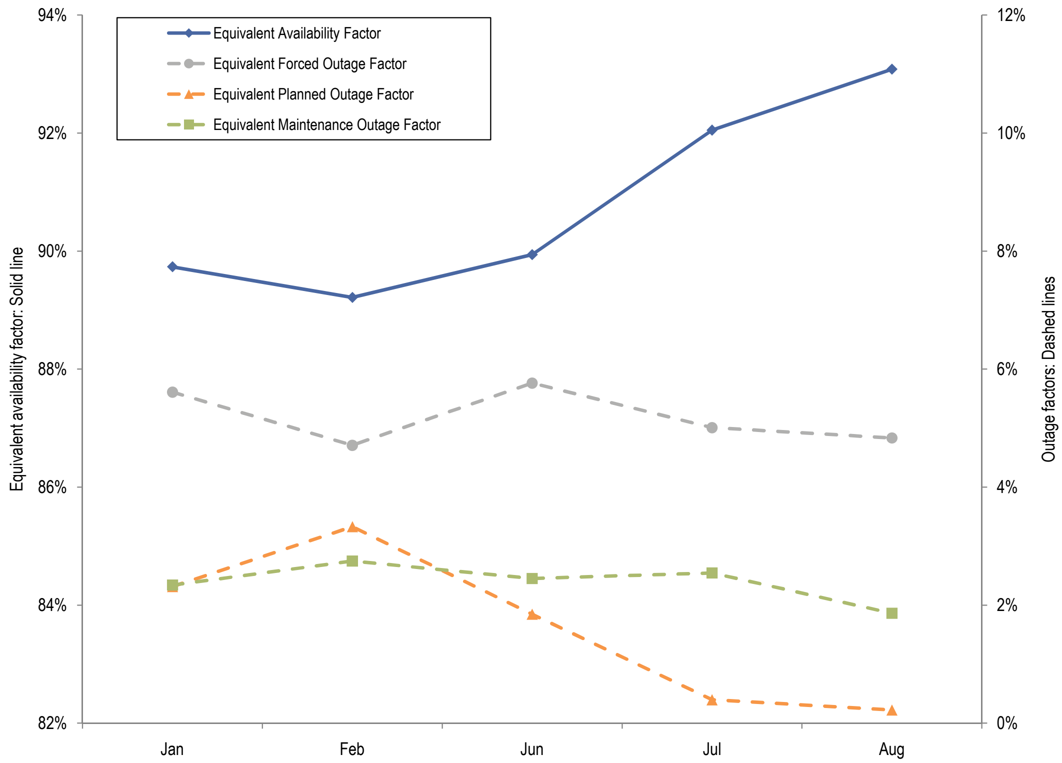
For the peak months of January, February, June, July and August, EFORp values were significantly less than EFORd and XEFORd values for the corresponding months as shown in Figure 5-12.

Figure 5-12 PJM peak month data



During the peak months of January, February, June, July and August, unit availability as measured by the equivalent availability factor increased, primarily due to decreasing planned outages, as illustrated in Figure 5-13.

Figure 5-13 PJM peak month generator performance factors



SECTION 6 – ANCILLARY SERVICE MARKETS

The United States Federal Energy Regulatory Commission (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.[1] 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.[2] 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.[3] 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 Market Monitoring Unit (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.

1 75 FERC ¶ 61,080 (1996).
2 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.
3 See 117 FERC ¶ 61,331 at P 29 n32 (2006).

Overview

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.[4] 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."[5] 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.

4 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).

5 See the *2009 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.[6] 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.[7] 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.

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

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

7 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. "

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.[8] 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.

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

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.

- **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."[9] 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 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.

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.

9 See the *2009 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).

DASR

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the RPM settlement.[10] 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.[11] 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.[12]

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

10 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).
11 PJM Manual 13, Emergency Requirements, Revision 39, 01/01/2010; pp 11-12.
12 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.

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.[13] 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.[14] A number of parties filed comments, including the MMU on October 20, 2008.[15]

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.[16]

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.

13 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).

14 PJM submitted its initial filing in FERC Docket No. ER09-13-000.

15 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>.

16 125 FERC ¶ 61,231, at P 18 (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."[17] 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.[18]

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.[19] 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."[20] 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."[21] 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."[22]

The MMU has updated the calculations, improved the calculations and made corrections as necessary, based in part on PJM's comments. [23] 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.

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

17 *2009 Quarterly State of the Market Report for PJM: January through June* at 120, 124.
18 *2009 Quarterly State of the Market Report for PJM: January through September* at 115.
19 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).
20 *Id.* at 2.
21 *Id.*
22 *Id.* at 8.
23 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).

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.

Regulation Market

Market Structure

The market structure of the 2009 PJM Regulation Market remained similar to the market structure of the 2008 Regulation Market. Rule changes significantly affected the design of the Regulation Market.

Supply

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

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

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

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

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

The average eligible regulation supply-to-requirement ratio in the PJM Regulation Market during 2009 was 2.98. Even during periods of diminished supply such as off-peak hours, eligible regulation supply was adequate to meet the regulation requirement.

Demand

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

The PJM regulation requirement is set by PJM Interconnection in accordance with NERC control standards. In August 2008 the requirement was adjusted to be 1.0 percent of the forecast peak load for on peak hours and 1.0 percent of the forecast valley load for off peak hours.[24] During 2009 the PJM regulation requirements ranged from 501 MW to 1,279 MW. The average required regulation off-peak was 773 and the average required regulation on-peak was 933 MW (Table 6-1).

Table 6-1 PJM Regulation Market required MW and ratio of supply to requirement: Calendar year 2009

Period Type	Average Required Regulation (MW)	Ratio of Supply to Requirement
All of 2009	849	2.98
Fall	772	3.1
Spring	771	2.9
Summer	929	3.15
Winter	928	2.76
Off Peak	773	2.89
On Peak	933	3.08

Market Concentration

During 2009 the PJM Regulation Market total capability was 7,805 MW.[25] Total capability is a theoretical measure which is never actually achieved. The level of regulation resources offered on a daily level and the level of regulation resources eligible to participate on an hourly level in the market were lower than the total regulation capability. In 2009 the average daily offer level was 6,343 MW or 81 percent of total capability while the average hourly eligible offer level was 2,537 MW or 33 percent of total capability. In 2009 the average hourly eligible offer level was 40 percent of the average daily offer level. Although regulation is offered daily, eligible regulation changes hourly. Typically less regulation is eligible during off-peak hours because fewer steam units are running during those hours. Table 6-2 shows capability, daily offer and average hourly eligible MW for all hours as well as for off-peak and on-peak hours.

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

25 Total offer capability is defined as the sum of the maximum daily offer volume for each offering unit during the period, without regard to the actual availability of the resource or to the day on which the maximum was offered.

Table 6-2 PJM regulation capability, daily offer and hourly eligible: Calendar year 2009

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	7,805	6343	81%	2,537	33%
Off Peak	7,805			2,190	28%
On Peak	7,805			2,865	37%

The ratio of the hourly eligible regulation supply to the hourly regulation requirement averaged 2.98 for PJM during 2009. When this ratio equals 1.0, it indicates that offered supply exactly equals demand for the referenced time period.

Hourly HHI values were calculated based on cleared regulation. In 2009 HHI values ranged from a maximum of 9405 to a minimum of 699, with a load weighted average value of 1365, which is categorized as moderately concentrated by the FERC definitions. Table 6-3 summarizes the 2009 PJM Regulation Market HHIs. 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.

Table 6-3 PJM cleared regulation HHI: Calendar year 2009

Market Type	Minimum HHI	Load-Weighted Average HHI	Maximum HHI
Cleared Regulation, 2008	707	1290	2767
Cleared Regulation, January through July	707	1226	2767
Cleared Regulation, August through December	736	1397	2480

In 2009, 13 percent of all periods had an HHI less than 1000 and 18 percent of all periods had an HHI greater than 1800, with a maximum of 9405. An HHI of 1800 is the threshold for "highly concentrated" by the FERC definitions. The maximum period HHI in 2008 was 2767. See the HHI distribution curve in Figure 6-1.

Figure 6-1 PJM Regulation Market HHI distribution: Calendar year 2009

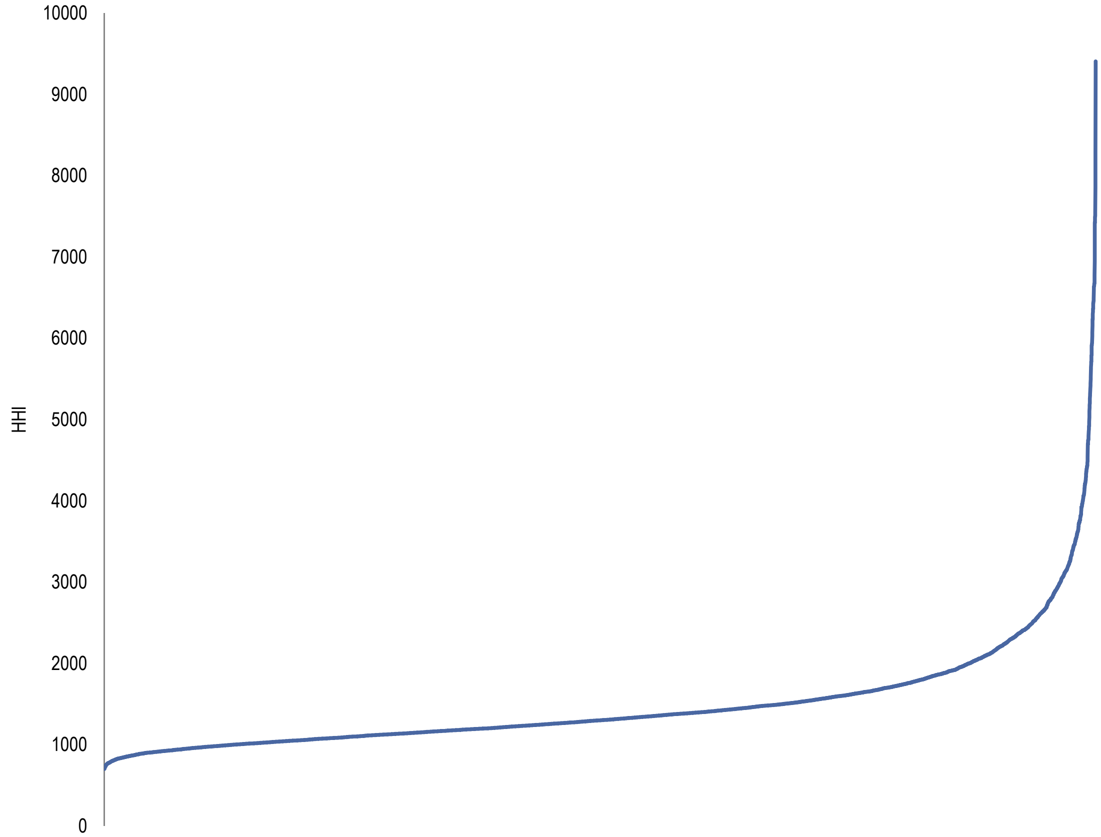
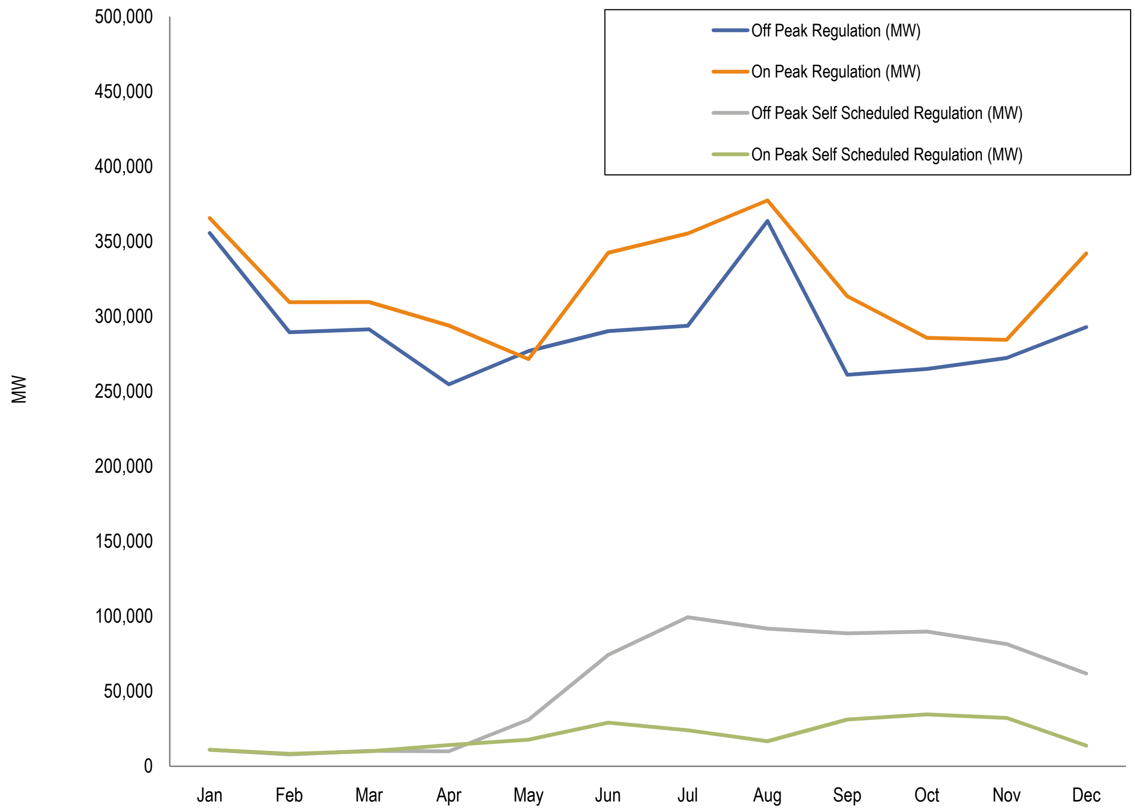


Figure 6-2 shows monthly regulation total MW off-peak and on-peak. The volume of self-scheduled regulation rose in May during off-peak hours. The rise in off-peak self scheduled regulation lowered the requirement for cleared regulation, putting downward pressure on prices and resulted in a reduced level of MW cleared in the market.

Figure 6-2 Off peak and on peak regulation levels: Calendar year 2009



The highest hourly market share was 97 percent (compared to the highest hourly market share in 2008 of 49 percent). Seventy two percent of all hours had a maximum market share greater than 20 percent in 2009. The largest annual average hourly market share by a company was 15 percent. The top five annual average hourly market shares for cleared regulation in 2009 are listed in Table 6-4.

Table 6-4 Highest annual average hourly Regulation Market shares: Calendar year 2009

Company Market Share Rank	Cleared Regulation Top Market Shares
1	15%
2	10%
3	9%
4	8%
5	8%

In 2009, 52 percent of hours failed the three pivotal supplier test. This means that for 52 percent of hours the total regulation requirement could not be met in the absence of the three largest suppliers. One supplier of regulation was pivotal in 99 percent of pivotal hours. A second company was pivotal in 89 percent of the pivotal hours. A third company was pivotal in 81 percent of pivotal hours. Table 6-5 includes a monthly summary of three pivotal supplier results.

Table 6-5 Regulation market monthly three pivotal supplier results: Calendar year 2009

Month	Percent Hours With Three Pivotal Suppliers
Jan	84%
Feb	61%
Mar	42%
Apr	39%
May	31%
Jun	37%
Jul	39%
Aug	35%
Sep	47%
Oct	64%
Nov	62%
Dec	80%

Thus, in addition to failing the three pivotal supplier test in a significant number of hours, the pivotal suppliers in the Regulation Market were the same suppliers in the majority of hours when the test was failed. This is a further indication that the structural market power issue in the Regulation Market remained persistent and repeated during 2009.

The MMU concludes from these results that the PJM Regulation Market in 2009 was characterized by structural market power. This conclusion is based on the results of the three pivotal supplier test.

Market Conduct

Offers

PJM implemented the three pivotal supplier test in the Regulation Market in December 2008. As a result, generators wishing to participate in the PJM Regulation Market must submit cost based regulation offers for specific units by 1800 Eastern Prevailing Time (EPT) of the day before the operating day. Generators may also submit price based offers. The regulation cost based offer price is limited to costs plus $12.00. The costs are validated in accordance with unit specific operating parameters entered with the cost based offer. A unit is not required to provide these parameters if its offer is less than $12.00. The unit specific operating parameters are heat rate at economic maximum, heat rate at regulation minimum, VOM rate and fuel cost. Regulation offers are applicable for the entire 24 hour period for which they are submitted. As in any competitive market, regulation offers at marginal cost are considered to be competitive.

The cost based and price based offers and the associated cost related parameters are the only components of the regulation offer applicable for the entire operating day. The following information must be included in each offer, but can be entered or changed up to 60 minutes prior to the operating hour: regulating status (i.e., available, unavailable or self-scheduled); regulation capability; regulation minimum (may be increased but not decreased); and regulation maximum (may be decreased but not increased). The Regulation Market is cleared on a real-time basis and regulation prices are posted hourly throughout the operating day. The amount of self-scheduled regulation is confirmed 60 minutes before each operating hour, and regulation assignments are made at least 30 minutes before each operating hour.

PJM's Regulation Market is cleared hourly, based on both offers submitted by the units and the hourly lost opportunity cost of each unit, calculated based on the forecast LMP at the location of each regulating unit.[26] The total offer price is the sum of the unit specific offer and the opportunity cost. In order to clear the market, PJM ranks the offer of all offered and eligible regulating resources in ascending total offer price order; it does the same for synchronized reserve and simultaneously determines the least expensive set of resources necessary to provide regulation, synchronized reserve and energy for the operating hour, taking into account any resources self-scheduled to provide any of these services. Units are assigned to regulate in ascending merit order by price until the required regulation is satisfied. The resulting assignments are evaluated to see which if any of the owning companies are pivotal. Pivotal companies will have their resources offer capped at the lesser of their cost based or price based offer. The generating units of companies which are not pivotal will then have their offer reset to their price based offer and the market is cleared.[27] The Regulation Market Clearing Price that results is the RMCP and the unit that sets this price is the marginal unit.

Market Performance

Price

Figure 6-3 shows the daily average regulation market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market. All units chosen to provide regulation received as payment the higher of the clearing price multiplied by the unit's assigned regulating capability, or the unit's regulation offer plus the individual unit's real-time opportunity cost, multiplied by its assigned regulating capability.[28]

For 2009, 35 percent of marginal units were pivotal. In 35 percent of hours the marginal unit failed the pivotal supplier test. This means that in 35 percent of hours the marginal unit's offer price was the lesser of its price based or cost based offer.

26 PJM estimates the opportunity cost for units providing regulation based on a forecast of locational marginal price (LMP) for the upcoming hour. In May 2009, PJM also began including the lost opportunity cost impact in adjoining hours of dispatching a unit to its regulation set point. As part of the settlement that included the implementation of the three pivotal supplier test on December 1, 2008, the opportunity cost calculator now uses the lesser of the available price based energy schedule or the most expensive available cost based energy schedule.

27 See PJM. "Manual 11: Scheduling Operations," Revision 43 (Redline), Regulation Market Clearing, September 24, 2009, p. 43.

28 See PJM. "Manual 28: Operating Agreement, Accounting," Revision 42, Section 4, "Regulation Credits" (July 31, 2009), p. 25. PJM uses estimated opportunity cost to clear the market and real-time opportunity cost to compensate generators that provide regulation and synchronized reserve. Real-time opportunity cost is calculated using real-time LMP.

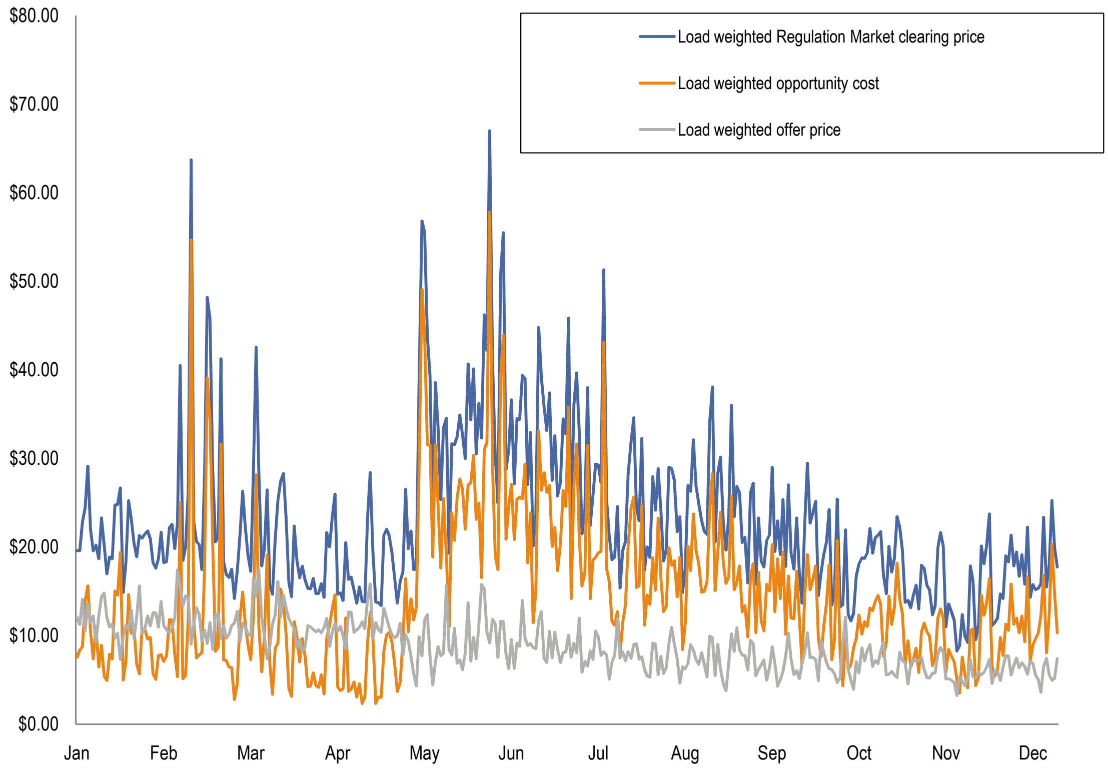
Table 6-6 Percent of hours when marginal unit supplier was pivotal: Calendar year 2009

Month	Percent of Hours When Marginal Supplier is Pivotal
Jan	37%
Feb	38%
Mar	20%
Apr	20%
May	19%
Jun	23%
Jul	21%
Aug	29%
Sep	40%
Oct	52%
Nov	55%
Dec	73%

Regulation credits are awarded to generation owners that have either self-scheduled or sold regulation into the market. Regulation credits for units self-scheduled to provide regulation are equal to the RMCP times the unit's self-scheduled regulating capability. Regulation credits for units that offer regulation into the market and are selected to provide regulation are the higher of the RMCP times the unit's assigned regulating capability, or the unit's regulation offer plus the opportunity cost that the unit has incurred times its assigned regulating capability. Although most units are paid RMCP times their assigned regulation MWh, a substantial portion of the RMCP is the opportunity cost calculated during market clearing based on forecast LMP of the marginal unit. This means that a substantial portion of the total cost of regulation is determined by opportunity cost. As shown in Figure 6-3, about half of the regulation price is the opportunity cost of the marginal unit. Opportunity cost is a greater percentage of price when prices are high since offers tend to remain constant.

The load weighted, average offer of the marginal unit for the PJM Regulation Market during 2009 was $8.79 per MWh. This is a significant reduction from the load weighted average offer in 2008 of $11.94. The lower offers are in part the result of the application of the three pivotal supplier test, which prevented non competitive offers from setting price. The load weighted, average opportunity cost of the marginal unit for the PJM Regulation Market during 2009 was $11.62. In the PJM Regulation Market the marginal unit opportunity cost averaged 49 percent of the RMCP. This is a significant reduction from the 2008 level of 72 percent meaning that the direct unit offers had a larger impact on the clearing price in 2009 than in 2008. The reduction in opportunity cost was clearly a function of lower energy prices.

Figure 6-3 PJM Regulation Market daily average market-clearing price, opportunity cost and offer price (Dollars per MWh): Calendar year 2009

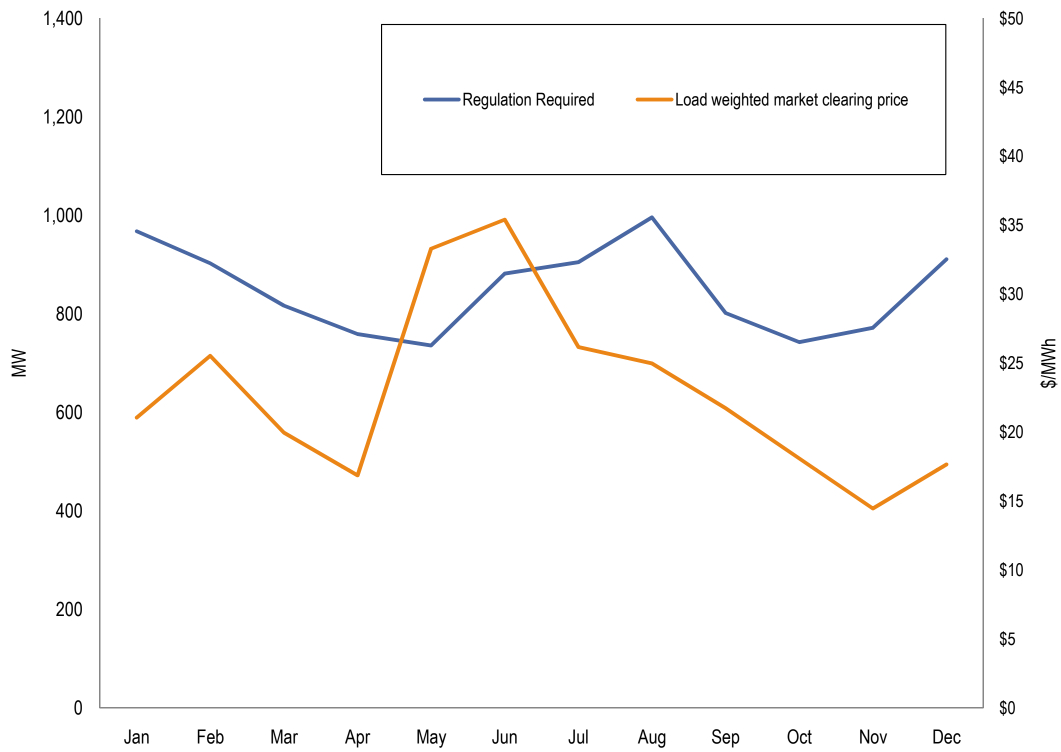


On a shorter term basis, regulation prices follow daily and weekly patterns. The supply of regulation is largest during on-peak hours, between 0600 and 2300 EPT, Monday through Friday.

During weekends and North American Electric Reliability Council (NERC) holidays, and weekdays between the hour ending at 2300 until the hour ending at 0800 (i.e., the off-peak hours), fewer steam generators are running and available to regulate. At times, units must be kept running for regulation that are not economic for energy, resulting in an increase in the opportunity cost portion of the clearing price. At other times, expensive combustion turbine generators must be started to meet regulation requirements. Although the regulation requirement is a function of reliability concerns, lower off-peak load allowed PJM to decrease the off-peak regulation requirement in August 2008, thus aligning demand with supply and moderating prices.

Figure 6-4 shows the level of demand for regulation by month in 2009 and the corresponding level of regulation price. The data show a correlation between price and demand.

Figure 6-4 Monthly average regulation demand (required) vs. price: Calendar year 2009



As with all ancillary services, the total cost of the service per MWh will exceed the price per MWh because some regulation is procured out of the market or because there are adjustments to unit specific opportunity cost after the market clears. A well designed and efficient market will minimize this difference. Units which provide regulation are paid the higher of the RMCP, or their offer plus their unit specific opportunity cost. The offer plus the unit specific opportunity cost may be higher than the RMCP for a number of reasons. If real time LMP is greater than the LMP forecast prior to the operating hour and included in the RMCP, unit specific opportunity costs will be higher than forecast. Such higher LMPs can be local, because of congestion, or more general, if system conditions change. Other reasons include unit redispatch because of constraints or unanticipated unit performance problems. When some units are paid more than the RMCP based on unit specific lost opportunity costs, the result is that PJM's regulation cost per MWh is higher than the RMCP. Figure 6-5 compares the regulation cost per MWh (price plus settled lost opportunity costs) with the regulation clearing price to show the difference between the price of regulation and the cost of regulation.

Figure 6-5 Monthly load weighted, average regulation cost and price: Calendar year 2009

Total scheduled regulation MWh, total regulation charges, regulation price and regulation cost are listed in Table 6-7.

Table 6-7 Total regulation charges: Calendar year 2009

Month	Scheduled Regulation (MW)	Total Regulation Charges	Load Weighted Regulation Market Clearing Price ($/MWh)	Cost Of Regulation ($/MWh)
Jan	719,972	$26,614,105	$21.04	$36.97
Feb	606,112	$20,972,293	$25.17	$34.60
Mar	609,426	$17,618,413	$19.90	$28.91
Apr	547,446	$12,171,811	$16.84	$22.23
May	547,941	$21,166,797	$32.41	$38.63
Jun	633,938	$24,566,721	$32.59	$38.75
Jul	673,708	$20,065,104	$24.10	$29.78
Aug	739,915	$23,010,216	$23.89	$31.10
Sep	574,820	$15,216,790	$20.09	$26.47
Oct	550,255	$12,882,665	$17.20	$23.41
Nov	557,139	$10,695,843	$14.06	$19.20
Dec	679,575	$17,303,919	$17.75	$25.46

For 2009, the load weighted, average regulation price was $23.56 per MWh. The average regulation cost was $29.87 per MWh. The difference between the Regulation Market price and the actual cost of regulation was narrower in 2009 than it was in 2008 but still remains significant. The cost of regulation was 27 percent higher than the market price of regulation. The payment of a large portion of regulation charges on a unit specific basis rather than on the basis of a market clearing price remains a cause for concern as it results in a weakened market price signal to the providers of regulation.

Analysis of Regulation Market Changes

There were significant changes made to Regulation Market effective December 1, 2008. The rule changes are summarized in Table 6-8.The changes were the result of a filing by PJM that reflected a compromise among market participants in the PJM process.[29] The MMU filed comments.[30] The MMU supported the 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."[31]

Table 6-8 Summary of changes to Regulation Market design

Prior Regulation Market Rules (Effective May 1, 2005 through November 30, 2008)	New Regulation Market Rules (Effective December 1, 2008)
1. No structural test for market power.	1. Three Pivotal Supplier structural test for market power.
2. Offers capped at cost for identified dominant suppliers. (American Electric Power Company(AEP) and Virginia Electric Power Company (Dominion)) Price offers capped at $100 per MW.	2. Offers capped at cost for owners that fail the TPS test. Price offers capped at $100 per MW.
3. Cost based offers include a margin of $7.50 per MW.	3. Cost based offers include a margin of $12.00 per MW.
4. Opportunity cost calculated based on the offer schedule on which the unit is dispatched in the energy market.	4. Opportunity cost calculated based on the lesser of the price-based offer schedule or the highest cost-based offer schedule in the energy market.
5. All regulation net revenue above offer plus opportunity cost credited against operating reserve credits to unit owners.	5. No regulation market revenue above offer plus opportunity cost credited against operating reserve credits to unit owners.

As directed by the FERC, the MMU performed an analysis of these Regulation Market rule changes, delivering a report on November 30, 2009.[32] The results of that report are updated and corrected here.

Introduction of TPS Testing

The implementation of the TPS test is consistent with the longstanding MMU recommendation that real-time, hourly market structure tests be implemented in the Regulation Market, that market

29 PJM filing initiating Docket No. ER09-13-000 (October 1, 2008).

30 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>.

31 *Id.* at 2.

32 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).

power mitigation be applied only for hours in which the market structure is noncompetitive and that market power mitigation be applied only to the companies failing the market structure tests. This more flexible and real-time approach to mitigation represents an improvement over the approach to mitigation which had been in place from August 2005 through November 2008, which required cost based offers from the two dominant suppliers at all times.

The results of the three pivotal supplier test for each hourly Regulation Market solution are shown in Table 6-9.

Table 6-9 Regulation Market pivotal supplier test results: December 2008 through December 2009 and December 2007 through December 2008

Year	Month	Percent of Hours With Three Pivotal Suppliers	Year	Month	Percent of Hours With Three Pivotal Suppliers
2008	Dec	92%	2007	Dec	79%
2009	Jan	84%	2008	Jan	84%
2009	Feb	61%	2008	Feb	83%
2009	Mar	42%	2008	Mar	89%
2009	Apr	39%	2008	Apr	88%
2009	May	31%	2008	May	97%
2009	Jun	37%	2008	Jun	77%
2009	Jul	39%	2008	Jul	75%
2009	Aug	35%	2008	Aug	80%
2009	Sep	47%	2008	Sep	74%
2009	Oct	64%	2008	Oct	89%
2009	Nov	62%	2008	Nov	59%
2009	Dec	80%	2008	Dec	92%

Increase Offer Margin from $7.50 to $12.00

The tariff modifications included an increase of the margin that may be added to cost-based regulation offers from $7.50 to $12.00 per MW. The average cost based regulation offer is less than $10.00 per MW, so this margin represents a substantial adder to costs. The MMU does not now recommend reducing the margin to the prior level of $7.50 per MW. While there was no analytical support provided for the increased margin, it is simply a direct increase in payments. If an increase in payments for regulation is the goal, this is the best mechanism for implementing that goal as it is transparent and does not require inconsistent changes in market rules to increase revenues to the owners of regulation.

Table 6-10 shows the additional revenues that are paid as a result of the rule change that increased the margin on cost based offers from $7.50 to $12.00 per MWh. In the November 30, 2009 report the MMU calculated the additional revenues based only on the offer margin of the unit that was marginal under the new rule. The MMU has refined this calculation (Table 6-10). The impact of the increased margin is now calculated using the offer margin of all offering units, creating a new supply curve, and re-solving for the new marginal unit and new RMCP. The calculation assumes that synchronized reserve assignments and operating reserve allocations remain the same as in the existing solution. In Table 6-10, the column “Load Weighted Regulation Market Clearing Price” is the monthly load weighted RMCP under the existing rules. The column "Load Weighted Regulation Market Clearing Price With Old Rule" is the recalculated RMCP that would have resulted if the old offer margin of $7.50 had remained in effect. The column "Regulation Credits Attributable to the New Rule" shows the additional charges for regulation that result from the rule change increasing the offer margin from $7.50 to $12.00. The percent increase in the last column, 2.5 percent, is the percent increase in total regulation credits that results from this change. The increase in credits paid, of $6,189,406, is a result of the higher offer margin permitted under the new rules.

Table 6-10 Impact of $12 adder to cost based regulation offer: December 2008 through December 2009

Year	Month	Load Weighted Regulation Market Clearing Price	Load Weighted Regulation Market Clearing Price With Old Rule	Total Regulation Credits	Regulation Credits Attributable to New Rule	Percent Increase in Total Credits Due to Increase of Markup from $7.50 to $12.00
2008	Dec	$24.79	$23.47	$25,608,465	$890,749	3%
2009	Jan	$21.04	$19.91	$26,614,105	$813,654	3%
2009	Feb	$25.17	$23.95	$20,972,293	$734,061	4%
2009	Mar	$19.90	$19.37	$17,618,413	$316,889	2%
2009	Apr	$16.84	$16.36	$12,171,811	$258,778	2%
2009	May	$32.41	$31.93	$21,166,797	$265,494	1%
2009	Jun	$32.59	$32.19	$24,566,721	$312,979	1%
2009	Jul	$24.10	$23.25	$20,065,104	$414,408	2%
2009	Aug	$23.89	$23.37	$23,010,216	$369,407	2%
2009	Sep	$20.09	$19.32	$15,216,790	$497,484	3%
2009	Oct	$17.20	$16.31	$12,882,665	$445,635	3%
2009	Nov	$14.06	$13.48	$10,695,843	$269,283	3%
2009	Dec	$17.75	$16.72	$17,303,919	$600,585	3%
Total				$247,893,142	$6,189,406	2.5%

Change in the Definition of Opportunity Cost

The tariff modifications included a change in the definition of opportunity cost. Offers in the Regulation Market consist of the direct offer price made by the market participant and the opportunity cost, which is calculated by PJM based on forecast LMP for the next hour and added by PJM to the direct offer price to get the total offer price. The tariff change to the definition of opportunity cost is the most significant, because the opportunity cost is, on average, more than half the total offer price. Any modification to the measurement of opportunity cost will have a significant impact on the Regulation Market. The opportunity cost is also directly affected by the levels of LMP. As LMP decreased in 2009, opportunity costs decreased, total offer prices decreased and the Regulation Market clearing prices decreased. As a result, the impact of this change to the definition of opportunity cost was lower in 2009 than it would have been had LMP levels been higher. The impact of this change will increase if LMP levels increase.

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 this modification be reversed and that the correct definition of opportunity cost be reinstated for regulation. In addition to getting the price right, the concept and application of opportunity cost is critical to ensuring an efficient allocation of resources between the energy market and the ancillary services markets. The goal is to hold generators neutral to the decision whether to sell MWh in the energy market or to regulate, in order to ensure that the energy markets and the ancillary markets all clear in an efficient manner.

The correct way to calculate opportunity cost and maintain incentives across both markets is to treat the offer on which the unit is dispatched as the measure of its marginal costs for both the energy market and the Regulation 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 the owner does.

Table 6-11 shows the additional revenues that are paid as a result of the rule change to the definition of opportunity cost. The percent increase in the last column, 19 percent, refers to the percent increase in total regulation credits that results from this change. The increase in credits paid, of $47,463,833, is a result of the higher opportunity costs calculated under the new rules.

Table 6-11 Impact to Regulation Market Clearing Price of using lesser of price based energy schedule or most expensive cost-based energy schedule

			New Rule		Old Rule			
Year	Month	Average Regulation Required (MW)	Load Weighted RMCP Using Lesser Schedule for Opportunity Cost	Using Lesser Schedule For Opportunity Costs, Total Charges	Load Weighted RMCP Using Current Dispatch Schedule for Opportunity Costs	Using Current Dispatch Schedule for Opportunity Costs, Total Charges	Additional Regulation Credits Paid Using New Rule	Pecentage Increase in Regulation Credits
2008	Dec	912	$24.79	$25,608,465	$22.50	$24,039,842	$1,568,623	6%
2009	Jan	970	$21.04	$26,614,105	$17.62	$24,136,240	$2,477,865	9%
2009	Feb	905	$25.83	$20,972,293	$17.10	$16,257,318	$4,714,975	22%
2009	Mar	819	$19.90	$17,618,413	$16.34	$15,645,792	$1,972,621	11%
2009	Apr	762	$16.84	$12,171,811	$13.93	$10,569,368	$1,602,443	13%
2009	May	738	$32.41	$21,166,797	$24.63	$16,514,576	$4,652,221	22%
2009	Jun	884	$32.59	$24,566,721	$23.08	$17,198,351	$7,368,370	30%
2009	Jul	908	$24.10	$20,065,104	$15.33	$12,992,257	$7,072,847	35%
2009	Aug	998	$23.89	$23,010,216	$14.18	$15,047,460	$7,962,756	35%
2009	Sep	803	$20.09	$15,216,790	$13.72	$10,656,302	$4,560,488	30%
2009	Oct	744	$17.20	$12,882,665	$13.62	$11,167,730	$1,714,935	13%
2009	Nov	779	$14.06	$10,695,843	$10.83	$9,230,018	$1,465,825	14%
2009	Dec	781	$17.75	$17,303,919	$11.71	$16,974,055	$329,864	2%
Total				$247,893,142		$200,429,309	$47,463,833	19%

Eliminate Offset Against Balancing Operating Reserves Credits

The tariff modifications included eliminating the offset of the net revenues earned in the Regulation Market against operating reserve credits. There was no specific rationale advanced for this change. This tariff modification is directly counter to the fundamentals of the PJM markets and the purpose of operating reserve credits. The MMU recommends that this modification 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.

The logic of including all market revenues in the calculation of operating reserve credits is clear. The goal is to ensure that unit owners are never required to run their units without compensation of all marginal costs, but all market compensation is included when determining whether there is a shortfall. The exclusion of the regulation revenues is arbitrary and results in an increase in operating reserve charges and a shift of revenues to the owners of regulating units from those who pay operating reserve charges. There is no reason to modify a fundamental market rule in order to provide greater incentives in the regulation market. This argument is reinforced by the appropriately increased scrutiny paid to operating reserve in recent years and given the overall goal to reduce these non market payments. If there is actually a need for greater incentives, it should be established directly and the incentive payment made directly in the Regulation Market, for example through the offer margin.

In the calculation of the impact of this change in the MMU report to the FERC of November 30, 2009, the MMU report did not reflect the modifications to the PJM operating reserve rules, effective December 1, 2008, including the implementation of segmented make-whole payments, and did include self-scheduled regulating units, which should not have been included. Table 6-12 below is a revision as well as an update to the November 30, 2009 report. These calculations reflect the changes to the operating reserves rules and exclude self-scheduled regulating units.

Table 6-12 shows the additional revenue paid as a result of the rule change that no longer nets regulation revenue against balancing operating reserves. This rule change did not change the regulation market clearing price. The additional revenue was paid to generators through operating reserves rather than through the regulation market as a direct result of this December 1, 2008 regulation market rule change. The percent increase in the last column, one percent, refers to the percent increase in total regulation credits that results from this change. The increase in credits paid, of $2,297,348, is a result of the elimination of the offset against operating reserve credits that results from the new rules.

Table 6-12 Additional credits paid to regulating units from no longer netting credits above RMCP against operating reserves: December 2008 through December 2009

Year	Month	Balancing Operating Reserve Credits No Longer Offset	Total Regulation Credits	Percent of Regulation Credits No Longer Offsetting Operating Reserves
2008	Dec	$253,165	$25,608,465	1%
2009	Jan	$127,036	$26,614,105	0%
2009	Feb	$220,460	$20,972,293	1%
2009	Mar	$79,726	$17,618,413	0%
2009	Apr	$8,893	$12,171,811	0%
2009	May	$182,624	$21,166,797	1%
2009	Jun	$274,916	$24,566,721	1%
2009	Jul	$191,538	$20,065,104	1%
2009	Aug	$267,116	$23,010,216	1%
2009	Sep	$252,136	$15,216,790	2%
2009	Oct	$169,130	$12,882,665	1%
2009	Nov	$166,112	$10,695,843	2%
2009	Dec	$104,496	$17,303,919	1%
Total		$2,297,348	$247,893,142	1%

Summary

The increase in total charges for regulation that resulted from each of the December 1, 2008 rule changes are summarized in Table 6-13.

Together, the changes to the tariff related to the Regulation Market resulted in an increase in payments to the providers of regulation of $56 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 23 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 compared to what they would have been with a competitive market design.

The addition of the Three Pivotal Supplier Test to the Regulation Market improved the competitiveness of the Regulation Market results, compared to the prior market design without the additional changes, by eliminating the non-competitive behaviors that had existed in prior years. However, the other changes in the rules for the Regulation Market, in particular the change to the calculation of the opportunity cost, produced market results that were not competitive. The other changes in the rules resulted in substantial price increases in the Regulation Market compared to the competitive price that would have resulted without these changes. While overall Regulation Market prices were lower in 2009 than in 2008, this was a result of lower LMPs. If LMPs increase, the impact of the rule changes on total regulation charges will be amplified. The result was a price greater than the competitive price. The competitive price is the price that would have resulted from the application of the prior, correct approach to the calculation of the opportunity cost and to the calculation of the offset against operating reserves. These regulation market results are not based on the behavior of market participants, which is competitive as a result of the application of the three pivotal supplier test.

As a result, the MMU concludes that the results of the Regulation Market were not competitive in 2009.

Table 6-13 Summary of additional charges paid as a result of December 1, 2008 changes to Regulation Market rules: December 2008 through December 2009

			Increasing Markup from $7.50 to $12.00		Opportunity Cost Calculated Using Lower of Price Based or Cost Based Price		Regulation Credits Above Cost Plus Opportunity Costs no Longer Offset Against Operating Reserves		Changes for Three Pivotal Supplier Testing, December 1, 2008 - Summary	
Year	Month	Total Regulation Credits	RMCP Credits Attributable to Marginal Units Cost Offer > Costs Plus $7.50	Percent Increase in Total Credits Due to Marginal Unit With Offer > Cost Plus $7.50	Additional Regulation Credits Paid Due to New Opportunity Cost Calculation	Percentage Increase in Regulation Credits Due to New Opportunity Cost Calculation	Balancing Operating Reserve Credits No Longer Offset	Percent of Regulation Credits No Longer Offsetting Operating Reserves	Total Additional Generator Credits	Total Percent of Regulation Credits Additional
2008	Dec	$25,608,465	$890,749	3%	$1,568,623	6%	$253,165	1%	$2,712,537	11%
2009	Jan	$26,614,105	$813,654	3%	$2,477,865	9%	$127,036	0%	$3,418,555	13%
2009	Feb	$20,972,293	$734,061	4%	$4,714,975	22%	$220,460	1%	$5,669,496	27%
2009	Mar	$17,618,413	$316,889	2%	$1,972,621	11%	$79,726	0%	$2,369,236	13%
2009	Apr	$12,171,811	$258,778	2%	$1,602,443	13%	$8,893	0%	$1,870,114	15%
2009	May	$21,166,797	$265,494	1%	$4,652,221	22%	$182,624	1%	$5,100,339	24%
2009	Jun	$24,566,721	$312,979	1%	$7,368,370	30%	$274,916	1%	$7,956,265	32%
2009	Jul	$20,065,104	$414,408	2%	$7,072,847	35%	$191,538	1%	$7,678,793	38%
2009	Aug	$23,010,216	$369,407	2%	$7,962,756	35%	$267,116	1%	$8,599,279	37%
2009	Sep	$15,216,790	$497,484	3%	$4,560,488	30%	$252,136	2%	$5,310,108	35%
2009	Oct	$12,882,665	$445,635	3%	$1,714,935	13%	$169,130	1%	$2,329,700	18%
2009	Nov	$10,695,843	$269,283	3%	$1,465,825	14%	$166,112	2%	$1,901,220	18%
2009	Dec	$17,303,919	$600,585	3%	$329,864	2%	$104,496	1%	$1,034,945	6%
Total		$247,893,142	$6,189,406	2.5%	$47,463,833	19%	$2,297,348	1%	$55,950,587	23%

Synchronized Reserve Market

Market Structure

PJM retained the two synchronized reserve markets it implemented on February 1, 2007. The RFC Synchronized Reserve Zone Market's reliability requirements are set by the Reliability*First* Corporation. The Southern Synchronized Reserve Zone Market's (Dominion) reliability requirements are set by the Southeastern Electric Reliability Council (SERC). PJM sets the synchronized reserve requirement for the RFC Synchronized Reserve Zone as the larger of ReliabilityFirst Corporation's imposed minimum requirement or the largest contingency on the system. The Southern Region's Synchronized Reserve Market remains a separate market. It falls under the reliability requirements of SERC and is referred to as the Southern Synchronized Reserve Zone. Although the RFC Synchronized Reserve Market is one market, transmission constraints often limit the amount of Tier 1 synchronized reserve that can be made available in the PJM Mid-Atlantic Subzone of the RFC. This subzone is defined as the RFC Synchronized Reserve Zone exclusive of parts of AP, parts of AEP, Dayton, Duquesne, and ComEd zones.[33] Therefore PJM's market must clear enough Tier 2 synchronized reserve in the Mid-Atlantic (Eastern) Subzone of the RFC Synchronized Reserve Market to ensure that the Mid-Atlantic locational synchronized reserve requirement of 1,150 MW is met, after accounting for available Tier 1 supply. This results in a separate Mid-Atlantic Subzone clearing price.

Supply

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

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

Under Synchronized Reserve Market rules, Tier 1 resources are paid when they respond to an identified spinning event as an incentive to respond when needed.[34] Tier 1 synchronized reserve payments or credits are equal to the integrated increase in MW output above economic dispatch from each generator over the length of a spinning event, multiplied by the synchronized reserve energy premium less the hourly integrated LMP. The synchronized reserve energy premium is

33 See PJM. "Manual 11: Scheduling Operations," Revision 43 (September 24, 2009), p. 51.
34 See PJM. "Manual 11: Scheduling Operations," Revision 43 (September 24, 2009), p. 58.

defined as the average of the five minute LMPs calculated during the spinning event plus $50 per MWh. All units called on to supply Tier 1 or Tier 2 synchronized reserve have their actual MW monitored. Tier 1 units are not penalized if their output fails to match their expected response as they are only compensated for their actual response.

Under Synchronized Reserve Market rules, Tier 2 synchronized reserve resources are paid to be available as synchronized reserve, regardless of whether the units are called upon to generate in response to a spinning event, and are subject to penalties if they do not provide synchronized reserve when called. The price for Tier 2 synchronized reserve is determined in a market for Tier 2 synchronized reserves. This market is termed the Synchronized Reserve Market. Several steps are necessary before the hourly Synchronized Reserve Market is cleared. Ninety minutes prior to the start of the hour, PJM estimates the amount of Tier 1 reserve available from every unit; 60 minutes prior to the start of the hour, self-scheduled Tier 2 units are identified. Thirty minutes prior to the hour, Tier 1 is estimated again. If synchronized reserve requirements are not met by Tier 1 and self-scheduled Tier 2 resources, then a Tier 2 clearing price is determined at least 30 minutes prior to the start of the hour. This Tier 2 price is equivalent to the merit-order price of the highest-priced, Tier 2 resource needed to meet the demand for synchronized reserve requirements, the marginal unit, based on the simultaneous clearing of the Regulation Market and the Synchronized Reserve Market.[35]

The synchronized reserve offer price submitted for a unit can be no greater than the unit's incremental operating and maintenance cost plus a $7.50 per MWh margin.[36, 37] The market clearing price is comprised of the marginal unit's synchronized reserve offer price, the cost of energy use, the startup cost (if the unit is not running) and the unit's lost opportunity cost. Opportunity cost is calculated by PJM based on forecast LMPs and generation schedules from the unit dispatch system. Opportunity cost for demand-side resources is always zero. All units cleared in the Synchronized Reserve Markets are paid the higher of either the market-clearing price or the unit's synchronized reserve offer plus the unit specific opportunity cost and the cost of energy use incurred.

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

For the RFC Synchronized Reserve Zone during 2009, the offered and eligible excess supply ratio was 1.93. Within the Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone, the offered and eligible excess supply ratio was 1.53.[38] These excess supply ratios are determined using the administratively established requirement for synchronized reserve. Actual market demand for Tier 2 synchronized reserve is lower than the synchronized reserve requirement because a significant amount of Tier 1 synchronized reserve is usually available.

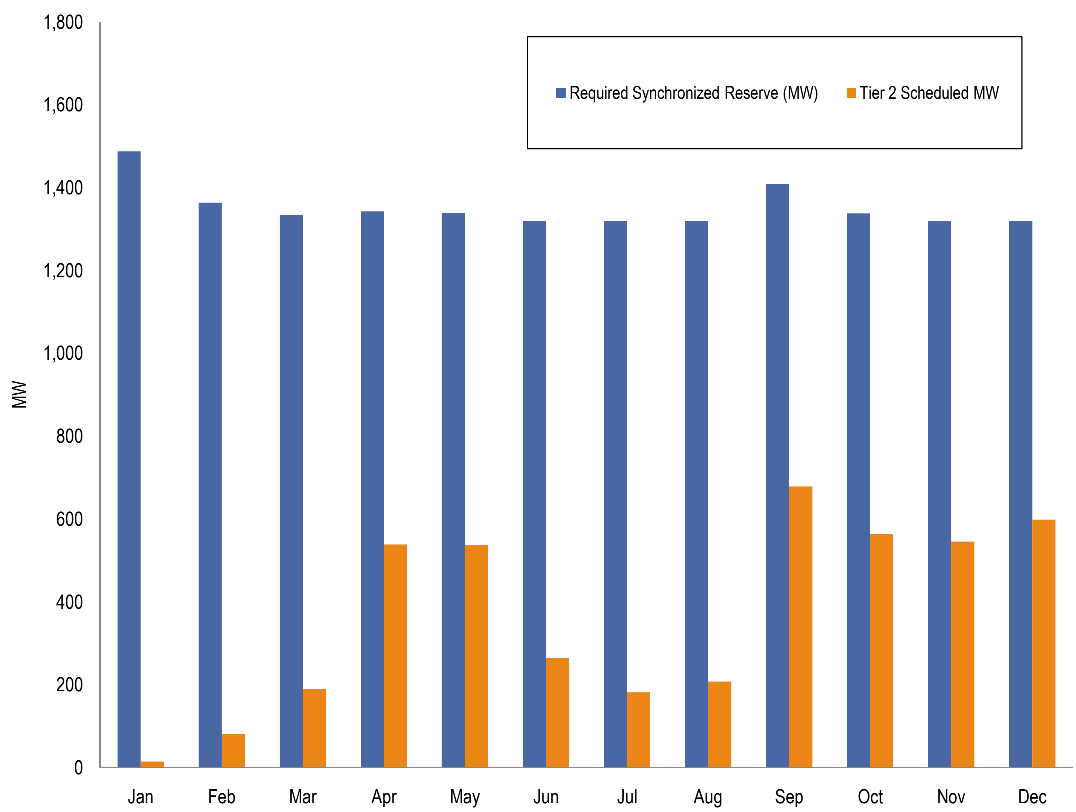
35 Although it is unusual, a PJM dispatcher can deselect units which have been committed after the clearing price has been established. This only happens if real-time system conditions require dispatch of a spinning unit for constraint control, or problems with a generator or monitoring equipment are reported.
36 See PJM. "Manual 11: Scheduling Operations," Revision 43 (September 24, 2009), p. 50.
37 See PJM. "Manual 15: Cost Development Guidelines," Revision 10 (June 1, 2009), p. 41.
38 The Synchronized Reserve Market in the PJM Southern Region cleared in so few hours that related data for that market are not meaningful.

Demand

The market demand for Tier 2 synchronized reserve is determined by subtracting the amount of forecast Tier 1 synchronized reserve available from each synchronized reserve zone's synchronized reserve requirement for the period. Market demand is further reduced by subtracting the amount of self scheduled Tier 2 resources. The total synchronized reserve requirement is different for the two Synchronized Reserve Markets. The synchronized reserve requirement is determined at the discretion of PJM after careful review to ensure appropriate system reliability and to maintain compliance with applicable NERC and regional reliability organization requirements. RFC and Dominion reserve requirements are determined on at least an annual basis. Mid-Atlantic Subzone requirements are established on a seasonal basis, recognizing potential deliverability issues.[39]

Currently the RFC synchronized reserve requirement is the greater of the ReliabilityFirst Corporation's imposed minimum requirement or the system's largest contingency. The actual synchronized reserve requirement for the RFC Zone for January, 2009 was 1,305 MW. For the rest of 2009 it has remained at 1,320 MW. Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency. Such a condition occurred between January 5 and January 23 and from February 23 through February 27, when the synchronized reserve requirement was set to 1,700 MW. A change in the synchronized reserve requirement to 1,755 MW occurred on April 16 and April 17. A change in the synchronized reserve requirement to 1,695 MW occurred on October 2 and October 3. Figure 6-6 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during 2009 for the RFC Synchronized Reserve Market.

Figure 6-6 RFC Synchronized Reserve Zone monthly average synchronized reserve required vs. Tier 2 scheduled MW: Calendar year 2009



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

The RFC Synchronized Reserve Zone is large and some available Tier 1 must be physically located in the Mid-Atlantic Subzone as a result of transmission limits between the western and eastern portions of the zone. PJM calculates the transfer capability of these transmission facilities. The calculation of Mid-Atlantic Subzone Tier 1 includes what is available in the east plus the amount of Tier 1 synchronized reserve in the west that can be transferred into the east. The PJM Synchronized Reserve Market solution is especially sensitive to this limit (known as transfer capacity). The higher this transfer capacity, the greater is the amount of Tier 1 synchronized reserve available in the East and so the less Tier 2 synchronized reserve that needs to be cleared to satisfy the synchronized reserve requirement. Since 2007, PJM market operations had estimated this transfer capacity at 70 percent. Oftentimes however PJM dispatch saw a more restrictive limitation on the western interface (Bedington—Black Oak) and needed to add additional synchronized reserve outside of the market solution in order to cover what they saw as a contingent need. This was the source of Added Synchronized Reserve resulting in lost opportunity costs being added to synchronized reserve costs.[40]

In mid March of 2009, PJM reset the transfer capacity from 70 percent to 15 percent. PJM also changed the transfer interface from Bedington – Black Oak to AP South. As a result, less Tier 1 synchronized reserve was available to the East for the market solution, increasing the amount of Tier 2 that had to be cleared to satisfy the requirement. This reduced the amount of Tier 2 synchronized reserve that had to be added by PJM dispatch after market. The impact of this transfer capacity change was immediate and significant (Table 6-14).

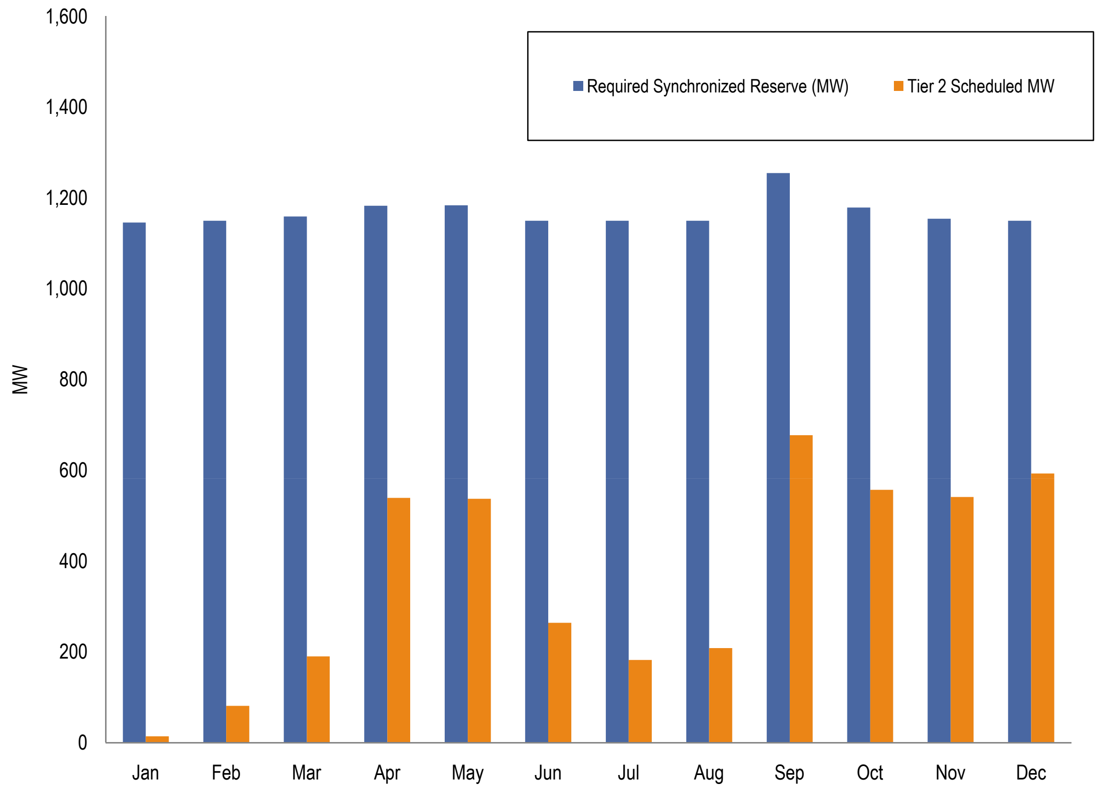
40 See *2007 State of the Market Report*, Volume II, section 6 Ancillary Service Markets pp. 299, 300. Also *2008 State of the Market Report for PJM*, Volume II, section 6 Ancillary Service Markets, p. 328.

Table 6-14 Effect of transfer capacity change on synchronized reserve market scheduled, self-scheduled, and added MW, daily totals: March, 2009

Day (March, 2009)	Eastern Synchronized Reserve Requirement (MW)	Remaining Capacity Parameter	Tier 2 Scheduled (MW)	Tier 2 Self-Scheduled (MW)	Tier 2 Added (MW)
1	1,150	70%	2,379	990	7,201
2	1,150	70%	1,643	0	4,614
3	1,150	70%	0	0	3,150
4	1,150	70%	0	0	0
5	1,150	70%	300	0	1,265
6	1,150	70%	2	0	148
7	1,150	70%	0	0	0
8	1,150	70%	445	0	2,348
9	1,150	70%	397	0	3,139
10	1,150	70%	256	0	2,734
11	1,150	70%	534	0	4,498
12	1,150	70%	51	0	3,038
13	1,150	49%	338	0	2,250
14	1,150	15%	2,528	1,710	519
15	1,150	15%	1,728	1,215	0
16	1,150	15%	3,124	45	1,677
17	1,150	15%	2,901	1,800	1,036
18	1,150	15%	1,711	945	0
19	1,150	15%	5,592	0	403
20	1,150	15%	6,549	2,790	359
21	1,150	15%	4,898	3,330	143
22	1,150	15%	3,719	4,170	381
23	1,150	15%	3,971	2,407	560
24	1,231	15%	5,261	2,520	138
25	1,150	15%	3,302	1,575	725
26	1,150	15%	3,742	2,430	431
27	1,356	15%	6,933	3,385	42
28	1,150	15%	5,543	3,110	178
29	1,150	15%	7,364	3,820	425
30	1,150	15%	2,261	2,910	373
31	1,150	15%	3,769	3,165	0

As a whole, the RFC Synchronized Reserve Zone almost always has enough Tier 1 to cover its synchronized reserve requirement. Available Tier 1 in the western part of the RFC Synchronized Reserve Zone generally exceeds the total synchronized reserve requirement in the west. In 2009, the RFC Synchronized Reserve Zone cleared a Tier 2 Synchronized Reserve Market in less than 3 percent of all hours. This is not the case in the Mid-Atlantic Subzone. As a result, there is frequently a Tier 2 synchronized reserve requirement only in the Mid-Atlantic Subzone and a separate clearing price for the Mid-Atlantic Subzone. The Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone cleared a separate Tier 2 market in 74 percent of all hours. Figure 6-7 compares the required synchronized reserve MW to the scheduled Tier 2 MW for the Mid-Atlantic Subzone only.

Figure 6-7 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone average hourly synchronized reserve required vs. Tier 2 scheduled: Calendar year 2009



The actual synchronized reserve requirement for the Mid-Atlantic Subzone for all of 2009 was usually 1,150 MW but there were several days when temporary grid conditions created a double contingency which increased the requirements. Required synchronized reserve was as high as 2,385 MW on September 14-16, 2009. Throughout all of 2009, the average synchronized reserve required MW in the Mid-Atlantic Subzone was 1,168 MW. The difference between the level of required synchronized reserve and the level of Tier 2 synchronized reserve scheduled is the amount of Tier 1 synchronized reserve available on the system.

The Mid-Atlantic Subzone, Synchronized Reserve Market MW accounts for 99.2 percent of Tier 2 Synchronized Reserve Market MW.

The Southern Synchronized Reserve Zone is part of the Virginia and Carolinas Area (VACAR) subregion of SERC. VACAR specifies that available, 15 minute quick start reserve can be subtracted from Dominion's share of the largest contingency to determine synchronized reserve requirements.[41] The amount of 15 minute quick start reserve available in VACAR is sufficient to make

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

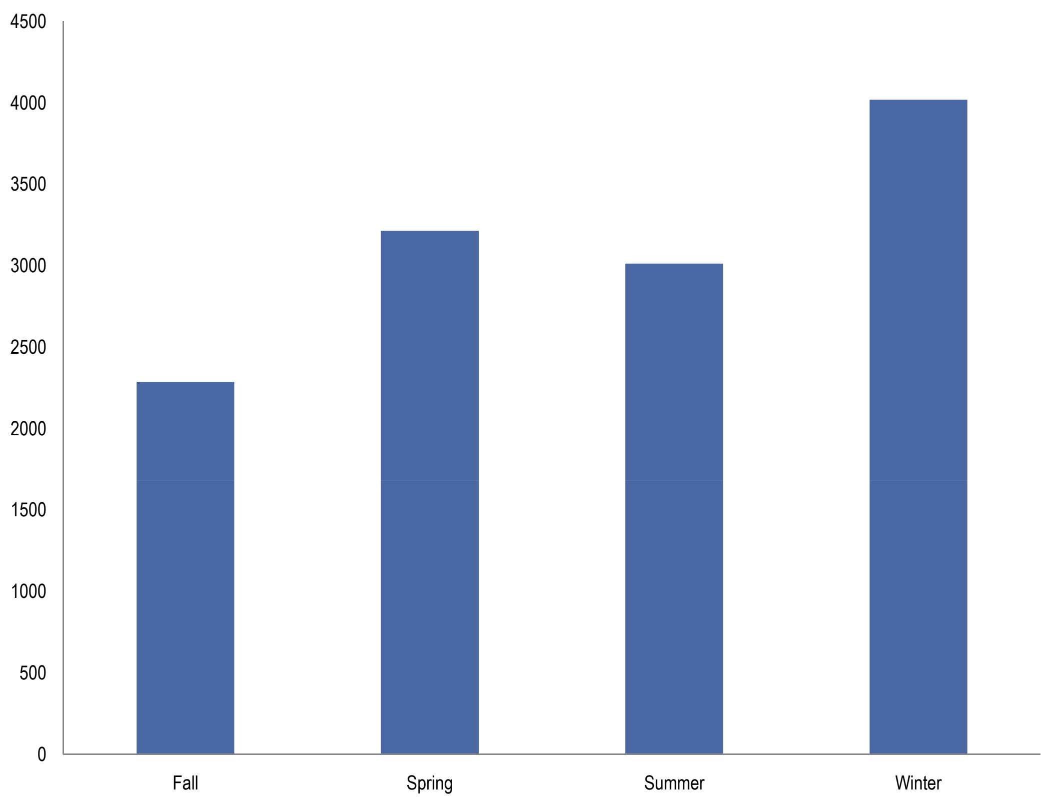
Tier 2 synchronized reserve demand zero for most hours. The actual hourly Southern Synchronized Reserve Zone's synchronized reserve requirement was usually zero because Dominion's share of the largest contingency within VACAR was offset by its quick start capability. On average, the hourly synchronized reserve requirement in Dominion was 3 MW.

Market Concentration

The Tier 2 Synchronized Reserve Market is the only Synchronized Reserve Market cleared by PJM. Although the RFC Tier 2 Synchronized Reserve Market was slightly less concentrated in 2009 than it had been in 2008, the 2009 RFC Synchronized Reserve Market remains highly concentrated and dominated by a relatively small number of companies. Concentration levels have been reduced as a result of the increased participation of demand-side response in the synchronized reserve market.

The HHI for the Mid-Atlantic Subzone of the 2009 RFC Synchronized Reserve Market was 3070, which is defined as "highly concentrated." (See Figure 6-8 which also provides seasonal details.)

Figure 6-8 Purchased Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market seasonal HHI: Calendar year 2009



The largest hourly market share was 100 percent and 36 percent of all hours had a maximum market share greater than or equal to 40 percent. In less than one percent of Mid-Atlantic Subzone hours during which a market was cleared in 2009, a single company had 100 percent of the market share. The highest annual average market share for a single company for all hours in which it had any market share, was 37 percent. In other words, a single company sold 37 percent of synchronized reserves on average for all hours in which it had market share over the entire year. (See Table 6-15)

Table 6-15 Mid-Atlantic Subzone RFC Tier 2 Synchronized Reserve Market's cleared market shares: Calendar year 2009

Company Market Share	Cleared Synchronized Reserve: All Units
1	37%
2	30%
3	26%
4	26%
5	23%

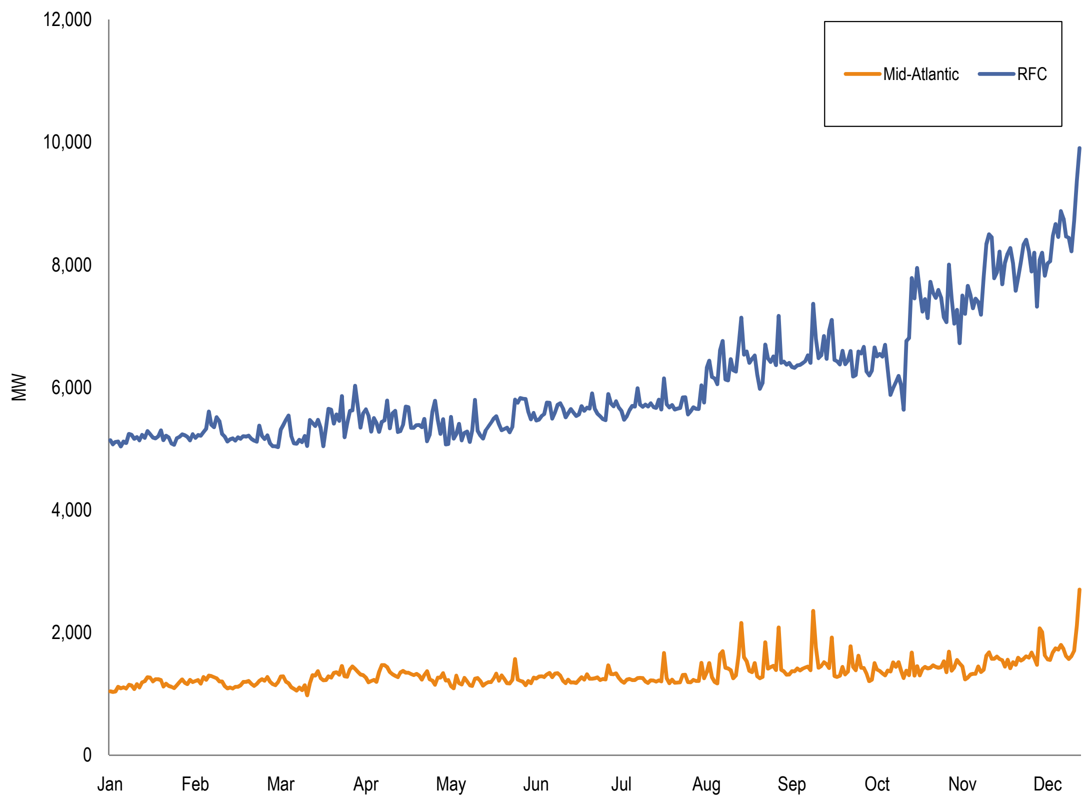
In 2009, 95 percent of hours in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market failed the three pivotal supplier test. One company was pivotal in 57 percent of all pivotal hours, a second company was pivotal in 53 percent of all pivotal hours, and a third company was pivotal in 51 percent of all pivotal hours. These results indicate that the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, the only synchronized reserve market that clears on a regular basis, is not structurally competitive.

Market Conduct

Offers

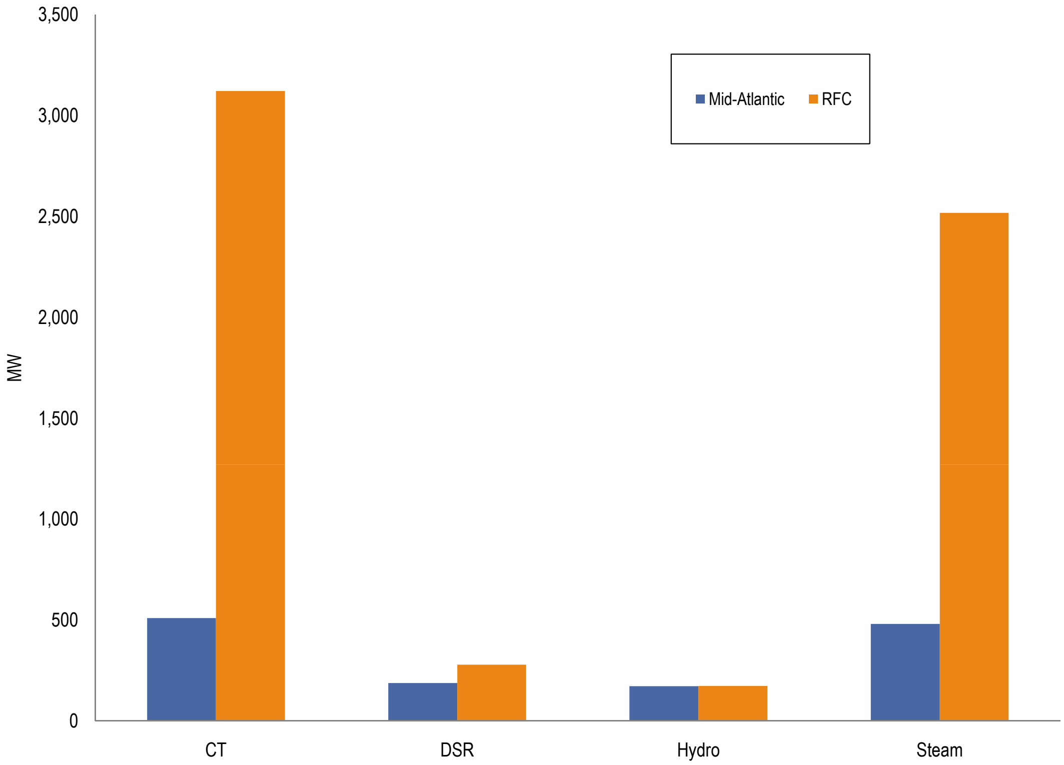
Figure 6-9 shows the daily average hourly offered Tier 2 synchronized reserve MW. For steam units, offered MW are eligible only if the offering unit is running. For that reason, the eligible offer volume shows weekly variability based on off-peak/on-peak operating cycles as well as seasonal variability.

Figure 6-9 Tier 2 synchronized reserve average hourly offer volume (MW): Calendar year 2009



Synchronized reserve is offered by steam, CT, hydroelectric and DSR resources. Figure 6-10 shows average offer MW volume by market and unit type.

Figure 6-10 Average daily Tier 2 synchronized reserve offer by unit type (MW): Calendar year 2009



The contribution of DSR resources to the Synchronized Reserve Market remained significant in 2009. The significance of DSR in the Synchronized Reserve Markets is greater than its eligible offer MW as illustrated in Figure 6-10. In 2009, DSR accounted for all cleared Tier 2 synchronized reserves in 12 percent of hours when a synchronized reserve market was cleared. In the hours when all supply was DSR, the unweighted average SRMCP was $1.87. The unweighted average SRMCP for all cleared hours was $6.47. As defined by PJM, demand-side resources may at times be generation that is behind the meter.

DSR

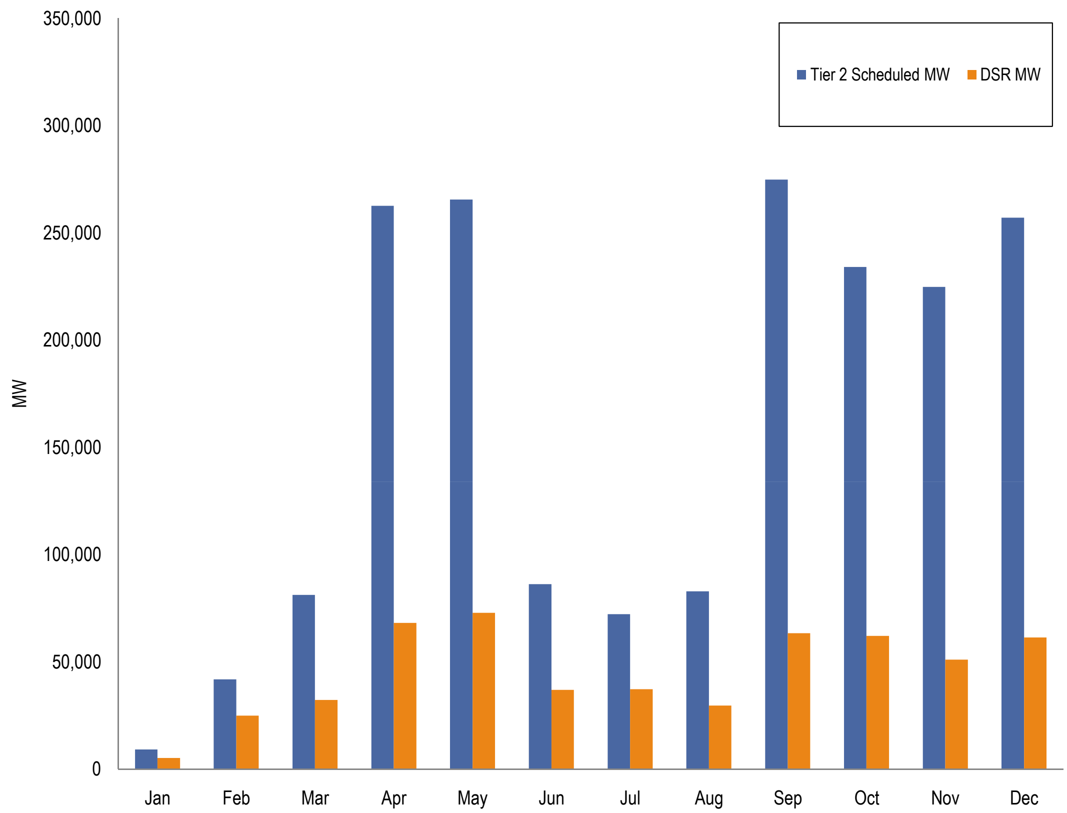
Demand-side resources were permitted to participate in the Synchronized Reserve Markets in August 2006. Although less significant in 2009 than in 2008, DSR continues to have a significant impact on the Synchronized Reserve Market. In 12 percent of hours where a synchronized reserve market was cleared in the Mid-Atlantic Subzone of the RFC (see Table 6-16), all cleared synchronized reserve was DSR synchronized reserve. The clearing price for those hours was significantly lower than the average clearing price overall.

Table 6-16 Average RFC SRMCP when all cleared synchronized reserve is DSR, average SRMCP, and percent of all cleared hours that all cleared synchronized reserve is DSR: Calendar year 2009

Month	Average SRMCP when all cleared synchronized reserve is DSR	Average SRMCP	Percent of cleared hours all synchronized reserve is DSR
Jan	$1.24	$5.90	43%
Feb	$2.01	$5.09	47%
Mar	$1.98	$5.50	26%
Apr	$2.49	$7.12	9%
May	$1.91	$7.56	12%
Jun	$1.76	$5.97	27%
Jul	$1.95	$5.41	31%
Aug	$1.36	$5.37	13%
Sep	$1.77	$7.65	2%
Oct	$1.37	$5.94	0%
Nov	$0.50	$6.47	1%
Dec	$1.05	$7.11	1%

Figure 6-11 shows total monthly synchronized reserve PJM-scheduled MW and cleared MW for DSR synchronized reserve. Participation of demand response in the Synchronized Reserve Market remained strong. Demand response remained significantly less expensive than other forms of synchronized reserve. Demand resources typically offer at a lower price, and demand resources do not have lost opportunity costs added to their offer in market clearing.

Figure 6-11 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: Calendar year 2009



Market Performance

Price

Figure 6-11 shows the relationship among required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and percent of cleared synchronized reserve satisfied by DSR in the Eastern Subzone of the PJM Synchronized Reserve Market. This figure shows both that the synchronized reserve clearing price tends to increase with demand and that DSR satisfies a large percentage of Tier 2 synchronized reserve when the demand is low.

Figure 6-12 Required Tier 2 synchronized reserve, Synchronized Reserve Market clearing price, and DSR percent of Tier 2

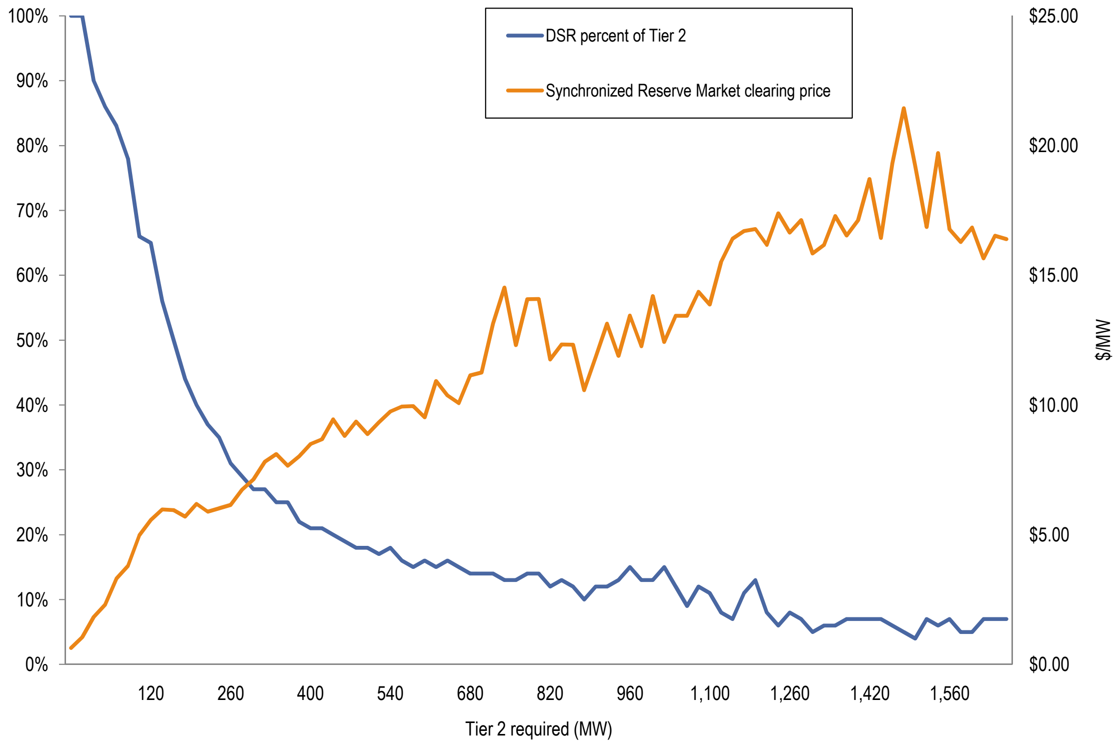


Figure 6-16 shows the load weighted, average Tier 2 price and the cost per MW associated with meeting PJM demand for synchronized reserve. The price of Tier 2 synchronized reserve is called the Synchronized Reserve Market-clearing price (SRMCP). Resources which provide synchronized reserve are paid the higher of the SRMCP or their offer plus their unit specific opportunity cost. The offer plus the unit specific opportunity cost may exceed the SRMCP for a number of reasons. If real time LMP is greater than the LMP forecast prior to the operating hour and included in the SRMCP, unit specific opportunity cost will be higher than forecast. Such higher LMPs can be local because of congestion or more general if system conditions change. The additional costs of noneconomic dispatch are added to the total cost of synchronized reserve. When some units are paid the value of their offer plus their unit specific opportunity cost, the result is that PJM's synchronized reserve cost per MW is higher than the SRMCP.

The RFC Synchronized Reserve Market cleared as a single market less than 3 percent of all hours in 2009 with a load weighted average $3.91 clearing price. The load weighted, average price for synchronized reserve in the PJM Mid-Atlantic Subzone of the RFC Synchronized Reserve Market in 2009 was $7.75 while the corresponding cost of synchronized reserve was $9.77.

Price and Cost

In 2009, PJM appears to have solved the problem of needing a significant amount of non-economic, out of market Tier 2 resources added to the resources procured in the Synchronized Reserve Market. Previously PJM dispatch procured additional Tier 2 reserves to cover anticipated operational needs because of an operations concern that Tier 1 resources located west of the

Bedington – Black Oak interface would not be available in the Mid-Atlantic Subzone if a spinning event should occur. This added Tier 2 MW increased the cost of Tier 2 synchronized reserve and has been a significant contributor to total synchronized reserve costs.

PJM had set the transfer capacity (a measure of the percent of Tier 1 available west of Bedington – Black Oak to the Mid-Atlantic Subzone) at 70 percent. On March 13, 2009, PJM reset the transfer capacity to 15 percent. PJM also changed the transfer interface from Bedington – Black Oak to AP South. These changes had the effect of segregating the Eastern Subzone from the rest of the RFC synchronized reserve zone. As a result, less Tier 1 synchronized reserve was available to the East during the market solution, increasing the amount of Tier 2 that had to be cleared to satisfy the requirement. This reduced the amount of Tier 2 synchronized reserve that had to be added by PJM dispatch after market clearing. The effect of this transfer capacity change can be seen clearly in Table 14, Figure 6-12, and Figure 6-13. This change has significantly affected the Synchronized Reserve Market since it was made on March 13. The result of this change was to minimize the amount of Tier 2 added by dispatch after the market cleared and maximize the amount of Tier 2 purchased through the market, resulting in an accurate clearing price and more closely aligning Tier 2 costs with prices; see Figure 6-14 and Figure 6-15.

Figure 6-13 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated

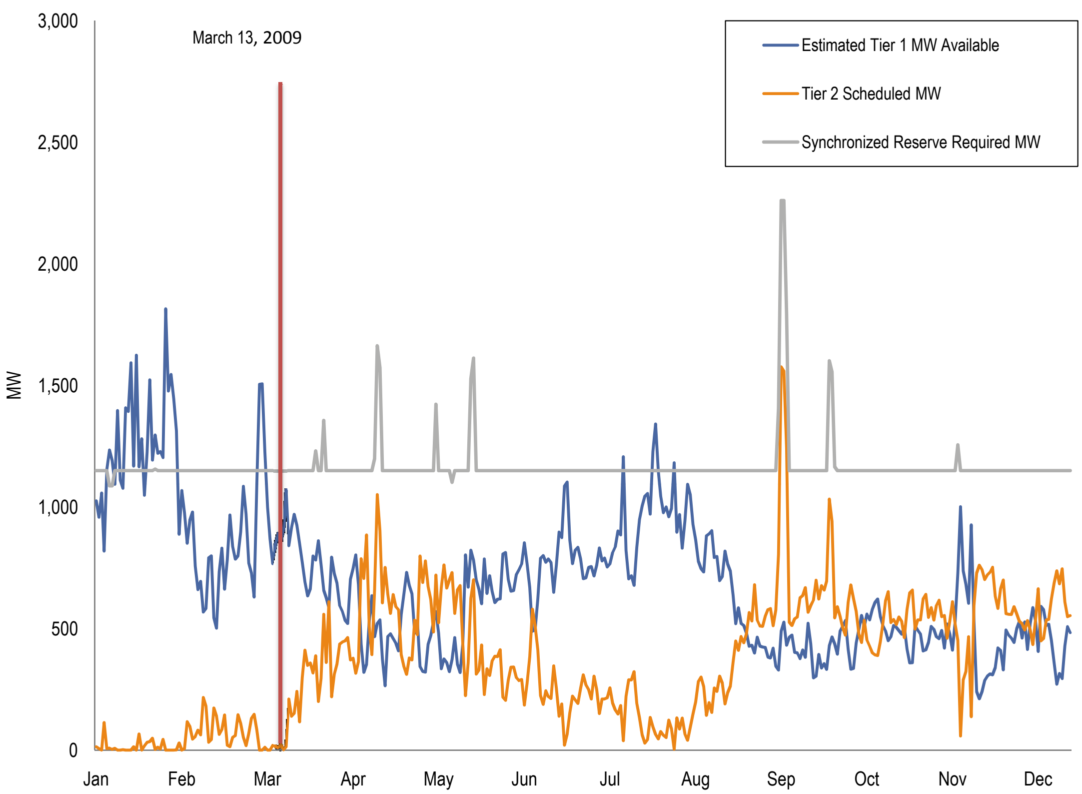
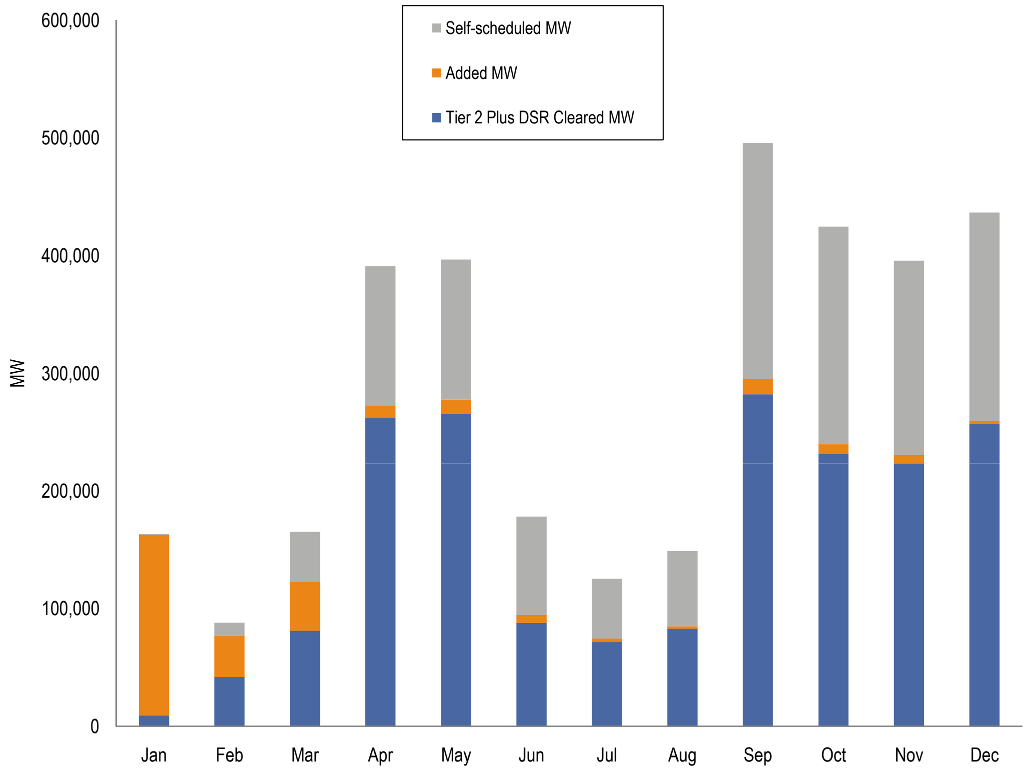


Figure 6-14 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone



The problem of out-of-market purchases of Tier 2 synchronized reserve was greatly diminished by the March 13, 2009 change in the transfer capacity used in the market solution. Figure 6-14 shows that added MW as a percentage of total MWs and opportunity costs as a percentage of total costs fell in March.

The difference between the Tier 2 Synchronized Reserve Market price and the cost for Tier 2 synchronized reserve in 2009 was significantly lower than it had been in 2008 (Figure 6-14). In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market for 2009 the cost of Tier 2 synchronized reserves was 26 percent higher than the load-weighted price. In 2008 this difference had been 54 percent (see Figure 6-15).

Figure 6-15 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic Subzone: Calendar year 2009

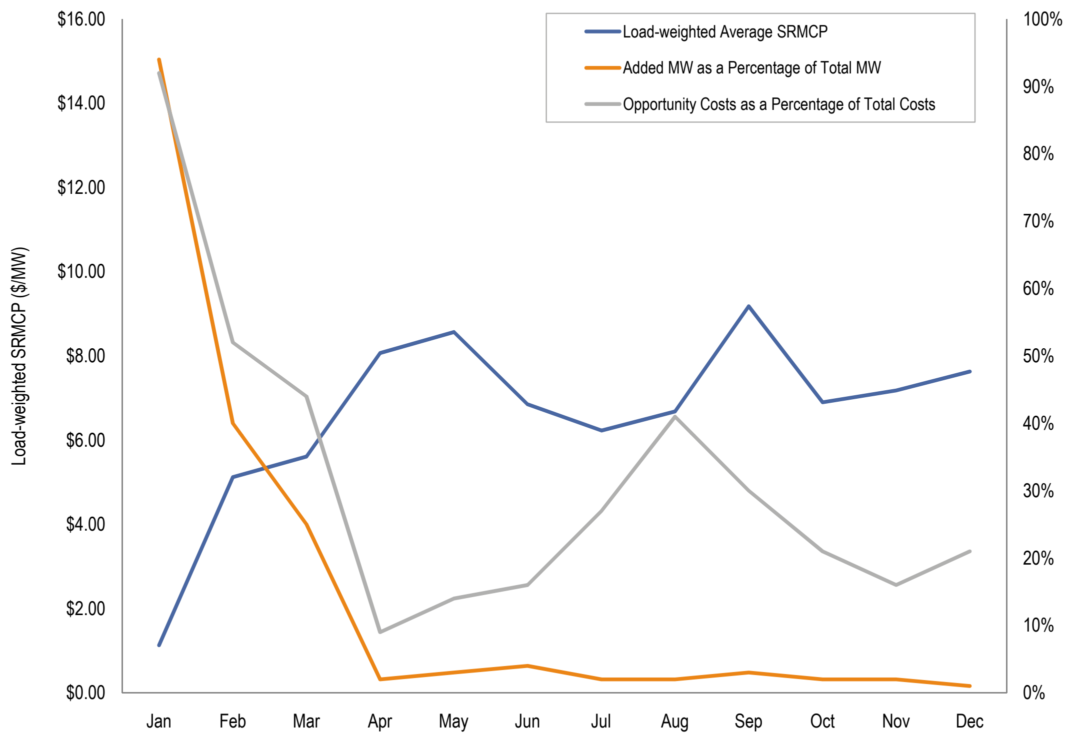
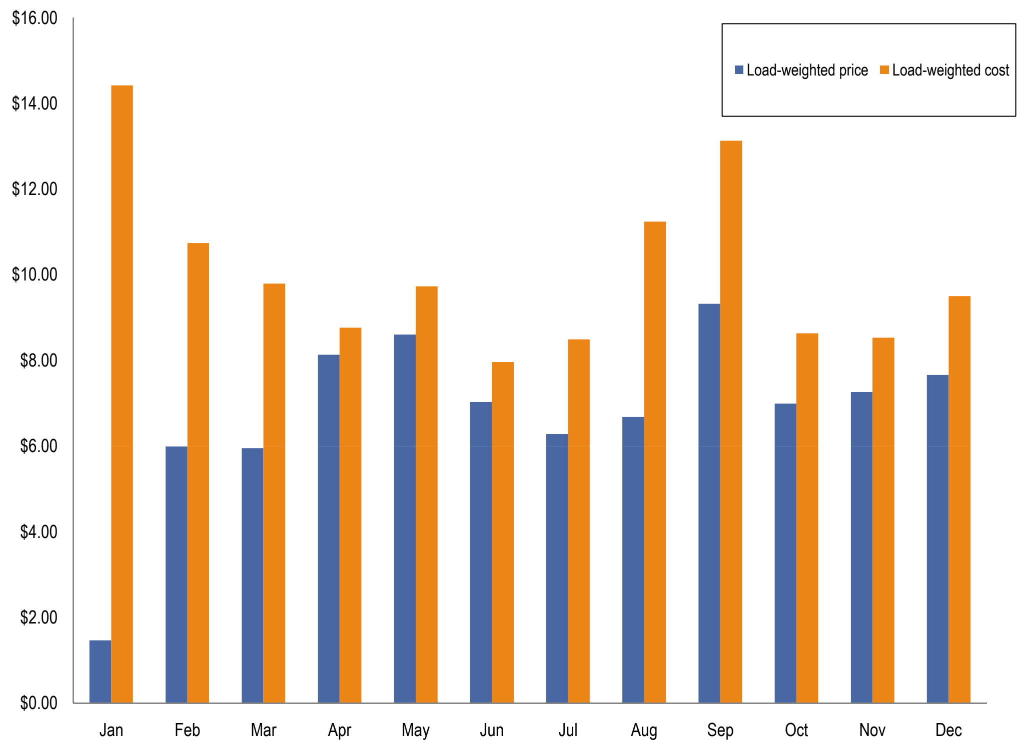


Figure 6-16 Comparison of RFC Mid-Atlantic Subzone Tier 2 synchronized reserve price and cost (Dollars per MW): Calendar year 2009



Market Solution and Actual Dispatch of Ancillary Services

The actual dispatch of ancillary services can and does differ from the market solution, in many cases, as a result of legitimate reliability concerns. The result is usually that total costs per MW (credits/MW) are higher than the clearing price (RMCP). The MMU analyzes this cost/price differential and reports the cost and price.

The market solution software (SPREGO) optimizes regulation and spinning using a theoretical unit dispatch and estimated Tier 1 synchronized reserve based on forecast load. The MMU attempts to document and categorize deviations from market solutions although there tends to be insufficient PJM documentation. Dispatchers can deselect a unit from regulation, Tier 1 or Tier 2 synchronized reserve, or unit dispatch prior to running the market solution. This is the equivalent of imposing a constraint on the market solution. 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.

Deselection of units as Tier 1 resources played a role in the synchronized reserve markets in the early part of 2009. After a PJM review of the accrued deselections, PJM reversed many of the deselections. The result was more Tier 1 resources available than had been reflected in market solutions but which had been showing up during spinning events when Tier 1 was called. This process significantly reduced the perceived need for Tier 2 purchases. The low level of purchased synchronized reserve in January 2009 (see Figure 6-13) as well as December 2008 was the result of PJM Market Operations undoing the deselection for Tier 1 that it had made for many units over time.[42] (See Figure 6-12.)

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 deficits during 2009.

Day Ahead Scheduling Reserve (DASR)

PJM has a requirement to procure supplemental reserves to ensure that differences in forecasted loads and forced generator outages will not have a negative impact on grid reliability.[43] Prior to June 1, 2008, PJM obtained supplemental reserves from several sources including available unused capacity of generating units that had been dispatched for energy, available capacity of units not dispatched for energy but capable of coming online in 30 minutes and dispatch of additional units for the purpose of making supplemental reserve available.

On June 1, 2008 PJM introduced the Day-Ahead Scheduling Reserve Market (DASR), as required by the settlement in the RPM case.[44] 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

42 See the *2008 State of the Market Report for PJM*, Volume II, Figure 6-12, p. 328 "Tier 2 synchronized reserve purchases by month for the Mid-Atlantic subzone DSR."
43 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.
44 See PJM Interconnection, L.L.C., 117 FERC ¶ 61,331 (2006).

clearing price. The DASR 30-minute reserve requirements are determined by the reliability region.[45] In the Reliability*First* (RFC) region, reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[46] Under-forecasted load rates are based on the 80th percentile of a rolling three-year average (November 1 – October 31). For 2009 the load forecast error component of this calculation was 2.10 percent of peak load forecast. The forced outage rate component of the calculation is based on a three-year rolling average of the forced outage rate that occurs from 1800 of the scheduling day through the operating day at 2000. For 2009 the forced outage component of the Day-Ahead Scheduling Reserve was 4.64 percent. For 2009 the Day-Ahead Scheduling Reserve for RFC areas of PJM was 6.75 percent times Peak Load Forecast for RFC. Dominion Day-Ahead Scheduling Reserve is based on its share of the VACAR Reserve Sharing agreement and is set annually. In 2009 VACAR scheduling reserve was set at 418 MW. The RFC and Dominion Day-Ahead Scheduling Reserve 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.

DASR is an offer-based market that clears for all hours of the day at 1600 EPT day-ahead. DASR Market clearing is simultaneous with the Day-Ahead Energy Market.

All generating resources capable of increasing their output in 30 minutes are eligible to provide DASR. Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are also eligible to provide DASR. All DASR offers must be submitted by 1200 EPT day-ahead. There is a must offer requirement in the DASR Market, but any offer price will satisfy the requirement. Resources which are eligible for DASR but which have not offered into the market will have their offers set to $0.00.

In 2009, approximately half of all generating units had no DASR offers or offers of $0. About 4% of all units had offers of $990 or above. Such an offer is high enough to ensure that that unit will never clear and thus constitutes economic withholding. In spite of this withholding, the DASR Market has been relatively stable and characterized by low prices.

45 PJM. "Manual 13, Emergency Requirements," Revision 35 (November 7, 2008), pp. 11-12.
46 PJM. "Manual 10, Pre-Scheduling Operations," Revision 25 (January 1, 2010), p. 17.

Table 6-17 2009 PJM, Day-Ahead Scheduling Reserve Market MW and clearing prices

Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Average Load Weighted Clearing Price	Total DASR MW Puchased	Total DASR Credits
Jan	5,875	$0.00	$0.50	$0.09	4,103,463	$381,735
Feb	5,517	$0.00	$0.25	$0.05	3,510,983	$180,767
Mar	5,068	$0.00	$1.00	$0.03	3,499,722	$113,507
Apr	4,910	$0.00	$0.50	$0.03	3,354,999	$92,158
May	4,957	$0.00	$0.07	$0.02	3,478,374	$77,850
Jun	5,936	$0.00	$0.75	$0.05	4,006,547	$191,578
Jul	6,071	$0.00	$0.50	$0.04	4,191,307	$155,790
Aug	6,725	$0.00	$4.00	$0.13	4,773,330	$620,430
Sep	5,438	$0.00	$0.42	$0.02	3,764,923	$77,945
Oct	5,023	$0.00	$0.42	$0.03	3,610,812	$102,984
Nov	5,188	$0.00	$0.42	$0.03	3,556,557	$113,027
Dec	5,992	$0.00	$0.50	$0.05	3,921,732	$191,599

DASR prices are closely related to energy prices, peaking in August. In 2009, the load weighted price of DASR was $0.05. DSR began to offer and clear the DASR market in November 2008. DSR participated in the market throughout 2009 but was less than one percent of cleared DASR MW and did not clear at all from July through December. Lower energy prices led to a reduction of demand response participation in all markets in the second half of 2009. The DASR Market in 2009 had three pivotal suppliers in a monthly average of 23 percent of all hours.

In December, about 5.3 percent of all units engaged in economic withholding from the DASR Market by providing high offers. Conversely, 48 percent of units had offers of $0.00, either by choice or by default.

The fact that there is substantial structural market power in the DASR Market, together with the fact that the clearing prices are low, suggests that market participants have the ability to exercise market power in this market but have not yet done so in a way that has affected market clearing prices.

There have been no significant impacts of the market power issues in the DASR market as a result of a favorable balance between supply and demand, but that balance could change quickly as a result of weather or other factors and the impacts could be significant.

The MMU concludes that the results of the DASR Market were competitive in 2009. The MMU concludes that the DASR Market is not structurally competitive, based on the analysis for 2009. The MMU recommends that the DASR Market rules be modified to incorporate the application of the three pivotal supplier test in order to address the identified market power issues.

Black Start Service

PJM and its transmission owners must provide for sufficient and appropriately located resources that are capable of providing black start service in the PJM region. To accomplish this, transmission owners prepare system restoration plans that identify critical resources for reenergizing the grid following a possible blackout. Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. PJM ensures the availability of black start by charging transmission customers according to their zonal load ratio share and compensating black start unit owners according to their revenue requirements (see Table 6-18 below). PJM defines a minimum critical black start for each transmission zone.[47]

Black start service is necessary to help ensure the reliable restoration of the grid following a black out. Black start service is the ability of a generating unit to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor to automatically remain operating at reduced levels when disconnected from the grid.[48]

Individual transmission owners, with PJM, identify the black start units included in each transmission owner's restoration plan. PJM defines required black start capability zonally and ensures the availability of black start by charging transmission customers according to their zonal load ratio share and compensating black start unit owners according to their revenue requirements (see Table 6-18). PJM defines a minimum critical black start for each transmission zone.[49]

Table 6-18 Black Start yearly zonal charges for network transmission use

Zone	Network Charges
AECO	$408,761
AEP	$737,082
AP	$136,340
BGE	$483,019
ComEd	$6,826,137
DAY	$146,531
DLCO	$26,736
DPL	$361,745
JCPL	$437,556
Met-Ed	$406,825
PECO	$726,207
PENELEC	$337,079
Pepco	$223,548
PPL	$122,610
PSEG	$949,280

Schedule 6A of the PJM OATT makes available formula rates for units identified as "critical" in system restoration plans to collect their costs and authorizes PJM to perform billing and settlement

47 PJM. "Manual 36, System Restoration," Revision 12 (January 1, 2010) p. 53.
48 PJM Tariff, Second Revised Sheet No. 33.01, March 1, 2007.
49 PJM. "Manual 36, System Restoration," Revision 12, (January 1, 2010) p. 53.

of these costs (including costs collected pursuant to separately filed and eligible FERC tariffs). Schedule 6A was originally implemented in a manner most suited to the needs of existing older units that were equipped to provide black start service. Because the investment in the equipment needed to provide black start service by these units was made some time ago, the purpose of Schedule 6A was primarily to provide a level of compensation sufficient to encourage the owners of identified critical resources to continue providing the service.[50] These provisions established a rolling two-year commitment, appropriate for older units with no requirement for new investment in black start related equipment.

In 2003, PJM, working with American Electric Power Service Corporation ("AEP"), determined that new black start capability was needed at a certain location on the AEP system, partly as a result of the retirement of a legacy black start service unit. PJM issued a request for proposal, and received only offers from suppliers who would need to install new equipment in order to provide the service. PJM selected from the few potentially viable projects, Constellation's offer to provide black start service from its Big Sandy Peaker Plant ("Big Sandy"). Big Sandy required approximately $667,000 to install a 750 kW diesel generator and associated controls. Constellation deemed the recovery provisions included in Schedule 6A inadequate, especially in light of the maximum two-year commitment to which AEP would agree. Constellation therefore sought and obtained FERC approval to collect its entire capital investment over that two-year period, citing as precedent a comparable arrangement between University Park Energy, LLC ("UPE") and Commonwealth Edison Company ("ComEd") that PJM grandfathered in the course of integrating ComEd's system into PJM.[51] Constellation indicated to the Commission its expectation that Big Sandy, like UPE, expected to collect payment under Schedule 6A's formula rates after completing recovery of 100 percent of its investment. This might also have served as the pattern for the procurement of black start services from Lincoln Generating Facility, LLC, except that, partly in response to concerns raised by the MMU, Lincoln agreed to file for a longer five-year commitment period, although full investment cost recovery was accelerated to the first two years.[52]

The MMU had concerns that Schedule 6A was not providing an appropriate framework for the procurement of black start service from new resources. The fundamental problem was that transmission customers in the PJM Region were paying over a short time the cost of substantial capital investments in black start capable resources with no assurance that those resources would continue to provide black start service after the expiration of the initial two-year term. Moreover, the rates of return for a new black start unit that recovered its full capital cost in two years and then reverted to the incentive structure under the formula rates, recovering its cost twice, were far in excess of returns typical for services procured under cost-of-service ratemaking.

In late 2007, PJM reactivated the Black Start Service Working Group ("BSSWG") in order to consider how to recover the new costs of compliance with the NERC's Critical Infrastructure Protection Standards (CIPS) applicable specifically to black start units and to update an outdated reference in the formula to the pre-RPM "Capacity Deficiency Rate." PJM's stakeholders agreed to also develop modifications to provide for a mechanism that conforms the commitment period to provide black start service to the period for recovery of the costs of new investment in black start equipment. The revisions to Schedule 6A developed by the BSSWG to address these and other issues were filed with the FERC on February 19, 2009.[53] By order issued May 29, 2009, the Commission approved the reforms.[54] The Commission did not approve a measure supported by the MMU that would

50 See PJM filing initiating FERC Docket No. ER02-2651-000 at 4 (September 30, 2002)("2002 Schedule 6A Filing").
51 See Big Sandy Peaker Plant, LLC filing initiating FERC Docket No. ER06-1357-000 (August 11, 2006), and the Letter Order of acceptance (September 13, 2006); University Park Energy, LLC filing initiating FERC Docket No. ER04-212-000 (November 21, 2003), and Letter Order of acceptance (January 29, 2004).
52 See Lincoln Generating Facility, LLC filing initiating FERC Docket No. ER08-63-000 (October 16, 2007), and Letter Order of acceptance (December 12, 2007).
53 PJM filed the revised Schedule 6A in FERC Docket No. ER09-730-000.
54 127 FERC ¶61,197.

have prevented double recovery of revenues by certain black start units that received accelerated recovery of investment in black start equipment prior to the reforms becoming effective on April 21, 2009.[55]

Structure

There is no organized market for black start service in PJM. PJM in conjunction with its transmission owners identifies locations where critical black start units are needed and conducts requests for proposals to procure service at those locations. Proposals are accepted from any party willing and able to provide the service at the required location. No customers or their representatives are involved in this process. The MMU is not aware that any request for proposal process has received more than a handful of offers. This result is not unexpected, as there are a very limited number of existing facilities at particular locations indentified in PJM's system restoration plans eligible to provide the service needed. The MMU has concerns that there is a disconnect between a service that is required for system reliability and the need to secure voluntary participation in the system restoration plans from the relatively few potentially cost-effective providers at the critical locations identified. Clearly, the owners of the few facilities able to respond to the requests for proposal have local market power in the provision of black start services as a result both of inelastic demand and the small size of the local market. The significantly increasing costs and risks associated with providing this service as a result of more rigorous and enforceable security standards may aggravate this problem, despite PJM's efforts to address this issue.

Conduct

PJM generally has managed the request-for-proposals process in an orderly and transparent manner. PJM has ensured the provision of black start service. The MMU is concerned that the process does not ensure adequate scrutiny of the proposals or meaningful competition.

Performance

Although the procurement process is transparent and administered well, it is not a "competitive" process. The request for proposal process cannot be relied upon to ensure just and reasonable rates for black start service because the market is characterized by inelastic demand and substantial local market power. PJM has correctly described Schedule 6A and its formula rates as a cost-of-service recovery mechanism, and its performance should be evaluated in that framework.[56]

As revised, the formula under Schedule 6A allows black start service providers to recover the costs of new investment and reasonably conforms the terms of commitment by the providers of black start service to the period over which investment costs are recovered. However, the inclusion of CIPS costs applicable to black start service may lead to substantial increases in the cost of black start service. Certain units may incur these costs and continue to be included in system restoration plans even though the plans could be developed in a manner that would provide the same service at much lower cost. The principal obstacle is that PJM does not have the authority to develop a

55 See Motion for Leave to Answer and Answer of the Independent Market Monitor for PJM filed in ER09-730-002 (August 28, 2009); 128 FERC ¶ 61,249 at PP 18—20 (September 17, 2009).
56 See 2002 Schedule 6A Filing at 4.

comprehensive system restoration plan or a clear mandate to conduct procurement in manner that results in a least cost solution for the entire system. The MMU recommends that PJM and the FERC, as well state regulators, reevaluate how black start service is procured in order to ensure that procurement is done in a least cost manner for the entire PJM market.

SECTION 7 – 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.[1] 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.[2]

The Market Monitoring Unit (MMU) analyzed congestion and its influence on PJM markets during 2009.

Overview

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.

1 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.

2 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.”

- **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.[3] 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 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.

3 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.

- **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 (Table 7-45). 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.

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 United States Federal Energy Regulatory Commission (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.[4]

4 126 FERC ¶ 61,152.

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.[5] 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.

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.[6] 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

5 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."

6 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.

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 (see Table 7-2).

Congestion

Congestion Accounting

Transmission congestion can exist in PJM's Day-Ahead and Real-Time Energy Market. Transmission congestion charges in the Day-Ahead Energy Market can be directly hedged by FTRs. Balancing market congestion charges can be hedged by FTRs to the extent that a participant's energy flows in real time are consistent with those in the Day-Ahead Energy Market.[7]

Total congestion charges are equal to the net congestion bill plus explicit congestion charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that increased congestion payments by load are offset by increased congestion revenues to generation, for the area analyzed. Whether the net congestion bill is an appropriate measure of congestion for load depends on who pays the load congestion payments and who receives the generation congestion credits. The net congestion bill is an appropriate measure of congestion for a utility that charges load congestion payments to load and credits generation congestion credits to load. The net congestion bill is not an appropriate measure of congestion in situations where load pays the load congestion payments but does not receive the generation credits as an offset.

In the 2009 analysis of total congestion costs, load congestion payments are netted against generation congestion credits on an hourly basis, by billing organization, and then summed for

7 The terms *congestion charges* and *congestion costs* are both used to refer to the costs associated with congestion. The term, *congestion charges*, is used in documents by PJM's Market Settlement Operations.

the given period.[8] A billing organization may offset load congestion payments with its generation portfolio or by purchasing supply from another entity via a bilateral transaction.

Load Congestion Payments and Generation Congestion Credits are calculated for both the Day-Ahead and Balancing Energy Markets.

- **Day-Ahead Load Congestion Payments.** Day-ahead load congestion payments are calculated for all cleared demand, decrement bids and Day-Ahead Energy Market sale transactions. (Decrement bids and energy sales can be thought of as scheduled load.) Day-ahead load congestion payments are calculated using MW and the load bus CLMP, the decrement bid CLMP or the CLMP at the source of the sale transaction, as applicable.

- **Day-Ahead Generation Congestion Credits.** Day-ahead generation congestion credits are calculated for all cleared generation and increment offers and Day-Ahead Energy Market purchase transactions. (Increment offers and energy purchases can be thought of as scheduled generation.) Day-ahead generation congestion credits are calculated using MW and the generator bus CLMP, the increment offer's CLMP or the CLMP at the sink of the purchase transaction, as applicable.

- **Balancing Load Congestion Payments.** Balancing load congestion payments are calculated for all deviations between a PJM member's real-time load and energy sale transactions and their day-ahead cleared demand, decrement bids and energy sale transactions. Balancing load congestion payments are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.

- **Balancing Generation Congestion Credits.** Balancing generation congestion credits are calculated for all deviations between a PJM member's real-time generation and energy purchase transactions and the day-ahead cleared generation, increment offers and energy purchase transactions. Balancing generation congestion credits are calculated using MW deviations and the real-time CLMP for each bus where a deviation exists.

- **Explicit Congestion Charges.** Explicit congestion charges are the net congestion charges associated with point-to-point energy transactions. These charges equal the product of the transacted MW and CLMP differences between sources (origins) and sinks (destinations) in the Day-Ahead Energy Market. Balancing energy market explicit congestion charges equal the product of the deviations between the real-time and day-ahead transacted MW and the differences between the real-time CLMP at the transactions' sources and sinks.

The congestion charges associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. The congestion charges in each zone are the sum of the congestion charges associated with each constraint that affects prices in the zone. The network nature of the transmission system means that congestion costs in a zone are frequently the result of constrained facilities located outside that zone.

8 This analysis does not treat affiliated billing organizations as a single organization. Thus, the generation congestion credits from one organization will not offset the load payments of its affiliate. This may overstate or understate the actual load payments or generation credits of an organization's parent company.

Congestion costs can be both positive and negative. The CLMP is calculated with respect to the system reference bus LMP, also called the system marginal price (SMP). When a transmission constraint occurs, the resulting CLMP is positive on one side of the constraint and negative on the other side of the constraint and the corresponding congestion costs are positive or negative. For each transmission constraint, the CLMP reflects the cost of a constraint at a pricing node and is equal to the product of the constraint shadow price and the distribution factor at the respective pricing node. The total CLMP at a pricing node is the sum of all constraint contributions to LMP and is equal to the difference between the actual LMP that results from transmission constraints, excluding losses, and the SMP. If an area experiences lower prices because of a constraint, the CLMP in that area is negative.[9]

Total Calendar Year Congestion

Congestion charges have ranged from 3 percent to 9 percent of annual total PJM billings since 2003.[10] Table 7-1 shows total congestion by year from 2003 through 2009. Total congestion charges were $719 million in calendar year 2009, a 66 percent decrease from $2.117 billion in calendar year 2008.[11]

Table 7-1 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%

Total congestion charges appearing in Table 7-1 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the Midwest ISO whose operating limits are respected by PJM.[12]

Table 7-2 shows the 2009 PJM congestion costs by category. The 2009 PJM total congestion costs were comprised of $253.3 million load congestion payments, $515.1 million negative generation congestion credits, and $49.4 million negative explicit congestion costs. Load payments

9 For an example of the congestion accounting methods used in this section, see the *2009 State of the Market Report for PJM*, Volume II, Appendix G, "Financial Transmission and Auction Revenue Rights," at Table G-1, "Congestion revenue, FTR target allocations and FTR congestion credits: Illustration."

10 Calculated values shown in Section 7, "Congestion," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

11 PJM reports congestion in terms of revenue collected to fund FTR Target Allocations. This means that any hour that results in a net negative congestion cost (i.e. the sum of day-ahead and balancing congestion costs in a given hour is less than zero) is excluded from the total congestion cost calculation for a given period. Therefore, the total congestion costs reported here will be less than those reported by PJM, for the same period, because they include the net negative congestion costs.

12 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. And PJM Interconnection, L.L.C." (December 11, 2008) (Accessed February 19, 2010), Section 6.1 <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx >.

for congestion decreased by 76 percent while generation credits for congestion increased by 53 percent and explicit congestion decreased by 59 percent.

Table 7-2 Total annual PJM congestion costs by category (Dollars (Millions)): Calendar years 2008 and 2009

	Congestion Costs (Millions)			
Year	Load Payments	Generation Credits	Explicit	Total
2008	$1,060.2	($1,087.5)	($31.1)	$2,116.6
2009	$253.3	($515.1)	($49.4)	$719.0

Monthly Congestion

Table 7-3 shows that during calendar year 2009, monthly congestion charges ranged from a maximum of $149.3 million in January 2009 to a minimum of $23.9 million in September 2009. Approximately 26 percent of all calendar year 2009 congestion occurred between the months of May and August.

Table 7-3 Monthly PJM congestion charges (Dollars (Millions)): Calendar years 2008 to 2009

	2008	2009	Change
Jan	$231.0	$149.3	($81.7)
Feb	$168.1	$83.0	($85.1)
Mar	$86.4	$74.6	($11.8)
Apr	$126.2	$25.6	($100.5)
May	$182.8	$25.9	($157.0)
Jun	$436.4	$49.8	($386.7)
Jul	$359.8	$39.4	($320.4)
Aug	$127.4	$72.1	($55.3)
Sep	$124.8	$23.9	($100.9)
Oct	$102.2	$42.7	($59.5)
Nov	$93.0	$36.3	($56.7)
Dec	$78.4	$96.4	$18.0
Total	$2,116.6	$719.0	($1,397.6)

Congestion Component of LMP

The congestion component of LMP was calculated for each PJM control zone, to provide an indication of the geographic dispersion of congestion costs. The congestion component of LMP for control zones is presented in Table 7-4 for calendar years 2008 and 2009.

Table 7-4 shows overall congestion patterns in 2009. Price separation between eastern and western control zones in PJM was primarily a result of congestion on the AP South interface. This constraint generally had a positive congestion component of LMP in eastern and southern control zones located on the constrained side of the affected facilities while the unconstrained western zones had a negative congestion component of LMP.

Table 7-4 Annual average congestion component of LMP: Calendar years 2008 to 2009

	2008		2009	
Control Zone	Day Ahead	Real Time	Day Ahead	Real Time
AECO	$7.93	$10.77	$2.03	$1.83
AEP	($9.56)	($10.46)	($2.12)	($2.16)
AP	($0.50)	$0.29	$0.62	$1.32
BGE	$10.96	$11.06	$3.33	$3.04
ComEd	($11.37)	($13.46)	($5.09)	($5.61)
DAY	($10.04)	($11.18)	($2.77)	($2.72)
DLCO	($11.77)	($14.47)	($3.37)	($3.02)
Dominion	$8.07	$8.76	$2.47	$2.37
DPL	$7.63	$7.69	$2.25	$2.32
JCPL	$7.92	$8.64	$1.82	$2.01
Met-Ed	$6.59	$6.51	$2.10	$2.03
PECO	$5.93	$6.11	$1.87	$1.71
PENELEC	($0.91)	($2.33)	($0.10)	($0.06)
Pepco	$12.28	$12.40	$3.75	$3.74
PPL	$5.62	$5.50	$1.88	$1.75
PSEG	$7.76	$8.92	$2.12	$2.27
RECO	$6.55	$7.62	$1.47	$1.55

Congested Facilities

A congestion event exists when a unit or units must be dispatched out-of-merit order to control the impact of a contingency on a monitored facility or to control an actual overload. A congestion-event hour exists when a specific facility is constrained for one or more five-minute intervals within an hour. A congestion-event hour differs from a constrained hour, which is any hour during which one or more facilities are congested. Thus, if two facilities are constrained during an hour, the result is two congestion-event hours and one constrained hour. Constraints are often simultaneous, so the number of congestion-event hours exceeds the number of constrained hours and the number of congestion-event hours can exceed the number of hours in a year. 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. This is also consistent with the way in which PJM reports real-time congestion. In 2009, there were 77,793 day-ahead, congestion-event hours compared to 74,745 day-ahead, congestion-event hours in 2008. In 2009, there were 15,454 real-time, congestion-event hours compared to 22,449 real-time, congestion-event hours in 2008.

Congestion by Facility Type and Voltage

Day-ahead, congestion-event hours increased on PJM transmission lines and on 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-event hours increased on the reciprocally coordinated flowgates between PJM and the Midwest ISO, while interfaces, transmission lines and transformers saw decreases.

Day-ahead congestion costs increased on the reciprocally coordinated flowgates between PJM and the Midwest ISO and decreased on all other facility types in 2009. Balancing congestion costs decreased on the reciprocally coordinated flowgates between PJM and the Midwest ISO and increased on all other facility types in 2009.

Table 7-5 provides congestion-event-hour subtotals and congestion cost subtotals comparing 2009 calendar year results by facility type: line, transformer, interface, flowgate and unclassified facilities.[13,14] For comparison, this information is presented in Table 7-6 for calendar year 2008.[15]

Total congestion costs associated with the reciprocally coordinated flowgates between PJM and the Midwest ISO increased by $33.2 million from -$19.9 million in 2008 to $13.3 million in 2009.[16] The Dunes Acres – Michigan City flowgate accounted for $16.7 million in congestion costs and was the largest contributor to positive congestion costs among flowgates in 2009. The largest contribution to negative congestion costs among flowgates came from the Pana North flowgate with -$8.9 million in 2009 congestion costs.

Total congestion costs associated with interfaces decreased from $937.4 million in 2008 to $322.8 million in 2009. Interfaces typically include multiple transmission facilities and reflect power flows into or through a wider geographic area. Interface congestion constituted 45 percent of total PJM congestion costs in 2009. Among interfaces, the AP South, the West and the 5004/5005 interfaces accounted for the largest contribution to positive congestion costs in 2009. The AP South interface, with $206.5 million in congestion, had the highest congestion cost of any facility in PJM, accounting for 29 percent of the total PJM congestion costs in 2009. The AP South, the West and the 5004/5005 interfaces together accounted for $293.8 million or 41 percent of total PJM congestion costs in 2009.

Total congestion costs associated with transmission lines decreased 66 percent from $837.4 million in 2008 to $281.0 million in 2009. Transmission line congestion accounted for 40 percent of the total PJM congestion costs for 2009. The Pleasant Valley – Belvidere and Mount Storm – Pruntytown lines together accounted for $54.7 million or 19 percent of all transmission line congestion costs and were the largest contributors to positive congestion among transmission lines in 2009. The

13 Unclassified constraints appear in the Day-Ahead Market only and represent congestion costs incurred on market elements which are not posted by PJM. Congestion frequency associated with these unclassified constraints is not presented in order to be consistent with the posting of constrained facilities by PJM.

14 The term *flowgate* refers to Midwest ISO flowgates in this context.

15 For 2008 and 2009, the load congestion payments and generation congestion credits represent the net load congestion payments and net generation congestion credits for an organization, as this shows the extent to which each organization's load or generation was exposed to congestion costs.

16 The congestion costs reported here for the reciprocally coordinated flowgates between PJM and the Midwest ISO flowgates are calculated in the same manner as all other internal PJM constraints and use the congestion accounting methods defined in this section. For the payments to and from the Midwest ISO based on the market-to-market settlement calculations, defined in the "Joint Operating Agreement between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.", see the *2009 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," at "PJM and Midwest ISO Joint Operating Agreement."

largest contribution to negative congestion costs among transmission lines came from the Crete – East Frankfurt line with -$8.0 million in 2009 congestion costs.

Total congestion costs associated with transformers decreased 69 percent from $338.9 million in 2008 to $103.6 million in 2009. Congestion on transformers accounted for 14 percent of the total PJM congestion costs in 2009. The Kammer and Doubs transformers together accounted for $59.1 million or 57 percent of all transformer congestion costs and were the largest contributors to positive congestion costs among transformers in 2009.

Table 7-5 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

Table 7-6 Congestion summary (By facility type): Calendar year 2008

	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	$9.6	($14.3)	$11.8	$35.7	($7.2)	$3.5	($44.8)	($55.5)	($19.9)	2,417	2,073
Interface	$368.3	($579.2)	$44.7	$992.2	($18.2)	$20.3	($16.3)	($54.8)	$937.4	8,866	2,263
Line	$597.5	($423.0)	$120.0	$1,140.6	($129.1)	$27.6	($146.4)	($303.1)	$837.4	50,640	13,231
Transformer	$300.4	($139.7)	$29.9	$470.0	($71.4)	$27.8	($32.0)	($131.2)	$338.9	12,822	4,882
Unclassified	$10.3	($10.5)	$2.0	$22.8	$0.0	$0.0	$0.0	$0.0	$22.8	NA	NA
Total	$1,286.1	($1,166.7)	$208.4	$2,661.2	($225.9)	$79.2	($239.5)	($544.6)	$2,116.6	74,745	22,449

Table 7-7 shows congestion costs by facility voltage class for 2009. In comparison to 2008 (shown in Table 7-8), congestion costs decreased across 765 kV, 500 kV, 230 kV, 138 kV, 115 kV, 34 kV, 12 kV and unclassified facilities in 2009. Congestion costs increased across 345 kV facilities in 2009.

Congestion costs associated with 765 kV facilities decreased 99 percent from $4.9 million in 2008 to the $0.1 million experienced in 2009. Congestion on 765 kV facilities comprised less than 1 percent of total 2009 PJM congestion costs.

Congestion costs associated with 500 kV facilities decreased 73 percent from $1.528 billion in 2008, to $407 million in 2009. Congestion on 500 kV facilities comprised 57 percent of total 2009

PJM congestion costs. The AP South interface, the West interface, the 5004/5005 interface and the Kammer transformer accounted for $327.8 million or 81 percent of all 500 kV congestion costs; they were the largest contributors to positive congestion among 500 kV facilities in 2009.

Congestion costs associated with 345 kV facilities increased by 2,090 percent from -$2.9 million in 2008, to $58.1 million in 2009. Congestion on 345 kV facilities comprised eight percent of total 2009 PJM congestion costs. The East Frankfurt – Crete line and the Crete – St. Johns line accounted for $40.0 million or 69 percent of all 345 kV congestion costs; they were the largest contributors to positive congestion among 345 kV facilities in 2009.

Congestion costs associated with 230 kV facilities decreased 66 percent from $243.1 million in 2008 to $83.2 million in 2009. Congestion on 230 kV facilities comprised 12 percent of total 2009 PJM congestion costs. The Doubs transformer accounted for $25.1 million or 30 percent of all 230 kV congestion costs and was the largest contributor to positive congestion among 230 kV facilities in 2009.

Congestion costs associated with 138 kV facilities decreased 38 percent from $257.3 million in 2008 to $158.3 million in 2009. Congestion on 138 kV facilities comprised 22 percent of total 2009 PJM congestion costs. The Pleasant Valley – Belvidere line and Dunes Acres – Michigan City flowgate together accounted for $50.9 million or 32 percent of all 138 kV congestion costs; they were the largest contributors to positive congestion among 138 kV facilities in 2009.

Congestion costs associated with 115 kV facilities decreased by 67 percent from $36.3 million in 2008, to $12.1 million in 2009. Congestion on 115 kV facilities comprised two percent of total 2009 PJM congestion costs. The Seward transformer and the Beechwood – Kerr Dam line together accounted for $5.5 million or 45 percent of all 115 kV congestion costs; they were the largest contributors to positive congestion among 115 kV facilities in 2009.

Congestion costs associated with 69 kV and below facilities decreased by nearly 100 percent from $50.5 million in 2008, to $0.2 million in 2009. Congestion on 69 kV and below facilities comprised less than one percent of total 2009 PJM congestion costs. The Short – Laurel line accounted for -$2.4 million in congestion costs. It had the largest contribution to congestion costs among 69 kV and below facilities.

Table 7-7 Congestion summary (By facility voltage): Calendar year 2009

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	($0.0)	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	24	0
500	$115.0	($275.8)	$14.2	$404.9	($0.5)	($15.0)	($12.3)	$2.1	$407.0	11,571	3,301
345	$30.6	($61.4)	$34.8	$126.8	($5.3)	$7.1	($56.3)	($68.7)	$58.1	8,396	2,506
230	$56.3	($45.4)	$9.5	$111.2	($15.0)	$5.9	($7.2)	($28.0)	$83.2	15,030	2,095
138	$68.2	($147.7)	$24.9	$240.7	($14.8)	$10.4	($57.2)	($82.5)	$158.3	30,328	6,669
115	$11.6	($0.7)	$0.4	$12.6	$0.4	$0.6	($0.2)	($0.5)	$12.1	4,892	552
69	$7.3	$0.7	$0.2	$6.8	($3.8)	$0.9	($0.1)	($4.8)	$1.9	6,420	329
34	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	181	2
12	$0.4	$0.3	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	951	0
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

Table 7-8 Congestion summary (By facility voltage): Calendar year 2008

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$1.6	($3.0)	$0.1	$4.7	$1.2	$0.5	($0.4)	$0.2	$4.9	83	31
500	$718.1	($861.2)	$90.1	$1,669.4	($98.5)	($0.7)	($44.1)	($141.9)	$1,527.5	19,171	7,185
345	$52.9	($62.6)	$46.7	$162.2	($38.6)	$8.0	($118.6)	($165.1)	($2.9)	5,887	2,627
230	$213.8	($106.8)	$28.8	$349.4	($33.9)	$49.7	($22.7)	($106.3)	$243.1	14,816	4,058
138	$191.9	($121.0)	$39.1	$351.9	($38.5)	$8.5	($47.7)	($94.7)	$257.3	20,551	6,478
115	$62.9	($4.5)	$1.4	$68.8	($15.4)	$11.4	($5.7)	($32.5)	$36.3	8,046	1,475
69	$34.7	$3.0	$0.4	$32.0	($2.3)	$1.8	($0.2)	($4.3)	$27.7	6,191	571
34	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	0	24
12	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
Unclassified	$10.3	($10.5)	$2.0	$22.8	$0.0	$0.0	$0.0	$0.0	$22.8	NA	NA
Total	$1,286.1	($1,166.7)	$208.4	$2,661.2	($225.9)	$79.2	($239.5)	($544.6)	$2,116.6	74,745	22,449

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Constraint Duration

Table 7-9 lists calendar year 2008 and 2009 constraints that were most frequently in effect and Table 7-10 shows the constraints which experienced the largest change in congestion-event hours from 2008 to 2009.[17]

The Kammer transformer, the AP South interface and the Pleasant Valley – Belvidere line were the most frequently occurring constraints in 2009. The Pleasant Valley – Belvidere line saw the largest increase in congestion-event hours from 2008. The Cloverdale – Lexington line saw the largest decrease in congestion-event hours from 2008 to 2009, but still remained in the top 25 of the most frequently occurring transmission constraints. The Kammer transformer, the AP South interface and the Pleasant Valley – Belvidere line were also among the top contributors to 2009 congestion costs (see Table 7-11).

Table 7-9 Top 25 constraints with frequent occurrence: Calendar years 2008 to 2009

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2008	2009	Change	2008	2009	Change	2008	2009	Change	2008	2009	Change
1	Kammer	Transformer	3,069	3,674	605	1,628	1,328	(300)	35%	42%	7%	19%	15%	(3%)
2	AP South	Interface	3,572	3,501	(71)	1,016	604	(412)	41%	40%	(1%)	12%	7%	(5%)
3	Pleasant Valley - Belvidere	Line	5	3,648	3,643	15	405	390	0%	42%	42%	0%	5%	4%
4	Leonia - New Milford	Line	919	3,847	2,928	84	39	(45)	10%	44%	33%	1%	0%	(1%)
5	Dunes Acres - Michigan City	Flowgate	687	2,949	2,262	435	910	475	8%	34%	26%	5%	10%	5%
6	Burlington - Croydon	Line	549	2,794	2,245	10	3	(7)	6%	32%	26%	0%	0%	(0%)
7	East Frankfort - Crete	Line	1,002	2,134	1,132	0	0	0	11%	24%	13%	0%	0%	0%
8	Crete - St Johns Tap	Flowgate	84	1,565	1,481	14	306	292	1%	18%	17%	0%	3%	3%
9	Tiltonsville - Windsor	Line	0	1,449	1,449	10	311	301	0%	17%	17%	0%	4%	3%
10	Waterman - West Dekalb	Line	178	1,499	1,321	1	57	56	2%	17%	15%	0%	1%	1%
11	Cloverdale - Lexington	Line	3,529	1,015	(2,514)	1,813	434	(1,379)	40%	12%	(29%)	21%	5%	(16%)
12	State Line - Wolf Lake	Flowgate	1,342	1,261	(81)	370	183	(187)	15%	14%	(1%)	4%	2%	(2%)
13	Oak Grove - Galesburg	Flowgate	0	754	754	12	638	626	0%	9%	9%	0%	7%	7%
14	Pana North	Flowgate	190	986	796	640	318	(322)	2%	11%	9%	7%	4%	(4%)
15	Athenia - Saddlebrook	Line	227	1,108	881	120	139	19	3%	13%	10%	1%	2%	0%
16	Cedar Grove - Clifton	Line	793	1,194	401	445	38	(407)	9%	14%	5%	5%	0%	(5%)
17	Pinehill - Stratford	Line	3,088	1,208	(1,880)	0	0	0	35%	14%	(21%)	0%	0%	0%
18	Glidden - West Dekalb	Line	10	1,166	1,156	0	21	21	0%	13%	13%	0%	0%	0%
19	Pumphrey - Westport	Line	1,092	1,181	89	0	0	0	12%	13%	1%	0%	0%	0%
20	5004/5005 Interface	Interface	736	776	40	449	294	(155)	8%	9%	0%	5%	3%	(2%)
21	Kammer - Ormet	Line	196	552	356	151	509	358	2%	6%	4%	2%	6%	4%
22	Bellehaven - Tasley	Line	96	1,055	959	0	0	0	1%	12%	11%	0%	0%	0%
23	Electric Jct - Nelson	Line	0	823	823	50	202	152	0%	9%	9%	1%	2%	2%
24	Ruth - Turner	Line	0	704	704	20	313	293	0%	8%	8%	0%	4%	3%
25	Deepcreek	Transformer	0	951	951	0	0	0	0%	11%	11%	0%	0%	0%

17 Presented in descending order of absolute change between 2008 and 2009 day-ahead and real-time, congestion-event hours.

Table 7-10 Top 25 constraints with largest year-to-year change in occurrence: Calendar years 2008 to 2009

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2008	2009	Change	2008	2009	Change	2008	2009	Change	2008	2009	Change
1	Pleasant Valley - Belvidere	Line	5	3,648	3,643	15	405	390	0%	42%	42%	0%	5%	4%
2	Cloverdale - Lexington	Line	3,529	1,015	(2,514)	1,813	434	(1,379)	40%	12%	(29%)	21%	5%	(16%)
3	Leonia - New Milford	Line	919	3,847	2,928	84	39	(45)	10%	44%	33%	1%	0%	(1%)
4	Dunes Acres - Michigan City	Flowgate	687	2,949	2,262	435	910	475	8%	34%	26%	5%	10%	5%
5	Mount Storm - Pruntytown	Line	2,559	525	(2,034)	812	132	(680)	29%	6%	(23%)	9%	2%	(8%)
6	Sammis - Wylie Ridge	Line	1,915	762	(1,153)	1,257	157	(1,100)	22%	9%	(13%)	14%	2%	(13%)
7	Burlington - Croydon	Line	549	2,794	2,245	10	3	(7)	6%	32%	26%	0%	0%	(0%)
8	Trainer - Delco Tap	Line	2,218	0	(2,218)	0	0	0	25%	0%	(25%)	0%	0%	0%
9	Pinehill - Stratford	Line	3,088	1,208	(1,880)	0	0	0	35%	14%	(21%)	0%	0%	0%
10	Crete - St Johns Tap	Flowgate	84	1,565	1,481	14	306	292	1%	18%	17%	0%	3%	3%
11	Tiltonsville - Windsor	Line	0	1,449	1,449	10	311	301	0%	17%	17%	0%	4%	3%
12	Atlantic - Larrabee	Line	1,556	280	(1,276)	380	73	(307)	18%	3%	(15%)	4%	1%	(3%)
13	West	Interface	1,690	504	(1,186)	390	87	(303)	19%	6%	(13%)	4%	1%	(3%)
14	Oak Grove - Galesburg	Flowgate	0	754	754	12	638	626	0%	9%	9%	0%	7%	7%
15	Waterman - West Dekalb	Line	178	1,499	1,321	1	57	56	2%	17%	15%	0%	1%	1%
16	Branchburg - Readington	Line	1,121	37	(1,084)	271	13	(258)	13%	0%	(12%)	3%	0%	(3%)
17	Glidden - West Dekalb	Line	10	1,166	1,156	0	21	21	0%	13%	13%	0%	0%	0%
18	Mount Storm	Transformer	935	151	(784)	469	80	(389)	11%	2%	(9%)	5%	1%	(4%)
19	East Frankfort - Crete	Line	1,002	2,134	1,132	0	0	0	11%	24%	13%	0%	0%	0%
20	East Towanda	Transformer	803	0	(803)	306	0	(306)	9%	0%	(9%)	3%	0%	(3%)
21	Krendale - Seneca	Line	1,389	324	(1,065)	24	0	(24)	16%	4%	(12%)	0%	0%	(0%)
22	Ruth - Turner	Line	0	704	704	20	313	293	0%	8%	8%	0%	4%	3%
23	Bedington	Transformer	1,192	354	(838)	303	149	(154)	14%	4%	(10%)	3%	2%	(2%)
24	Dickerson - Plesant View	Line	844	54	(790)	218	30	(188)	10%	1%	(9%)	2%	0%	(2%)
25	Electric Jct - Nelson	Line	0	823	823	50	202	152	0%	9%	9%	1%	2%	2%

Constraint Costs

Table 7-11 and Table 7-12 present the top constraints affecting congestion costs by facility for calendar years 2008 and 2009.[18] 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 comprised 50 percent of the total PJM congestion costs in 2009.

Table 7-11 Top 25 constraints affecting annual PJM congestion costs (By facility): Calendar year 2009

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2009
1	AP South	Interface	500	$12.0	($186.0)	($0.2)	$197.8	$2.9	($2.9)	$2.9	$8.7	$206.5	29%
2	West	Interface	500	$19.4	($22.9)	$0.7	$42.9	$0.4	($0.3)	$0.1	$0.8	$43.7	6%
3	5004/5005 Interface	Interface	500	$11.1	($31.0)	$0.3	$42.4	$1.3	$0.3	$0.2	$1.1	$43.6	6%
4	Pleasant Valley - Belvidere	Line	ComEd	($6.3)	($45.2)	$4.0	$42.9	($0.6)	$2.9	($5.3)	($8.8)	$34.2	5%
5	Kammer	Transformer	500	$50.8	$16.1	$9.0	$43.8	($4.9)	($6.7)	($11.6)	($9.8)	$34.0	5%
6	East Frankfort - Crete	Line	ComEd	$5.9	($19.1)	$8.6	$33.6	$0.0	$0.0	$0.0	$0.0	$33.6	5%
7	Doubs	Transformer	AP	$17.6	($10.8)	$0.9	$29.3	($2.1)	$0.2	($1.8)	($4.2)	$25.1	3%
8	Mount Storm - Pruntytown	Line	AP	$1.8	($16.8)	$0.5	$19.1	$0.9	($1.7)	($1.1)	$1.5	$20.5	3%
9	Bedington - Black Oak	Interface	500	$3.8	($15.5)	$0.8	$20.1	($0.4)	($0.1)	$0.1	($0.2)	$19.8	3%
10	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$13.5	($23.2)	$8.6	$45.4	($7.2)	($2.0)	($23.4)	($28.6)	$16.7	2%
11	Cloverdale - Lexington	Line	AEP	$8.1	($5.3)	$2.0	$15.3	($0.0)	($3.1)	($2.8)	$0.3	$15.6	2%
12	Crete - St Johns Tap	Flowgate	Midwest ISO	$3.2	($15.1)	$3.8	$22.0	($1.1)	$0.4	($6.1)	($7.7)	$14.4	2%
13	AEP-DOM	Interface	500	$1.4	($7.6)	$0.5	$9.5	($0.5)	($0.2)	($0.0)	($0.3)	$9.2	1%
14	Pana North	Flowgate	Midwest ISO	$0.1	($2.2)	$1.8	$4.2	($0.5)	$1.1	($11.5)	($13.0)	($8.9)	(1%)
15	Graceton - Raphael Road	Line	BGE	$1.5	($6.0)	$0.6	$8.1	$1.5	$0.1	($0.7)	$0.7	$8.8	1%
16	Tiltonsville - Windsor	Line	AP	$8.4	($0.4)	$0.3	$9.1	($0.4)	($0.6)	($0.7)	($0.6)	$8.6	1%
17	Ruth - Turner	Line	AEP	$2.5	($6.5)	$0.5	$9.5	($1.5)	($0.6)	($0.6)	($1.5)	$8.0	1%
18	Crete - East Frankfurt	Line	ComEd	$0.0	$0.0	$0.0	$0.0	($1.0)	$1.3	($5.7)	($8.0)	($8.0)	(1%)
19	Sammis - Wylie Ridge	Line	AP	$4.5	($3.5)	$3.5	$11.5	($1.1)	($0.2)	($2.8)	($3.7)	$7.8	1%
20	Kanawha River	Transformer	AEP	$2.0	($3.7)	$0.3	$6.0	$0.1	($0.5)	($0.1)	$0.5	$6.5	1%
21	Kammer - Ormet	Line	AEP	$4.3	($4.1)	($0.1)	$8.3	($1.6)	$0.5	($0.0)	($2.2)	$6.2	1%
22	Glidden - West Dekalb	Line	ComEd	($0.6)	($6.0)	$0.4	$5.9	$0.1	($0.0)	($0.0)	$0.1	$6.0	1%
23	Breed - Wheatland	Line	AEP	($0.2)	($5.2)	$0.6	$5.6	$0.0	($0.0)	($0.0)	($0.0)	$5.6	1%
24	Kanawha - Kincaid	Line	AEP	$1.9	($3.5)	$0.2	$5.6	$0.0	$0.0	$0.0	$0.0	$5.6	1%
25	Schahfer - Burr Oak	Flowgate	Midwest ISO	$0.4	($1.3)	$0.6	$2.3	($2.0)	$0.4	($5.4)	($7.8)	($5.6)	(1%)

18 Presented in descending order of annual total congestion costs.

Table 7-12 Top 25 constraints affecting annual PJM congestion costs (By facility): Calendar year 2008

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2008
1	AP South	Interface	500	$196.2	($367.1)	$23.8	$587.1	($11.9)	$5.5	($11.7)	($29.1)	$558.0	26%
2	Cloverdale - Lexington	Line	AEP	$153.8	($77.5)	$9.0	$240.3	($20.6)	($18.6)	($9.1)	($11.0)	$229.3	11%
3	Mount Storm - Pruntytown	Line	AP	$60.1	($157.0)	$15.8	$232.8	($21.6)	($15.8)	($2.9)	($8.7)	$224.1	11%
4	Bedington - Black Oak	Interface	500	$52.2	($106.2)	$7.0	$165.5	($1.3)	($0.6)	($0.2)	($0.9)	$164.6	8%
5	West	Interface	500	$67.8	($42.5)	$8.0	$118.3	($2.0)	$8.2	($2.2)	($12.4)	$105.9	5%
6	Kammer	Transformer	500	$100.9	$23.3	$10.4	$88.0	($17.0)	($3.7)	$1.4	($11.9)	$76.1	4%
7	Sammis - Wylie Ridge	Line	AP	$18.4	($5.9)	$23.1	$47.4	($29.7)	$5.2	($71.9)	($106.9)	($59.5)	(3%)
8	Bedington	Transformer	AP	$21.5	($33.2)	$2.2	$56.9	($1.8)	($1.4)	($1.1)	($1.4)	$55.4	3%
9	5004/5005 Interface	Interface	500	$16.5	($34.9)	$3.0	$54.4	($2.8)	$6.9	($2.0)	($11.7)	$42.7	2%
10	Mount Storm	Transformer	AP	$22.3	($61.3)	$10.0	$93.6	($20.9)	$14.1	($15.9)	($50.9)	$42.7	2%
11	East	Interface	500	$21.7	($17.5)	$1.2	$40.4	($0.1)	($0.0)	$0.0	($0.0)	$40.4	2%
12	Atlantic - Larrabee	Line	JCPL	$41.1	($15.4)	$5.4	$61.9	($9.7)	$8.2	($4.8)	($22.7)	$39.2	2%
13	Meadow Brook	Transformer	AP	$21.8	($17.5)	$0.8	$40.1	($4.4)	($1.2)	($0.4)	($3.6)	$36.5	2%
14	Branchburg - Readington	Line	PSEG	$31.0	($12.2)	$4.8	$48.1	($6.4)	$8.8	($2.0)	($17.2)	$30.9	1%
15	East Frankfort - Crete	Line	ComEd	$7.7	($13.8)	$6.7	$28.2	$0.0	$0.0	$0.0	$0.0	$28.2	1%
16	Aqueduct - Doubs	Line	AP	$23.7	($3.9)	$0.5	$28.0	$0.0	($0.1)	($0.0)	$0.1	$28.1	1%
17	Central	Interface	500	$13.9	($11.1)	$1.6	$26.6	($0.1)	$0.0	$0.1	($0.0)	$26.6	1%
18	Axton	Transformer	AEP	$9.1	($15.4)	$1.6	$26.2	$0.0	$0.0	$0.0	$0.0	$26.2	1%
19	Harwood - Susquehanna	Line	PPL	$9.0	($19.9)	$0.5	$29.4	($2.6)	$3.0	($0.7)	($6.3)	$23.2	1%
20	Unclassified	Unclassified	Unclassified	$10.3	($10.5)	$2.0	$22.8	$0.0	$0.0	$0.0	$0.0	$22.8	1%
21	Krendale - Seneca	Line	AP	$18.6	$3.4	$7.4	$22.5	($0.1)	$0.0	($0.1)	($0.3)	$22.3	1%
22	Dickerson - Plesant View	Line	Pepco	$41.5	$24.9	$2.2	$18.8	($0.4)	($1.2)	($1.4)	($0.6)	$18.3	1%
23	Bristers - Ox	Line	Dominion	$8.7	($7.4)	($0.9)	$15.3	$0.5	$0.4	$0.4	$0.5	$15.8	1%
24	North Seaford - Pine Street	Line	DPL	$21.2	$5.4	$0.1	$16.0	($1.0)	($0.6)	($0.1)	($0.6)	$15.4	1%
25	Branchburg - Flagtown	Line	PSEG	$12.2	($4.1)	$0.2	$16.4	$0.5	$1.0	($1.1)	($1.6)	$14.8	1%

Congestion-Event Summary for Midwest ISO Flowgates

PJM and the Midwest ISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes reciprocal, coordinated flowgates in the combined footprint whose operating limits are respected by the operators of both organizations.[19] A flowgate is a representative modeling of facilities or groups of facilities that may act as constraint points on the regional system.[20] PJM models these coordinated flowgates

19 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2009) (Accessed February 19, 2010) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.

20 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. And PJM Interconnection, L.L.C." (December 11, 2009) (Accessed February 19, 2010), Section 2.2.24 <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx>.

and controls for them in its security-constrained, economic dispatch. Table 7-13 and Table 7-14 show the Midwest ISO flowgates which PJM took dispatch action to control during 2009 and 2008, respectively, and which had the greatest congestion cost impact on PJM. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The top congestion cost impacts for Midwest ISO flowgates affecting PJM dispatch are presented by constraint, in descending order of the absolute value of total congestion costs. Among Midwest ISO flowgates in 2009, the Dunes Acres – Michigan City flowgate made the most significant contribution to positive congestion while the Pana North flowgate made the most significant contribution to negative congestion. Among Midwest ISO flowgates in 2008, the State Line – Wolf Lake flowgate made the most significant contributions to positive congestion, while the Pana North flowgate made the most significant negative contribution.

Table 7-13 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): Calendar year 2009

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Dunes Acres - Michigan City	$13.5	($23.2)	$8.6	$45.4	($7.2)	($2.0)	($23.4)	($28.6)	$16.7	2,949	910
2	Crete - St Johns Tap	$3.2	($15.1)	$3.8	$22.0	($1.1)	$0.4	($6.1)	($7.7)	$14.4	1,565	306
3	Pana North	$0.1	($2.2)	$1.8	$4.2	($0.5)	$1.1	($11.5)	($13.0)	($8.9)	986	318
4	Schahfer - Burr Oak	$0.4	($1.3)	$0.6	$2.3	($2.0)	$0.4	($5.4)	($7.8)	($5.6)	62	81
5	Paddock - Townline	$0.5	($3.6)	$0.4	$4.6	$0.6	$0.3	($0.3)	($0.0)	$4.5	404	215
6	Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.1	$0.7	($3.2)	($3.8)	($3.8)	0	161
7	Rising	($0.1)	($2.7)	$0.5	$3.1	$0.0	$0.2	($0.8)	($1.0)	$2.1	565	150
8	Palisades - Argenta	$0.1	($0.1)	$0.1	$0.3	($0.3)	$0.6	($1.1)	($2.1)	($1.8)	49	58
9	Pleasant Prairie - Zion	($0.0)	($0.4)	$0.1	$0.5	$0.3	$0.5	($1.9)	($2.2)	($1.7)	100	45
10	State Line - Wolf Lake	$0.5	($2.6)	$1.1	$4.3	($0.5)	$0.6	($1.6)	($2.7)	$1.6	1,261	183
11	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	($1.1)	($1.3)	($1.3)	0	44
12	Oak Grove - Galesburg	($0.6)	($4.3)	$0.1	$3.8	$0.8	$1.4	($4.2)	($4.8)	($1.0)	754	638
13	State Line - Roxana	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.0	($0.4)	($0.6)	($0.6)	0	30
14	Pawnee	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.4)	($0.4)	($0.4)	0	35
15	Lanesville	$0.3	($0.1)	$0.1	$0.5	$0.0	$0.1	($0.8)	($0.9)	($0.4)	104	32
16	Pierce - Foster	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.3	($0.0)	($0.4)	($0.4)	0	5
17	Burr Oak	$0.1	($0.4)	$0.5	$0.9	($0.2)	$0.2	($0.8)	($1.3)	($0.3)	71	66
18	Krendale - Seneca	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.1)	($0.2)	($0.2)	0	30
19	Bunsonville - Eugene	$0.0	($0.1)	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	24	0
20	State Line	$0.0	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	299	0

Table 7-14 Top congestion cost impacts from Midwest ISO flowgates affecting PJM dispatch (By facility): Calendar year 2008

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Pana North	$0.7	($1.8)	$0.6	$3.1	($0.7)	$1.4	($11.5)	($13.5)	($10.5)	190	640
2	Pleasant Prairie - Zion	$0.0	$0.0	$0.0	$0.0	($0.7)	$0.2	($5.3)	($6.2)	($6.2)	0	72
3	Lanesville	$0.2	($0.4)	$0.3	$0.9	($0.2)	$0.8	($5.7)	($6.7)	($5.8)	60	153
4	State Line - Wolf Lake	$2.2	($4.4)	$5.0	$11.7	($1.0)	$1.2	($4.1)	($6.3)	$5.3	1,342	370
5	Schahfer - Burr Oak	$0.2	($0.4)	$0.1	$0.7	($1.2)	($0.7)	($2.3)	($2.7)	($2.0)	38	160
6	Rising	$0.0	($0.0)	$0.0	$0.1	($0.2)	$0.0	($1.8)	($2.0)	($1.9)	16	89
7	Crete - St Johns Tap	$0.9	($1.3)	$0.3	$2.5	($0.2)	$0.1	($0.4)	($0.7)	$1.8	84	14
8	Dunes Acres - Michigan City	$5.3	($6.0)	$5.5	$16.8	($2.9)	$0.2	($13.0)	($16.1)	$0.7	687	435
9	Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.1	$0.2	($0.3)	($0.5)	($0.5)	0	11
10	State Line - Roxana	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.3)	($0.4)	($0.4)	0	37
11	Ontario Hydro - NYISO	$0.0	$0.0	$0.0	$0.0	($0.3)	($0.1)	($0.0)	($0.2)	($0.2)	0	15
12	Krendale - Seneca	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.0	($0.0)	($0.2)	($0.2)	0	23
13	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.1)	($0.1)	($0.1)	0	12
14	Salem	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	0	1
15	State Line	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
16	DC Cook - Palisades	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	0	3
17	Eau Claire - Arpin	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	($0.0)	0	10
18	Greenfield - Lakeview	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	0	8
19	Paddock - Townline	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	0	6
20	Pawnee	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	0	1

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 7-15 and Table 7-16 show the 500 kV constraints impacting congestion costs in PJM. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The 500 kV constraints impacting congestion costs in PJM are presented by constraint, in descending order of the absolute value of total congestion costs. In 2009, the AP South interface constraint contributed to positive congestion. There were no significant contributions to negative congestion from 500 kV constraints in 2009. In 2008, the AP South and Bedington — Black Oak interface constraints contributed to positive congestion. In 2008, the Juniata – Keystone and Cabot – Wylie Ridge lines contributed to negative congestion.

Table 7-15 Regional constraints summary (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$12.0	($186.0)	($0.2)	$197.8	$2.9	($2.9)	$2.9	$8.7	$206.5	3,501	604
2	West	Interface	500	$19.4	($22.9)	$0.7	$42.9	$0.4	($0.3)	$0.1	$0.8	$43.7	504	87
3	5004/5005 Interface	Interface	500	$11.1	($31.0)	$0.3	$42.4	$1.3	$0.3	$0.2	$1.1	$43.6	776	294
4	Kammer	Transformer	500	$50.8	$16.1	$9.0	$43.8	($4.9)	($6.7)	($11.6)	($9.8)	$34.0	3,674	1,328
5	Bedington - Black Oak	Interface	500	$3.8	($15.5)	$0.8	$20.1	($0.4)	($0.1)	$0.1	($0.2)	$19.8	645	73
6	AEP-DOM	Interface	500	$1.4	($7.6)	$0.5	$9.5	($0.5)	($0.2)	($0.0)	($0.3)	$9.2	325	136
7	East	Interface	500	$0.3	($0.3)	($0.0)	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	32	0
8	Doubs - Mount Storm	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	$0.0	$0.1	$0.1	0	18
9	Harrison Tap - Kammer	Line	500	$0.0	($0.0)	$0.0	$0.0	$0.1	$0.0	$0.0	$0.1	$0.1	1	11
10	Central	Interface	500	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.1	($0.0)	($0.1)	$0.1	19	8
11	Belmont - Harrison	Line	500	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	5	2
12	Harrison - Pruntytown	Line	500	$0.0	($0.0)	$0.0	$0.0	($0.0)	($0.1)	($0.0)	($0.0)	$0.0	2	43
13	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)	($0.0)	0	1
14	Harrison Tap - North Longview	Line	500	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0

Table 7-16 Regional constraints summary (By facility): Calendar year 2008

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$196.2	($367.1)	$23.8	$587.1	($11.9)	$5.5	($11.7)	($29.1)	$558.0	3,572	1,016
2	Bedington - Black Oak	Interface	500	$52.2	($106.2)	$7.0	$165.5	($1.3)	($0.6)	($0.2)	($0.9)	$164.6	1,384	284
3	West	Interface	500	$67.8	($42.5)	$8.0	$118.3	($2.0)	$8.2	($2.2)	($12.4)	$105.9	1,690	390
4	Kammer	Transformer	500	$100.9	$23.3	$10.4	$88.0	($17.0)	($3.7)	$1.4	($11.9)	$76.1	3,069	1,628
5	5004/5005 Interface	Interface	500	$16.5	($34.9)	$3.0	$54.4	($2.8)	$6.9	($2.0)	($11.7)	$42.7	736	449
6	East	Interface	500	$21.7	($17.5)	$1.2	$40.4	($0.1)	($0.0)	$0.0	($0.0)	$40.4	758	12
7	Central	Interface	500	$13.9	($11.1)	$1.6	$26.6	($0.1)	$0.0	$0.1	($0.0)	$26.6	726	42
8	Fort Martin - Harrison	Line	500	$2.0	($0.3)	$0.4	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	45	0
9	Juniata - Keystone	Line	500	$0.0	$0.0	$0.0	$0.0	($0.8)	$0.4	$0.2	($1.0)	($1.0)	0	21
10	Conemaugh - Keystone	Line	500	$0.4	($0.2)	$0.2	$0.8	$0.9	$0.8	($0.1)	$0.1	$0.9	16	41
11	Cabot - Wylie Ridge	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.7	($0.1)	($0.8)	($0.8)	0	6
12	AEP-DOM	Interface	500	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.2	($0.2)	($0.5)	($0.5)	0	49
13	Doubs - Mount Storm	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	$0.1	$0.1	$0.1	0	6
14	Conemaugh - Hunterstown	Line	500	$1.6	($1.6)	$0.4	$3.6	($0.5)	$1.3	($1.9)	($3.6)	($0.1)	62	98
15	Harrison - Pruntytown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	($0.0)	$0.0	$0.0	0	2

Zonal Congestion

Summary

Day-ahead and balancing congestion costs within specific zones for calendar years 2009 and 2008 are presented in Table 7-17 and Table 7-18. 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. 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).

PJM congestion accounting nets load congestion payments against generation congestion credits by billing organization. The net congestion bill for a zone or constraint may be either positive or negative, depending on the relative size and sign of load congestion payments and generation congestion credits. When summed across a zone, the net congestion bill shows the overall congestion charge or credit for an area, not including explicit congestion, but the net congestion bill is not a good measure of whether load is paying higher prices in the form of congestion.

The ComEd Control Zone, the Dominion Control Zone and the AP Control Zone are good examples of how a positive net congestion bill can result from very different combinations of load payments and generation credits. The ComEd Control Zone had the highest congestion charges, $219.7 million, of any control zone in 2009. The large positive congestion costs in the ComEd Control Zone were the result of large negative load congestion payments offset by even larger negative generation congestion credits. The Dominion Control Zone had the second highest congestion charges, $112.9 million, of any control zone in 2009. The large positive congestion costs in the Dominion Control Zone were the result of large positive load congestion payments offset only in part by relatively low positive generation congestion credits. The AP Control Zone had the third highest congestion charges, $95.3 million, of any control zone in 2009. The positive congestion costs in the AP Control Zone were the result of positive load congestion payments and larger negative generation congestion credits, which added to the total congestion costs for AP rather than offsetting the positive load congestion payments.

Table 7-17 Congestion cost summary (By control zone): Calendar year 2009

Control Zone	Day Ahead Load Payments	Day Ahead Generation Credits	Day Ahead Explicit	Day Ahead Total	Balancing Load Payments	Balancing Generation Credits	Balancing Explicit	Balancing 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

Congestion Costs (Millions)

Table 7-18 Congestion cost summary (By control zone): Calendar year 2008

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
Control Zone	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total
AECO	$111.1	$31.8	$1.2	$80.5	($12.9)	$8.1	($2.0)	($23.0)	$57.5
AEP	($367.1)	($671.0)	$15.7	$319.6	($85.2)	$4.0	($6.9)	($96.1)	$223.6
AP	$124.4	($391.6)	$38.7	$554.7	($13.6)	$21.5	($32.6)	($67.7)	$487.1
BGE	$314.3	$245.3	$3.2	$72.2	$10.1	($14.2)	($4.5)	$19.8	$92.0
ComEd	($480.9)	($820.9)	$4.8	$344.8	($54.9)	$0.4	($5.2)	($60.6)	$284.2
DAY	($45.5)	($56.5)	$0.2	$11.1	$3.5	$2.6	($0.3)	$0.6	$11.8
DLCO	($159.2)	($249.2)	$1.1	$91.2	($49.4)	$22.2	$0.3	($71.3)	$19.9
Dominion	$337.2	$5.2	$33.0	$364.9	($9.3)	($0.9)	($33.9)	($42.3)	$322.6
DPL	$149.5	$54.1	$1.1	$96.5	$8.0	$6.2	($1.8)	($0.1)	$96.4
External	($59.5)	($51.5)	$35.6	$27.5	($31.6)	($36.4)	($107.5)	($102.7)	($75.2)
JCPL	$260.6	$72.1	$9.1	$197.6	($0.0)	($0.4)	($8.9)	($8.5)	$189.0
Met-Ed	$104.9	$104.5	$3.3	$3.8	$2.3	$0.8	$10.4	$12.0	$15.7
PECO	$70.9	$118.1	$0.5	($46.8)	($0.5)	$15.5	($0.7)	($16.8)	($63.5)
PENELEC	($43.2)	($224.3)	$4.8	$186.0	($4.8)	$13.6	($1.4)	($19.9)	$166.1
Pepco	$642.4	$436.2	$8.4	$214.7	$6.6	($3.7)	($9.1)	$1.2	$215.9
PPL	$29.0	$39.9	$12.7	$1.8	$0.2	$5.6	($5.2)	($10.6)	($8.8)
PSEG	$287.3	$190.9	$33.3	$129.7	$5.2	$34.5	($27.9)	($57.3)	$72.5
RECO	$10.0	$0.1	$1.5	$11.4	$0.5	($0.2)	($2.2)	($1.5)	$9.9
Total	$1,286.1	($1,166.7)	$208.4	$2,661.2	($225.9)	$79.2	($239.5)	($544.6)	$2,116.6

Details of Regional and Zonal Congestion

Constraints were examined by zone and categorized by their effect on regions. Zones correspond to regulated utility franchise areas. Regions generally comprise two or more zones. PJM is comprised of three regions: the PJM Mid-Atlantic Region with 11 control zones (the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones); the PJM Western Region with five control zones (the AP, ComEd, AEP, DLCO and DAY control zones); and the PJM Southern Region with one control zone (the Dominion Control Zone).

Table 7-19 through Table 7-52 present the top 15 constraints affecting each control zone's congestion costs, including the facility type and the location of the constrained facility for both 2009 and 2008. In addition, day-ahead and real-time congestion-event hours are presented for each of the highlighted constraints. Constraints can have wide-ranging effects, influencing prices and congestion across multiple zones. Many constraints that are physically located outside of a control zone can impact the congestion costs of that control zone. The following tables present the constraints in descending order of the absolute value of total congestion costs. In addition to the top 15 constraints, these tables show the top five local constraints for the control zone, which were not in the top 15 constraints, but are located inside the respective control zone. These constraints are shown to illustrate the effect local constraints have on the control zone in which they are located. In

2009, the RECO and DAY control zones did not have any constraints within their boundaries, thus the tables show only the top 15 constraints.

For each of the constraints presented in the following tables, the zonal cost impacts are decomposed into their Day-Ahead Energy Market and balancing market components. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value.

Mid-Atlantic Region Congestion-Event Summaries

AECO Control Zone

Table 7-19 AECO Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Kammer	Transformer	500	$4.2	$1.3	$0.0	$2.9	$0.2	($0.0)	$0.0	$0.3	$3.1	3,674	1,328
2	West	Interface	500	$4.9	$2.3	$0.1	$2.6	$0.0	($0.0)	($0.0)	$0.0	$2.7	504	87
3	5004/5005 Interface	Interface	500	$4.4	$1.9	$0.0	$2.5	$0.1	$0.0	$0.0	$0.1	$2.7	776	294
4	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$1.4	$0.3	$0.0	$1.1	$0.1	($0.0)	$0.0	$0.2	$1.3	2,949	910
5	Graceton - Raphael Road	Line	BGE	($1.5)	($0.5)	($0.0)	($1.1)	$0.2	$0.1	$0.0	$0.0	($1.1)	527	152
6	Wylie Ridge	Transformer	AP	$1.8	$0.9	$0.0	$0.9	($0.0)	$0.1	$0.1	($0.0)	$0.9	354	335
7	Absecon - Lewis	Line	AECO	$1.0	$0.1	$0.0	$1.0	($1.2)	$0.5	($0.0)	($1.7)	($0.8)	22	149
8	Atlantic - Larrabee	Line	JCPL	($0.5)	($0.1)	($0.0)	($0.4)	($0.2)	$0.1	$0.0	($0.3)	($0.7)	280	73
9	Doubs	Transformer	AP	$1.0	$0.4	$0.0	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	429	246
10	AP South	Interface	500	$1.0	$0.5	$0.0	$0.6	$0.0	$0.0	$0.1	$0.1	$0.6	3,501	604
11	Monroe	Transformer	AECO	$0.5	$0.0	$0.0	$0.4	$0.1	($0.0)	$0.0	$0.1	$0.5	263	13
12	Shieldalloy - Vineland	Line	AECO	$1.1	$0.3	$0.0	$0.9	($0.3)	$0.1	($0.0)	($0.4)	$0.5	148	61
13	East Frankfort - Crete	Line	ComEd	$0.7	$0.2	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	2,134	0
14	Tiltonsville - Windsor	Line	AP	$0.6	$0.2	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.1	$0.5	1,449	311
15	Sammis - Wylie Ridge	Line	AP	$0.7	$0.3	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.5	762	157
16	Monroe - New Freedom	Line	AECO	$0.8	$0.4	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	584	0
23	Lewis - Motts - Cedar	Line	AECO	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	108	0
34	Corson - Union	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.1	$0.1	0	3
87	Clayton - Williams	Line	AECO	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	3	0
121	Corson	Transformer	AECO	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0

Table 7-20 AECO Control Zone top congestion cost impacts (By facility): Calendar year 2008

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Monroe	Transformer	AECO	$34.4	$3.6	$0.2	$31.0	($14.5)	$4.3	($0.7)	($19.5)	$11.5	815	254
2	West	Interface	500	$12.6	$5.6	$0.1	$7.2	$0.5	($0.0)	($0.1)	$0.4	$7.6	1,690	390
3	AP South	Interface	500	$13.0	$5.6	$0.3	$7.7	$0.1	$0.1	($0.2)	($0.1)	$7.6	3,572	1,016
4	Cloverdale - Lexington	Line	AEP	$8.0	$4.2	$0.0	$3.8	$0.7	($0.1)	($0.1)	$0.7	$4.5	3,529	1,813
5	Atlantic - Larrabee	Line	JCPL	($6.5)	($2.9)	($0.0)	($3.6)	($0.4)	$0.4	$0.0	($0.8)	($4.4)	1,556	380
6	Kammer	Transformer	500	$7.2	$3.4	$0.1	$3.9	$0.4	$0.1	($0.1)	$0.3	$4.1	3,069	1,628
7	Churchtown	Transformer	AECO	($0.3)	($3.0)	$0.0	$2.7	$0.4	$0.3	($0.0)	$0.1	$2.8	179	104
8	East	Interface	500	$5.3	$2.8	$0.0	$2.6	$0.0	($0.0)	$0.0	$0.0	$2.6	758	12
9	Quinton - Roadstown	Line	AECO	$6.3	$1.0	$0.0	$5.3	($1.3)	$1.4	($0.1)	($2.8)	$2.5	288	124
10	5004/5005 Interface	Interface	500	$4.2	$1.8	$0.0	$2.3	$0.1	$0.0	($0.0)	$0.0	$2.4	736	449
11	Central	Interface	500	$4.5	$2.4	$0.0	$2.1	$0.0	($0.0)	($0.0)	$0.0	$2.1	726	42
12	Sickler	Transformer	AECO	$0.9	$0.1	$0.0	$0.8	($0.2)	$0.4	($0.2)	($0.8)	$0.0	31	55
13	Sammis - Wylie Ridge	Line	AP	$2.4	$1.3	$0.0	$1.1	$0.6	$0.1	($0.1)	$0.4	$1.5	1,915	1,257
14	Dickerson - Pleasant View	Line	Pepco	$2.6	$1.3	$0.0	$1.3	$0.0	($0.0)	($0.0)	$0.0	$1.4	844	218
15	Mount Storm - Pruntytown	Line	AP	$2.7	$1.2	$0.2	$1.6	($0.1)	$0.0	($0.2)	($0.3)	$1.4	2,559	812
18	Cumberland	Transformer	AECO	$0.8	$0.1	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	57	0
22	Laurel - Roadstown	Line	AECO	$0.7	$0.1	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	147	0
25	Lenox - Lewis	Line	AECO	$0.5	$0.1	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	25	0
27	Orchard	Transformer	AECO	$0.6	$0.4	$0.0	$0.2	($0.2)	$0.3	($0.1)	($0.6)	($0.4)	20	14
33	Shieldalloy - Vineland	Line	AECO	$0.4	$0.0	$0.0	$0.4	($0.1)	($0.0)	($0.0)	($0.1)	$0.3	91	6

BGE Control Zone

Table 7-21 BGE Control Zone top congestion cost impacts (By facility): Calendar year 2009

No.	Constraint	Type	Location	Congestion Costs (Millions) Day Ahead Load Payments	Day Ahead Generation Credits	Day Ahead Explicit	Day Ahead Total	Balancing Load Payments	Balancing Generation Credits	Balancing Explicit	Balancing Total	Grand Total	Event Hours Day Ahead	Event Hours Real Time
1	AP South	Interface	500	$25.2	$23.7	$0.5	$2.0	$1.7	($1.2)	($0.5)	$2.5	$4.5	3,501	604
2	Kammer	Transformer	500	$11.9	$9.0	$0.2	$3.2	$1.0	($0.6)	($0.2)	$1.3	$4.5	3,674	1,328
3	Brandon Shores - Riverside	Line	BGE	$1.9	($1.0)	$0.0	$3.0	($0.1)	($0.0)	($0.0)	($0.1)	$2.9	134	13
4	Doubs	Transformer	AP	$6.4	$5.0	$0.4	$1.8	$0.5	($0.6)	($0.4)	$0.7	$2.5	429	246
5	Graceton - Raphael Road	Line	BGE	$6.6	$4.2	$0.1	$2.4	$0.0	$0.0	($0.1)	($0.1)	$2.3	527	152
6	5004/5005 Interface	Interface	500	$3.1	$1.7	$0.1	$1.5	$0.3	($0.2)	($0.1)	$0.4	$1.9	776	294
7	West	Interface	500	$8.9	$7.4	$0.2	$1.6	$0.1	($0.2)	($0.1)	$0.2	$1.9	504	87
8	Wylie Ridge	Transformer	AP	$3.6	$3.4	$0.1	$0.3	$0.6	($0.7)	($0.2)	$1.2	$1.5	354	335
9	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$3.4	$2.8	$0.0	$0.6	$0.3	($0.0)	($0.0)	$0.4	$1.0	2,949	910
10	Bedington - Black Oak	Interface	500	$3.9	$3.3	$0.1	$0.8	$0.1	($0.0)	($0.0)	$0.1	$0.9	645	73
11	Mount Storm - Pruntytown	Line	AP	$3.2	$2.9	$0.0	$0.2	$0.5	($0.3)	($0.1)	$0.6	$0.9	525	132
12	Pumphrey - Westport	Line	Pepco	$0.5	($0.1)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	1,181	0
13	Fullerton - Windyedge	Line	BGE	$0.5	($0.1)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	31	0
14	Tiltonsville - Windsor	Line	AP	$1.2	$0.8	$0.0	$0.5	$0.1	($0.0)	($0.0)	$0.1	$0.6	1,449	311
15	Cloverdale - Lexington	Line	AEP	$2.6	$2.5	$0.0	$0.2	$0.4	($0.1)	($0.1)	$0.4	$0.6	1,015	434
16	Five Forks - Rock Ridge	Line	BGE	$0.7	$0.2	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	136	0
21	Conastone	Transformer	BGE	$1.0	$0.6	($0.0)	$0.3	$0.0	($0.0)	($0.0)	$0.1	$0.4	75	12
24	Green Street - Westport	Line	BGE	$0.3	($0.0)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	365	0
28	Conastone - Otter	Line	BGE	$0.4	$0.2	$0.0	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	92	32
31	Waugh Chapel	Transformer	BGE	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.2)	$0.0	$0.2	$0.2	0	8

Table 7-22 BGE Control Zone top congestion cost impacts (By facility): Calendar year 2008

No.	Constraint	Type	Location	Congestion Costs (Millions) Day Ahead Load Payments	Day Ahead Generation Credits	Day Ahead Explicit	Day Ahead Total	Balancing Load Payments	Balancing Generation Credits	Balancing Explicit	Balancing Total	Grand Total	Event Hours Day Ahead	Event Hours Real Time
1	AP South	Interface	500	$86.9	$68.9	$0.6	$18.6	$4.6	($3.8)	($0.9)	$7.6	$26.2	3,572	1,016
2	Mount Storm - Pruntytown	Line	AP	$38.9	$32.3	$0.3	$6.9	$0.1	($2.3)	($0.1)	$2.3	$9.2	2,559	812
3	West	Interface	500	$21.7	$15.9	$0.4	$6.2	$1.1	($0.8)	($0.6)	$1.3	$7.5	1,690	390
4	Kammer	Transformer	500	$18.9	$15.4	$0.4	$4.0	$1.2	($1.4)	($0.4)	$2.2	$6.2	3,069	1,628
5	Dickerson - Pleasant View	Line	Pepco	$12.5	$8.1	$0.4	$4.8	$0.7	($0.5)	($0.2)	$1.0	$5.8	844	218
6	Aqueduct - Doubs	Line	AP	$12.2	$7.0	$0.0	$5.2	($0.0)	($0.0)	($0.0)	$0.0	$5.2	307	7
7	Pumphrey - Westport	Line	Pepco	$4.3	($0.4)	$0.0	$4.7	$0.0	$0.0	$0.0	$0.0	$4.7	1,092	0
8	Bedington - Black Oak	Interface	500	$24.8	$22.7	$0.3	$2.4	$1.0	($0.6)	($0.1)	$1.5	$3.9	1,384	284
9	Conastone	Transformer	BGE	$4.4	$1.4	($0.0)	$3.1	$0.1	($0.0)	$0.0	$0.1	$3.2	95	15
10	Sammis - Wylie Ridge	Line	AP	$5.2	$4.3	$0.1	$1.0	$1.1	($0.8)	($0.4)	$1.5	$2.5	1,915	1,257
11	Mount Storm	Transformer	AP	$12.7	$11.0	$0.1	$1.8	($0.3)	($1.0)	($0.1)	$0.7	$2.5	935	469
12	Green Street - Westport	Line	BGE	$2.3	($0.0)	$0.0	$2.3	$0.0	$0.0	$0.0	$0.0	$2.3	346	0
13	Cloverdale - Lexington	Line	AEP	$40.5	$41.6	$0.5	($0.7)	$2.1	($1.0)	($0.4)	$2.8	$2.2	3,529	1,813
14	5004/5005 Interface	Interface	500	$3.4	$1.9	$0.1	$1.6	$0.2	($0.3)	($0.1)	$0.3	$1.9	736	449
15	Brandon Shores - Riverside	Line	BGE	$1.3	($0.8)	$0.0	$2.1	($0.6)	$0.2	($0.0)	($0.9)	$1.2	150	58
23	Graceton - Raphael Road	Line	BGE	$0.3	$0.2	$0.0	$0.1	($1.0)	($0.2)	($0.0)	($0.9)	($0.7)	29	49
37	Concord - Green Street	Line	BGE	$0.0	($0.0)	$0.0	$0.0	($0.2)	$0.1	($0.0)	($0.3)	($0.3)	88	24
38	Conastone - Graceton	Line	BGE	$0.5	$0.2	$0.0	$0.3	$0.0	$0.0	($0.0)	($0.0)	$0.3	19	2
39	Mapes Road - Dorsey Run	Line	BGE	$0.4	$0.1	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	51	0
58	Gwynnbrook - Mays Chapel	Line	BGE	$0.4	$0.1	$0.0	$0.3	($0.2)	($0.1)	($0.0)	($0.1)	$0.2	8	8

DPL Control Zone

Table 7-23 DPL Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Kammer	Transformer	500	$7.5	$1.7	$0.0	$5.9	($0.1)	$0.3	($0.1)	($0.4)	$5.4	3,674	1,328
2	West	Interface	500	$9.2	$3.8	$0.0	$5.5	($0.0)	$0.1	($0.0)	($0.1)	$5.3	504	87
3	5004/5005 Interface	Interface	500	$7.3	$2.8	$0.1	$4.5	$0.1	$0.3	($0.1)	($0.3)	$4.2	776	294
4	Short - Laurel	Line	DPL	$0.0	$0.0	$0.0	$0.0	($2.1)	$0.2	($0.1)	($2.4)	($2.4)	0	27
5	Wylie Ridge	Transformer	AP	$3.4	$1.3	$0.0	$2.1	$0.2	$0.2	($0.0)	($0.0)	$2.1	354	335
6	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$2.4	$0.3	($0.0)	$2.1	($0.1)	$0.0	$0.0	($0.1)	$2.0	2,949	910
7	AP South	Interface	500	$3.0	$0.9	$0.0	$2.1	$0.0	$0.1	($0.0)	($0.1)	$1.9	3,501	604
8	Graceton - Raphael Road	Line	BGE	($2.7)	($0.7)	($0.0)	($2.0)	$0.4	($0.2)	$0.0	$0.6	($1.4)	527	152
9	Middletown - Mt Pleasant	Line	DPL	$1.8	$0.3	$0.0	$1.5	($0.2)	$0.0	$0.0	($0.2)	$1.3	312	17
10	Sammis - Wylie Ridge	Line	AP	$1.5	$0.3	$0.0	$1.2	($0.0)	$0.0	($0.0)	($0.1)	$1.1	762	157
11	East Frankfort - Crete	Line	ComEd	$1.3	$0.3	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	2,134	0
12	North Seaford - Pine Street	Line	DPL	$1.0	$0.2	$0.0	$0.8	($0.0)	($0.0)	($0.0)	$0.0	$0.8	331	1
13	Cloverdale - Lexington	Line	AEP	$1.0	$0.2	$0.0	$0.8	$0.0	($0.0)	($0.0)	$0.0	$0.8	1,015	434
14	Doubs	Transformer	AP	$1.8	$1.1	$0.0	$0.8	$0.0	$0.1	($0.0)	($0.1)	$0.7	429	246
15	Tiltonsville - Windsor	Line	AP	$1.0	$0.2	$0.0	$0.8	($0.0)	$0.0	($0.0)	($0.1)	$0.7	1,449	311
17	Easton - Trappe	Line	DPL	$0.7	$0.1	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	212	0
18	Church - I.B. Corners	Line	DPL	$0.7	$0.1	$0.0	$0.6	($0.0)	$0.0	($0.0)	($0.0)	$0.6	66	5
20	Longwood - Wye Mills	Line	DPL	$0.6	$0.1	$0.0	$0.5	($0.0)	$0.0	$0.0	($0.0)	$0.5	250	3
22	Edgemoor - Harmony	Line	DPL	$0.8	$0.3	$0.0	$0.5	($0.1)	($0.0)	($0.0)	($0.1)	$0.4	28	7
23	Red Lion At20	Transformer	DPL	$0.4	$0.1	$0.0	$0.4	$0.0	($0.0)	$0.0	$0.0	$0.4	45	6

Table 7-24 DPL Control Zone top congestion cost impacts (By facility): Calendar year 2008

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	North Seaford - Pine Street	Line	DPL	$21.2	$5.4	$0.1	$16.0	($1.0)	($0.6)	($0.1)	($0.6)	$15.4	690	147
2	West	Interface	500	$20.0	$7.3	$0.2	$12.9	$1.0	$1.0	($0.0)	$0.0	$12.9	1,690	390
3	AP South	Interface	500	$23.0	$11.0	$0.2	$12.2	$1.5	$1.2	($0.1)	$0.2	$12.4	3,572	1,016
4	Cloverdale - Lexington	Line	AEP	$14.4	$4.7	$0.1	$9.9	$1.0	($0.0)	($0.1)	$0.9	$10.8	3,529	1,813
5	Kammer	Transformer	500	$12.1	$4.3	$0.1	$7.9	$1.1	$0.7	($0.1)	$0.3	$8.2	3,069	1,628
6	East	Interface	500	$9.2	$3.4	$0.1	$5.9	$0.0	($0.0)	($0.0)	$0.0	$5.9	758	12
7	Central	Interface	500	$7.6	$3.4	$0.0	$4.3	$0.1	($0.0)	($0.0)	$0.1	$4.3	726	42
8	5004/5005 Interface	Interface	500	$6.6	$2.6	$0.0	$4.0	$0.6	$0.6	($0.1)	($0.1)	$4.0	736	449
9	Mount Storm - Pruntytown	Line	AP	$5.6	$2.3	$0.1	$3.5	$0.3	$0.2	($0.1)	$0.0	$3.5	2,559	812
10	Sammis - Wylie Ridge	Line	AP	$4.3	$1.2	$0.0	$3.1	$1.0	$0.6	($0.1)	$0.2	$3.3	1,915	1,257
11	Bedington - Black Oak	Interface	500	$5.1	$2.0	$0.0	$3.1	$0.2	$0.0	($0.0)	$0.1	$3.2	1,384	284
12	Atlantic - Larrabee	Line	JCPL	($4.4)	($1.9)	($0.0)	($2.6)	($0.5)	($0.1)	$0.1	($0.4)	($2.9)	1,556	380
13	Dickerson - Pleasant View	Line	Pepco	$4.7	$2.2	$0.1	$2.6	$0.1	($0.0)	($0.1)	($0.0)	$2.6	844	218
14	Red Lion At5n	Transformer	DPL	$3.8	$1.4	$0.1	$2.5	$0.0	($0.1)	$0.0	$0.1	$2.5	53	3
15	Branchburg - Readington	Line	PSEG	($3.3)	($1.4)	($0.1)	($2.0)	($0.2)	$0.3	$0.1	($0.4)	($2.4)	1,121	271
19	Longwood - Wye Mills	Line	DPL	$1.1	$0.2	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	228	0
23	Keeney At5n	Transformer	DPL	$5.6	$2.0	$0.0	$3.6	$0.2	$2.1	($0.9)	($2.8)	$0.8	157	134
36	Middletown - Mt Pleasant	Line	DPL	$0.5	$0.1	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	28	0
41	Bridgeville - Greenwood	Line	DPL	$0.4	$0.1	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	6	0
48	Red Lion At20	Transformer	DPL	$0.0	$0.0	($0.0)	$0.0	$0.2	($0.0)	($0.0)	$0.2	$0.3	35	14

JCPL Control Zone

Table 7-25 JCPL Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	5004/5005 Interface	Interface	500	$9.5	$4.0	$0.0	$5.5	$0.2	($1.0)	($0.0)	$1.2	$6.6	776	294
2	West	Interface	500	$10.4	$4.3	$0.0	$6.1	$0.1	($0.2)	($0.0)	$0.2	$6.3	504	87
3	Kammer	Transformer	500	$8.2	$3.5	$0.0	$4.8	$0.1	($0.6)	($0.0)	$0.7	$5.4	3,674	1,328
4	Wylie Ridge	Transformer	AP	$3.9	$1.4	$0.0	$2.5	$0.1	($0.6)	($0.0)	$0.7	$3.2	354	335
5	Atlantic - Larrabee	Line	JCPL	$2.6	$0.4	$0.0	$2.2	($0.6)	($0.4)	($0.0)	($0.2)	$2.0	280	73
6	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$3.0	$1.3	($0.1)	$1.6	($0.0)	($0.2)	$0.0	$0.2	$1.7	2,949	910
7	Sammis - Wylie Ridge	Line	AP	$1.7	$0.6	$0.0	$1.1	$0.0	($0.0)	($0.0)	$0.0	$1.2	762	157
8	Athenia - Saddlebrook	Line	PSEG	($1.3)	($0.3)	($0.0)	($1.0)	($0.0)	$0.1	$0.0	($0.1)	($1.1)	1,108	139
9	Graceton - Raphael Road	Line	BGE	($2.7)	($1.5)	($0.0)	($1.2)	$0.3	$0.2	$0.0	$0.1	($1.0)	527	152
10	East Frankfort - Crete	Line	ComEd	$1.6	$0.7	$0.0	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	2,134	0
11	Cloverdale - Lexington	Line	AEP	$1.0	$0.4	$0.0	$0.6	$0.0	($0.0)	($0.0)	$0.1	$0.7	1,015	434
12	Crete - St Johns Tap	Flowgate	Midwest ISO	$1.1	$0.5	$0.0	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.7	1,565	306
13	Tiltonsville - Windsor	Line	AP	$1.3	$0.7	$0.0	$0.6	($0.0)	($0.1)	($0.0)	$0.0	$0.6	1,449	311
14	Doubs	Transformer	AP	$1.7	$1.2	$0.0	$0.6	($0.0)	($0.1)	($0.0)	$0.1	$0.6	429	246
15	Krendale - Seneca	Line	AP	$0.9	$0.4	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	324	0
29	Gilbert - Morris Park	Line	JCPL	$0.2	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	38	0
47	Redoak - Sayreville	Line	JCPL	($0.0)	($0.1)	$0.0	$0.1	($0.0)	$0.0	$0.0	($0.0)	$0.1	59	7
82	Deep Run - Englishtown	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	0	2
88	Franklin - West Wharton	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	35	0
93	Kilmer - Sayreville	Line	JCPL	$0.4	$0.2	$0.0	$0.2	($0.0)	$0.2	$0.0	($0.2)	$0.0	0	16

Table 7-26 JCPL Control Zone top congestion cost impacts (By facility): Calendar year 2008

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Atlantic - Larrabee	Line	JCPL	$47.5	$2.2	$2.2	$47.5	($3.0)	$2.8	($2.4)	($8.2)	$39.3	1,556	380
2	Branchburg - Readington	Line	PSEG	$27.7	$4.5	$2.2	$25.4	($2.2)	($0.8)	($1.8)	($3.3)	$22.2	1,121	271
3	West	Interface	500	$29.5	$11.9	$0.3	$17.9	$0.1	($0.2)	($0.6)	($0.4)	$17.6	1,690	390
4	Cloverdale - Lexington	Line	AEP	$18.8	$5.2	$0.7	$14.4	$0.6	($0.2)	($0.5)	$0.3	$14.6	3,529	1,813
5	AP South	Interface	500	$22.6	$9.2	$0.8	$14.1	$0.2	($0.4)	($1.0)	($0.4)	$13.7	3,572	1,016
6	Kammer	Transformer	500	$18.0	$6.3	$0.4	$12.2	$0.5	($0.0)	($0.4)	$0.2	$12.4	3,069	1,628
7	Central	Interface	500	$12.2	$3.6	$0.5	$9.0	$0.0	($0.1)	($0.0)	$0.0	$9.1	726	42
8	Branchburg - Flagtown	Line	PSEG	$11.2	$3.0	$0.1	$8.3	$1.4	$0.6	($0.1)	$0.7	$9.0	284	61
9	5004/5005 Interface	Interface	500	$11.7	$4.2	$0.3	$7.8	$0.4	($0.1)	($0.2)	$0.3	$8.1	736	449
10	East	Interface	500	$11.4	$3.5	$0.0	$8.0	($0.0)	($0.0)	($0.0)	($0.0)	$7.9	758	12
11	Cedar Grove - Roseland	Line	PSEG	($9.4)	($1.7)	($0.2)	($7.9)	($0.4)	($0.4)	$0.1	$0.1	($7.8)	627	185
12	Buckingham - Pleasant Valley	Line	PECO	$10.7	$3.8	$0.2	$7.1	($0.1)	($0.1)	($0.1)	($0.1)	$6.9	647	74
13	Sammis - Wylie Ridge	Line	AP	$5.9	$1.8	$0.1	$4.2	$0.6	$0.0	($0.3)	$0.3	$4.4	1,915	1,257
14	Dickerson - Pleasant View	Line	Pepco	$6.0	$2.3	$0.2	$3.9	$0.0	($0.2)	($0.1)	$0.1	$4.0	844	218
15	Redoak - Sayreville	Line	JCPL	$0.2	($2.3)	$0.0	$2.5	$0.2	($0.5)	$0.4	$1.1	$3.6	254	30
68	Gilbert - Hosensack	Line	JCPL	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	($0.1)	($0.1)	($0.1)	0	10
171	Kilmer - Sayreville	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
182	Sayreville - Werner	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	0	2
197	Franklin - West Wharton	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	17	0
350	Franklin - Vernon	Line	JCPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	6	0

Met-Ed Control Zone

Table 7-27 Met-Ed Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Kammer	Transformer	500	$6.0	$7.9	$0.1	($1.8)	($0.0)	($0.3)	($0.1)	$0.2	($1.6)	3,674	1,328
2	Brunner Island - Yorkana	Line	Met-Ed	$0.3	($0.7)	$0.0	$1.0	$0.0	$0.0	($0.0)	$0.0	$1.0	86	27
3	Graceton - Raphael Road	Line	BGE	($2.1)	($3.0)	($0.0)	$0.9	$0.1	$0.3	$0.0	($0.2)	$0.7	527	152
4	AP South	Interface	500	$2.5	$1.8	$0.0	$0.7	($0.0)	($0.0)	($0.0)	($0.0)	$0.7	3,501	604
5	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$2.0	$2.5	$0.0	($0.5)	($0.0)	($0.0)	($0.0)	$0.0	($0.5)	2,949	910
6	5004/5005 Interface	Interface	500	$5.9	$6.6	$0.0	($0.6)	($0.1)	($0.3)	($0.0)	$0.2	($0.4)	776	294
7	Hunterstown	Transformer	Met-Ed	$0.3	($0.1)	($0.0)	$0.4	($0.0)	($0.0)	$0.0	($0.0)	$0.4	53	1
8	West	Interface	500	$7.4	$7.2	$0.0	$0.3	$0.0	($0.1)	($0.0)	$0.1	$0.3	504	87
9	Tiltonsville - Windsor	Line	AP	$0.9	$1.3	$0.0	($0.4)	$0.0	($0.1)	($0.0)	$0.1	($0.3)	1,449	311
10	Wylie Ridge	Transformer	AP	$3.1	$2.8	$0.0	$0.3	($0.1)	($0.2)	($0.0)	$0.0	$0.3	354	335
11	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.2	$0.0	$0.0	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	32	2
12	Conastone	Transformer	BGE	($0.1)	($0.3)	($0.0)	$0.2	($0.0)	$0.0	($0.0)	($0.0)	$0.2	75	12
13	Hummelstown - Middletown Jct	Line	Met-Ed	$0.1	$0.3	$0.0	($0.2)	$0.0	($0.0)	($0.0)	$0.0	($0.2)	51	14
14	Middletown Jct	Transformer	Met-Ed	$0.3	($0.0)	$0.0	$0.3	($0.1)	$0.0	($0.0)	($0.1)	$0.2	62	12
15	East Frankfort - Crete	Line	ComEd	$1.1	$1.3	$0.0	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	2,134	0
32	Collins - Middletown Jct	Line	Met-Ed	$0.1	($0.1)	$0.0	$0.1	($0.0)	$0.0	$0.0	($0.1)	$0.1	103	16
36	Ironwood - South Lebanon	Line	Met-Ed	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	20	0
42	Cly - Newberry	Line	Met-Ed	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	13	0
69	Middletown Jct - S Lebanon	Line	Met-Ed	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	4	0
157	Germantown	Transformer	Met-Ed	($0.0)	($0.0)	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	($0.0)	10	0

Table 7-28 Met-Ed Control Zone top congestion cost impacts (By facility): Calendar year 2008

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$17.9	$19.3	$0.7	($0.8)	$0.5	($0.2)	$3.4	$4.1	$3.3	3,572	1,016
2	Cloverdale - Lexington	Line	AEP	$12.5	$11.7	$0.7	$1.5	$0.2	$0.3	$0.5	$0.4	$1.9	3,529	1,813
3	Bedington	Transformer	AP	$1.8	$0.3	$0.0	$1.5	($0.0)	$0.0	$0.2	$0.2	$1.7	1,192	303
4	Bedington - Black Oak	Interface	500	$4.3	$3.5	$0.1	$0.9	$0.0	($0.0)	$0.6	$0.7	$1.6	1,384	284
5	Kammer	Transformer	500	$10.4	$11.1	$0.5	($0.2)	$0.2	($0.3)	$1.3	$1.8	$1.5	3,069	1,628
6	Brunner Island - Yorkana	Line	Met-Ed	$0.5	($0.9)	$0.0	$1.4	$0.1	$0.1	($0.0)	($0.0)	$1.4	57	27
7	Conemaugh - Hunterstown	Line	500	$0.6	$1.5	$0.0	($0.9)	($0.1)	($0.1)	($0.4)	($0.3)	($1.2)	62	98
8	Middletown Jct	Transformer	Met-Ed	$1.0	($0.1)	$0.0	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	59	1
9	Collins - Middletown Jct	Line	Met-Ed	$1.0	($0.0)	$0.0	$1.1	($0.0)	$0.2	$0.1	($0.1)	$1.0	272	31
10	West	Interface	500	$15.1	$18.3	$0.6	($2.6)	$0.3	($0.2)	$1.3	$1.8	($0.9)	1,690	390
11	Conastone	Transformer	BGE	$0.4	($0.3)	($0.1)	$0.7	$0.0	$0.1	$0.1	$0.0	$0.7	95	15
12	East Towanda	Transformer	PENELEC	$0.3	$0.4	$0.0	$0.0	$0.1	($0.1)	$0.4	$0.6	$0.6	803	306
13	Aqueduct - Doubs	Line	AP	($0.8)	($0.2)	$0.0	($0.6)	$0.0	$0.0	$0.0	$0.0	($0.6)	307	7
14	Harwood - Susquehanna	Line	PPL	$1.2	$0.4	$0.0	$0.8	$0.0	$0.3	($0.0)	($0.2)	$0.6	117	99
15	Mount Storm - Pruntytown	Line	AP	$4.6	$4.4	$0.2	$0.4	($0.0)	$0.0	$0.2	$0.2	$0.6	2,559	812
20	Hunterstown	Transformer	Met-Ed	$0.0	($0.0)	($0.0)	$0.0	($0.1)	$0.4	$0.1	($0.4)	($0.4)	2	45
21	Middletown Jct - Yorkhaven	Line	Met-Ed	$0.3	($0.0)	$0.0	$0.4	($0.0)	$0.0	($0.0)	($0.0)	$0.3	32	7
24	Carlisle Pike - Gardners	Line	Met-Ed	$0.4	$0.2	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	9	0
27	Yorkana A	Transformer	Met-Ed	$0.2	$0.0	$0.0	$0.1	$0.1	$0.0	$0.0	$0.1	$0.2	13	5
31	Cly - Collins	Line	Met-Ed	$0.3	$0.1	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	18	0

PECO Control Zone

Table 7-29 PECO Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Kammer	Transformer	500	$3.7	$9.8	$0.0	($6.0)	($0.2)	($0.0)	$0.0	($0.2)	($6.2)	3,674	1,328
2	West	Interface	500	$3.3	$7.1	$0.0	($3.8)	($0.0)	($0.1)	($0.0)	$0.0	($3.7)	504	87
3	AP South	Interface	500	$0.5	$3.7	$0.0	($3.1)	($0.0)	$0.0	$0.0	($0.1)	($3.2)	3,501	604
4	5004/5005 Interface	Interface	500	$4.9	$7.9	$0.0	($3.0)	$0.0	($0.0)	$0.0	$0.1	($3.0)	776	294
5	Graceton - Raphael Road	Line	BGE	($1.4)	($4.4)	($0.0)	$2.9	$0.5	$0.5	($0.0)	($0.0)	$2.9	527	152
6	Doubs	Transformer	AP	$1.0	$3.3	$0.0	($2.3)	($0.2)	$0.2	$0.0	($0.3)	($2.6)	429	246
7	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$1.5	$3.6	($0.0)	($2.0)	($0.1)	$0.1	($0.0)	($0.1)	($2.1)	2,949	910
8	East Frankfort - Crete	Line	ComEd	$0.7	$1.8	($0.0)	($1.1)	$0.0	$0.0	$0.0	$0.0	($1.1)	2,134	0
9	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.4	$1.4	($0.0)	($1.0)	($0.0)	$0.0	($0.0)	($0.1)	($1.1)	1,565	306
10	Wylie Ridge	Transformer	AP	$1.3	$2.3	$0.0	($0.9)	($0.1)	$0.0	($0.1)	($0.1)	($1.1)	354	335
11	Conastone	Transformer	BGE	($0.1)	($1.0)	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	75	12
12	Sammis - Wylie Ridge	Line	AP	$0.6	$1.4	$0.0	($0.9)	($0.0)	$0.0	($0.0)	($0.1)	($0.9)	762	157
13	Tiltonsville - Windsor	Line	AP	$0.6	$1.6	$0.0	($0.9)	($0.0)	($0.0)	$0.0	$0.0	($0.9)	1,449	311
14	Cloverdale - Lexington	Line	AEP	$0.4	$1.2	$0.0	($0.7)	($0.0)	($0.0)	($0.0)	($0.0)	($0.8)	1,015	434
15	Holmesburg - Richmond	Line	PECO	($0.2)	($0.7)	($0.0)	$0.5	($0.0)	($0.1)	$0.0	$0.1	$0.6	428	40
19	Burlington - Croydon	Line	PECO	($0.3)	($0.7)	($0.0)	$0.4	($0.0)	($0.0)	$0.0	$0.0	$0.4	2,794	3
23	Emilie	Transformer	PECO	$0.3	($1.9)	($0.0)	$2.2	($0.2)	$1.7	$0.0	($1.9)	$0.3	281	247
28	Eddystone - Scott Paper	Line	PECO	$0.2	($0.0)	$0.0	$0.2	($0.0)	$0.0	$0.0	($0.0)	$0.2	30	2
41	Buckingham - Pleasant Valley	Line	PECO	($0.4)	($0.4)	($0.0)	($0.0)	($0.0)	$0.1	$0.0	($0.1)	($0.1)	131	60
44	Bryn Mawr - Plymouth Meeting	Line	PECO	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	5	0

Table 7-30 PECO Control Zone top congestion cost impacts (By facility): Calendar year 2008

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$8.2	$27.7	$0.0	($19.5)	$0.0	$1.2	$0.0	($1.2)	($20.7)	3,572	1,016
2	West	Interface	500	$9.4	$23.1	$0.1	($13.6)	$0.1	$1.7	$0.0	($1.5)	($15.1)	1,690	390
3	East	Interface	500	$10.0	$0.4	($0.0)	$9.7	($0.0)	($0.1)	$0.0	$0.1	$9.7	758	12
4	Kammer	Transformer	500	$6.7	$13.9	$0.0	($7.1)	$0.4	$1.1	$0.0	($0.6)	($7.7)	3,069	1,628
5	Cloverdale - Lexington	Line	AEP	$8.6	$14.5	$0.1	($5.8)	$0.1	$1.4	($0.0)	($1.4)	($7.1)	3,529	1,813
6	Mount Storm - Pruntytown	Line	AP	$1.4	$6.8	$0.0	($5.4)	($0.1)	$0.2	($0.0)	($0.3)	($5.7)	2,559	812
7	Bedington - Black Oak	Interface	500	$1.6	$6.2	$0.0	($4.6)	($0.0)	$0.2	$0.0	($0.1)	($4.7)	1,384	284
8	5004/5005 Interface	Interface	500	$3.5	$7.3	$0.0	($3.8)	$0.2	$0.7	($0.0)	($0.5)	($4.3)	736	449
9	Dickerson - Pleasant View	Line	Pepco	$2.1	$6.0	$0.0	($3.9)	($0.1)	$0.0	$0.0	($0.1)	($4.0)	844	218
10	Sammis - Wylie Ridge	Line	AP	$2.8	$4.1	$0.0	($1.2)	($0.1)	$1.8	$0.0	($1.9)	($3.1)	1,915	1,257
11	Branchburg - Readington	Line	PSEG	($1.9)	($4.6)	($0.0)	$2.6	($0.0)	$0.2	($0.0)	($0.3)	$2.4	1,121	271
12	Conastone	Transformer	BGE	($0.2)	($2.4)	($0.0)	$2.2	$0.0	($0.0)	($0.0)	$0.0	$2.3	95	15
13	Unclassified	Unclassified	Unclassified	$2.0	$0.2	$0.0	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	9,999	9,999
14	Bradford - Planebrook	Line	PECO	$0.7	($1.1)	($0.0)	$1.8	$0.0	$0.1	$0.0	($0.1)	$1.7	124	24
15	Whitpain	Transformer	PECO	$3.8	($1.4)	$0.1	$5.2	($0.4)	$2.8	($0.3)	($3.5)	$1.7	89	68
17	Buckingham - Pleasant Valley	Line	PECO	($4.3)	($2.9)	($0.0)	($1.5)	$0.1	$0.1	$0.0	($0.0)	($1.5)	647	74
18	Graceton - Peach Bottom	Line	PECO	$0.4	$0.1	$0.0	$0.3	($1.2)	$0.5	$0.0	($1.7)	($1.4)	33	163
24	North Philadelphia - Waneeta	Line	PECO	$0.5	($0.5)	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	381	10
28	Trainer - Delco Tap	Line	PECO	$0.8	$0.1	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	2,218	0
30	Plymouth Meeting - Whitpain	Line	PECO	$0.9	$0.1	$0.0	$0.8	($0.0)	$0.0	$0.0	($0.0)	$0.7	13	3

PENELEC Control Zone

Table 7-31 PENELEC Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($17.8)	($35.0)	($0.1)	$17.1	$0.7	($0.2)	$0.1	$1.0	$18.2	3,501	604
2	West	Interface	500	($2.4)	($16.3)	($0.0)	$13.9	$0.0	$0.1	$0.0	($0.0)	$13.9	504	87
3	5004/5005 Interface	Interface	500	($3.5)	($18.7)	($0.0)	$15.2	$0.3	$1.6	$0.1	($1.3)	$13.9	776	294
4	Kammer	Transformer	500	$4.8	$15.9	$0.2	($10.8)	($0.5)	($0.9)	($0.1)	$0.2	($10.6)	3,674	1,328
5	Wylie Ridge	Transformer	AP	$1.5	$10.3	$0.1	($8.8)	($0.6)	($0.7)	($0.0)	$0.1	($8.7)	354	335
6	Seward	Transformer	PENELEC	$8.0	$4.6	($0.0)	$3.4	$0.0	$0.0	$0.0	$0.0	$3.4	283	0
7	Sammis - Wylie Ridge	Line	AP	$1.2	$4.5	$0.1	($3.3)	($0.1)	($0.1)	$0.0	($0.0)	($3.3)	762	157
8	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$4.1	$7.6	($0.0)	($3.5)	$0.2	($0.5)	$0.0	$0.6	($2.9)	2,949	910
9	Mount Storm - Pruntytown	Line	AP	($2.4)	($4.6)	($0.0)	$2.2	$0.3	($0.1)	$0.0	$0.5	$2.7	525	132
10	Bedington - Black Oak	Interface	500	($2.3)	($4.4)	($0.0)	$2.2	($0.0)	($0.0)	$0.0	$0.0	$2.2	645	73
11	Tiltonsville - Windsor	Line	AP	$1.1	$3.1	$0.0	($2.0)	$0.1	($0.0)	($0.0)	$0.1	($2.0)	1,449	311
12	East Frankfort - Crete	Line	ComEd	$2.2	$3.8	$0.0	($1.6)	$0.0	$0.0	$0.0	$0.0	($1.6)	2,134	0
13	Homer City - Seward	Line	PENELEC	$2.9	$1.6	($0.0)	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	67	0
14	Homer City - Shelocta	Line	PENELEC	($3.9)	($5.5)	($0.1)	$1.6	($0.2)	$0.1	$0.0	($0.3)	$1.3	386	103
15	Krendale - Seneca	Line	AP	$1.4	$2.6	$0.0	($1.2)	$0.0	$0.0	$0.0	$0.0	($1.2)	324	0
16	Homer City	Transformer	PENELEC	$1.4	$0.2	($0.0)	$1.1	($0.0)	$0.0	$0.0	($0.0)	$1.1	248	2
18	Altoona - Bear Rock	Line	PENELEC	($1.9)	($3.0)	($0.0)	$1.1	($0.1)	($0.1)	$0.0	($0.1)	$1.1	176	32
27	Keystone - Shelocta	Line	PENELEC	($0.4)	($0.8)	($0.0)	$0.4	$0.1	$0.1	$0.0	($0.0)	$0.4	104	43
28	Altoona - Raystown	Line	PENELEC	($0.8)	($1.1)	($0.0)	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	55	0
36	Bear Rock - Johnstown	Line	PENELEC	($0.5)	($0.7)	($0.0)	$0.2	($0.1)	($0.1)	$0.0	($0.0)	$0.2	80	45

Table 7-32 PENELEC Control Zone top congestion cost impacts (By facility): Calendar year 2008

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($35.4)	($69.6)	$0.3	$34.5	$3.1	$0.7	$0.7	$3.1	$37.6	3,572	1,016
2	West	Interface	500	($7.9)	($46.5)	($0.3)	$38.2	$0.1	$1.5	$0.3	($1.1)	$37.1	1,690	390
3	Mount Storm - Pruntytown	Line	AP	($27.4)	($55.5)	$0.1	$28.1	$0.9	($0.3)	$0.0	$1.2	$29.3	2,559	812
4	Kammer	Transformer	500	$10.1	$33.1	$0.8	($22.2)	($0.8)	($1.3)	$0.2	$0.7	($21.6)	3,069	1,628
5	Bedington - Black Oak	Interface	500	($16.6)	($37.5)	$0.1	$20.9	$0.6	$0.3	$0.1	$0.4	$21.4	1,384	284
6	5004/5005 Interface	Interface	500	($3.8)	($23.7)	($0.1)	$19.8	($0.7)	$1.3	$0.1	($1.8)	$18.0	736	449
7	Seward	Transformer	PENELEC	$33.2	$20.4	$0.1	$12.8	$0.9	$1.0	($0.1)	($0.1)	$12.7	363	50
8	Sammis - Wylie Ridge	Line	AP	$6.2	$17.6	$0.6	($10.8)	($0.4)	($0.4)	($1.1)	($1.1)	($11.8)	1,915	1,257
9	Mount Storm	Transformer	AP	($8.2)	($17.9)	$0.1	$9.7	($0.8)	$0.0	($0.0)	($0.9)	$8.8	935	469
10	Krendale - Seneca	Line	AP	$4.7	$13.2	$0.3	($8.3)	$0.0	$0.0	($0.0)	$0.0	($8.2)	1,389	24
11	Central	Interface	500	($0.5)	($8.6)	($0.0)	$8.0	$0.0	($0.0)	$0.0	$0.0	$8.0	726	42
12	East Towanda	Transformer	PENELEC	$14.1	($8.8)	$1.0	$23.8	($9.2)	$8.4	($0.5)	($18.1)	$5.7	803	306
13	East	Interface	500	($1.4)	($6.3)	($0.1)	$4.9	$0.0	($0.0)	$0.0	$0.0	$4.9	758	12
14	Bedington	Transformer	AP	($0.5)	($4.4)	$0.0	$3.9	$0.0	$0.1	$0.0	($0.0)	$3.9	1,192	303
15	Altoona - Bear Rock	Line	PENELEC	($4.9)	($8.5)	($0.0)	$3.6	$0.1	$0.1	($0.0)	($0.0)	$3.6	221	30
18	Blairsville East	Transformer	PENELEC	($4.5)	($6.6)	($0.0)	$2.1	$0.1	$0.0	$0.0	$0.1	$2.2	201	23
21	Homer City - Shelocta	Line	PENELEC	($0.8)	($1.1)	($0.0)	$0.3	$1.4	($0.1)	$0.0	$1.6	$1.8	74	163
28	Homer City	Transformer	PENELEC	$1.5	$0.4	($0.0)	$1.1	$0.0	($0.0)	$0.0	$0.0	$1.2	49	4
31	Bear Rock - Johnstown	Line	PENELEC	($1.3)	($2.3)	($0.0)	$1.0	$0.2	$0.0	$0.0	$0.1	$1.1	138	24
32	East Towanda - Grover	Line	PENELEC	($0.5)	($1.6)	($0.0)	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	109	0

Pepco Control Zone

Table 7-33 Pepco Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$57.5	$42.6	$1.1	$16.0	($1.7)	($3.5)	($1.1)	$0.7	$16.7	3,501	604
2	Kammer	Transformer	500	$21.9	$15.1	$0.3	$7.1	($1.1)	($2.0)	($0.4)	$0.5	$7.6	3,674	1,328
3	Doubs	Transformer	AP	$16.2	$8.7	$0.3	$7.8	($1.7)	($0.2)	($0.3)	($1.7)	$6.0	429	246
4	Buzzard - Ritchie	Line	Pepco	$25.3	$3.2	$0.2	$22.3	($13.9)	$1.9	($0.6)	($16.4)	$5.9	421	149
5	Unclassified	Unclassified	Unclassified	$2.7	$8.6	$0.1	($5.9)	$0.0	$0.0	$0.0	$0.0	($5.9)	9,999	9,999
6	Graceton - Raphael Road	Line	BGE	$6.7	$4.2	$0.2	$2.6	($0.7)	($1.0)	($0.2)	$0.2	$2.8	527	152
7	Bedington - Black Oak	Interface	500	$8.5	$6.0	$0.2	$2.6	($0.0)	($0.1)	($0.0)	$0.1	$2.7	645	73
8	West	Interface	500	$8.9	$6.5	$0.1	$2.4	($0.1)	($0.2)	($0.0)	$0.0	$2.5	504	87
9	Mount Storm - Pruntytown	Line	AP	$7.5	$5.8	$0.1	$1.9	($0.2)	($0.8)	($0.1)	$0.5	$2.4	525	132
10	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$6.3	$4.2	($0.0)	$2.1	($0.2)	($0.5)	$0.0	$0.3	$2.4	2,949	910
11	Cloverdale - Lexington	Line	AEP	$6.0	$4.3	$0.1	$1.8	($0.2)	($0.5)	($0.1)	$0.2	$1.9	1,015	434
12	Wylie Ridge	Transformer	AP	$6.2	$4.9	$0.0	$1.3	($0.3)	($0.7)	($0.0)	$0.3	$1.7	354	335
13	East Frankfort - Crete	Line	ComEd	$3.1	$2.0	$0.0	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	2,134	0
14	Sammis - Wylie Ridge	Line	AP	$3.1	$2.2	$0.1	$1.0	($0.1)	($0.2)	($0.0)	$0.0	$1.0	762	157
15	Mount Storm	Transformer	AP	$2.1	$1.5	$0.0	$0.7	$0.0	($0.3)	($0.1)	$0.2	$0.9	151	80
20	Alabama Ave. - Palmers Corner	Line	Pepco	$0.5	$0.0	$0.0	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	12	0
25	Brighton	Transformer	Pepco	$0.7	$0.4	$0.0	$0.3	$0.0	($0.0)	$0.0	$0.0	$0.3	43	1
29	Dickerson - Pleasant View	Line	Pepco	$0.8	$0.5	$0.0	$0.3	($0.3)	($0.2)	($0.1)	($0.1)	$0.2	54	30
38	Burtonsville - Oak Grove	Line	Pepco	($0.3)	($0.4)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	29	0
49	Oak Grove - Ritchie	Line	Pepco	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.1)	($0.0)	$0.1	$0.1	0	6

Table 7-34 Pepco Control Zone top congestion cost impacts (By facility): Calendar year 2008

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Ex-plicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$186.4	$129.8	$1.8	$58.4	($2.6)	($1.4)	($1.8)	($2.9)	$55.5	3,572	1,016
2	Cloverdale - Lexington	Line	AEP	$91.0	$64.8	$1.8	$28.1	$5.9	($1.2)	($1.7)	$5.4	$33.5	3,529	1,813
3	Mount Storm - Pruntytown	Line	AP	$86.7	$61.8	$0.6	$25.5	$0.8	($1.5)	($0.3)	$2.0	$27.5	2,559	812
4	Bedington - Black Oak	Interface	500	$58.9	$40.0	$0.6	$19.5	($0.3)	$0.0	($0.3)	($0.7)	$18.8	1,384	284
5	Aqueduct - Doubs	Line	AP	$38.5	$23.5	$0.2	$15.2	$0.1	($0.0)	($0.0)	$0.1	$15.3	307	7
6	Kammer	Transformer	500	$36.9	$24.5	$0.7	$13.1	($0.3)	($0.9)	($0.7)	($0.0)	$13.1	3,069	1,628
7	Dickerson - Pleasant View	Line	Pepco	$34.0	$23.1	$1.2	$12.1	($0.2)	($0.1)	($1.1)	($1.1)	$11.0	844	218
8	West	Interface	500	$25.0	$15.6	$0.6	$10.0	($0.3)	($0.5)	($0.6)	($0.4)	$9.6	1,690	390
9	Mount Storm	Transformer	AP	$25.8	$19.0	$0.1	$6.9	$2.0	($0.5)	($0.1)	$2.5	$9.3	935	469
10	Brighton	Transformer	Pepco	$11.7	$7.4	$0.2	$4.5	($0.7)	($0.3)	($0.8)	($1.2)	$3.3	116	78
11	Sammis - Wylie Ridge	Line	AP	$9.3	$6.3	$0.1	$3.1	$0.7	$0.2	($0.4)	$0.1	$3.2	1,915	1,257
12	Buzzard - Ritchie	Line	Pepco	$1.1	$0.1	$0.1	$1.1	($0.6)	$0.7	($0.2)	($1.5)	($0.4)	57	32
13	Dickerson - Quince Orchard	Line	Pepco	$3.4	$1.1	$0.0	$2.4	($0.0)	($0.0)	$0.0	($0.0)	$2.4	46	2
14	Black Oak	Transformer	AP	$6.8	$4.6	$0.0	$2.2	($0.0)	($0.1)	($0.0)	$0.1	$2.3	386	29
15	Central	Interface	500	($8.1)	($6.0)	($0.1)	($2.1)	$0.0	($0.0)	($0.0)	$0.0	($2.1)	726	42
29	Bells Mill	Transformer	Pepco	$1.4	$0.5	$0.0	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	7	0
32	Aqueduct - Dickerson	Line	Pepco	$2.0	$1.3	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	10	0
38	Pumphrey - Westport	Line	Pepco	($1.6)	($1.1)	($0.0)	($0.5)	$0.0	$0.0	$0.0	$0.0	($0.5)	1,092	0
47	Dickerson - Doubs	Line	Pepco	$0.0	$0.0	$0.0	$0.0	$0.1	$0.3	($0.1)	($0.3)	($0.3)	2	8
61	Quince Orchard	Transformer	Pepco	$0.2	$0.0	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	2	0

PPL Control Zone

Table 7-35 PPL Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Kammer	Transformer	500	$1.7	$5.5	$0.6	($3.2)	($0.2)	($0.2)	($0.1)	($0.0)	($3.2)	3,674	1,328
2	5004/5005 Interface	Interface	500	$2.9	$7.0	$0.5	($3.5)	$0.0	($0.8)	($0.0)	$0.7	($2.8)	776	294
3	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.6	$2.3	($0.1)	($1.8)	($0.2)	($0.2)	$0.0	$0.0	($1.8)	2,949	910
4	AP South	Interface	500	$0.5	($0.6)	$0.3	$1.4	$0.1	($0.1)	$0.1	$0.3	$1.7	3,501	604
5	Graceton - Raphael Road	Line	BGE	($0.9)	($2.3)	($0.1)	$1.3	$0.1	$0.1	$0.0	$0.1	$1.4	527	152
6	Hummelstown - Middletown Jct	Line	Met-Ed	$1.0	($0.0)	$0.0	$1.1	$0.0	($0.0)	($0.0)	$0.0	$1.1	51	14
7	West	Interface	500	$3.0	$4.6	$0.5	($1.1)	($0.0)	($0.2)	($0.0)	$0.1	($0.9)	504	87
8	Brunner Island - Yorkana	Line	Met-Ed	($0.0)	($0.9)	($0.0)	$0.8	$0.0	$0.1	($0.0)	($0.0)	$0.8	86	27
9	Sammis - Wylie Ridge	Line	AP	$0.2	$1.0	$0.1	($0.7)	$0.0	($0.0)	$0.0	$0.0	($0.7)	762	157
10	Harwood - Susquehanna	Line	PPL	$0.2	($0.5)	$0.0	$0.7	($0.0)	$0.0	$0.0	($0.1)	$0.7	31	10
11	East Frankfort - Crete	Line	ComEd	$0.4	$1.0	$0.0	($0.6)	$0.0	$0.0	$0.0	$0.0	($0.6)	2,134	0
12	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.4	$0.8	($0.0)	($0.4)	($0.1)	($0.1)	$0.0	($0.0)	($0.5)	1,565	306
13	Atlantic - Larrabee	Line	JCPL	$0.1	$0.1	($0.0)	($0.0)	($0.1)	$0.1	$0.0	($0.3)	($0.3)	280	73
14	Wylie Ridge	Transformer	AP	$1.1	$1.8	$0.3	($0.4)	$0.2	$0.1	$0.0	$0.1	($0.3)	354	335
15	PL North	Interface	PPL	$0.0	$0.0	$0.0	$0.0	$0.4	$0.6	($0.0)	($0.3)	($0.3)	0	176
27	Jenkins - Susquehanna	Line	PPL	$0.1	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	12	0
47	Dauphin - Juniata	Line	PPL	$0.0	($0.0)	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	6	4
58	Eldred - Sunbury	Line	PPL	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	4	0
60	Harwood	Transformer	PPL	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	($0.0)	$0.0	15	1
129	Quarry - Steel City	Line	PPL	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	0	5

Table 7-36 PPL Control Zone top congestion cost impacts (By facility): Calendar year 2008

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Harwood - Susquehanna	Line	PPL	$2.7	($14.5)	($0.1)	$17.1	($1.2)	$2.0	$0.2	($3.0)	$14.1	117	99
2	West	Interface	500	$2.7	$13.2	$1.6	($8.9)	$0.2	$1.0	($0.2)	($1.0)	($9.9)	1,690	390
3	Cloverdale - Lexington	Line	AEP	$1.4	$9.0	$1.7	($5.8)	($0.2)	$0.0	($0.1)	($0.3)	($6.2)	3,529	1,813
4	East Towanda	Transformer	PENELEC	$0.4	$1.8	$0.0	($1.4)	$0.1	$1.1	($2.9)	($3.8)	($5.2)	803	306
5	East	Interface	500	$0.2	($4.6)	($0.0)	$4.8	$0.0	($0.0)	$0.0	$0.0	$4.8	758	12
6	Kammer	Transformer	500	$1.9	$7.4	$1.4	($4.1)	$0.2	$0.4	($0.3)	($0.5)	($4.7)	3,069	1,628
7	Sammis - Wylie Ridge	Line	AP	$0.3	$4.1	$0.6	($3.2)	$0.0	$0.1	($0.8)	($0.9)	($4.1)	1,915	1,257
8	Central	Interface	500	$0.8	$4.9	$0.4	($3.7)	($0.0)	($0.1)	($0.0)	$0.1	($3.6)	726	42
9	5004/5005 Interface	Interface	500	$1.5	$5.6	$0.8	($3.3)	($0.2)	($0.2)	($0.3)	($0.3)	($3.6)	736	449
10	Mount Storm - Pruntytown	Line	AP	$1.8	($0.8)	$1.0	$3.5	$0.1	$0.2	($0.1)	($0.1)	$3.4	2,559	812
11	Krendale - Seneca	Line	AP	$0.4	$2.4	$0.3	($1.7)	($0.0)	$0.0	$0.0	($0.0)	($1.7)	1,389	24
12	Bedington - Black Oak	Interface	500	$1.6	$0.6	$0.5	$1.5	$0.1	$0.0	$0.1	$0.1	$1.6	1,384	284
13	Branchburg - Readington	Line	PSEG	$0.7	($0.8)	($0.1)	$1.4	$0.0	($0.1)	$0.1	$0.2	$1.6	1,121	271
14	Conastone	Transformer	BGE	$0.1	($1.2)	($0.0)	$1.2	$0.0	($0.0)	$0.0	$0.1	$1.3	95	15
15	Burnham - Munster	Line	ComEd	$0.3	$1.5	($0.0)	($1.3)	$0.0	($0.1)	$0.0	$0.2	($1.1)	476	140
19	Lackawana - Stanton	Line	PPL	$0.0	($0.5)	$0.4	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	83	0
28	Martins Creek - Siegfried	Line	PPL	($0.0)	($0.8)	($0.0)	$0.8	($0.0)	$0.4	($0.0)	($0.5)	$0.3	28	61
31	Wescosville	Transformer	PPL	$0.0	$0.0	$0.0	$0.0	$0.1	($0.1)	$0.0	$0.3	$0.3	0	9
37	Frackville - Siegfried	Line	PPL	($0.0)	($0.3)	($0.0)	$0.3	$0.0	$0.1	($0.0)	($0.1)	$0.2	27	55
39	Susquehanna	Transformer	PPL	$0.3	$0.0	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	5	0

PSEG Control Zone

Table 7-37 PSEG Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Leonia - New Milford	Line	PSEG	$2.1	$0.8	$3.1	$4.4	($0.0)	$0.0	($0.3)	($0.3)	$4.1	3,847	39
2	Athenia - Saddlebrook	Line	PSEG	$3.2	$0.6	$1.3	$4.0	($0.2)	$0.1	($0.5)	($0.8)	$3.2	1,108	139
3	Plainsboro - Trenton	Line	PSEG	$3.5	($0.1)	$0.1	$3.8	($0.3)	$0.4	($0.1)	($0.7)	$3.1	389	164
4	Cedar Grove - Clifton	Line	PSEG	$2.3	$0.5	$1.0	$2.8	($0.1)	$0.0	($0.1)	($0.2)	$2.6	1,194	38
5	AP South	Interface	500	$0.2	$3.5	$1.1	($2.2)	$0.1	($0.2)	($0.5)	($0.2)	($2.4)	3,501	604
6	Fairlawn - Saddlebrook	Line	PSEG	$1.1	$0.2	$0.6	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	945	0
7	West	Interface	500	$11.8	$13.8	$0.9	($1.1)	($0.1)	$0.1	($0.2)	($0.3)	($1.4)	504	87
8	Wylie Ridge	Transformer	AP	$4.3	$5.4	$0.5	($0.6)	$0.0	$0.1	($0.6)	($0.7)	($1.3)	354	335
9	Hillsdale - Waldwick	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.4	($0.5)	($1.0)	($1.0)	0	59
10	Monroe - New Freedom	Line	AECO	($0.1)	($1.1)	($0.0)	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	584	0
11	Bayway - Federal Square	Line	PSEG	$0.5	($0.3)	$0.0	$0.8	($0.0)	($0.0)	($0.0)	$0.0	$0.8	220	11
12	Buckingham - Pleasant Valley	Line	PECO	$0.9	($0.1)	$0.0	$1.0	($0.0)	$0.2	($0.0)	($0.3)	$0.7	131	60
13	Atlantic - Larrabee	Line	JCPL	$0.6	($0.7)	$0.0	$1.3	($0.0)	$0.6	($0.1)	($0.7)	$0.7	280	73
14	Brunswick - Edison	Line	PSEG	$1.0	($0.0)	$0.0	$1.1	($0.1)	$0.2	($0.2)	($0.5)	$0.6	138	76
15	Cedar Grove - Roseland	Line	PSEG	$0.4	$0.0	$0.0	$0.4	($0.2)	$0.5	($0.2)	($0.9)	($0.5)	64	71
16	Bayonne - PVSC	Line	PSEG	$0.0	($0.4)	$0.0	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	686	0
17	Branchburg - Flagtown	Line	PSEG	$0.6	($0.0)	$0.1	$0.7	($0.0)	$0.1	($0.1)	($0.2)	$0.4	161	16
18	Athenia - Fairlawn	Line	PSEG	$0.4	$0.0	$0.0	$0.4	$0.0	$0.0	($0.0)	($0.0)	$0.4	165	6
22	East Windsor - Windsor	Line	PSEG	$0.1	($0.3)	$0.0	$0.3	($0.0)	($0.0)	($0.0)	$0.0	$0.4	107	3
24	Sewaren	Transformer	PSEG	$0.3	($0.0)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	89	0

Table 7-38 PSEG Control Zone top congestion cost impacts (By facility): Calendar year 2008

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Atlantic - Larrabee	Line	JCPL	$13.3	($6.0)	$0.4	$19.7	$0.5	$2.7	($0.9)	($3.1)	$16.6	1,556	380
2	Branchburg - Readington	Line	PSEG	$17.0	$0.8	$0.8	$17.0	$0.2	$2.9	($0.7)	($3.3)	$13.6	1,121	271
3	Buckingham - Pleasant Valley	Line	PECO	$11.4	$2.4	$0.6	$9.6	($0.1)	$0.4	($0.1)	($0.6)	$9.0	647	74
4	Cedar Grove - Roseland	Line	PSEG	$12.6	$1.9	$0.5	$11.3	($0.0)	$2.7	($0.9)	($3.6)	$7.7	627	185
5	Branchburg - Flagtown	Line	PSEG	$6.9	$0.1	$0.2	$6.9	$0.4	($0.0)	($0.4)	($0.0)	$6.9	284	61
6	Unclassified	Unclassified	Unclassified	$3.7	($2.9)	$0.2	$6.8	$0.0	$0.0	$0.0	$0.0	$6.8	9,999	9,999
7	AP South	Interface	500	$25.3	$31.6	$3.9	($2.4)	($0.1)	$1.0	($2.2)	($3.3)	($5.7)	3,572	1,016
8	Brunswick - Edison	Line	PSEG	$5.6	$0.3	$0.3	$5.6	($0.0)	$0.6	($0.3)	($0.9)	$4.6	535	293
9	Mount Storm - Pruntytown	Line	AP	$1.7	$6.6	$1.9	($2.9)	$0.1	($0.2)	($1.5)	($1.2)	($4.1)	2,559	812
10	Trainer - Delco Tap	Line	PECO	($2.2)	($5.9)	($0.1)	$3.6	$0.0	$0.0	$0.0	$0.0	$3.6	2,218	0
11	Cloverdale - Lexington	Line	AEP	$22.1	$24.9	$2.8	($0.0)	$0.4	$1.9	($2.0)	($3.5)	($3.5)	3,529	1,813
12	Sammis - Wylie Ridge	Line	AP	$7.5	$8.1	$1.0	$0.4	$0.8	$1.9	($2.7)	($3.7)	($3.3)	1,915	1,257
13	Bedington - Black Oak	Interface	500	$3.8	$7.3	$1.0	($2.4)	$0.0	($0.0)	($0.4)	($0.4)	($2.8)	1,384	284
14	Leonia - New Milford	Line	PSEG	$1.7	$0.4	$2.5	$3.8	($0.2)	$0.7	($0.5)	($1.3)	$2.5	919	84
15	Athenia - Fairlawn	Line	PSEG	$2.0	$0.3	$0.7	$2.4	($0.0)	$0.0	($0.3)	($0.3)	$2.1	428	36
16	North Ave - Pvsc	Line	PSEG	$0.6	($1.1)	$0.1	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	592	0
19	Linden - North Ave	Line	PSEG	$0.7	($0.7)	$0.1	$1.6	$0.0	($0.0)	($0.0)	$0.0	$1.6	484	23
20	Lawrence - Pleasant Valley	Line	PSEG	$2.3	$0.6	$0.3	$2.0	$0.1	$0.4	($0.2)	($0.5)	$1.6	142	39
21	Meadow Rd - Metuchen	Line	PSEG	$1.6	$0.1	$0.1	$1.5	($0.0)	($0.0)	($0.0)	($0.0)	$1.5	133	4
24	Bergen - Hoboken	Line	PSEG	$0.4	($0.3)	$0.6	$1.3	($0.0)	$0.0	($0.0)	($0.1)	$1.2	188	5

RECO Control Zone

Table 7-39 RECO Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$0.5	$0.0	$0.0	$0.6	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	504	87
2	5004/5005 Interface	Interface	500	$0.5	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.0)	($0.1)	$0.4	776	294
3	Kammer	Transformer	500	$0.4	$0.0	$0.0	$0.4	$0.0	($0.0)	($0.0)	$0.0	$0.4	3,674	1,328
4	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.2	$0.0	($0.0)	$0.2	$0.0	($0.0)	($0.0)	$0.0	$0.2	2,949	910
5	Wylie Ridge	Transformer	AP	$0.2	$0.0	$0.0	$0.2	($0.0)	($0.0)	($0.0)	($0.0)	$0.2	354	335
6	Graceton - Raphael Road	Line	BGE	($0.2)	($0.0)	($0.0)	($0.2)	$0.0	$0.0	$0.0	$0.0	($0.2)	527	152
7	AP South	Interface	500	($0.1)	($0.0)	($0.0)	($0.1)	($0.0)	$0.0	$0.0	($0.0)	($0.1)	3,501	604
8	Athenia - Saddlebrook	Line	PSEG	$0.1	($0.0)	$0.0	$0.1	($0.0)	($0.0)	$0.0	($0.0)	$0.1	1,108	139
9	East Frankfort - Crete	Line	ComEd	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	2,134	0
10	Doubs	Transformer	AP	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	429	246
11	Sammis - Wylie Ridge	Line	AP	$0.1	$0.0	$0.0	$0.1	$0.0	($0.0)	($0.0)	($0.0)	$0.1	762	157
12	Crete - St Johns Tap	Flowgate	Midwest ISO	$0.1	$0.0	($0.0)	$0.1	$0.0	($0.0)	$0.0	$0.0	$0.1	1,565	306
13	Tiltonsville - Windsor	Line	AP	$0.1	$0.0	$0.0	$0.1	($0.0)	($0.0)	($0.0)	$0.0	$0.1	1,449	311
14	Fairlawn - Saddlebrook	Line	PSEG	($0.1)	($0.0)	($0.0)	($0.1)	$0.0	$0.0	$0.0	$0.0	($0.1)	945	0
15	Krendale - Seneca	Line	AP	$0.1	$0.0	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	324	0

Table 7-40 RECO Control Zone top congestion cost impacts (By facility): Calendar year 2008

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	West	Interface	500	$1.4	$0.0	$0.2	$1.6	$0.1	($0.0)	($0.4)	($0.3)	$1.3	1,690	390
2	Branchburg - Readington	Line	PSEG	$1.0	$0.0	$0.0	$1.0	$0.0	($0.0)	($0.0)	$0.0	$1.0	1,121	271
3	Cedar Grove - Roseland	Line	PSEG	$0.8	$0.0	$0.0	$0.8	$0.1	($0.0)	($0.0)	$0.1	$0.9	627	185
4	Kammer	Transformer	500	$0.8	$0.0	$0.1	$0.9	$0.0	($0.0)	($0.1)	($0.0)	$0.9	3,069	1,628
5	Cloverdale - Lexington	Line	AEP	$0.7	$0.0	$0.2	$0.8	$0.0	($0.0)	($0.1)	($0.1)	$0.8	3,529	1,813
6	AP South	Interface	500	$0.7	$0.0	$0.1	$0.7	$0.0	($0.0)	($0.1)	($0.1)	$0.6	3,572	1,016
7	Atlantic - Larrabee	Line	JCPL	$0.6	$0.0	$0.0	$0.6	$0.0	($0.0)	($0.1)	($0.0)	$0.5	1,556	380
8	Central	Interface	500	$0.5	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	726	42
9	East	Interface	500	$0.5	$0.0	$0.0	$0.5	($0.0)	($0.0)	($0.0)	($0.0)	$0.5	758	12
10	Buckingham - Pleasant Valley	Line	PECO	$0.5	$0.0	$0.0	$0.5	$0.0	($0.0)	($0.0)	$0.0	$0.5	647	74
11	5004/5005 Interface	Interface	500	$0.5	$0.0	$0.1	$0.6	$0.0	($0.0)	($0.3)	($0.3)	$0.3	736	449
12	Krendale - Seneca	Line	AP	$0.2	$0.0	$0.1	$0.3	($0.0)	($0.0)	$0.0	$0.0	$0.3	1,389	24
13	Dickerson - Pleasant View	Line	Pepco	$0.3	$0.0	$0.0	$0.3	($0.0)	($0.0)	($0.0)	($0.0)	$0.3	844	218
14	Cedar Grove - Clifton	Line	PSEG	$0.2	$0.0	$0.0	$0.2	$0.1	($0.0)	($0.0)	$0.1	$0.3	793	445
15	Burnham - Munster	Line	ComEd	$0.2	$0.0	$0.0	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.2	476	140

Western Region Congestion-Event Summaries

AEP Control Zone

Table 7-41 AEP Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($20.1)	($39.8)	$1.2	$20.9	($1.2)	$0.4	$0.5	($1.1)	$19.7	3,501	604
2	Kammer	Transformer	500	($20.6)	($34.6)	($0.6)	$13.4	($0.8)	$2.5	$0.4	($2.9)	$10.6	3,674	1,328
3	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$17.5	$8.9	$1.1	$9.7	($2.6)	($1.1)	($2.4)	($3.9)	$5.8	2,949	910
4	Ruth - Turner	Line	AEP	$4.9	($1.6)	$0.5	$7.0	($1.4)	($0.4)	($0.1)	($1.2)	$5.8	704	313
5	Kanawha - Kincaid	Line	AEP	$2.8	($2.1)	$0.2	$5.1	$0.0	$0.0	$0.0	$0.0	$5.1	291	0
6	Kammer - Ormet	Line	AEP	$7.8	$1.1	$0.3	$6.9	($1.6)	$0.5	($0.1)	($2.2)	$4.7	552	509
7	AEP-DOM	Interface	500	$1.3	($3.7)	$0.4	$5.3	($0.2)	$0.5	($0.0)	($0.8)	$4.5	325	136
8	Kanawha River	Transformer	AEP	$3.3	($0.3)	$0.5	$4.1	$0.1	($0.3)	($0.1)	$0.4	$4.4	163	37
9	Kanawha River - Bradley	Line	AEP	$1.3	($2.2)	$0.2	$3.8	($0.0)	$0.1	$0.0	($0.1)	$3.7	24	15
10	Breed - Wheatland	Line	AEP	$0.1	($3.9)	($0.5)	$3.5	$0.0	$0.0	$0.0	$0.0	$3.5	591	2
11	5004/5005 Interface	Interface	500	($9.2)	($12.9)	$0.0	$3.7	$0.1	$0.6	$0.1	($0.3)	$3.4	776	294
12	East Frankfort - Crete	Line	ComEd	$4.6	$2.9	$1.5	$3.2	$0.0	$0.0	$0.0	$0.0	$3.2	2,134	0
13	Sammis - Wylie Ridge	Line	AP	($5.0)	($3.1)	($0.1)	($2.0)	($0.3)	$0.2	($0.0)	($0.5)	($2.6)	762	157
14	Bedington - Black Oak	Interface	500	($2.8)	($5.1)	$0.1	$2.4	($0.1)	($0.0)	$0.0	($0.0)	$2.3	645	73
15	Mount Storm - Pruntytown	Line	AP	($3.1)	($5.2)	$0.2	$2.3	$0.0	$0.2	$0.1	($0.1)	$2.2	525	132
18	Cloverdale - Lexington	Line	AEP	($7.0)	($5.1)	($0.4)	($2.3)	$0.4	$0.2	$0.2	$0.4	($1.9)	1,015	434
21	Axton	Transformer	AEP	$0.3	($0.8)	$0.1	$1.2	($0.1)	$0.1	$0.0	($0.2)	$1.1	116	12
29	Poston - Postel Tap	Line	AEP	$0.4	($0.6)	$0.2	$1.2	$0.1	$0.5	($0.0)	($0.4)	$0.8	148	118
30	Marquis - Waverly	Line	AEP	$0.7	$0.0	$0.1	$0.7	($0.0)	$0.0	($0.0)	($0.0)	$0.7	74	14
33	Kanawha River - Kincaid	Line	AEP	$0.0	$0.0	$0.0	$0.0	$0.3	($0.1)	$0.1	$0.5	$0.5	0	105

Table 7-42 AEP Control Zone top congestion cost impacts (By facility): Calendar year 2008

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($88.3)	($149.7)	$2.4	$63.8	($15.1)	$0.6	$0.3	($15.4)	$48.4	3,572	1,016
2	Mount Storm - Pruntytown	Line	AP	($28.8)	($71.8)	$3.8	$46.9	($9.2)	$0.4	($0.4)	($9.9)	$36.9	2,559	812
3	Kammer	Transformer	500	($31.2)	($80.1)	($0.5)	$48.3	($10.1)	$3.9	$0.4	($13.5)	$34.8	3,069	1,628
4	Bedington - Black Oak	Interface	500	($21.7)	($47.4)	$2.1	$27.8	($2.5)	$0.9	$0.0	($3.4)	$24.4	1,384	284
5	Axton	Transformer	AEP	$2.8	($13.0)	$2.2	$18.1	$0.0	$0.0	$0.0	$0.0	$18.1	425	0
6	West	Interface	500	($23.8)	($41.1)	$0.2	$17.5	($3.3)	$0.9	$0.1	($4.1)	$13.4	1,690	390
7	Sammis - Wylie Ridge	Line	AP	($17.1)	($9.7)	($0.3)	($7.7)	($4.3)	($0.5)	($1.4)	($5.2)	($12.9)	1,915	1,257
8	Mount Storm	Transformer	AP	($8.9)	($23.7)	$1.4	$16.2	($5.2)	($1.6)	($0.2)	($3.8)	$12.5	935	469
9	Cloverdale - Lexington	Line	AEP	($96.5)	($104.8)	($6.0)	$2.3	($16.0)	($3.7)	$0.9	($11.4)	($9.1)	3,529	1,813
10	Amos	Transformer	AEP	$5.9	($1.6)	$0.2	$7.7	$0.4	$0.6	$0.1	($0.2)	$7.5	31	19
11	Mahans Lane - Tidd	Line	AEP	($2.0)	($4.8)	$2.8	$5.6	$0.1	$0.2	$0.0	($0.0)	$5.6	847	217
12	Bedington	Transformer	AP	($4.7)	($8.9)	$0.3	$4.5	($0.5)	$0.1	($0.0)	($0.6)	$3.9	1,192	303
13	Breed - Wheatland	Line	AEP	$0.1	($3.9)	($0.4)	$3.5	$0.0	($0.0)	$0.0	$0.0	$3.5	338	1
14	Central	Interface	500	($6.3)	($9.8)	($0.0)	$3.4	($0.0)	$0.1	$0.0	($0.1)	$3.3	726	42
15	Aqueduct - Doubs	Line	AP	($5.6)	($8.7)	$0.1	$3.3	($0.1)	($0.0)	$0.0	($0.1)	$3.2	307	7
17	Axton - Jacksons Ferry	Line	AEP	$0.5	($2.3)	$0.3	$3.1	$0.0	$0.0	$0.0	$0.0	$3.1	83	0
18	Kanawha River	Transformer	AEP	$1.7	($0.2)	$0.5	$2.4	$0.2	($0.6)	($0.2)	$0.5	$2.9	113	36
21	Cloverdale	Transformer	AEP	($0.1)	($2.4)	$0.1	$2.4	($0.2)	$0.1	$0.0	($0.2)	$2.1	50	74
28	Darwin - Eugene	Line	AEP	$0.0	($0.3)	($0.0)	$0.3	$0.1	$2.0	($0.0)	($1.9)	($1.5)	22	30
32	Kammer - Natrium	Line	AEP	$1.0	($0.2)	$0.1	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	58	0

AP Control Zone

Table 7-43 AP Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($17.3)	($65.9)	($4.6)	$44.0	$2.6	$2.6	$3.3	$3.4	$47.4	3,501	604
2	Kammer	Transformer	500	$17.8	$27.8	$6.8	($3.2)	($3.0)	($0.9)	($8.2)	($10.3)	($13.5)	3,674	1,328
3	Mount Storm - Pruntytown	Line	AP	($2.0)	($10.1)	($0.6)	$7.4	$0.8	$0.8	$0.5	$0.5	$7.9	525	132
4	Doubs	Transformer	AP	$1.9	($6.6)	($0.2)	$8.4	($0.2)	$1.2	$0.2	($1.1)	$7.3	429	246
5	Bedington - Black Oak	Interface	500	($1.9)	($8.5)	($0.2)	$6.3	($0.3)	$0.2	$0.4	($0.2)	$6.2	645	73
6	5004/5005 Interface	Interface	500	($9.9)	($13.9)	($1.3)	$2.7	$1.0	$0.9	$1.8	$1.9	$4.6	776	294
7	Tiltonsville - Windsor	Line	AP	$7.5	$2.3	$0.5	$5.7	($0.5)	($0.3)	($0.8)	($1.1)	$4.6	1,449	311
8	Wylie Ridge	Transformer	AP	$6.1	$7.4	$5.4	$4.1	($1.1)	($0.5)	($7.2)	($7.7)	($3.6)	354	335
9	Belmont	Transformer	AP	$3.5	$0.2	$0.6	$4.0	($0.2)	$0.5	($0.1)	($0.7)	$3.2	1,029	76
10	Bedington - Harmony	Line	AP	$2.1	($0.1)	$0.5	$2.8	$0.0	$0.0	($0.0)	($0.1)	$2.7	280	28
11	Cloverdale - Lexington	Line	AEP	$1.3	($1.5)	$0.8	$3.6	($0.1)	$0.0	($0.9)	($1.0)	$2.6	1,015	434
12	Carroll - Catoctin	Line	AP	$0.4	$0.0	($0.0)	$0.3	$0.7	($0.8)	$0.2	$1.6	$2.0	99	22
13	Yukon	Transformer	AP	$2.2	$0.4	$0.0	$1.9	$0.0	$0.2	$0.1	($0.1)	$1.7	149	39
14	Krendale - Seneca	Line	AP	$1.6	$0.1	$0.2	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	324	0
15	Tiltonsville - Windsor	Line	AEP	$1.6	$0.3	$0.0	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	592	0
17	Mount Storm	Transformer	AP	($0.5)	($2.2)	($0.3)	$1.4	$0.2	$0.5	$0.3	($0.1)	$1.4	151	80
19	Sammis - Wylie Ridge	Line	AP	$3.9	$2.9	$1.6	$2.6	($0.3)	($0.1)	($1.2)	($1.4)	$1.2	762	157
21	Kingwood - Pruntytown	Line	AP	$1.0	($0.1)	($0.0)	$1.1	$0.0	($0.0)	($0.0)	$0.0	$1.2	161	10
22	Middlebourne - Willow	Line	AP	$1.3	$0.1	($0.1)	$1.1	($0.1)	($0.1)	($0.0)	$0.0	$1.1	348	45
23	Elrama - Mitchell	Line	AP	$2.5	$1.2	$0.1	$1.5	($0.2)	$0.0	($0.2)	($0.4)	$1.1	367	198

Table 7-44 AP Control Zone top congestion cost impacts (By facility): Calendar year 2008

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$9.2	($141.1)	($0.3)	$150.0	$2.8	$8.7	$1.2	($4.6)	$145.3	3,572	1,016
2	Mount Storm - Pruntytown	Line	AP	($8.2)	($94.1)	($0.4)	$85.5	($0.3)	$3.7	($0.1)	($4.1)	$81.4	2,559	812
3	Bedington - Black Oak	Interface	500	($3.8)	($57.5)	($1.3)	$52.5	$0.7	$0.3	$0.8	$1.2	$53.7	1,384	284
4	Cloverdale - Lexington	Line	AEP	$21.4	($27.6)	$6.2	$55.2	($3.1)	($0.5)	($7.8)	($10.5)	$44.8	3,529	1,813
5	Bedington	Transformer	AP	$32.9	($7.7)	$1.3	$41.9	($0.6)	($0.6)	($0.5)	($0.6)	$41.4	1,192	303
6	Meadow Brook	Transformer	AP	$28.4	($1.5)	$0.6	$30.5	($3.1)	($0.2)	($0.1)	($3.1)	$27.4	774	173
7	Mount Storm	Transformer	AP	$0.8	($28.2)	$1.1	$30.2	($2.0)	$2.3	($0.9)	($5.2)	$25.0	935	469
8	Sammis - Wylie Ridge	Line	AP	$11.5	$7.8	$5.7	$9.4	($7.1)	$1.0	($15.0)	($23.1)	($13.7)	1,915	1,257
9	Kammer	Transformer	500	$26.7	$39.9	$7.1	($6.2)	($3.5)	($2.7)	($6.4)	($7.1)	($13.3)	3,069	1,628
10	Aqueduct - Doubs	Line	AP	($17.0)	($6.0)	($0.4)	($11.3)	$0.1	$0.1	$0.0	$0.0	($11.3)	307	7
11	Krendale - Seneca	Line	AP	$7.8	($0.1)	$2.2	$10.1	($0.0)	$0.0	($0.0)	($0.1)	$10.0	1,389	24
12	West	Interface	500	($18.7)	($25.4)	($0.7)	$6.0	$2.0	$1.0	$0.7	$1.7	$7.7	1,690	390
13	Cedar Grove - Roseland	Line	PSEG	$5.7	$1.8	$2.0	$5.9	$0.0	$0.0	$0.4	$0.4	$6.3	627	185
14	5004/5005 Interface	Interface	500	($6.9)	($12.0)	($0.4)	$4.8	$1.7	$1.3	$0.8	$1.2	$6.0	736	449
15	Kingwood - Pruntytown	Line	AP	$5.2	($0.0)	$0.1	$5.3	$0.0	$0.0	($0.0)	$0.0	$5.3	360	13
17	Eureka - Willow Island	Line	AP	($0.3)	($4.7)	($0.1)	$4.3	($0.2)	$0.0	$0.0	($0.2)	$4.1	288	37
25	Middlebourne - Willow	Line	AP	$0.5	($2.6)	$0.0	$3.2	($0.7)	$0.0	($0.1)	($0.8)	$2.4	122	51
26	Elrama - Mitchell	Line	AP	$3.2	$1.4	$1.4	$3.3	($0.1)	$0.1	($1.0)	($1.1)	$2.1	577	237
27	Black Oak	Transformer	AP	($2.9)	($4.8)	$0.0	$1.9	$0.1	$0.0	($0.0)	$0.0	$1.9	386	29
28	Yukon	Transformer	AP	$1.9	$0.1	$0.1	$1.9	($0.1)	$0.2	$0.0	($0.3)	$1.6	98	44

ComEd Control Zone

Table 7-45 ComEd Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Pleasant Valley - Belvidere	Line	ComEd	($4.7)	($42.8)	($0.0)	$38.1	($0.2)	$2.4	$0.1	($2.5)	$35.6	3,648	405
2	East Frankfort - Crete	Line	ComEd	($20.1)	($41.5)	($0.3)	$21.1	$0.0	$0.0	$0.0	$0.0	$21.1	2,134	0
3	Dunes Acres - Michigan City	Flowgate	Midwest ISO	($46.2)	($70.5)	($3.1)	$21.3	($3.4)	($1.1)	$0.9	($1.4)	$19.8	2,949	910
4	Kammer	Transformer	500	($30.8)	($49.7)	($0.1)	$18.7	($0.4)	($0.9)	($0.0)	$0.4	$19.1	3,674	1,328
5	AP South	Interface	500	($34.7)	($53.5)	($0.1)	$18.7	($1.1)	($0.1)	($0.1)	($1.0)	$17.6	3,501	604
6	Crete - St Johns Tap	Flowgate	Midwest ISO	($14.7)	($30.3)	($0.4)	$15.2	($0.4)	$0.1	$0.1	($0.4)	$14.8	1,565	306
7	Electric Jct - Nelson	Line	ComEd	$0.2	($7.9)	$0.1	$8.2	$2.1	$1.4	($0.1)	$0.6	$8.8	823	202
8	5004/5005 Interface	Interface	500	($12.4)	($17.6)	($0.0)	$5.1	($0.6)	($1.1)	($0.0)	$0.4	$5.6	776	294
9	Glidden - West Dekalb	Line	ComEd	($0.4)	($5.7)	$0.1	$5.4	$0.1	($0.0)	$0.0	$0.2	$5.6	1,166	21
10	Paddock - Townline	Flowgate	Midwest ISO	($0.8)	($5.0)	($0.1)	$4.0	$0.5	$0.2	$0.1	$0.4	$4.4	404	215
11	Sliver Lake - Cherry Valley	Line	ComEd	$0.1	($3.7)	$0.1	$3.9	$0.8	$0.2	($0.1)	$0.5	$4.3	340	41
12	West	Interface	500	($12.4)	($16.6)	($0.0)	$4.1	($0.1)	($0.1)	($0.0)	$0.0	$4.1	504	87
13	Wylie Ridge	Transformer	AP	($7.9)	($10.9)	($0.0)	$3.0	($0.8)	($1.5)	$0.0	$0.8	$3.8	354	335
14	Doubs	Transformer	AP	($7.5)	($11.8)	($0.0)	$4.3	($0.7)	$0.1	$0.0	($0.7)	$3.6	429	246
15	Cloverdale - Lexington	Line	AEP	($5.1)	($9.0)	($0.0)	$3.9	($0.5)	($0.1)	$0.0	($0.3)	$3.5	1,015	434
19	Cherry Valley	Transformer	ComEd	$0.4	($2.4)	$0.0	$2.8	$0.0	$0.0	$0.0	($0.0)	$2.8	25	6
23	Waterman - West Dekalb	Line	ComEd	($0.6)	($2.4)	$0.0	$1.9	$0.3	($0.1)	($0.0)	$0.3	$2.2	1,499	57
24	Wilton Center - Pontiac Midpoint	Line	ComEd	$1.6	$0.4	$0.0	$1.3	$0.1	$0.7	$0.0	($0.6)	$0.7	205	55
29	Quad Cities - Cordova	Line	ComEd	$0.2	($1.0)	$0.0	$1.3	($0.0)	$0.1	$0.0	($0.1)	$1.2	115	15
30	Burnham - Munster	Line	ComEd	($2.1)	($3.4)	($0.0)	$1.3	($0.0)	$0.0	($0.0)	($0.1)	$1.2	140	15

Table 7-46 ComEd Control Zone top congestion cost impacts (By facility): Calendar year 2008

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Cloverdale - Lexington	Line	AEP	($68.5)	($129.4)	$0.6	$61.5	($5.5)	($1.3)	($0.2)	($4.4)	$57.2	3,529	1,813
2	AP South	Interface	500	($94.4)	($145.2)	$1.1	$51.9	($5.2)	($1.2)	($0.1)	($4.2)	$47.7	3,572	1,016
3	Kammer	Transformer	500	($41.3)	($72.2)	($0.0)	$30.8	($5.1)	$2.9	($0.1)	($8.1)	$22.7	3,069	1,628
4	East Frankfort - Crete	Line	ComEd	($14.4)	($32.9)	($0.1)	$18.4	$0.0	$0.0	$0.0	$0.0	$18.4	1,002	0
5	Mount Storm - Pruntytown	Line	AP	($45.5)	($70.9)	$0.0	$25.5	($6.5)	$1.1	($0.2)	($7.9)	$17.6	2,559	812
6	Bedington - Black Oak	Interface	500	($25.4)	($42.0)	$0.2	$16.8	($0.2)	($0.4)	$0.0	$0.2	$17.0	1,384	284
7	West	Interface	500	($26.9)	($42.8)	$0.1	$16.0	($0.3)	($0.7)	($0.0)	$0.4	$16.4	1,690	390
8	Burnham - Munster	Line	ComEd	($23.6)	($38.2)	$2.2	$16.8	($2.6)	($2.6)	($0.5)	($0.5)	$16.3	476	140
9	Dunes Acres - Michigan City	Flowgate	Midwest ISO	($9.5)	($17.3)	$0.0	$7.8	($2.1)	$0.1	($0.2)	($2.4)	$5.4	687	435
10	Krendale - Seneca	Line	AP	($6.1)	($11.0)	($0.0)	$4.8	$0.0	($0.0)	$0.0	$0.0	$4.9	1,389	24
11	Crete - East Frankfurt	Line	ComEd	$0.0	$0.0	$0.0	$0.0	($5.0)	($1.1)	($0.7)	($4.6)	($4.6)	0	337
12	Central	Interface	500	($5.6)	($10.0)	($0.0)	$4.4	($0.1)	($0.1)	($0.0)	($0.1)	$4.3	726	42
13	Axton	Transformer	AEP	($7.2)	($11.4)	$0.1	$4.3	$0.0	$0.0	$0.0	$0.0	$4.3	425	0
14	Dickerson - Pleasant View	Line	Pepco	($6.4)	($10.2)	$0.0	$3.8	($0.2)	($0.4)	$0.0	$0.2	$4.0	844	218
15	5004/5005 Interface	Interface	500	($10.3)	($15.6)	($0.0)	$5.3	($1.4)	($0.0)	($0.0)	($1.4)	$3.9	736	449
19	Sliver Lake - Cherry Valley	Line	ComEd	$0.1	($3.0)	$0.0	$3.1	$0.0	$0.0	$0.0	$0.0	$3.1	99	0
20	Cherry Valley	Transformer	ComEd	$2.1	($1.1)	$0.0	$3.3	$0.3	$0.5	($0.1)	($0.3)	$3.0	92	128
22	Kincaid - Pana North	Line	ComEd	($1.3)	($3.8)	($0.0)	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	605	0
26	Dresden - Elwood	Line	ComEd	$1.9	($1.5)	$0.0	$3.5	($0.2)	$1.3	($0.0)	($1.5)	$1.9	116	86
39	Wilton Center - Pontiac Midpoint	Line	ComEd	$0.3	($0.0)	$0.0	$0.4	($0.2)	$0.3	($0.0)	($0.5)	($0.1)	84	69

DAY Control Zone

Table 7-47 DAY Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Kammer	Transformer	500	($1.9)	($4.5)	($0.1)	$2.6	$0.4	($0.1)	$0.0	$0.5	$3.1	3,674	1,328
2	AP South	Interface	500	($2.6)	($3.9)	($0.0)	$1.3	$0.0	$0.3	($0.0)	($0.3)	$1.0	3,501	604
3	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$0.4	$1.0	($0.5)	($1.1)	($0.0)	($0.0)	$0.1	$0.2	($0.9)	2,949	910
4	Doubs	Transformer	AP	($0.4)	($1.3)	$0.0	$0.9	$0.0	$0.1	$0.0	($0.1)	$0.8	429	246
5	West	Interface	500	($0.9)	($1.5)	($0.0)	$0.7	$0.0	$0.0	$0.0	($0.0)	$0.7	504	87
6	Cloverdale - Lexington	Line	AEP	($0.3)	($0.9)	$0.0	$0.6	$0.0	$0.1	$0.0	($0.1)	$0.6	1,015	434
7	Wylie Ridge	Transformer	AP	($0.6)	($1.1)	($0.0)	$0.5	$0.2	$0.2	$0.0	($0.0)	$0.4	354	335
8	5004/5005 Interface	Interface	500	($0.8)	($1.2)	($0.0)	$0.4	$0.1	$0.1	$0.0	($0.0)	$0.4	776	294
9	Tiltonsville - Windsor	Line	AP	($0.3)	($0.7)	($0.0)	$0.4	$0.0	$0.1	$0.0	($0.1)	$0.3	1,449	311
10	East Frankfort - Crete	Line	ComEd	$0.2	$0.5	$0.0	($0.3)	$0.0	$0.0	$0.0	$0.0	($0.3)	2,134	0
11	Marquis - Waverly	Line	AEP	$0.0	($0.3)	($0.0)	$0.3	($0.0)	$0.0	$0.0	($0.0)	$0.2	74	14
12	Elrama - Mitchell	Line	AP	($0.1)	($0.3)	($0.0)	$0.2	$0.1	$0.0	$0.0	$0.1	$0.2	367	198
13	Sammis - Wylie Ridge	Line	AP	($0.3)	($0.5)	($0.0)	$0.2	$0.0	$0.1	($0.0)	($0.0)	$0.2	762	157
14	AEP-DOM	Interface	500	($0.2)	($0.3)	$0.0	$0.2	$0.0	($0.0)	$0.0	$0.0	$0.2	325	136
15	Pierce - Foster	Flowgate	Midwest ISO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.0)	($0.2)	($0.2)	0	5

Table 7-48 DAY Control Zone top congestion cost impacts (By facility): Calendar year 2008

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Cloverdale - Lexington	Line	AEP	($8.4)	($10.9)	$0.1	$2.5	$0.3	($0.6)	$0.0	$1.0	$3.5	3,529	1,813
2	Kammer	Transformer	500	($5.0)	($6.4)	($0.0)	$1.3	$1.1	$0.3	$0.0	$0.9	$2.2	3,069	1,628
3	AP South	Interface	500	($9.5)	($12.0)	($0.0)	$2.5	$0.4	$0.8	($0.0)	($0.4)	$2.1	3,572	1,016
4	Bedington - Black Oak	Interface	500	($2.9)	($4.2)	($0.0)	$1.3	$0.1	$0.3	($0.0)	($0.3)	$1.0	1,384	284
5	West	Interface	500	($2.5)	($3.9)	$0.0	$1.4	$0.2	$0.6	($0.0)	($0.5)	$0.9	1,690	390
6	Mount Storm - Pruntytown	Line	AP	($5.2)	($4.7)	$0.0	($0.5)	$0.1	$0.4	($0.0)	($0.3)	($0.8)	2,559	812
7	5004/5005 Interface	Interface	500	($0.9)	($1.6)	$0.0	$0.7	$0.1	$0.1	($0.0)	($0.0)	$0.7	736	449
8	Axton	Transformer	AEP	($0.7)	($1.1)	($0.0)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	425	0
9	Central	Interface	500	($0.6)	($1.0)	$0.0	$0.4	$0.0	$0.0	$0.0	($0.0)	$0.4	726	42
10	Conemaugh - Keystone	Line	500	($0.0)	($0.0)	$0.0	$0.0	$0.3	$0.0	($0.0)	$0.3	$0.3	16	41
11	Dickerson - Pleasant View	Line	Pepco	($0.6)	($0.9)	$0.0	$0.3	($0.0)	$0.0	$0.0	($0.0)	$0.3	844	218
12	Sammis - Wylie Ridge	Line	AP	($1.5)	($1.2)	($0.0)	($0.4)	$0.8	($0.0)	($0.2)	$0.6	$0.2	1,915	1,257
13	Mount Storm	Transformer	AP	($1.8)	($1.3)	$0.0	($0.4)	($0.0)	($0.2)	($0.0)	$0.1	($0.2)	935	469
14	Axton - Jacksons Ferry	Line	AEP	($0.1)	($0.3)	($0.0)	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	83	0
15	Whitpain	Transformer	PECO	($0.0)	($0.1)	$0.0	$0.1	$0.0	($0.0)	($0.0)	$0.1	$0.2	89	68
325	Miami Fort	Transformer	DAY	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	2
467	Hutching - Carlisle	Line	DAY	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	($0.0)	$0.0	$0.0	0	1

DLCO Control Zone

Table 7-49 DLCO Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($15.3)	($21.2)	($0.1)	$5.8	($0.8)	$0.4	$0.1	($1.1)	$4.7	3,501	604
2	Sammis - Wylie Ridge	Line	AP	($5.2)	($10.0)	($0.0)	$4.7	($0.2)	$0.6	$0.0	($0.7)	$4.0	762	157
3	Elrama - Mitchell	Line	AP	($3.1)	($2.0)	($0.0)	($1.1)	($0.2)	$0.9	$0.0	($1.1)	($2.2)	367	198
4	West	Interface	500	($4.3)	($6.0)	($0.0)	$1.8	($0.1)	$0.0	$0.0	($0.1)	$1.6	504	87
5	Logans Ferry - Universal	Line	DLCO	$0.2	($1.3)	$0.0	$1.5	$0.0	$0.1	($0.0)	($0.1)	$1.4	395	156
6	Collier	Transformer	DLCO	$1.4	$0.3	$0.0	$1.2	$0.0	$0.0	$0.0	$0.0	$1.2	46	0
7	Wylie Ridge	Transformer	AP	($8.5)	($12.9)	($0.0)	$4.4	($1.2)	$2.2	$0.0	($3.3)	$1.1	354	335
8	Kammer	Transformer	500	($3.6)	($4.8)	$0.0	$1.3	($0.4)	($0.1)	($0.0)	($0.4)	$0.9	3,674	1,328
9	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$1.7	$2.6	($0.0)	($0.9)	$0.2	$0.1	($0.0)	$0.1	($0.8)	2,949	910
10	Krendale - Seneca	Line	AP	($1.7)	($2.3)	($0.0)	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	324	0
11	Doubs	Transformer	AP	($1.9)	($1.4)	($0.0)	($0.5)	($0.1)	$0.0	$0.0	($0.2)	($0.7)	429	246
12	Mount Storm - Pruntytown	Line	AP	($1.9)	($2.8)	($0.0)	$0.9	($0.2)	$0.1	$0.0	($0.3)	$0.6	525	132
13	Kammer - West Bellaire	Line	AP	$1.2	$1.0	$0.0	$0.3	$0.2	($0.1)	($0.0)	$0.3	$0.6	227	54
14	Bedington - Black Oak	Interface	500	($1.8)	($2.4)	($0.0)	$0.6	($0.0)	$0.0	$0.0	($0.1)	$0.5	645	73
15	5004/5005 Interface	Interface	500	($4.8)	($6.1)	($0.0)	$1.3	($0.4)	$0.5	$0.0	($0.9)	$0.4	776	294
18	Collier - Elwyn	Line	DLCO	$0.3	$0.0	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	30	0
20	Beaver - Clinton	Line	DLCO	$0.1	($0.2)	$0.0	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	20	0
25	Cheswick - Logans Ferry	Line	DLCO	$0.0	($0.1)	$0.0	$0.1	($0.0)	($0.0)	($0.0)	$0.0	$0.1	49	3
26	Crescent	Transformer	DLCO	$0.1	$0.0	$0.0	$0.1	$0.2	$0.1	($0.0)	$0.0	$0.1	18	23
29	Cheswick - Evergreen	Line	DLCO	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	($0.0)	$0.1	35	5

Table 7-50 DLCO Control Zone top congestion cost impacts (By facility): Calendar year 2008

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	($37.3)	($53.7)	$0.7	$17.1	($7.7)	$2.0	$0.0	($9.7)	$7.4	3,572	1,016
2	Sammis - Wylie Ridge	Line	AP	($15.5)	($33.8)	($0.1)	$18.2	($16.9)	$7.3	$0.2	($24.0)	($5.8)	1,915	1,257
3	Bedington - Black Oak	Interface	500	($13.3)	($19.0)	$0.3	$6.0	($1.2)	$0.7	$0.0	($1.9)	$4.1	1,384	284
4	Krendale - Seneca	Line	AP	($5.2)	($8.8)	($0.0)	$3.7	($0.1)	$0.0	$0.0	($0.1)	$3.6	1,389	24
5	Cloverdale - Lexington	Line	AEP	($11.3)	($17.8)	$0.2	$6.7	($2.8)	$1.0	($0.0)	($3.9)	$2.8	3,529	1,813
6	Cheswick - Universal	Line	DLCO	($1.3)	($3.7)	$0.0	$2.4	$0.1	$0.3	($0.0)	($0.2)	$2.3	411	158
7	Beaver - Clinton	Line	DLCO	$0.8	($1.1)	$0.0	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	184	0
8	Mount Storm	Transformer	AP	($6.9)	($10.1)	($0.0)	$3.2	($3.1)	$1.7	$0.0	($4.8)	($1.6)	935	469
9	Central	Interface	500	($2.0)	($3.3)	($0.0)	$1.3	($0.1)	$0.0	$0.0	($0.1)	$1.2	726	42
10	Cheswick - Evergreen	Line	DLCO	$0.4	($1.3)	$0.0	$1.7	($0.2)	$0.4	$0.0	($0.5)	$1.1	94	130
11	Crescent	Transformer	DLCO	$0.0	$0.0	$0.0	$0.0	$0.7	($0.3)	($0.0)	$1.0	$1.0	0	33
12	East	Interface	500	($1.3)	($2.2)	$0.0	$0.9	($0.0)	$0.0	$0.0	($0.0)	$0.9	758	12
13	Mount Storm - Pruntytown	Line	AP	($21.6)	($31.3)	$0.1	$9.8	($5.6)	$3.3	$0.0	($9.0)	$0.8	2,559	812
14	Kammer	Transformer	500	($4.7)	($6.7)	$0.0	$2.0	($1.2)	$0.0	($0.0)	($1.2)	$0.8	3,069	1,628
15	West	Interface	500	($10.2)	($13.5)	$0.1	$3.3	($1.6)	$1.0	$0.0	($2.5)	$0.8	1,690	390
18	Cheswick - Logans Ferry	Line	DLCO	$0.7	($1.0)	$0.0	$1.7	($0.3)	$0.7	($0.0)	($1.0)	$0.8	166	155
26	Brunot Island - Montour	Line	DLCO	$0.5	$0.0	$0.0	$0.5	$0.0	$0.0	$0.0	($0.0)	$0.5	12	6
36	Beaver	Transformer	DLCO	$0.2	($0.0)	$0.0	$0.3	$0.0	$0.0	$0.0	$0.0	$0.3	10	0
39	Arsenal - Oakland	Line	DLCO	$0.2	($0.0)	$0.0	$0.2	($0.1)	($0.1)	($0.0)	$0.0	$0.2	44	50
58	Collier	Transformer	DLCO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.0)	$0.1	$0.1	0	8

Southern Region Congestion-Event Summaries

Dominion Control Zone

Table 7-51 Dominion Control Zone top congestion cost impacts (By facility): Calendar year 2009

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$37.3	($31.2)	($0.3)	$68.2	$1.6	$1.2	$0.4	$0.8	$69.0	3,501	604
2	Doubs	Transformer	AP	$0.4	($5.5)	$0.0	$5.8	$0.3	$0.1	$0.1	$0.3	$6.1	429	246
3	Cloverdale - Lexington	Line	AEP	$7.0	$2.7	$1.1	$5.4	($0.0)	($1.8)	($1.4)	$0.4	$5.8	1,015	434
4	Kammer	Transformer	500	$10.3	$8.3	$2.1	$4.2	($0.0)	($0.8)	($2.0)	($1.2)	$3.0	3,674	1,328
5	Dunes Acres - Michigan City	Flowgate	Midwest ISO	$4.4	$2.1	$0.1	$2.4	($0.2)	($0.6)	($0.1)	$0.3	$2.7	2,949	910
6	Bedington - Black Oak	Interface	500	$4.3	$2.5	$0.7	$2.6	($0.1)	($0.1)	($0.2)	($0.1)	$2.4	645	73
7	Beechwood - Kerr Dam	Line	Dominion	$1.5	($0.8)	($0.1)	$2.3	($0.2)	$0.1	$0.1	($0.2)	$2.1	665	234
8	Bristers - Ox	Line	Dominion	($0.1)	($1.9)	$0.0	$1.8	$0.1	$0.4	$0.0	($0.2)	$1.6	62	42
9	Chuckatuck - Benns Church	Line	Dominion	$1.5	($0.0)	$0.0	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	45	0
10	AEP-DOM	Interface	500	$1.7	$1.1	$0.1	$0.7	($0.2)	($0.7)	($0.1)	$0.3	$1.1	325	136
11	East Frankfort - Crete	Line	ComEd	$1.9	$1.0	$0.1	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	2,134	0
12	West	Interface	500	($2.6)	($3.6)	$0.0	$1.0	$0.1	$0.2	$0.1	$0.0	$1.0	504	87
13	Wylie Ridge	Transformer	AP	$2.5	$1.7	$0.4	$1.2	($0.1)	($0.2)	($0.4)	($0.2)	$1.0	354	335
14	Ox	Transformer	Dominion	$0.8	($0.1)	$0.0	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	8	0
15	Crete - St Johns Tap	Flowgate	Midwest ISO	$1.6	$0.8	$0.2	$0.9	($0.1)	($0.3)	($0.2)	$0.0	$0.9	1,565	306
17	Crozet - Dooms	Line	Dominion	$0.7	($0.3)	$0.0	$1.0	($0.3)	($0.2)	($0.0)	($0.1)	$0.9	55	37
20	Beaumeade - Ashburn	Line	Dominion	$0.8	$0.0	$0.0	$0.8	$0.0	$0.0	$0.0	$0.0	$0.8	25	0
21	Chickahominy - Lanexa	Line	Dominion	$0.5	($0.0)	$0.0	$0.6	($0.1)	($0.3)	$0.0	$0.1	$0.7	42	19
22	Clover - Farmville	Line	Dominion	($0.0)	($0.7)	$0.0	$0.7	$0.0	$0.0	$0.0	$0.0	$0.7	41	0
23	Crozet - Barracks Rd	Line	Dominion	$0.8	$0.3	($0.0)	$0.4	$0.1	($0.1)	$0.0	$0.2	$0.6	39	11

Table 7-52 Dominion Control Zone top congestion cost impacts (By facility): Calendar year 2008

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$82.8	($94.7)	$4.6	$182.2	$6.3	$7.8	($3.6)	($5.1)	$177.1	3,572	1,016
2	Cloverdale - Lexington	Line	AEP	$111.7	$45.7	$11.5	$77.5	($0.4)	($8.5)	($10.3)	($2.1)	$75.3	3,529	1,813
3	Bedington - Black Oak	Interface	500	$34.0	$18.4	$1.9	$17.5	$0.3	($1.0)	($0.8)	$0.6	$18.1	1,384	284
4	Mount Storm	Transformer	AP	$21.4	$8.6	$3.9	$16.7	($8.8)	$16.4	($4.4)	($29.6)	($12.9)	935	469
5	Aqueduct - Doubs	Line	AP	$9.3	($2.8)	$0.2	$12.3	$0.0	($0.0)	($0.0)	$0.0	$12.3	307	7
6	Bristers - Ox	Line	Dominion	($1.2)	($12.4)	($0.6)	$10.7	$0.8	$1.1	$0.4	$0.1	$10.8	77	38
7	Dickerson - Pleasant View	Line	Pepco	($12.6)	($4.6)	($0.3)	($8.2)	($0.2)	$0.9	$0.3	($0.7)	($8.9)	844	218
8	Mount Storm - Pruntytown	Line	AP	$60.1	$62.2	$6.9	$4.8	($4.3)	($14.8)	($6.7)	$3.9	$8.7	2,559	812
9	Meadow Brook	Transformer	AP	($0.7)	($6.8)	($0.1)	$6.1	($0.1)	$0.3	$0.1	($0.3)	$5.8	774	173
10	Kammer	Transformer	500	$16.7	$14.0	$1.8	$4.5	($0.1)	($3.2)	($1.9)	$1.1	$5.6	3,069	1,628
11	Danville - East Danville	Line	Dominion	$4.9	$2.0	$0.2	$3.1	($0.2)	($0.2)	$0.3	$0.3	$3.4	692	152
12	East	Interface	500	($5.6)	($2.7)	($0.4)	($3.3)	$0.0	$0.0	$0.0	($0.0)	($3.3)	758	12
13	Brighton	Transformer	Pepco	$3.8	$1.0	$0.2	$3.1	($0.2)	($0.8)	($0.5)	$0.2	$3.3	116	78
14	Pleasantville - Ashburn	Line	Dominion	$3.2	$0.2	$0.0	$3.1	$0.0	$0.0	$0.0	$0.0	$3.1	10	0
15	Sammis - Wylie Ridge	Line	AP	$4.5	$2.2	$1.0	$3.3	($0.3)	($1.8)	($1.8)	($0.3)	$3.0	1,915	1,257
19	Beechwood - Kerr Dam	Line	Dominion	$1.6	($1.0)	$0.3	$3.0	($0.1)	$0.3	($0.2)	($0.6)	$2.3	318	168
22	Harrisonburg - Endless Caverns	Line	Dominion	$1.3	($0.6)	($0.0)	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	83	0
26	Halifax - Halifax	Line	Dominion	$0.0	$0.0	$0.0	$0.0	$0.1	($0.5)	($1.8)	($1.2)	($1.2)	0	63
29	Cradock - Chesapeake	Line	Dominion	$0.5	($0.5)	$0.0	$1.1	($0.0)	$0.0	($0.0)	($0.0)	$1.0	79	3
30	Sideburn - Ravensworth	Line	Dominion	($0.1)	($1.2)	($0.0)	$1.0	$0.0	$0.0	$0.0	($0.0)	$1.0	10	3

Economic Planning Process

Transmission system investments can be evaluated on a reliability basis or on an economic basis. The reliability evaluation examines whether a transmission upgrade is required in order to maintain reliability on the system in a particular area or areas, using specific planning and reliability criteria.[21] The economic evaluation examines whether a transmission upgrade, including reliability upgrades, results in positive economic benefits. The economic evaluation is more complex than a reliability evaluation because there is more judgment involved in the choice of relevant metrics for both benefits and costs. PJM's responsibility as an RTO requires PJM to constantly evaluate the need for transmission investments related to reliability and to help ensure that the responsible transmission owner constructs needed facilities. As the operator and designer of markets, PJM also needs to consider the appropriate role for the economic evaluation of transmission system investments.

Investments in transmission are currently compensated under the FERC's traditional cost of service regulatory approach. Although PJM's Tariff permits merchant projects, the significant merchant transmission projects have been direct current (DC) tie lines to export power rather than investments in network facilities. 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 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. Although the PJM Tariff does not yet comprehensively address the issue of competition between transmission and generation projects to solve congestion problems, 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.

After multiple filings in a proceeding concerning PJM's proposed economic metrics for evaluating transmission investments (Docket No. ER06-1474), the United States Federal Energy Regulatory Commission (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.[22]

On September 8, 2006, PJM filed to modify its Regional Transmission Expansion Plan ("RTEP") protocol.[23] PJM proposed to replace its economic planning process with processes that would evaluate the economic benefits of accelerating or modifying planned reliability-based upgrades or of constructing new enhancements or expansions to relieve costly congestion. In its initial order, the FERC conditionally accepted PJM's proposed changes to the economic transmission planning process component of the RTEP, including the requisite amendments to Schedule 6 of the OA

21 See PJM OA Schedule 6.
22 126 FERC ¶ 61,152.
23 PJM Initial Filing, Docket No. ER06-1474-000.

and the PJM OATT. The Commission also directed PJM to make a compliance filing that would: (i) explain how PJM considers and weighs the various metrics used to evaluate whether to recommend including an upgrade in the RTEP for economic reasons; (ii) clarify the role of demand response, generation and merchant transmission in the process; and (iii) provide additional information regarding the advanced technologies currently assessed.[24]

On March 21, 2007, PJM submitted its first compliance filing, providing further explanation of its metrics.[25] By order issued June 11, 2007, the Commission determined that PJM's proposal was still inadequate and directed PJM to file a formulaic approach to choosing economic projects proposed to reduce congestion that describes exactly how any metrics will be calculated, weighed, considered and combined.[26]

On October 9, 2007, PJM submitted its second compliance filing to address these issues, proposing a formulaic approach modeled on one developed by the Midwest ISO.[27] By order issued April 17, 2008, the FERC largely accepted PJM's proposed formulaic approach, but it required that PJM revise its proposal to (i) calculate load payments net of the change in the value of transmission rights, (ii) include more specific descriptions of the method of determining the discount rate and recovery period, and (iii) either reinstate provisions for sensitivity analyses or explain why such analyses are unnecessary. [28]

PJM's third compliance filing, submitted June 16, 2008,[29] addressed each of the three issues identified by the Commission in its 2006 order. In addressing the third item, PJM filed a new approach to perform sensitivity analyses. The new approach provides that PJM will perform a sensitivity analysis for projects included in the RTEP on the basis of certain objective criteria, including, but not limited to, the discount rate used to determine the present value of the Total Annual Enhancement Benefit and Total Enhancement Cost, and the annual revenue requirement, including the recovery period, used to determine the Total Enhancement Cost. Such analyses will consider key inputs used in market simulations performed by PJM (such as price forecasts and expected levels of demand response) in order to determine a "Benefit/Cost Ratio." PJM proposed to provide these results to the Transmission Expansion Advisory Committee (TEAC) in order to assist its evaluation. On February 20, 2009, the FERC issued an order accepting PJM's third compliance filing and denying requests for rehearing of its second order on compliance.[30]

The economic planning process creates market based signals for transmission investment and incorporates improvements over the prior process. The most significant improvements are the inclusion of less discretionary metrics and the evaluation of demand side response and generation resources as alternatives to transmission investment. New transmission projects, and the limits of the existing transmission system, can and do have significant impacts on PJM energy and capacity markets.

The goal of transmission planning in the PJM market design should ultimately be the incorporation of transmission investment decisions into market driven processes as much as possible.

24 117 FERC ¶ 61,218 (2006).
25 PJM submitted its first compliance filing in Subdocket No. ER06-1474-003.
26 119 FERC ¶ 61,265.
27 PJM submitted its second compliance filing in Subdocket No. ER06-1474-004.
28 123 FERC ¶ 61,051.
29 PJM submitted its third compliance filing in Subdocket No. ER06-1474-006.
30 126 FERC ¶ 61,152.

SECTION 8 – FINANCIAL TRANSMISSION AND AUCTION REVENUE 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.[1] 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.

1 87 FERC ¶ 61,054 (1999).

Overview

Financial Transmission Rights

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 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.[2] 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.

2 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."

- **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.[3] The proceeding for compliance with the Commission's conditions is not yet resolved.[4] 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 competitive auction. In order to provide additional information about the ownership of prevailing flow and counter flow FTRs, the Market Monitoring Unit (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.

3 127 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).
4 *See* FERC Docket No. ER09-650.

- **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.[5] The weighted-average price paid for buy-bid FTRs in the Monthly Balance of Planning Period FTR 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.

5 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).

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.

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.

Financial Transmission Rights

While FTRs have been available to eligible participants since the 1998 introduction of LMP, the Annual FTR Auction was first implemented for the 2003 to 2004 planning period. Since the 2006 to 2007 planning period, the auction has covered all control zones.

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the Day-Ahead Energy Market across specific FTR transmission paths. Effective June 1, 2007, PJM added marginal losses as a component in the calculation of LMP.[6] The value of an FTR reflects the difference in congestion prices rather than the difference in LMPs, which includes both congestion and marginal losses. Auction market participants are free to request FTRs between any pricing nodes on the system, including hubs,

6 For additional information on marginal losses, see the *2009 State of the Market Report for PJM*, Volume II, Section 2, “Energy Market, Part 1,” at “Real-Time Annual LMP Loss Component.”

control zones, aggregates, generator buses, load buses and interface pricing points. FTRs are available to the nearest 0.1 MW. The FTR target allocation is calculated hourly and is equal to the product of the FTR MW and the congestion price difference between sink and source that occurs in the Day-Ahead Energy Market. The value of an FTR can be positive or negative depending on the sink minus source congestion price difference, with a negative difference resulting in a liability for the holder. The FTR target allocation represents what the holders would receive if sufficient revenues are collected to fund FTRs.

Depending on the amount of FTR revenues collected, FTR holders with a positively valued FTR may receive congestion credits between zero and their target allocations. FTR holders with a negatively valued FTR are required to pay charges equal to their target allocations. When FTR holders receive their target allocations, the associated FTRs are fully funded. The objective function of all FTR auctions is to maximize the bid-based value of FTRs awarded in each auction.

FTRs can be bought, sold and self scheduled. Buy bids are FTRs that are bought in the auctions; sell offers are existing FTRs that are sold in the auctions; and self scheduled bids are FTRs that have been directly converted from ARRs.

There are two FTR hedge type products: obligations and options. An obligation provides a credit, positive or negative, equal to the product of the FTR MW and the congestion price difference between FTR sink (destination) and source (origin) that occurs in the Day-Ahead Energy Market. An option provides only positive credits and options are available for only a subset of the possible FTR transmission paths.

There are three FTR class type products: 24-hour, on peak and off peak. The 24-hour products are effective 24 hours a day, seven days a week, while the on peak products are effective during on peak periods defined as the hours ending 0800 through 2300, Eastern Prevailing Time (EPT) Mondays through Fridays, excluding North American Electric Reliability Council (NERC) holidays. The off peak products are effective during hours ending 2400 through 0700, EPT, Mondays through Fridays, and during all hours on Saturdays, Sundays and NERC holidays.

FTR buy bids and sell offers may be made as obligations or options and as any of the three class types. FTR self scheduled bids are available only as obligations and 24-hour class types, consistent with the associated ARRs.

Market Structure

Prior to implementation of the Annual FTR Auction, only network service and long-term, firm, point-to-point transmission service customers were able to directly obtain Annual FTRs. Now all transmission service customers and PJM members can participate in the Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions.

Supply

Throughout the year, PJM oversees the process of selling and buying FTRs through FTR Auctions. Market participants purchase FTRs by participating in Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.[7] The Annual FTR Auction includes the ability to directly convert allocated ARRs into self scheduled FTRs. Total FTR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested FTRs and the numerous combinations of FTRs that are feasible. For the Annual FTR Auction, known transmission outages that are expected to last for two months or more are included, while known outages of five days or more are included for the Monthly Balance of Planning Period FTR Auctions as well as any outages of a shorter duration that PJM determines would cause FTR revenue inadequacy if not modeled.[8] But, the auction process does not account for the fact that significant transmission outages, which have not been provided to PJM by transmission owners prior to the auction date, will occur during the periods covered by the auctions. Such transmission outages may not be planned in advance or may be emergency in nature. FTRs can be traded between market participants through bilateral transactions.

During the 2009 to 2010 planning period, binding transmission constraints prevented the award of all requested FTRs in the Long Term FTR Auction, the Annual FTR Auction and Monthly Balance of Planning Period FTR Auctions.[9] Table 8-1 and Table 8-2 list the top 10 binding constraints along with their corresponding control zones in the Long Term FTR Auction and the Annual FTR Auction, respectively. They are listed in order of severity, irrespective of auction round. For each of the top 10 binding constraints, a numerical ranking in order of severity for each auction round is also listed. The order of severity is determined by the marginal value of the binding constraint. The marginal value measures the value gained by relieving a constraint by 1 MW. The marginal value is computed and generated in the optimization engine for both on peak and off peak hours.[10] Table 8-1 and Table 8-2 demonstrate the marginal value for on peak hours only.

Table 8-1 Top 10 principal binding transmission constraints limiting the Long Term FTR Auction: Planning periods 2010 to 2013[11]

			Severity Ranking by Auction Round	
Constraint	Type	Control Zone	1	2
Carroll	Transformer	AP	1	NA
Philipsburg - Shawville	Line	PENELEC	21	1
Smith - Wylie Ridge	Line	AP	NA	2
Oak Grove - Galesburg	Flowgate	External	2	3
MECS - IMO	Flowgate	External	46	4
Arnold - Hazleton	Flowgate	External	52	5
Roxbury - Shade Gap	Line	PENELEC	3	8
Doubs - Mount Storm	Line	500	4	19
Bull Run - Volunteer	Line	AEP	5	58
Branchburg - Ramapo	Line	PSEG	6	25

7 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 38.
8 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 54.
9 Binding constraints for Monthly Balance of Planning Period Auctions are posted to the PJM website in monthly files at <http://www.pjm.com/markets-and-operations/ftr/auction-user-info/historical-ftr-auction.aspx>.
10 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 57.
11 The transmission facilities that were not constrained during a certain auction round are listed as NA (not applicable).

Table 8-2 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2009 to 2010

			Severity Ranking by Auction Round			
Constraint	Type	Control Zone	1	2	3	4
AP South	Interface	AP	1	1	1	1
Mahans Lane - Tidd	Line	AEP	2	3	2	2
Albright - Mt. Zion	Line	AP	36	2	7	13
Kingwood - Pruntytown	Line	AP	22	4	3	5
Mount Storm - Pruntytown	Line	AP	3	6	4	4
Pana North	Flowgate	External	8	5	6	3
Mt. Jackson - Edinburg	Line	Dominion	4	7	9	6
Monroe - Shieldalloy	Line	AECO	5	10	8	7
Tiltonsville - Windsor	Line	AP	9	9	5	8
Keisters - Campbell OE	Flowgate	External	10	8	45	166

Long Term FTR Auction

During the 2008 to 2009 planning period, a new Long Term FTR Auction was introduced.[12] PJM conducts a Long Term FTR Auction for the three consecutive planning periods immediately following the planning period during which the Long Term FTR Auction is conducted. The capacity offered for sale in Long Term FTR Auctions is the residual system capability after the assumption that all ARRs allocated in the immediately prior annual ARR allocation process are self scheduled as FTRs. These ARRs are modeled as fixed injections and withdrawals in the Long Term FTR Auction. Future transmission upgrades are not included in the model. The Long Term FTR Auction consists of two rounds. In each round 50 percent of the feasible FTR available capability is awarded.[13]

- **Round 1.** The first round is conducted approximately 11 months prior to the start of the term covered by the Long Term FTR Auction. Market participants make offers for FTRs between any source and sink. These offers can be 24-hour, on peak or off peak FTR obligations. FTR option products are not available in Long Term FTR Auctions.

- **Round 2.** The second round is conducted approximately 4 months after the first round.[14] FTRs purchased in the first round may be offered for sale in the second round.

FTRs obtained in the Long Term Auctions may have terms of one year or a term of three years.

12 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to its Open Access Transmission Tariff and the Amended and Restated Operating Agreement pursuant to Section 205 of the Federal Power Act. The proposed revisions modify the FTR auction rules in the PJM Interchange Energy Market by establishing a Long Term FTR Auction process, Docket No. ER08-1016-000, (May 28, 2008).

13 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 38.

14 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 42.

Annual FTR Auction

Each April, PJM conducts an Annual FTR Auction during which all eligible market participants may bid on FTRs for the next planning period consistent with total transmission system capability, excluding the FTRs approved in prior Long Term FTR Auctions. The auction takes place over four rounds with 25 percent of the feasible transmission system capability awarded in each round:

- **Round 1.** Market participants make offers for FTRs between any source and sink. These offers can be 24-hour, on peak or off peak FTR obligations or FTR options. Locational prices are determined by maximizing the net revenue based on offer-based value of FTRs.[15] Any transmission service customer or PJM member can bid for available FTRs. ARR holders wishing to directly convert their previously allocated ARRs into self scheduled FTRs must initiate that process in this round. One quarter of each self scheduled FTR clears as a 24-hour FTR in each of the four rounds. Self scheduled FTRs must have the same source and sink as the corresponding ARR. Self scheduled FTRs clear as price-taking FTR bids that are not eligible to set auction price.

- **Rounds 2 to 4.** Market participants make offers for FTRs. Locational prices are determined by maximizing the offer-based value of FTRs cleared. FTRs purchased in earlier rounds can be offered for sale in later rounds.

By self scheduling ARRs as price-taking bids in the Annual FTR Auction, customers with ARRs receive FTRs for their ARR paths. ARR holders are guaranteed that they will receive their requested FTRs. ARRs can be self scheduled only as 24-hour FTR obligations. ARR holders that self schedule ARRs as FTRs still hold the associated ARR. Self scheduling transactions net out such that the ARR holder buys the FTR in the auction, receives the corresponding revenue based on holding the ARR and is left with ownership of the FTR as a hedge. The following is an illustrative example of self scheduling ARRs as FTRs. An ARR holder has received an allocation of 1 MW from source A to sink B. The ARR holder self schedules the 1 MW allocated ARR as an FTR. In the Annual FTR Auction, the price for a 1 MW FTR from A to B is $100. The ARR holder pays $100 to buy the 1 MW FTR in the Annual FTR Auction, but receives a $100 ARR target credit based on the associated 1 MW ARR. In addition, the ARR holder obtains the corresponding FTR target allocation as a hedge.

Monthly Balance of Planning Period FTR Auctions

The Monthly Balance of Planning Period FTR Auctions make available the residual FTR capability on the PJM transmission system after the Long Term and Annual FTR Auctions are concluded. They are single-round monthly auctions that allow any transmission service customers or PJM members to bid for any FTR or to offer for sale any FTR that they currently hold. Market participants can bid for or offer monthly FTRs for any of the next three months remaining in the planning period, or quarterly FTRs for any of the quarters remaining in the balance of the planning period. FTRs in the auctions can be either obligations or options and can be 24-hour, on peak or off peak products.[16]

15 Long Term, Annual and Monthly Balance of Planning Period FTR Auctions determine nodal prices as a function of market participants' FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces maximum net revenue, thus maximizing the value of transmission assets. A feasible set of FTR bids is a set that does not impose a flow on any transmission facility in excess of its rating.

16 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 39.

Under the auction rules, market participants may bid to buy or offer to sell FTRs that have the following two terms. The first term is for one month for any of the next three months remaining in the planning period. For example, if the auction is conducted in May, any FTR valid for the months of June, July and August is included in the auction. The second term is for three months for any of the quarters remaining in the planning period (if technically feasible within the specified market time frame). For example, for planning period quarter 1 (Q1), the auction period would be June, July and August. For planning period quarter 2 (Q2), the auction period would be September, October and November. Similarly, December, January and February would be for planning period quarter 3 (Q3) and March, April and May would be for planning period quarter 4 (Q4). For example, an auction held in May would have all four quarters available, while an auction held in June would include quarter 2, quarter 3 and quarter 4, but not quarter 1.

Secondary Bilateral Market

Market participants can buy and sell existing FTRs through the PJM-administered, bilateral market, or market participants can trade FTRs among themselves without PJM involvement. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions that are done outside of PJM's secondary bilateral market system.

For bilateral trades done through PJM, the FTR transmission path must remain the same; FTR obligations must remain obligations and FTR options must remain options. However, an individual FTR may be split up into multiple, smaller FTRs, down to increments of 0.1 MW. FTRs can also be given different start and end times, but the start time cannot be earlier than the original FTR start time and the end time cannot be later than the original FTR end time.

Demand

Under current rules, participants may submit unlimited bids for FTRs for any single auction round in the Annual FTR Auction or for any single Monthly Balance of Planning Period FTR Auction.

FTR Credit Issues

Default

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.[17] Effective June 1, 2009, PJM performs weekly rather than monthly billing 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

17 127 FERC ¶ 61,017. In 2008, the FERC approved a number of PJM's earlier revisions. 122 FERC ¶ 61,279.

it to close out and liquidate forward FTR positions held by market participants who have defaulted on their obligations.

Prevailing flow FTRs hedge congestion on a path. Participants purchase prevailing flow FTRs for a positive price with the expectation that the FTR revenues will exceed the cost of the FTRs. Counter flow FTRs expose the owner to paying congestion on a path. Participants receive a payment to take counter flow FTRs with the expectation that the payment will exceed the FTR charges they must pay. The risk of a prevailing flow FTR is generally limited to the purchase price, although risk could increase if congestion reversed. The risk of a counter flow FTR derives from the underlying congestion and is, therefore, not limited to a fixed payment. The risk is substantially greater for a counter flow FTR than for a prevailing flow FTR.

FTR Credit Rules

In response to a series of high profile defaults, PJM began in 2007 an effort to reform its credit policies that continued into 2009.[18] On February 3, 2009, PJM proposed tariff revisions that would reduce the per member allowance of unsecured credit by two thirds, limit the unsecured credit allowance for a family of affiliates to an aggregate $150 million, eliminate unsecured credit allowances for FTR trading activity, shorten settlement periods by transitioning to weekly from monthly billing for invoice line items that represent most of PJM's billings, and allow PJM to close and liquidate a member's FTR positions after a declaration of that member's default.[19]

By order issued April 3, 2009, the Commission accepted PJM's revisions subject to conditions.[20] The provisions concerning the FTR market, including the elimination of unsecured credit in those markets, became effective April 6, 2009.[21] The Commission conditioned its approval on PJM's filing and justifying revisions to allow appropriate collateral reductions for LSEs having physical assets that reduce the risk of default. PJM filed revisions on May 4, 2009, proposing to (i) allow 25 percent of current planning year ARR credits to offset each planning year's undiversified credit requirement in the Long Term FTR auctions and (ii) qualify the definition and calculation of "FTR Portfolio Auction Value" to exclude negatively priced FTRs that sink at such an LSE's location (as determined from the effective ARR allocation) and to require that the MW quantity of FTRs not exceed the peak load of the LSE at each location.[22] The Commission found PJM's filing deficient, and requested responses to questions by letter dated October 8, 2009. PJM responded in a submittal dated November 9, 2009. Further action on PJM's filing is now pending before the FERC.

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.[23]

18 See the *2008 State of the Market Report for PJM* at 393 through 395 for discussion of reforms made effective in 2007 through 2008.
19 PJM filed proposed revisions to Attachment Q in Docket No. ER09-650-000.
20 127 FERC ¶61,017.
21 *Id.* at 30.
22 PJM Compliance filing in ER09-650-002 at 3–4.
23 PJM has indicated, as part of its Counterparty Initiative, that its ability to assert claims for deficiencies in a bankruptcy proceeding may be further compromised by its current lack of privity in such transactions insofar as this affects the ability to net credits and charges. *See, e.g.*, presentation of Suzanne Daugherty and Vincent Duane to the October 22, 2009 meeting of the PJM Tariff Advisory Committee, "Counterparty Initiative—Follow-up Items from First Information Session", which can be accessed at the following link: <http://www.pjm.com/~/media/committees-groups/committees/tac/20091022/20091022-item-02a-counterparty-initiative-second-information-session.ashx>.

Patterns of Ownership

The overall ownership structure of FTRs and the ownership of prevailing flow and counter flow FTRs is descriptive and is not necessarily a measure of actual or potential FTR market structure issues, as the ownership positions result from competitive auctions. The percentage of FTR ownership shares may change when FTR owners buy or sell FTRs in the Monthly Balance of Planning Period FTR Auctions or secondary bilateral market.

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.

For cleared FTR buy-bid obligations in the 2009 to 2010 Annual FTR Auction, the HHIs were 1038 for 24-hour, 821 for on peak and 835 for off peak FTR products while maximum market shares were 20 percent for 24-hour, which is associated with a physical entity, 14 percent for on peak, which is associated with a financial entity, and 13 percent for off peak FTR products, which is associated with a financial entity.

For cleared FTR buy-bid options in the 2009 to 2010 Annual FTR Auction, HHIs were 4399 for 24-hour, 1868 for on peak and 2040 for off peak products while maximum market shares were 58 percent for 24-hour, which is associated with a physical entity, 27 percent for on peak, which is associated with a financial entity, and 31 percent for off peak FTR products, which is associated with a financial entity.

In order to evaluate 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. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 8-3 presents the 2010 to 2013 Long Term FTR Auction market cleared FTRs by organization type and FTR direction. The results show that financial entities own 77 percent of prevailing flow FTRs and 80 percent of counter flow FTRs. Overall, financial entities own about 78 percent of all Long Term FTRs.

Table 8-3 Long Term FTR Auction patterns of ownership by FTR direction: Planning periods 2010 to 2013

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	23.3%	20.4%	22.0%
Financial	76.7%	79.6%	78.0%
Total	100.0%	100.0%	100.0%

Table 8-4 presents the Annual FTR Auction market cleared FTRs in the 2009 to 2010 planning period by organization type and FTR direction. The results show that physical entities own 61 percent of prevailing flow FTRs while financial entities own 57 percent counter flow FTRs. Overall, financial entities own about 43 percent of all Annual FTRs.

Table 8-4 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2009 to 2010

		FTR Direction		
Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Physical	Yes	36.7%	5.9%	29.6%
	No	24.4%	36.8%	27.3%
	Total	61.2%	42.7%	56.9%
Financial	No	38.8%	57.3%	43.1%
Total		100.0%	100.0%	100.0%

Table 8-5 presents the Monthly Balance of Planning Period FTR Auction market cleared FTRs in calendar year 2009 by organization type and FTR direction. The results show that financial entities own 68 percent of prevailing flow FTRs and 82 percent of counter flow FTRs. Overall, financial entities own 74 percent of all Monthly Balance of Planning Period FTRs.

Table 8-5 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: Calendar year 2009

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	32.3%	18.2%	26.3%
Financial	67.7%	81.8%	73.7%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

Table 8-6 shows the 2010 to 2013 Long Term FTR Auction volume by trade type, FTR direction and period type.[24] The total volume was 1,064,620 MW for FTR buy bids and 51,582 MW for FTR sell offers in the 2010 to 2013 Long Term FTR Auction. This is up from the total volume of 803,911 MW for FTR buy bids and 15,757 MW for FTR sell offers in the 2009 to 2012 Long Term FTR Auction.

The 2010 to 2013 Long Term FTR Auction cleared 86,108 MW (8.1 percent) leaving 978,513 MW (91.9 percent) of uncleared FTR buy bids. There were 5,147 MW (10.0 percent) of cleared FTR sell offers leaving 46,435 MW (90.0 percent) of uncleared FTR sell offers. This is up from the total of 52,369 MW (6.5 percent) of cleared FTR buy bids and 1,010 MW (6.4 percent) of cleared FTR sell offers in the 2009 to 2012 Long Term FTR Auction.

In the 2010 to 2013 Long Term FTR Auction, there were 38,000 MW (14.0 percent) cleared out of 271,944 MW counter flow FTR buy bids and 48,108 MW (6.1 percent) cleared out of 792,676 MW prevailing flow FTR buy bids. In the 2010 to 2013 Long Term FTR Auction, there were 2,225 MW

24 Calculated values shown in Section 8, "Financial Transmission and Auction Revenue Rights," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

(13.7 percent) cleared out of 16,210 MW counter flow FTR sell offers and 2,922 MW (8.3 percent) cleared out of 35,373 MW prevailing flow FTR offers.

Table 8-6 Long Term FTR Auction market volume: Planning periods 2010 to 2013

Trade Type	FTR Direction	Period Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Counter Flow	Year 1	34,672	129,869	17,627	13.6%	112,241	86.4%
		Year 2	15,258	93,733	9,849	10.5%	83,884	89.5%
		Year 3	12,569	47,954	10,517	21.9%	37,437	78.1%
		Year All	25	389	7	1.7%	382	98.3%
		Total	62,524	271,944	38,000	14.0%	233,944	86.0%
	Prevailing Flow	Year 1	68,326	313,683	17,779	5.7%	295,904	94.3%
		Year 2	49,950	252,781	15,206	6.0%	237,574	94.0%
		Year 3	43,037	226,172	15,102	6.7%	211,070	93.3%
		Year All	7	40	20	50.0%	20	50.0%
		Total	161,320	792,676	48,108	6.1%	744,568	93.9%
	Total		223,844	1,064,620	86,108	8.1%	978,513	91.9%
Sell offers	Counter Flow	Year 1	2,503	7,800	1,473	18.9%	6,327	81.1%
		Year 2	1,468	5,190	727	14.0%	4,462	86.0%
		Year 3	1,032	3,220	25	0.8%	3,195	99.2%
		Year All	NA	NA	NA	NA	NA	NA
		Total	5,003	16,210	2,225	13.7%	13,985	86.3%
	Prevailing Flow	Year 1	4,445	17,211	1,552	9.0%	15,659	91.0%
		Year 2	3,367	13,294	1,191	9.0%	12,103	91.0%
		Year 3	1,267	4,868	179	3.7%	4,689	96.3%
		Year All	NA	NA	NA	NA	NA	NA
		Total	9,079	35,373	2,922	8.3%	32,451	91.7%
	Total		14,082	51,582	5,147	10.0%	46,435	90.0%

Table 8-7 shows the Annual FTR Auction volume by trade type, hedge type and FTR direction for the 2009 to 2010 planning period. The total volume was 1,436,335 MW for FTR buy bids and 142,154 MW for FTR sell offers for the 2009 to 2010 planning period. This is down from the total volume of 2,181,273 MW for FTR buy bids and up from 83,453 MW for FTR sell offers for the 2008 to 2009 planning period.

There were 155,612 MW (10.8 percent) of cleared FTR buy bids and 7,399 MW (5.2 percent) of cleared FTR sell offers for the 2009 to 2010 planning period. This is down from the total of 204,349 MW (9.4 percent) of cleared FTR buy bids and up from 4,534 MW (5.4 percent) of cleared FTR sell offers for the 2008 to 2009 planning period.

For the 2009 to 2010 planning period, there were 48,017 MW (15.6 percent) cleared out of 307,750 MW counter flow FTR buy bids and 107,595 MW (9.5 percent) cleared out of 1,128,585 MW prevailing flow FTR buy bids. During the 2009 to 2010 planning period, there were 2,390 MW (5.3 percent) cleared out of 44,772 MW counter flow FTR sell offers and 5,009 MW (5.1 percent) cleared out of 97,381 MW prevailing flow FTR offers.

Table 8-7 Annual FTR Auction market volume: Planning period 2009 to 2010

Trade Type	Hedge Type	FTR Direction	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Obligations	Counter Flow	80,464	304,889	45,356	14.9%	259,533	85.1%
		Prevailing Flow	179,814	986,613	84,161	8.5%	902,452	91.5%
		Total	260,278	1,291,502	129,517	10.0%	1,161,985	90.0%
	Options	Counter Flow	26	2,861	2,661	93.0%	200	7.0%
		Prevailing Flow	6,242	141,972	23,433	16.5%	118,538	83.5%
		Total	6,268	144,833	26,095	18.0%	118,738	82.0%
	Total	Counter Flow	80,490	307,750	48,017	15.6%	259,733	84.4%
		Prevailing Flow	186,056	1,128,585	107,595	9.5%	1,020,990	90.5%
		Total	266,546	1,436,335	155,612	10.8%	1,280,723	89.2%
Self-scheduled bids	Obligations	Counter Flow	620	3,175	3,175	100.0%	0	0.0%
		Prevailing Flow	8,796	65,414	65,414	100.0%	0	0.0%
		Total	9,416	68,589	68,589	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	81,084	308,064	48,531	15.8%	259,533	84.2%
		Prevailing Flow	188,610	1,052,027	149,576	14.2%	902,452	85.8%
		Total	269,694	1,360,091	198,107	14.6%	1,161,985	85.4%
	Options	Counter Flow	26	2,861	2,661	93.0%	200	7.0%
		Prevailing Flow	6,242	141,972	23,433	16.5%	118,538	83.5%
		Total	6,268	144,833	26,095	18.0%	118,738	82.0%
	Total	Counter Flow	81,110	310,925	51,192	16.5%	259,733	83.5%
		Prevailing Flow	194,852	1,193,999	173,009	14.5%	1,020,990	85.5%
		Total	275,962	1,504,924	224,201	14.9%	1,280,723	85.1%
Sell offers	Obligations	Counter Flow	13,789	42,950	2,390	5.6%	40,560	94.4%
		Prevailing Flow	21,608	83,797	4,869	5.8%	78,929	94.2%
		Total	35,397	126,747	7,259	5.7%	119,489	94.3%
	Options	Counter Flow	19	1,822	0	0.0%	1,822	100.0%
		Prevailing Flow	940	13,584	140	1.0%	13,444	99.0%
		Total	959	15,406	140	0.9%	15,266	99.1%
	Total	Counter Flow	13,808	44,772	2,390	5.3%	42,382	94.7%
		Prevailing Flow	22,548	97,381	5,009	5.1%	92,372	94.9%
		Total	36,356	142,154	7,399	5.2%	134,755	94.8%

Table 8-8 shows that for the 2009 to 2010 planning period, eligible market participants converted 68,589 MW of ARRs out of a possible 109,413 MW into Annual FTRs. In comparison, during the 2008 to 2009 planning period, eligible market participants converted 72,851 MW of ARRs out of a possible 112,011 MW.

Table 8-8 Comparison of self scheduled FTRs: Planning periods 2008 to 2009 and 2009 to 2010

Planning Period	Self-Scheduled FTRs (MW)	Maximum Possible Self-Scheduled FTRs (MW)	Percent of ARRs Self-Scheduled as FTRs
2008/2009	72,851	112,011	65.0%
2009/2010	68,589	109,413	62.7%

Table 8-9 shows that there were 5,166,634 MW of FTR buy bid obligations and 1,621,113 MW of FTR sell offer obligations for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2009 to 2010 planning period through December 31, 2009. The monthly auctions cleared 555,727 MW (10.8 percent) leaving 4,610,907 MW (89.2 percent) of uncleared FTR buy bid obligations. There were 129,451 MW (8.0 percent) of cleared FTR sell offer obligations leaving 1,491,662 MW (92.0 percent) of uncleared FTR sell offer obligations.

There were 173,184 MW of FTR buy bid options and 341,723 MW of FTR sell offer options for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2009 to 2010 planning period through December 31, 2009. The monthly auctions cleared 13,015 MW (7.5 percent) leaving 160,169 MW (92.5 percent) of uncleared FTR buy bid options. There were 47,846 MW (14.0 percent) of cleared FTR sell offer options leaving 293,878 MW (86.0 percent) of uncleared FTR sell offer options.

The Monthly Balance of Planning Period FTR Auctions for the full 12-month 2008 to 2009 planning period had a total demand of 10,223,437 MW for FTR buy bids and 2,172,401 MW for FTR sell offers. The monthly auctions cleared 804,215 MW (7.9 percent) of FTR buy bids and 258,747 MW (11.9 percent) of FTR sell offers.

Table 8-9 Monthly Balance of Planning Period FTR Auction market volume: Calendar year 2009

Monthly Auction	Hedge Type	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-09	Obligations	Buy bids	166,943	648,482	59,472	9.2%	589,011	90.8%
		Sell offers	36,552	172,413	17,489	10.1%	154,924	89.9%
	Options	Buy bids	473	25,043	3,628	14.5%	21,415	85.5%
		Sell offers	475	13,010	1,871	14.4%	11,139	85.6%
Feb-09	Obligations	Buy bids	167,297	613,252	54,064	8.8%	559,188	91.2%
		Sell offers	33,278	135,132	13,663	10.1%	121,469	89.9%
	Options	Buy bids	1,000	26,021	1,408	5.4%	24,613	94.6%
		Sell offers	399	11,925	1,370	11.5%	10,555	88.5%
Mar-09	Obligations	Buy bids	153,613	542,094	54,409	10.0%	487,685	90.0%
		Sell offers	43,579	176,838	14,931	8.4%	161,907	91.6%
	Options	Buy bids	738	38,982	4,626	11.9%	34,356	88.1%
		Sell offers	472	12,300	1,382	11.2%	10,918	88.8%
Apr-09	Obligations	Buy bids	121,034	417,636	49,603	11.9%	368,034	88.1%
		Sell offers	31,574	131,945	12,924	9.8%	119,021	90.2%
	Options	Buy bids	204	22,992	614	2.7%	22,379	97.3%
		Sell offers	353	8,776	1,607	18.3%	7,168	81.7%
May-09	Obligations	Buy bids	79,272	285,448	31,020	10.9%	254,428	89.1%
		Sell offers	19,030	70,521	8,843	12.5%	61,678	87.5%
	Options	Buy bids	131	9,750	183	1.9%	9,567	98.1%
		Sell offers	195	2,585	1,345	52.0%	1,240	48.0%
Jun-09	Obligations	Buy bids	202,097	807,023	72,951	9.0%	734,073	91.0%
		Sell offers	79,699	276,795	24,514	8.9%	252,281	91.1%
	Options	Buy bids	734	40,968	2,552	6.2%	38,416	93.8%
		Sell offers	5,377	69,781	11,567	16.6%	58,214	83.4%
Jul-09	Obligations	Buy bids	196,831	802,217	67,977	8.5%	734,240	91.5%
		Sell offers	79,359	300,588	22,533	7.5%	278,055	92.5%
	Options	Buy bids	547	47,525	2,954	6.2%	44,570	93.8%
		Sell offers	4,264	60,406	7,011	11.6%	53,396	88.4%
Aug-09	Obligations	Buy bids	202,379	702,162	76,065	10.8%	626,096	89.2%
		Sell offers	70,434	245,516	17,981	7.3%	227,535	92.7%
	Options	Buy bids	101	6,290	1,287	20.5%	5,003	79.5%
		Sell offers	3,264	48,784	4,111	8.4%	44,673	91.6%
Sep-09	Obligations	Buy bids	173,626	681,422	79,711	11.7%	601,711	88.3%
		Sell offers	67,180	237,135	18,347	7.7%	218,788	92.3%
	Options	Buy bids	474	36,824	2,180	5.9%	34,644	94.1%
		Sell offers	3,565	53,891	6,546	12.1%	47,345	87.9%
Oct-09	Obligations	Buy bids	198,431	783,022	85,207	10.9%	697,815	89.1%
		Sell offers	62,543	216,852	15,759	7.3%	201,093	92.7%
	Options	Buy bids	293	14,047	1,317	9.4%	12,730	90.6%
		Sell offers	2,529	41,741	6,436	15.4%	35,305	84.6%
Nov-09	Obligations	Buy bids	184,294	729,780	82,710	11.3%	647,070	88.7%
		Sell offers	46,896	155,974	12,043	7.7%	143,931	92.3%
	Options	Buy bids	463	15,553	1,679	10.8%	13,874	89.2%
		Sell offers	1,943	29,609	6,769	22.9%	22,840	77.1%
Dec-09	Obligations	Buy bids	157,014	661,008	91,106	13.8%	569,902	86.2%
		Sell offers	52,471	188,253	18,275	9.7%	169,978	90.3%
	Options	Buy bids	367	11,978	1,046	8.7%	10,932	91.3%
		Sell offers	2,278	37,512	5,407	14.4%	32,105	85.6%
2008/2009*	Obligations	Buy bids	2,143,034	9,449,644	782,007	8.3%	8,667,637	91.7%
		Sell offers	504,152	1,991,496	226,544	11.4%	1,764,952	88.6%
	Options	Buy bids	11,754	773,793	22,209	2.9%	751,584	97.1%
		Sell offers	6,550	180,904	32,203	17.8%	148,701	82.2%
2009/2010**	Obligations	Buy bids	1,314,672	5,166,634	555,727	10.8%	4,610,907	89.2%
		Sell offers	458,582	1,621,113	129,451	8.0%	1,491,662	92.0%
	Options	Buy bids	2,979	173,184	13,015	7.5%	160,169	92.5%
		Sell offers	23,220	341,723	47,846	14.0%	293,878	86.0%

* Shows Twelve Months for 2008/2009; ** Shows seven months ended 31-Dec-2009 for 2009/2010

Table 8-10 shows the bid and cleared volume for FTR buy bids in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2009 through December 2009.

Table 8-10 Monthly Balance of Planning Period FTR Auction buy-bid bid and cleared volume (MW per period): Calendar year 2009

Monthly Auction	MW Type	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-09	Bid	299,268	129,139	99,968				145,151	673,525
	Cleared	41,932	9,425	3,985				7,758	63,100
Feb-09	Bid	311,274	106,999	93,220				127,781	639,274
	Cleared	37,183	6,216	5,347				6,727	55,472
Mar-09	Bid	305,146	120,085	115,103				40,741	581,075
	Cleared	41,859	8,073	6,687				2,415	59,034
Apr-09	Bid	306,763	133,866						440,629
	Cleared	41,884	8,332						50,216
May-09	Bid	295,198							295,198
	Cleared	31,204							31,204
Jun-09	Bid	283,451	121,774	119,403	24,320	104,418	102,266	92,358	847,992
	Cleared	33,822	9,100	8,599	2,500	7,967	7,524	5,991	75,503
Jul-09	Bid	306,644	133,812	95,573		100,333	107,062	106,318	849,742
	Cleared	38,785	8,346	3,991		5,869	6,325	7,615	70,932
Aug-09	Bid	314,301	85,842	75,477		69,309	79,140	84,383	708,452
	Cleared	47,960	6,627	6,057		4,214	5,276	7,219	77,353
Sep-09	Bid	342,826	89,939	86,533		22,245	90,764	85,939	718,246
	Cleared	52,579	7,095	6,539		2,150	6,268	7,260	81,891
Oct-09	Bid	464,697	91,286	76,482			85,335	79,268	797,069
	Cleared	58,957	9,039	5,096			6,019	7,413	86,524
Nov-09	Bid	409,943	78,942	76,920			96,707	82,822	745,333
	Cleared	57,249	5,494	6,121			7,423	8,102	84,389
Dec-09	Bid	351,985	101,436	98,036			24,867	96,662	672,986
	Cleared	55,233	10,906	9,364			3,379	13,269	92,152

Table 8-11 shows the secondary bilateral FTR market volume and weighted-average cleared prices by hedge type and class type for the 2008 to 2009 and the 2009 to 2010 planning periods. There were 1,643 MW of total bilateral FTR activity for the 2009 to 2010 planning period through December 31, 2009 while there were 1,948 MW during the 2008 to 2009 planning period. During the 2009 to 2010 planning period through December 31, 2009, the weighted-average prices of bilateral FTR obligations and options were $0.37 per MWh and $5.93 per MWh, respectively. Comparable weighted-average prices were $0.59 per MWh for bilateral FTR obligations and $6.25 per MWh for bilateral FTR options for the 2008 to 2009 planning period.

Table 8-11 Secondary bilateral FTR market volume and weighted-average cleared prices (Dollars per MWh): Planning periods 2008 to 2009 and 2009 to 2010[25]

Planning Period	Hedge Type	Class Type	Volume (MW)	Price
2008/2009	Obligation	24-Hour	800	$0.46
		On Peak	1,133	$1.14
		Off Peak	9	$0.84
		Total	1,942	$0.59
	Option	24-Hour	0	NA
		On Peak	6	$6.25
		Off Peak	0	NA
		Total	6	$6.25
2009/2010*	Obligation	24-Hour	1,468	$0.38
		On Peak	20	($0.23)
		Off Peak	125	($1.79)
		Total	1,613	$0.37
	Option	24-Hour	30	$5.93
		On Peak	0	NA
		Off Peak	0	NA
		Total	30	$5.93

* Shows seven months ended 31-Dec-2009

Price

Table 8-12 shows the cleared, weighted-average prices by trade type, FTR direction, period type and class type for the 2010 to 2013 Long Term FTR Auction. Only FTR obligation products are available in Long Term FTR Auctions. In this auction, weighted-average, buy-bid FTR prices were $0.10 per MWh while weighted-average sell offer FTR prices were $0.35 per MWh. Comparable weighted-average, buy-bid FTR prices were $0.16 per MWh while weighted-average sell offer FTR prices were $0.29 per MWh in the 2009 to 2012 Long Term FTR Auction.

25 The 2009 to 2010 planning period covers the 2009 to 2010 Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions through the December 2009 FTR Auction.

Table 8-12 Long Term FTR Auction weighted-average cleared prices (Dollars per MWh): Planning periods 2010 to 2013

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($1.62)	($0.32)	($0.46)	($0.54)
		Year 2	($2.48)	($0.38)	($0.50)	($0.58)
		Year 3	($2.34)	($0.24)	($0.36)	($0.38)
		Year All	($1.80)	NA	NA	($1.80)
		Total	($1.88)	($0.31)	($0.44)	($0.51)
	Prevailing Flow	Year 1	$3.16	$0.40	$0.62	$0.73
		Year 2	$3.35	$0.25	$0.44	$0.56
		Year 3	$2.19	$0.27	$0.38	$0.43
		Year All	$3.91	$2.62	$5.37	$3.64
		Total	$3.00	$0.31	$0.49	$0.59
	Total		$0.53	$0.03	$0.10	$0.10
Sell offers	Counter Flow	Year 1	($0.18)	($0.02)	($0.03)	($0.02)
		Year 2	NA	($0.01)	($0.01)	($0.01)
		Year 3	NA	($0.09)	($0.09)	($0.09)
		Year All	NA	NA	NA	NA
		Total	($0.18)	($0.02)	($0.03)	($0.02)
	Prevailing Flow	Year 1	$0.51	$0.39	$0.66	$0.55
		Year 2	NA	$0.50	$1.06	$0.78
		Year 3	NA	$0.69	$0.47	$0.57
		Year All	NA	NA	NA	NA
		Total	$0.51	$0.46	$0.80	$0.64
	Total		$0.47	$0.23	$0.47	$0.35

The 2010 to 2013 Long Term FTR Auction price duration curve for cleared buy bids in Figure 8-1 shows that 93.7 percent of Long Term FTRs were purchased for less than $1 per MWh, 96.6 percent for less than $2 per MWh and 97.2 percent for less than $3 per MWh. Negative prices occur because some FTRs are bid with negative prices and some winning FTR bidders are paid to take FTRs (counter flow FTRs).

Figure 8-1 Long Term FTR auction clearing price duration curve: Planning periods 2010 to 2013

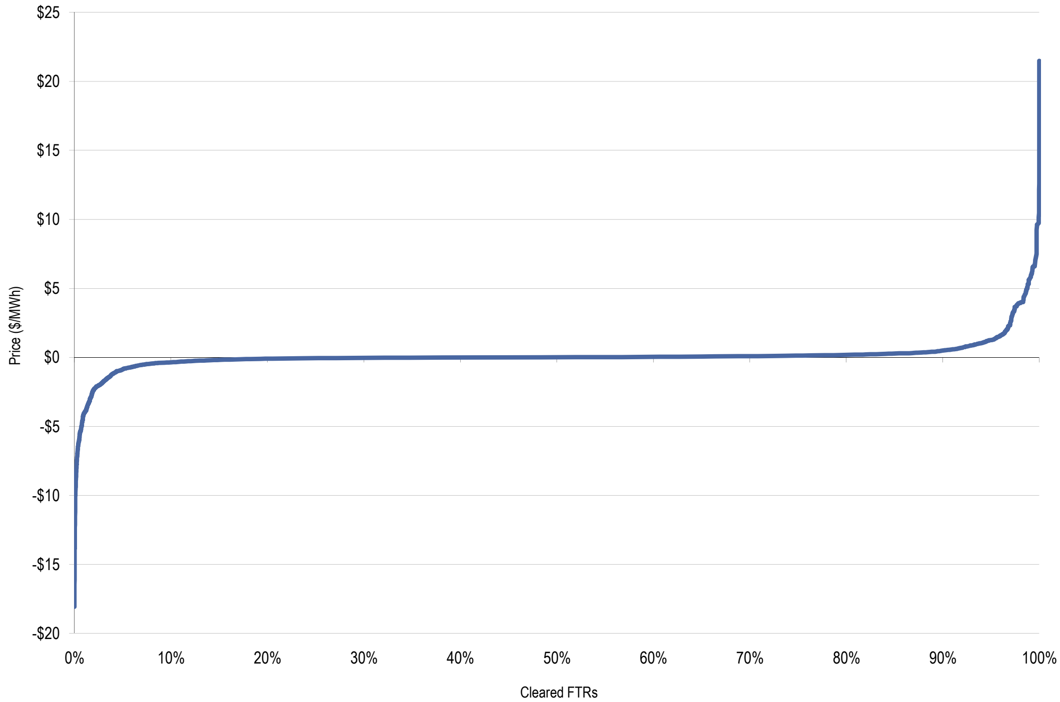


Table 8-13 shows the cleared, weighted-average prices by trade type, hedge type, FTR direction and class type for Annual FTRs during the 2009 to 2010 planning period. For the 2009 to 2010 planning period, weighted-average, buy-bid FTR obligation prices were $0.53 per MWh while weighted-average, buy-bid FTR option prices were $0.35 per MWh. Comparable weighted-average prices for the 2008 to 2009 planning period were $0.69 per MWh for buy-bid FTR obligations and $0.24 per MWh for buy-bid FTR options.

During the 2009 to 2010 planning period, weighted-average sell offer FTR obligation prices were $0.28 per MWh while weighted-average sell offer FTR option prices were $0.11 per MWh. Comparable weighted-average prices for the 2008 to 2009 planning period were $0.86 per MWh for sell offer FTR obligations and $0.84 per MWh for sell offer FTR options.

On average during the 2009 to 2010 planning period in the Annual FTR Auction, self scheduled FTRs were priced $1.05 per MWh higher than buy-bid obligation FTRs. They were priced $1.25 per MWh less than the cleared, weighted-average price of self scheduled FTRs during the 2008 to 2009 planning period.

During the 2009 to 2010 planning period, weighted-average, buy-bid FTR obligation prices were -$0.58 per MWh for counter flow FTRs and $1.13 per MWh for prevailing flow FTRs. Weighted-average sell offer FTR obligation prices were -$0.42 per MWh for counter flow FTRs and $0.63 per MWh for prevailing flow FTRs during the 2009 to 2010 planning period. On average during the 2009 to 2010 planning period in the Annual FTR Auction, self scheduled counter flow FTRs were priced

$0.26 per MWh higher than buy-bid counter flow obligation FTRs and self scheduled prevailing FTRs were priced $0.54 per MWh higher than buy-bid prevailing flow obligation FTRs.

Table 8-13 Annual FTR Auction weighted-average cleared prices (Dollars per MWh): Planning period 2009 to 2010

			Class Type			
Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.75)	($0.56)	($0.49)	($0.58)
		Prevailing Flow	$1.35	$1.13	$0.95	$1.13
		Total	$0.66	$0.57	$0.40	$0.53
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.53	$0.50	$0.32	$0.41
		Total	$0.18	$0.46	$0.30	$0.35
Self-scheduled bids	Obligations	Counter Flow	($0.32)	NA	NA	($0.32)
		Prevailing Flow	$1.67	NA	NA	$1.67
		Total	$1.58	NA	NA	$1.58
Buy and self-scheduled bids	Obligations	Counter Flow	($0.61)	($0.56)	($0.49)	($0.55)
		Prevailing Flow	$1.62	$1.13	$0.95	$1.44
		Total	$1.37	$0.57	$0.40	$1.03
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.53	$0.50	$0.32	$0.41
		Total	$0.18	$0.46	$0.30	$0.35
Sell offers	Obligations	Counter Flow	($1.76)	($0.24)	($0.37)	($0.42)
		Prevailing Flow	$0.49	$0.80	$0.37	$0.63
		Total	($0.28)	$0.52	$0.06	$0.28
	Options	Counter Flow	NA	NA	NA	NA
		Prevailing Flow	$0.04	$0.03	$0.26	$0.11
		Total	$0.04	$0.03	$0.26	$0.11

The 2009 to 2010 planning period price duration curve for cleared buy bids in Figure 8-2 shows that 83.2 percent of Annual FTRs were purchased for less than $1 per MWh, 90.6 percent for less than $2 per MWh and 93.4 percent for less than $3 per MWh. Negative prices occur because some FTRs are bid with negative prices and some winning FTR bidders are paid to take FTRs. The 2009 to 2010 planning period FTR obligation price duration curve for cleared buy bids in Figure 8-2 shows that 81.7 percent of annual FTR obligations were purchased for less than $1 per MWh, 89.1 percent for less than $2 per MWh and 92.3 percent for less than $3 per MWh. The 2009 to 2010 planning period FTR option price duration curve for cleared buy bids in Figure 8-2 shows that 90.7 percent of annual FTR options were purchased for less than $1 per MWh, 98.0 percent for less than $2 per MWh and 99.0 percent for less than $3 per MWh.

Figure 8-2 Annual FTR auction clearing price duration curves: Planning period 2009 to 2010

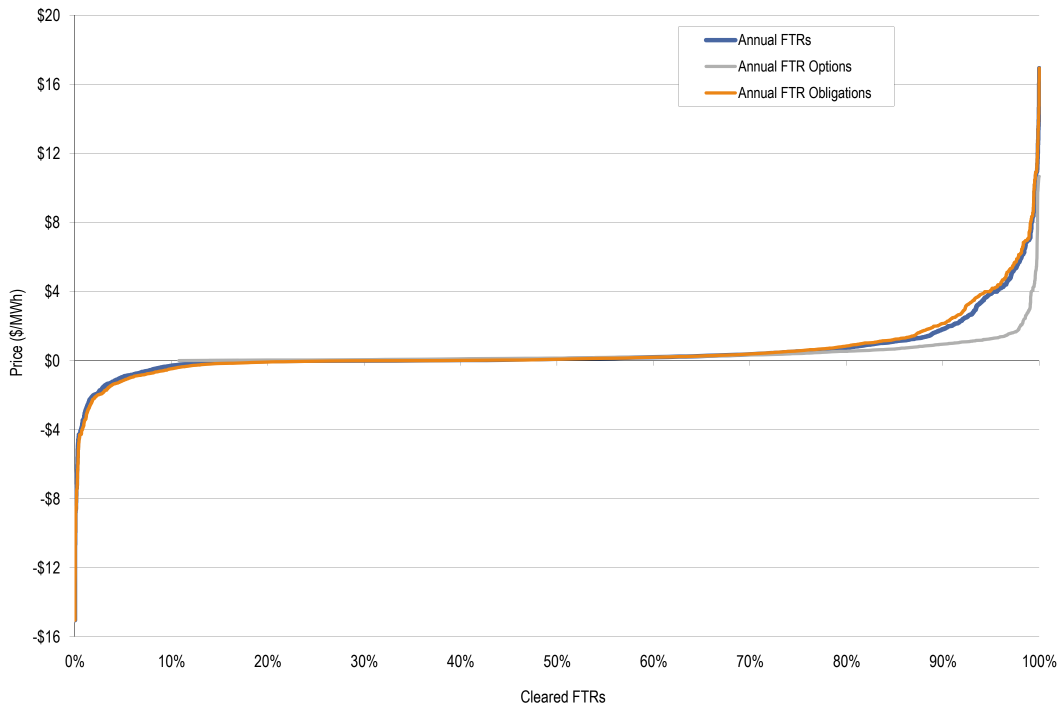


Table 8-14 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2009 through December 2009. For example, for the June 2009 Monthly Balance of Planning Period FTR Auction, the current month column is June, the second month column is July and the third month column is August. Quarters 1 through 4 are represented in the Q1, Q2, Q3 and Q4 columns. The total column represents all of the activity within the June 2009 Monthly Balance of Planning Period FTR Auction.

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

Table 8-14 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MWh): Calendar year 2009

Monthly Auction	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-09	$0.08	$0.18	$0.24				$0.04	$0.09
Feb-09	$0.10	$0.28	$0.21				$0.21	$0.16
Mar-09	$0.11	$0.25	$0.17				$0.55	$0.18
Apr-09	$0.12	$0.24						$0.14
May-09	$0.09							$0.09
Jun-09	$0.17	$0.25	$0.17	$1.16	$0.37	$0.48	$0.46	$0.38
Jul-09	$0.17	$0.40	$0.17		$0.25	$0.31	$0.23	$0.24
Aug-09	$0.06	$0.15	$0.19		$0.16	$0.15	$0.16	$0.12
Sep-09	$0.12	$0.28	$0.23		$0.10	$0.37	$0.34	$0.22
Oct-09	$0.08	$0.15	$0.06			$0.21	$0.18	$0.12
Nov-09	$0.09	$0.07	$0.12			$0.23	$0.26	$0.16
Dec-09	$0.05	$0.13	$0.12			$0.73	$0.16	$0.15

Revenue

Long Term FTR Auction Revenue

Table 8-15 shows Long Term FTR Auction revenue data by trade type, FTR direction, period type, and class type. The 2010 to 2013 Long Term FTR Auction netted $31.14 million in revenue, with buyers paying $39.11 million and sellers receiving $7.97 million. The 2009 to 2012 Long Term FTR Auction netted $38.93 million in revenue, with buyers paying $40.21 million and sellers receiving $1.28 million.

For the 2010 to 2013 Long Term FTR Auction, the counter flow FTRs netted -$87.68 million in revenue, with buyers receiving $87.89 million and sellers paying $0.21 million, and the prevailing flow FTRs netted $118.82 million in revenue, with buyers paying $127.00 million and sellers receiving $8.18 million.

Table 8-15 Long Term FTR Auction revenue: Planning periods 2010 to 2013

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($16,206,834)	($16,530,051)	($11,224,427)	($43,961,312)
		Year 2	($7,220,619)	($11,104,230)	($7,301,666)	($25,626,515)
		Year 3	($4,644,808)	($7,929,305)	($5,418,753)	($17,992,867)
		Year All	($308,164)	NA	NA	($308,164)
		Total	($28,380,426)	($35,563,586)	($23,944,847)	($87,888,858)
	Prevailing Flow	Year 1	$20,028,096	$25,041,954	$13,370,610	$58,440,661
		Year 2	$16,167,574	$14,826,317	$7,585,799	$38,579,691
		Year 3	$7,430,163	$14,050,302	$7,282,788	$28,763,253
		Year All	$513,923	$330,083	$367,681	$1,211,687
		Total	$44,139,757	$54,248,656	$28,606,879	$126,995,292
	Total		$15,759,332	$18,685,070	$4,662,032	$39,106,434
Sell offers	Counter Flow	Year 1	($1,282)	($99,514)	($60,657)	($161,453)
		Year 2	$0	($16,334)	($21,167)	($37,501)
		Year 3	NA	($6,535)	($3,484)	($10,019)
		Year All	NA	NA	NA	NA
		Total	($1,282)	($122,383)	($85,308)	($208,972)
	Prevailing Flow	Year 1	$55,249	$2,605,054	$1,037,322	$3,697,625
		Year 2	$0	$2,754,165	$1,287,066	$4,041,231
		Year 3	NA	$202,583	$238,825	$441,408
		Year All	NA	NA	NA	NA
		Total	$55,249	$5,561,802	$2,563,213	$8,180,264
	Total		$53,967	$5,439,419	$2,477,905	$7,971,292

Figure 8-3 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue from the 2010 to 2013 Long Term FTR Auction.[26] The top 10 positive revenue producing FTR sinks accounted for $62.43 million of the total revenue of $31.14 million paid in the auction.[27] They also comprised 8.2 percent of all FTRs bought in the auction. The sinks with the highest positive auction revenue are all control zones or large aggregates. The top 10 negative revenue producing FTR sinks accounted for -$23.04 million of revenue and constituted 3.5 percent of all FTRs bought in the auction.

26 As some FTRs are bid with negative prices, some winning FTR bidders are paid to take FTRs. These are counter flow FTRs. These payments reduce net auction revenue. Therefore, the sum of the highest revenue producing FTRs can exceed net auction revenue.

27 The total positive revenue producing FTR sinks was $92.12 million and the total negative revenue producing FTR sinks was -$60.98 million. The overall revenue paid in the auction was $31.14 million.

Figure 8-3 Ten largest positive and negative revenue producing FTR sinks purchased in the Long Term FTR Auction: Planning periods 2010 to 2013[28]

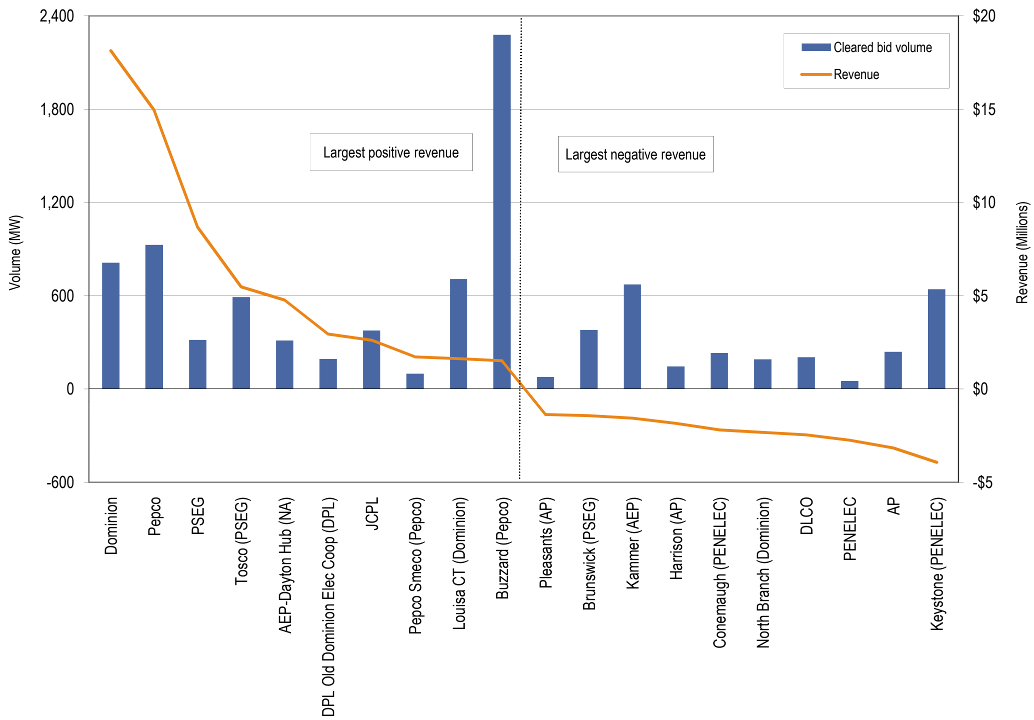
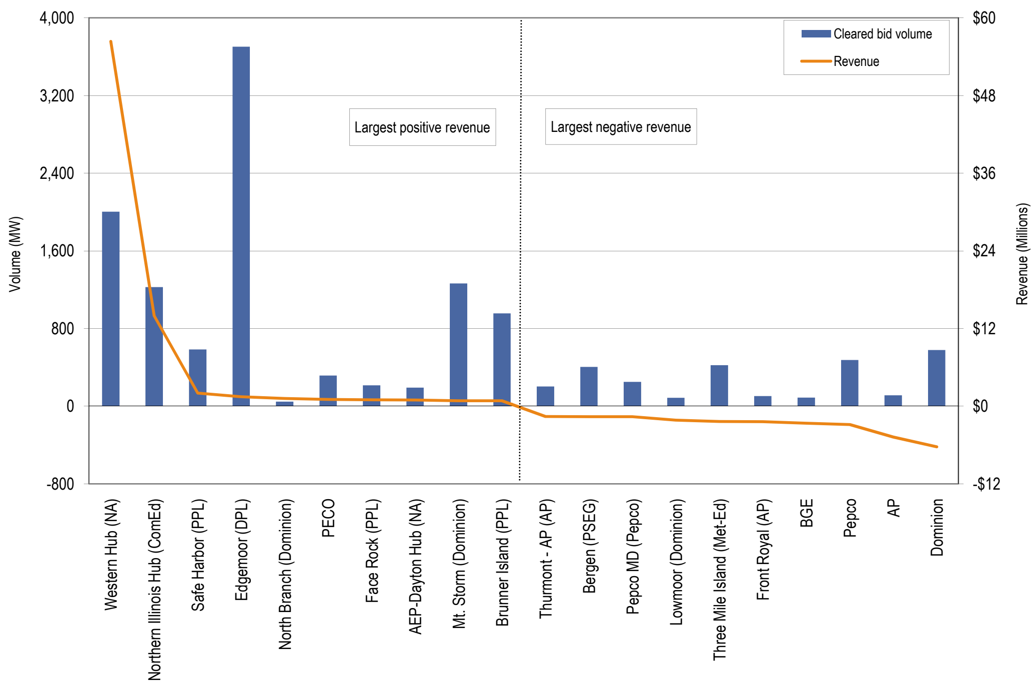


Figure 8-4 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the 2010 to 2013 Long Term FTR Auction. The top 10 positive revenue producing FTR sources accounted for $79.63 million of the total revenue of $31.14 million paid in the auction. They also comprised 13.0 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sources accounted for -$28.32 million of revenue and constituted 3.4 percent of all FTRs bought in the auction.

28 For Figure 8-3 through Figure 8-10, each FTR sink and source that is not a control zone has its corresponding control zone listed in parentheses after its name. Most FTR sink and source control zone identifications for hubs and interface pricing points are listed as NA because they cannot be assigned to a specific control zone.

Figure 8-4 Ten largest positive and negative revenue producing FTR sources purchased in the Long Term FTR Auction: Planning periods 2010 to 2013



Annual FTR Auction Revenue

Table 8-16 shows Annual FTR Auction revenue data by trade type, hedge type, FTR direction and class type. For the 2009 to 2010 planning period, the Annual FTR Auction netted $1,329.80 million in revenue, with buyers paying $1,338.88 million and sellers receiving $9.09 million. For the 2008 to 2009 planning period, the Annual FTR Auction netted $2,422.55 million in revenue, with buyers paying $2,442.57 million and sellers receiving $20.02 million.

For the 2009 to 2010 planning period, the counter flow FTRs in the Annual FTR Auction netted -$135.76 million in revenue, with buyers receiving $140.33 million and sellers paying $4.57 million, and the prevailing flow FTRs in the Annual FTR Auction netted $1,465.56 million in revenue, with buyers paying $1,479.21 million and sellers receiving $13.65 million.

Table 8-16 Annual FTR Auction revenue: Planning period 2009 to 2010

						Class Type
Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($43,363,985)	($44,760,870)	($43,432,206)	($131,557,061)
		Prevailing Flow	$158,105,703	$185,216,383	$136,397,384	$479,719,470
		Total	$114,741,718	$140,455,513	$92,965,178	$348,162,410
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$2,457,455	$22,913,596	$17,326,182	$42,697,232
		Total	$2,457,455	$22,913,596	$17,326,182	$42,697,232
	Total	Counter Flow	($43,363,985)	($44,760,870)	($43,432,206)	($131,557,061)
		Prevailing Flow	$160,563,158	$208,129,979	$153,723,566	$522,416,703
		Total	$117,199,173	$163,369,109	$110,291,360	$390,859,642
Self-scheduled bids	Obligations	Counter Flow	($8,772,739)	NA	NA	($8,772,739)
		Prevailing Flow	$956,797,012	NA	NA	$956,797,012
		Total	$948,024,273	NA	NA	$948,024,273
Buy and self-scheduled bids	Obligations	Counter Flow	($52,136,724)	($44,760,870)	($43,432,206)	($140,329,799)
		Prevailing Flow	$1,114,902,715	$185,216,383	$136,397,384	$1,436,516,482
		Total	$1,062,765,992	$140,455,513	$92,965,178	$1,296,186,683
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$2,457,455	$22,913,596	$17,326,182	$42,697,232
		Total	$2,457,455	$22,913,596	$17,326,182	$42,697,232
	Total	Counter Flow	($52,136,724)	($44,760,870)	($43,432,206)	($140,329,799)
		Prevailing Flow	$1,117,360,170	$208,129,979	$153,723,566	$1,479,213,715
		Total	$1,065,223,446	$163,369,109	$110,291,360	$1,338,883,915
Sell offers	Obligations	Counter Flow	($1,385,244)	($1,089,452)	($2,094,504)	($4,569,201)
		Prevailing Flow	$736,568	$9,964,413	$2,864,123	$13,565,105
		Total	($648,676)	$8,874,961	$769,619	$8,995,904
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$15,598	$5,268	$68,488	$89,353
		Total	$15,598	$5,268	$68,488	$89,353
	Total	Counter Flow	($1,385,244)	($1,089,452)	($2,094,504)	($4,569,201)
		Prevailing Flow	$752,166	$9,969,681	$2,932,611	$13,654,458
		Total	($633,078)	$8,880,229	$838,107	$9,085,257

Figure 8-5 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue from the Annual FTR Auction for the 2009 to 2010 planning period. The top 10 positive revenue producing FTR sinks accounted for $1,096.93 million (82.5 percent) of the total revenue of $1,329.80 million paid in the auction. They also comprised 37.7 percent of all FTRs bought in the auction. The sinks with the highest positive auction revenue are all control zones or large aggregates. The top 10 negative revenue producing

FTR sinks accounted for -$24.50 million of revenue and constituted 2.4 percent of all FTRs bought in the auction.

Figure 8-5 Ten largest positive and negative revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2009 to 2010

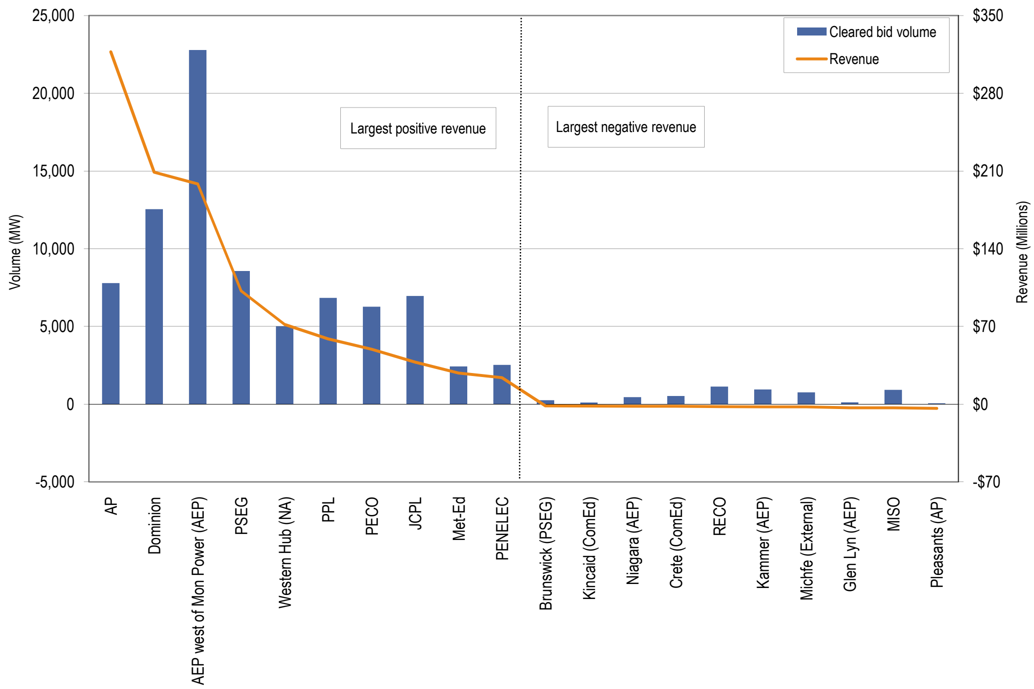
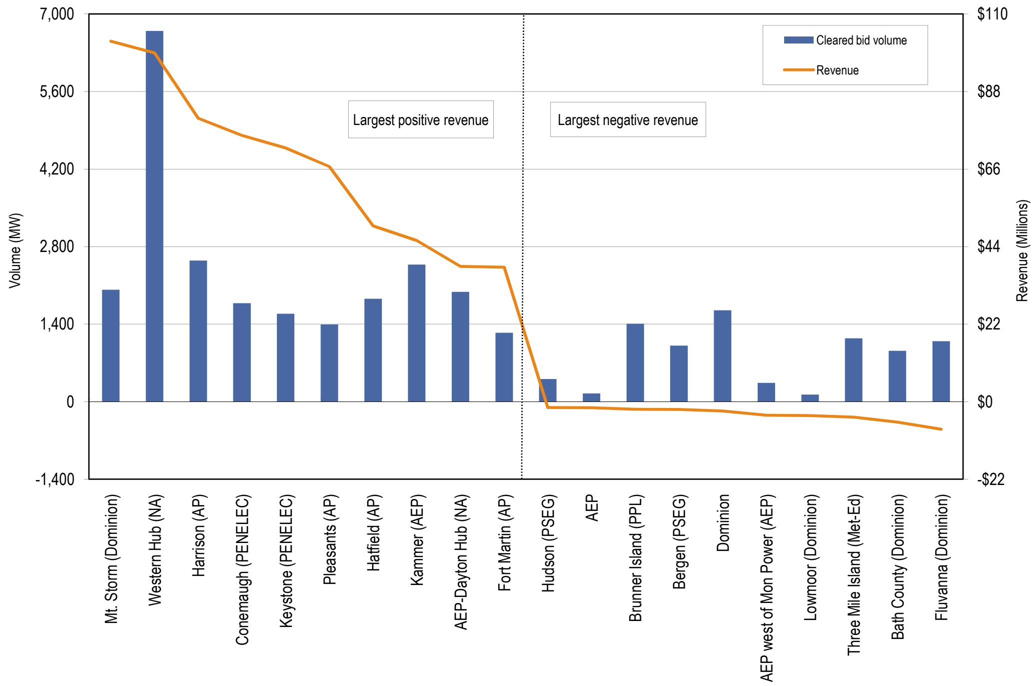


Figure 8-6 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Annual FTR Auction for the 2009 to 2010 planning period. The top 10 positive revenue producing FTR sources accounted for $667.87 million (50.2 percent) of the total revenue of $1,329.80 million paid in the auction. They also comprised 10.9 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sources accounted for -$36.35 million of revenue and constituted 3.8 percent of all FTRs bought in the auction.

Figure 8-6 Ten largest positive and negative revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2009 to 2010



Monthly Balance of Planning Period FTR Auction Revenue

Table 8-17 shows Monthly Balance of Planning Period FTR Auction revenue data by trade type, hedge type and class type. For the 2009 to 2010 planning period through December 31, 2009, the Monthly Balance of Planning Period FTR Auctions netted $13.07 million in revenue, with buyers paying $60.22 million and sellers receiving $47.15 million. For the 2008 to 2009 planning period, the Monthly Balance of Planning Period FTR Auctions netted $67.05 million in revenue, with buyers paying $128.97 million and sellers receiving $61.92 million.

Table 8-17 Monthly Balance of Planning Period FTR Auction revenue: Calendar year 2009

			Class Type			
Monthly Auction	Hedge Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-09	Obligations	Buy bids	$1,207,292	$934,011	$244,584	$2,385,888
		Sell offers	$248,591	$573,963	$77,911	$900,466
	Options	Buy bids	$26,505	$140,359	$145,245	$312,108
		Sell offers	$0	$203,453	$129,447	$332,900
Feb-09	Obligations	Buy bids	($83,145)	$2,193,269	$1,332,926	$3,443,050
		Sell offers	$413,446	$1,442,454	$530,041	$2,385,941
	Options	Buy bids	$31,233	$278,934	$178,062	$488,229
		Sell offers	$0	$193,821	$118,916	$312,737
Mar-09	Obligations	Buy bids	$395,276	$2,107,188	$1,467,981	$3,970,446
		Sell offers	$308,687	$1,724,949	$1,167,153	$3,200,789
	Options	Buy bids	$34,097	$435,416	$54,453	$523,967
		Sell offers	$0	$181,733	$52,487	$234,221
Apr-09	Obligations	Buy bids	($223,411)	$1,471,041	$1,062,859	$2,310,489
		Sell offers	$19,324	$954,279	$602,223	$1,575,826
	Options	Buy bids	$1,511	$291,731	$15,883	$309,126
		Sell offers	$0	$260,520	$67,733	$328,253
May-09	Obligations	Buy bids	($234,075)	$902,305	$371,453	$1,039,683
		Sell offers	($12,927)	$429,537	$118,031	$534,641
	Options	Buy bids	$0	$10,099	$8,754	$18,854
		Sell offers	$1,336	$115,521	$48,174	$165,031
Jun-09	Obligations	Buy bids	($455,827)	$9,859,792	$7,471,308	$16,875,272
		Sell offers	$940,697	$4,742,041	$3,783,072	$9,465,811
	Options	Buy bids	$0	$454,961	$67,016	$521,977
		Sell offers	$21,245	$3,150,642	$1,819,405	$4,991,291
Jul-09	Obligations	Buy bids	$415,277	$4,786,066	$4,229,832	$9,431,174
		Sell offers	($59,890)	$2,992,345	$2,645,320	$5,577,775
	Options	Buy bids	$25,700	$221,441	$78,308	$325,449
		Sell offers	$1,231	$959,249	$766,196	$1,726,677
Aug-09	Obligations	Buy bids	$300,985	$2,594,442	$1,835,069	$4,730,497
		Sell offers	($35,209)	$1,385,079	$1,265,654	$2,615,525
	Options	Buy bids	NA	$151,123	$3,931	$155,054
		Sell offers	$130	$512,880	$284,359	$797,368
Sep-09	Obligations	Buy bids	$1,017,942	$4,713,934	$3,266,091	$8,997,967
		Sell offers	$453,760	$3,108,304	$2,190,037	$5,752,101
	Options	Buy bids	$42,397	$103,279	$85,804	$231,480
		Sell offers	$2,554	$1,000,222	$537,203	$1,539,979
Oct-09	Obligations	Buy bids	$217,461	$2,417,026	$2,329,518	$4,964,005
		Sell offers	($3,094)	$1,182,029	$1,200,681	$2,379,616
	Options	Buy bids	NA	$61,586	$68,144	$129,730
		Sell offers	$22,884	$764,026	$649,044	$1,435,954
Nov-09	Obligations	Buy bids	($2,883,260)	$5,357,702	$3,927,246	$6,401,688
		Sell offers	$288,449	$1,459,674	$1,306,985	$3,055,109
	Options	Buy bids	$0	$168,017	$55,779	$223,796
		Sell offers	$35,176	$1,289,570	$852,156	$2,176,902
Dec-09	Obligations	Buy bids	$2,273,482	$3,395,670	$1,346,904	$7,016,056
		Sell offers	$1,035,061	$2,107,920	$1,227,779	$4,370,760
	Options	Buy bids	$29,551	$98,932	$88,190	$216,673
		Sell offers	$6,525	$667,140	$595,297	$1,268,963
2008/2009*	Obligations	Buy bids	$18,536,366	$62,983,127	$39,113,790	$120,633,283
		Sell offers	$10,238,514	$20,746,786	$12,003,977	$42,989,277
	Options	Buy bids	$164,213	$5,175,296	$2,995,811	$8,335,320
		Sell offers	$26,515	$13,614,983	$5,286,634	$18,928,133
2009/2010**	Obligations	Buy bids	$886,061	$33,124,632	$24,405,967	$58,416,660
		Sell offers	$2,619,774	$16,977,392	$13,619,529	$33,216,695
	Options	Buy bids	$97,648	$1,259,338	$447,173	$1,804,159
		Sell offers	$89,745	$8,343,729	$5,503,660	$13,937,134

* Shows Twelve Months for 2008/2009; ** Shows seven months ended 31-Dec-2009 for 2009/2010

Figure 8-7 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue in the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2009 to 2010 planning period. The top 10 positive revenue producing FTR sinks accounted for $46.80 million of revenue and 13.1 percent of all FTRs bought in the Monthly Balance of Planning Period FTR Auctions. In the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2009 to 2010 planning period, there were 551 MW cleared bids for FTRs sunk at the new Neptune 230 kV line which generated $0.1 million of revenue. In the Monthly Balance of Planning Period FTR Auctions during the 2008 to 2009 planning period, there were 1,013 MW cleared bids for FTRs sunk at the new Neptune 230 kV line which generated $2.4 million of revenue. There were no FTRs sunk at the new Linden VFT line during the first seven months of the 2009 to 2010 planning period. The top 10 negative revenue producing FTR sinks accounted for -$12.91 million of revenue and constituted 2.0 percent of all FTRs bought in the auctions. The net market volume sunk into the Western Hub was negative since the total cleared volume of the monthly FTR buy bids sunk into the West Interface Hub was less than the total cleared volume of the monthly FTR sell offers sunk into the West Interface Hub.

Figure 8-7 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2009 to 2010 through December 31, 2009

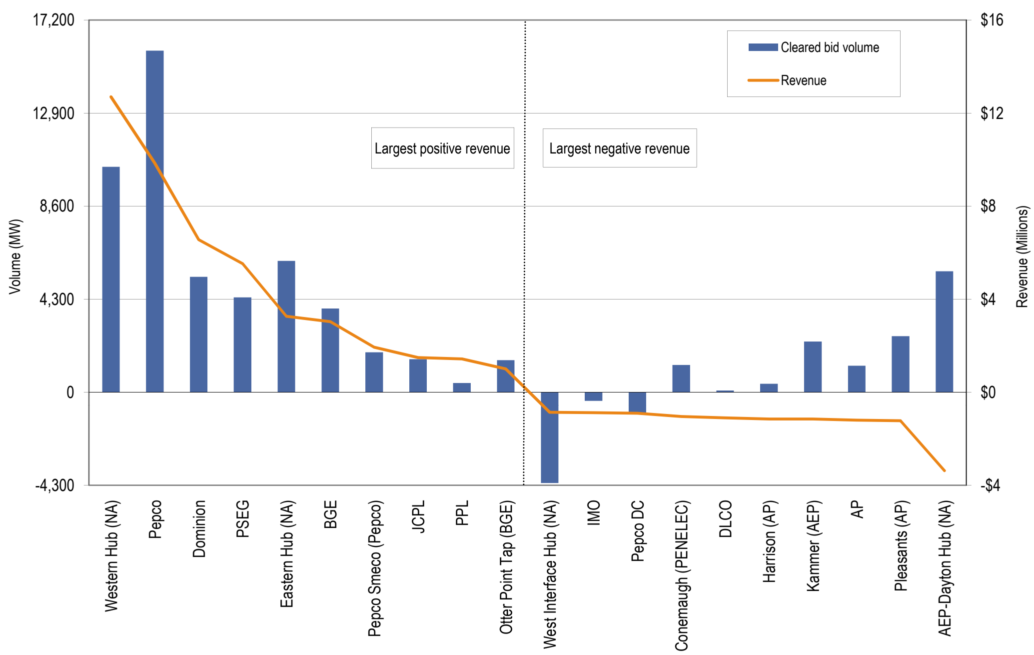
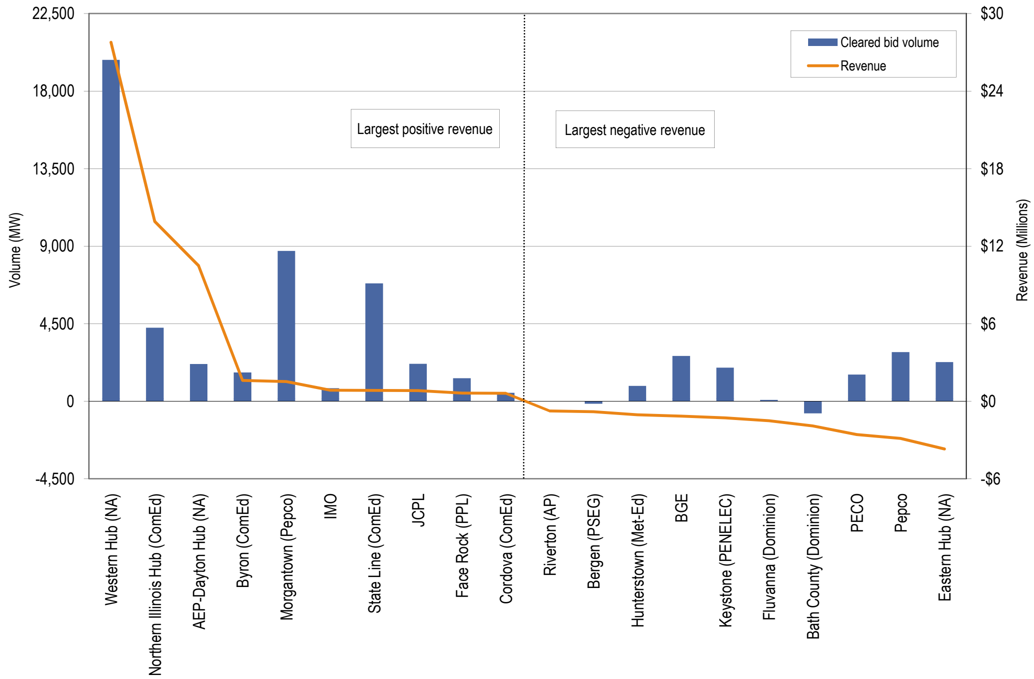


Figure 8-8 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2009 to 2010 planning period. The top 10 positive revenue producing FTR sources accounted for $59.05 million and 12.3 percent of all FTRs bought in the auctions. The top 10 negative revenue producing FTR sources accounted for -$17.64 million of revenue and constituted 2.9 percent of all FTRs bought in the auctions.

Figure 8-8 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2009 to 2010 through December 31, 2009



Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay and all generators receive their respective LMPs. When load pays more than the amount that generators receive, excluding losses, positive congestion revenue exists and is available to cover the target allocations of FTR holders. The MW of load exceeds the MW of generation in constrained areas because a part of the load is served by imports using transmission capability into the constrained areas. Generating units that are the source of such imports are paid the price at their own bus which does not reflect congestion in constrained areas. Generation in a constrained area receives the congestion price and all load in the constrained area pays the congestion price. As a result, load congestion payments are usually greater than the congestion-related increase in payments to generation.[29] In general, FTR revenue adequacy exists when the sum of congestion credits is as great as the sum of congestion across the positively valued FTRs.

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 total congestion on the system as a measure of the extent to which FTRs hedged market participants against actual, total congestion across all paths, regardless of the availability or purchase of FTRs.

29 For an illustration of how total congestion revenue is generated and how FTR target allocations and congestion receipts are determined, see Table G-1, "Congestion revenue, FTR target allocations and FTR congestion credits: Illustration," *2009 State of the Market Report for PJM*, Volume II, Appendix G, "Financial Transmission and Auction Revenue Rights."

FTRs are paid out for each month from congestion revenues, FTR auction revenues and excess revenues carried forward from prior months and distributed back from later months. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs during the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning year. For the 2008 to 2009 planning period, FTRs were fully funded and thus no uplift charge was collected. Table 8-18 shows the composition of FTR target allocations and FTR revenues for the 2008 to 2009 and the 2009 to 2010 planning periods, with the latter shown through December 31, 2009. FTR targets are composed of FTR target allocations and associated adjustments. Other adjustments may be made for items such as modeling changes or errors.

FTR revenues are primarily comprised of hourly congestion revenue and net negative congestion. FTR revenues also include ARR excess which is the difference between ARR target allocations and FTR auction revenues. Competing use revenues are based on the Unscheduled Transmission Service Agreement between the New York Independent System Operator (NYISO) and PJM. This agreement sets forth the terms and conditions under which compensation is provided for transmission service in connection with transactions not scheduled directly or otherwise prearranged between NYISO and PJM. Congestion revenues appearing in Table 8-18 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the Midwest ISO whose operating limits are respected by PJM.[30] The operating protocol governing the wheeling contracts between Public Service Electric and Gas Company (PSE&G) and Consolidated Edison Company of New York (Con Edison) resulted in a reimbursement of $0.5 million in congestion charges to Con Edison in the 2009 to 2010 planning period through December 31, 2009.[31,32]

30 See “Joint Operating Agreement between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C.” (December 11, 2008) (Accessed January 19, 2010), Section 6.1 <http://www.pjm.com/~/Media/documents/agreements/joa-complete.ashx> (1,528 KB).

31 111 FERC ¶ 61,228 (2005).

32 See the *2009 State of the Market Report for PJM*, Volume II, Section 4, “Interchange Transactions,” at “Con Edison and PSE&G Wheeling Contracts 2009 Update” and Appendix D, “Interchange Transactions” at Table D-1, “Con Edison and PSE&G wheel settlements data: Calendar year 2009.”

Table 8-18 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010

Accounting Element	2008/2009	2009/2010*
ARR information		
ARR target allocations	$2,361.3	$747.6
FTR auction revenue	$2,489.6	$799.1
ARR excess	$128.3	$51.5
FTR targets		
FTR target allocations	$1,747.9	$398.1
Adjustments:		
Adjustments to FTR target allocations	($4.1)	($0.5)
Total FTR targets	$1,743.8	$397.6
FTR revenues		
ARR excess	$128.3	$51.5
Competing uses	$0.7	$0.0
Congestions		
Net Negative Congestion (enter as negative)	($59.0)	($20.1)
Hourly congestion revenue	$1,735.7	$380.9
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($52.3)	($23.4)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	($3.1)	($0.5)
Adjustments:		
Excess revenues carried forward into future months	$36.8	$23.5
Excess revenues distributed back to previous months	$16.1	$8.5
Other adjustments to FTR revenues	($2.0)	($0.2)
Total FTR revenues	$1,801.2	$420.2
Excess revenues distributed to other months	($30.0)	($31.9)
Excess revenues distributed to CEPSW for end-of-year distribution	$0.5	$0.0
Excess revenues distributed to FTR holders	$4.0	$0.0
Total FTR congestion credits	$1,743.8	$388.3
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$1,751.4	$388.8
Remaining deficiency	$0.0	$9.3

* Shows seven months ended 31-Dec-09

FTR target allocations are based on hourly prices in the Day-Ahead Energy Market for the respective FTR paths and equal the revenue required to hedge FTR holders fully against congestion on the specific paths for which the FTRs are held. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations. Table 8-19 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month. At the end of the 12-month planning period, excess congestion charges are used to offset any monthly congestion credit deficiencies. FTRs were paid at 100 percent of the target allocation level for the 2008 to 2009 planning period and were paid at 97.7 percent of the target allocation level for the 2009 to 2010 planning period through December 31, 2009.

The total row in Table 8-19 is not the simple sum of each of the monthly rows because the monthly rows may include excess revenues carried forward from prior months and excess revenues carried back from later months. For example, August 2009 FTR revenues are shown as $90.0 million, which includes revenues from congestion charges for the month, excess revenues carried forward from prior months ($12.8 million) and excess revenues carried back from later months ($2.2 million). For the 2008 to 2009 planning period, the total FTR revenues were $1,748.3 million which is the sum of total FTR credits ($1,743.8 million) and total excess credits ($4.5 million). For the first seven months of the 2009 to 2010 planning period, the total FTR revenues were $388.3 million, which equal the total FTR credits ($388.3 million) because there were credit deficiencies of $9.3 million.

Table 8-19 Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010

Period	FTR Revenues	FTR Target Allocations	FTR Credits	FTR Payout Ratio	Credits Deficiency	Credits Excess
Jun-08	$436.9	$432.3	$432.3	100%	$0	$4.7
Jul-08	$371.4	$364.2	$364.2	100%	$0	$7.2
Aug-08	$140.5	$125.0	$125.0	100%	$0	$15.4
Sep-08	$154.6	$154.6	$154.6	100%	$0	$0.0
Oct-08	$109.4	$109.4	$109.4	100%	$0	$0.0
Nov-08	$97.2	$97.2	$97.2	100%	$0	$0.0
Dec-08	$85.3	$77.6	$77.6	100%	$0	$7.7
Jan-09	$159.5	$151.1	$151.1	100%	$0	$8.4
Feb-09	$92.0	$84.3	$84.3	100%	$0	$7.7
Mar-09	$86.7	$86.7	$86.7	100%	$0	$0.0
Apr-09	$32.8	$31.1	$31.1	100%	$0	$1.7
May-09	$34.8	$30.3	$30.3	100%	$0	$4.5
Summary for Planning Period 2008 to 2009						
Total	$1,748.3	$1,743.8	$1,743.8	100%	$0	$4.5
Jun-09	$54.6	$43.9	$43.9	100%	$0	$10.7
Jul-09	$53.2	$40.4	$40.4	100%	$0	$12.8
Aug-09	$90.0	$92.4	$90.0	97.4%	$2.4	$0.0
Sep-09	$29.3	$31.4	$29.3	93.5%	$2.0	$0.0
Oct-09	$52.9	$57.8	$52.9	91.5%	$4.9	$0.0
Nov-09	$38.2	$37.9	$37.9	100%	$0.0	$0.3
Dec-09	$101.9	$93.8	$93.8	100%	$0.0	$8.2
Summary for Planning Period 2009 to 2010 through Dec 31, 2009						
Total	$388.3	$397.6	$388.3	97.7%	$9.3	$0.0

FTR target allocations were examined separately. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source for the 2009 to 2010 planning period through December 31, 2009. Figure 8-9 shows the FTR sinks with the largest positive and negative target allocations. The top 10 sinks that produced a financial benefit accounted for 64.8 percent of total positive target allocations during the first seven months of the 2009 to 2010 planning period. FTRs with the AP Control Zone as the sink included 13.0 percent of all positive target allocations. The sinks with the highest positive target allocations are all control zones or large aggregates. The top 10 sinks that created liability accounted for 43.9 percent of total negative target allocations. FTRs with the Northern Illinois Hub as the sink encompassed 6.4 percent of all negative target allocations.

Figure 8-9 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2009 to 2010 through December 31, 2009

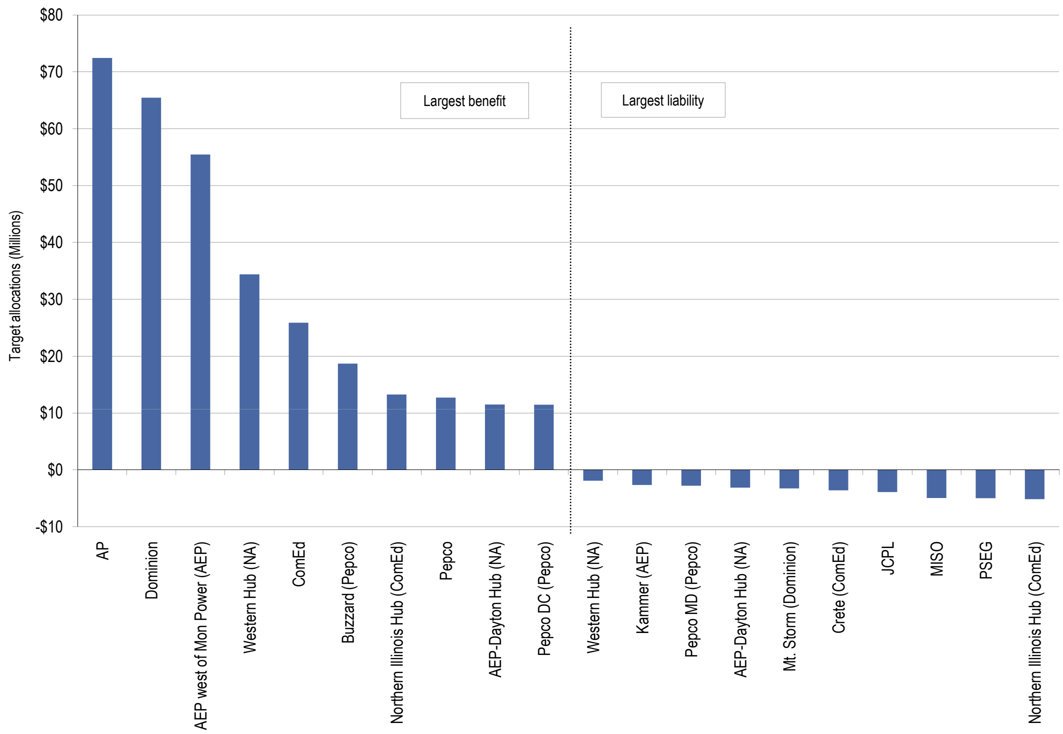
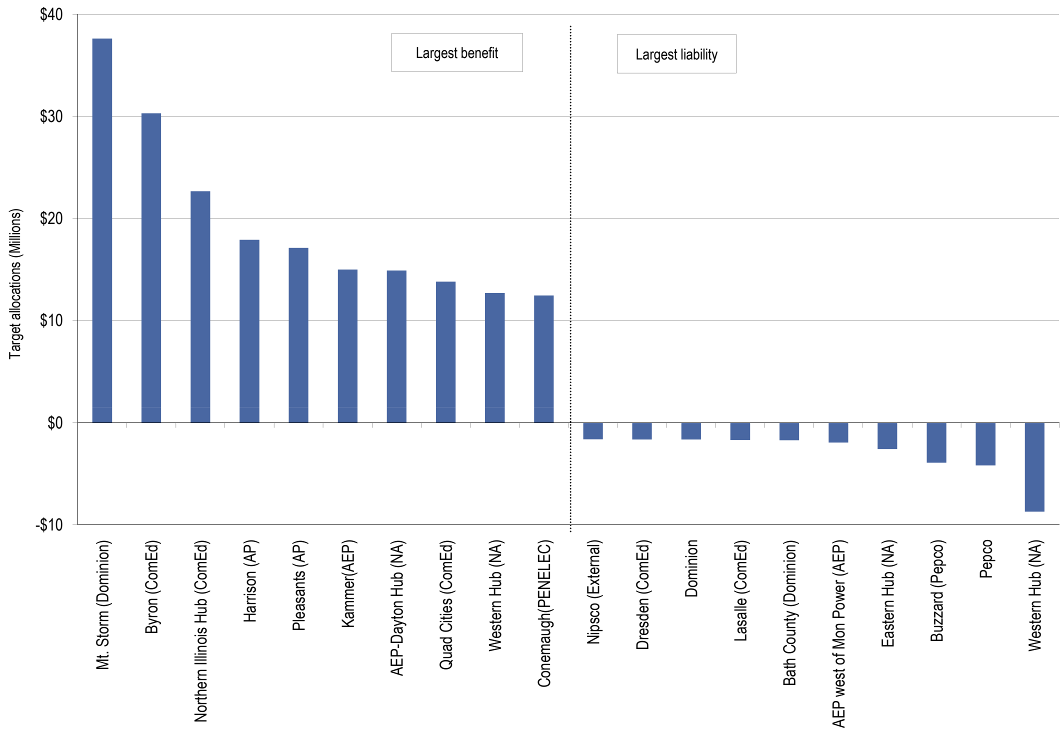


Figure 8-10 shows the FTR sources with the largest positive and negative target allocations during the first seven months of the 2009 to 2010 planning period. The top 10 sources with a positive target allocation accounted for 39.8 percent of total positive target allocations. FTRs with the Mount Storm aggregate as their source included 7.7 percent of all positive target allocations. The top 10 sources with a negative target allocation accounted for 32.6 percent of total negative target allocations. FTRs with the Western Hub as the source encompassed 9.6 percent of all negative target allocations.

Figure 8-10 Ten largest positive and negative FTR target allocations summed by source: Planning period 2009 to 2010 through December 31, 2009



Auction Revenue Rights

FTRs and ARRs are both financial instruments that entitle the holder to receive revenues or to pay charges based on nodal price differences. FTRs provide holders with revenues or charges based on the locational congestion price differences actually experienced in the Day-Ahead Energy Market while ARRs are financial instruments that entitle their holders to receive revenue or to pay charges based on prices determined in the Annual FTR Auction.[33] These price differences are based on the bid prices of participants in the Annual FTR Auction which relate to their expectations about the level of congestion in the Day-Ahead Energy Market. The auction clears the set of feasible FTR bids which produce the highest net revenue. In other words, ARR revenues are a function of FTR auction participants' expectations of locational congestion price differences in the Day-Ahead Energy Market.

ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to the product of the ARR MW and the price difference between sink and source from the Annual FTR Auction. An ARR value can be positive or negative depending on the sink-minus-source price difference, with a negative difference resulting in a liability for the holder. The ARR target allocation represents the revenue that an ARR holder should receive. All ARR holders receive ARR credits equal to

33 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces the most net revenue.

their target allocations if total net revenues from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions are greater than, or equal to, the sum of all ARR target allocations. ARR credits can be positive or negative and can range from zero to the ARR target allocation. If the combined net revenues from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions are less than that, available revenue is proportionally allocated among all ARR holders.

ARRs are available only as obligation hedge type and 24-hour class type products. An ARR obligation provides a credit, positive or negative, equal to the product of the ARR MW and the price difference between ARR sink and source that occurs in the Annual FTR Auction. The 24-hour products are effective 24 hours a day, seven days a week.

When a new control zone is integrated into PJM, the participants in that control zone must choose to receive either an FTR allocation or an ARR allocation before the start of the Annual FTR Auction for two consecutive planning periods following their integration date. After the transition period, such participants receive ARRs from the annual allocation process and are ineligible for directly allocated FTRs.

Market Structure

ARRs have been available to network service and firm, point-to-point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003 to 2004 planning period. The initial allocation covered the Mid-Atlantic Region and the AP Control Zone. For the 2006 to 2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the AEP, DAY, DLCO and Dominion control zones. For the 2007 to 2008 and subsequent planning periods, all eligible market participants were allocated ARRs.

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 ARRs that are feasible.

ARR Allocation

For the 2007 to 2008 planning period, the annual ARR allocation process was revised to include Long Term ARRs that would be in effect for 10 consecutive planning periods.[34] Long Term ARRs can give LSEs the ability to hedge their congestion costs on a long-term basis by providing price certainty throughout the 10 planning period time frame. Long Term ARR holders can opt out of any planning period during the 10 planning period timeline and self schedule their Long Term ARRs as FTRs.

Each March, PJM allocates ARRs to eligible customers in a three-stage process, whereby the first and second stages are each one round and the third stage is a three-round allocation procedure:

34 See the *2006 State of the Market Report* (March 8, 2007) for the rules of the annual ARR allocation process for the 2006 to 2007 and prior planning periods.

- **Stage 1A.** In the first stage of the allocation, network transmission service customers can obtain Long Term ARRs, up to their share of the zonal base load, after taking into account generation resources that historically have served load in each control zone and up to 50 percent of their historical nonzone network load. Nonzone network load is load that is located outside of the PJM footprint. Firm, point-to-point transmission service customers can obtain Long Term ARRs, based on up to 50 percent of the MW of long-term, firm, point-to-point transmission service provided between the receipt and delivery points for the historical reference year. Stage 1A ARR holders can also opt out of any planning period during the 10-planning-period timeline and self schedule their Long Term ARRs as FTRs.

- **Stage 1B.** ARRs unallocated in Stage 1A are available in the Stage 1B allocation. Network transmission service customers can obtain ARRs, up to their share of the zonal peak load, based on generation resources that historically have served load in each control zone and up to 100 percent of their transmission responsibility for nonzone network load. Firm, point-to-point transmission service customers can obtain ARRs based on the MW of long-term, firm, point-to-point service provided between the receipt and delivery points for the historical reference year. These long-term point-to-point service agreements must also remain in effect for the planning period covered by the allocation.

- **Stage 2.** The third stage of the annual ARR allocation is a three-step procedure, with one-third of the remaining system capability allocated in each step of the process. Network transmission service customers can obtain ARRs from any hub, control zone, generator bus or interface pricing point to any part of their aggregate load in the control zone or load aggregation zone for which an ARR was not allocated in Stage 1A or Stage 1B. Firm, point-to-point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

Prior to the start of the Stage 2 annual ARR allocation process, ARR holders can relinquish any portion of their ARRs resulting from the Stage 1A or Stage 1B allocation process, provided that all remaining outstanding ARRs are simultaneously feasible following the return of such ARRs.[35] Participants may seek additional ARRs in the Stage 2 allocation.

ARRs can also be traded between LSEs, but these trades must be made before the first round of the Annual FTR Auction. LSEs trading ARRs must trade all of their ARRs associated with a control zone and their zonal network service peak load is also reassigned to the new LSE. Traded ARRs are effective for the full 12-month planning period.

When ARRs are allocated, all ARRs must be simultaneously feasible to ensure that the physical transmission system can support the approved set of ARRs. In making simultaneous feasibility determinations, PJM utilizes a power flow model of security-constrained dispatch that takes into account generation and transmission facility outages and is based on reasonable assumptions about the configuration and availability of transmission capability during the planning period.[36] This simultaneous feasibility requirement is necessary to ensure that there are sufficient revenues from transmission congestion charges to satisfy all resulting ARR obligations, thereby preventing underfunding of the ARR obligations for a given planning period. If the requested set of ARRs is

35 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 21.
36 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 54-55.

not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints:

Equation 8-1 Calculation of prorated ARRs

Individual prorated MW = (Constraint capability) • (Individual requested MW / Total requested MW) • (1 / MW effect on line).[37]

The effect of an ARR request on a binding constraint is measured using the ARR's power flow distribution factor. An ARR's distribution factor is the percent of each requested MW of ARR that would have a power flow on the binding constraint. The PJM methodology prorates those ARR requests with the greatest impact on the binding constraint to avoid prorating more requests but having smaller or minimal impact on the binding constraint. PJM's method results in the prorating of ARRs that cause the greatest flows on the binding constraint instead of those that produce less flow on it. Were all ARR requests prorated equally, irrespective of their proportional impact on the binding constraints, the result would be a significant reduction in market participants' ARRs even when they have little impact on the binding constraints and the reduction of ARRs, and their associated benefits, with primary impacts on unrelated constraints.

Residual ARRs

On June 19, 2007, PJM submitted to the FERC revisions to the OATT to include a new type of ARR known as a residual ARR.[38] On August 13, 2007, the FERC issued an order accepting the revisions to the PJM OATT with an effective date of August 20, 2007.[39] Only ARR holders that had their Stage 1A or Stage 1B ARRs prorated are eligible to receive residual ARRs. Residual ARRs would be available if additional transmission system capability were added during the planning period after the annual ARR allocation. This additional transmission system capability would not have been accounted for in the initial annual ARR allocation, but it enables the creation of residual ARRs. Residual ARRs would be effective on the first day of the month in which the additional transmission system capability is included in FTR auctions and would exist until the end of the planning period. For the following planning period, any residual ARRs would be available as ARRs in the annual ARR allocation process as they would be included in the power flow model. The amount of a residual ARR would be the difference between the ARR holder's Stage 1A or Stage 1B request and their actual prorated Stage 1A or Stage 1B ARR MW. Stage 1 ARR holders have a priority right to ARRs and those holders who had ARRs prorated because of the simultaneous feasibility requirement previously had no recourse from the impact of proration. Residual ARRs are a separate product from incremental ARRs. No residual ARRs have been allocated to date.

37 See the *2009 State of the Market Report for PJM*, Volume II, Appendix G, "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining this calculation in greater detail.

38 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to its Amended and Restated Operating Agreement and Open Access Transmission Tariff pursuant to Section 205 of the Federal Power Act, Docket No. ER07-1053-000 (June 19, 2007).

39 *PJM Interconnection, L.L.C.*, Letter Order accepting PJM Interconnection, L.L.C.'s June 19, 2007, filing of Second Revised Sheet No. 6A et al to the Third Revised Rate Schedule, FERC No. 24 et al, Docket No. ER07-1053-000 (August 13, 2007).

Incremental ARRs

Market participants constructing generation interconnection or transmission expansion projects may request an allocation of incremental ARRs consistent with the project's increased transmission capability.[40] Incremental ARRs are available in a three-round allocation process with a single point-to-point combination requested and one-third of the incremental ARR MW allocated in each round. Incremental ARRs can be accepted or refused after rounds one and two. If accepted, that ARR is removed from availability in subsequent rounds; if it is refused, that ARR is available in the next rounds. Such incremental ARRs are effective for the lesser of 30 years or the life of the facility or upgrade. At any time during this 30-year period, in place of continuing this 30-year ARR, the participant has a single opportunity to replace the allocated ARRs with a right to request ARRs during the annual ARR allocation process between the same source and sink. Such participants can also permanently relinquish their incremental ARRs at any time during the life of the ARRs as long as overall the system simultaneous feasibility can be Table 8-20 lists the incremental ARR allocation volume for the 2008 to 2009 and the 2009 to 2010 planning periods. For the 2009 to 2010 planning period, there were bids for 531 MW and 100 percent of the bids were cleared. For the 2008 to 2009 planning period, there were bids for 891 MW and 100 percent of the bids were cleared.

Table 8-20 Incremental ARR allocation volume: Planning periods 2008 to 2009 and 2009 to 2010

Planning Period	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2008/2009	15	891	891	100%	0	0%
2009/2010	14	531	531	100%	0	0%

Table 8-21 lists the top 10 principal binding constraints, along with their corresponding control zones in order of severity that limited supply in the annual ARR allocation for the 2009 to 2010 planning period. The order of severity is determined by the violation degree of the binding constraint as computed in the simultaneous feasibility test.[41] The violation degree is a measure of the MW that a constraint is over the limit for a type of facility; a higher number indicates a more severe constraint.

Table 8-21 Top 10 principal binding transmission constraints limiting the annual ARR allocation: Planning period 2009 to 2010

Constraint	Type	Control Zone
AP South	Interface	AP
Electric Junction - Frontenac	Line	ComEd
Linden - North Ave	Line	PSEG
East Frankfort - Braidwood	Line	ComEd
Des Plaines	Transformer	ComEd
Doubs	Transformer	AP
North Seaford - Pine Street	Line	DPL
Garman - Westover	Line	PENELEC
Logans Ferry - Universal	Line	DLCO
Joliet - Joliet Central	Line	ComEd

40 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 30.
41 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 54-55.

Demand

PJM's OATT specifies the types of transmission services that are available to eligible customers. Eligible customers submit requests to PJM for network and firm, point-to-point transmission service through the PJM Open Access Same-Time Information System (OASIS). ARRs associated with firm transmission service that spans the entire next planning period, outside of the annual ARR allocation window, can also be requested through the PJM OASIS.[42] PJM evaluates each transmission service request for its impact on the system and approves or denies the request accordingly. All approved transmission services can be accommodated by the PJM transmission system. Theoretically, since total eligible ARR demand for the system cannot exceed the combined MW of network and firm, point-to-point transmission service, ARR supply should equal ARR demand if ARR nominations are consistent with the historic use of the transmission system. However, the demand for some ARRs could be left unmet if the same resources are nominated as ARR source points by multiple parties for delivery across shared paths and the result exceeds the stated capability of the transmission system to deliver from those sources to load. The combination might not be simultaneously feasible. When the requested set of ARRs is not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints.

ARR Reassignment for Retail Load Switching

Current PJM rules provide that when load switches among LSEs during the planning period, a proportional share of associated ARRs that sink into a given control or load aggregation zone is automatically reassigned to follow that load.[43] ARR reassignment occurs daily only if the LSE losing load has ARRs with a net positive economic value to that control zone. 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. ARRs are reassigned to the nearest 0.001 MW and any MW of load may be reassigned multiple times over a planning period. Residual ARRs are also subject to the rules of ARR reassignment. This practice supports competition by ensuring that the hedge against congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, these underlying self scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may diminish the value of the hedge.

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.

42 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 16-17.
43 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 28.

Table 8-22 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2008 and December 2009. About 10,531 MW of ARRs associated with $195,300 per MW-day of revenue were automatically reassigned in the first seven months of the 2009 to 2010 planning period. About 15,326 MW of ARRs with $533,900 per MW-day of revenue were reassigned for the entire 12-month 2008 to 2009 planning period.

Table 8-22 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2008, through December 31, 2009

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2008/2009 (12 months)	2009/2010 (7 months)*	2008/2009 (12 months)	2009/2010 (7 months)*
AECO	501	327	$16.1	$6.0
AEP	11	244	$0.2	$5.8
AP	707	413	$164.7	$48.0
BGE	3,361	2,112	$124.3	$43.7
ComEd	3,074	1,760	$10.0	$5.4
DAY	1	2	$0.0	$0.0
DLCO	471	217	$2.1	$0.6
Dominion	5	0	$0.4	$0.0
DPL	1,404	747	$24.8	$8.5
JCPL	1,094	864	$45.0	$13.1
Met-Ed	0	10	$0.0	$0.2
PECO	47	20	$1.4	$0.3
PENELEC	0	1	$0.0	$0.0
Pepco	3,040	1,949	$79.9	$19.9
PPL	35	282	$2.2	$5.8
PSEG	1,537	1,535	$62.7	$38.0
RECO	40	50	$0.0	$0.0
Total	15,326	10,531	$533.9	$195.3

* Through 31-Dec-09

Market Performance

Volume

Table 8-23 lists the annual ARR allocation volume by stage and round for the 2008 to 2009 and the 2009 to 2010 planning periods. For the 2009 to 2010 planning period, there were 64,987 MW (46.4 percent of total demand) bid in Stage 1A, 26,517 MW (18.9 percent of total demand) bid in Stage 1B and 48,533 MW (34.7 percent of total demand) bid in Stage 2. Of 140,037 MW in total ARR requests, 64,913 MW were allocated in Stage 1A and 26,514 MW were allocated in Stage 1B while 17,986 MW were allocated in Stage 2 for a total of 109,413 MW (78.1 percent) allocated. Eligible market participants subsequently converted 68,589 MW of these allocated ARRs into Annual FTRs (62.7 percent of total allocated ARRs), leaving 40,824 MW of ARRs outstanding. For the 2008 to 2009 planning period, there had been 64,546 MW (45.9 percent of total demand) bid in Stage 1A, 27,291 MW (19.4 percent of total demand) bid in Stage 1B and 48,831 MW (34.7 percent of total demand) bid in Stage 2. Of 140,668 MW in total ARR requests, 64,520 MW were allocated in Stage 1A and 26,685 MW were allocated in Stage 1B while 20,806 MW were allocated in Stage 2 for a total of 112,011 MW (79.6 percent) allocated. There were 72,851 MW or 65.0 percent of the allocated ARRs converted into FTRs. Immediately after the Stage 1B ARR allocation for the 2009 to 2010 planning period, ARR holders relinquished 2.9 MW of the allocated Stage 1B ARRs. In comparison, for the 2008 to 2009 planning period, ARR holders relinquished 26.8 MW of the allocated Stage 1A ARRs and 0.3 MW of the allocated Stage 1B ARRs. The uncleared volume in Table 8-23 includes ARRs that were relinquished.

Table 8-23 Annual ARR allocation volume: Planning periods 2008 to 2009 and 2009 to 2010

Planning Period	Stage	Round	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2008/2009	1A	0	7,845	64,546	64,520	100.0%	26	0.0%
	1B	1	3,147	27,291	26,685	97.8%	606	2.2%
	2	2	1,691	16,737	6,753	40.3%	9,984	59.7%
		3	1,312	15,464	6,304	40.8%	9,160	59.2%
		4	1,118	16,630	7,749	46.6%	8,881	53.4%
		Total	4,121	48,831	20,806	42.6%	28,025	57.4%
	Total		15,113	140,668	112,011	79.6%	28,657	20.4%
2009/2010	1A	0	7,527	64,987	64,913	99.9%	74	0.1%
	1B	1	3,582	26,517	26,514	100.0%	3	0.0%
	2	2	1,580	16,521	5,680	34.4%	10,841	65.6%
		3	1,157	16,413	6,013	36.6%	10,400	63.4%
		4	994	15,599	6,293	40.3%	9,306	59.7%
		Total	3,731	48,533	17,986	37.1%	30,547	62.9%
	Total		14,840	140,037	109,413	78.1%	30,624	21.9%

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

The degree to which ARR credits provide a hedge against congestion on specific ARR paths is determined by the prices that result from the Annual FTR Auction. The resultant ARR credit could be greater than, less than, or equal to the actual congestion on the selected path. This is the same concept as FTR revenue adequacy.

Customers that are allocated ARRs can choose to retain the underlying FTRs linked to their ARRs through a process termed self scheduling. Just like any other FTR, the underlying FTRs have a target hedge value based on actual day-ahead congestion on the selected path.

As with FTRs, revenue adequacy for ARRs must be distinguished from the adequacy of ARRs as a hedge against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion across specific paths for which ARRs were available and allocated. The adequacy of ARRs as a hedge against congestion compares ARR revenues to total congestion sinking in the participant's load zone as a measure of the extent to which ARRs hedged market participants against actual, total congestion into their zone, regardless of the availability or allocation of ARRs.

ARR holders will receive $1,273.5 million in credits from the Annual FTR Auction during the 2009 to 2010 planning period, with an average hourly ARR credit of $1.33 per MWh. During the comparable 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.

Table 8-24 lists ARR target allocations and net revenue sources from the Annual and Monthly Balance of Planning Period FTR Auctions for the 2008 to 2009 and the 2009 to 2010 (through December 31, 2009) planning periods. Annual FTR Auction net revenue has been sufficient to cover ARR target allocations for both planning periods. The 2009 to 2010 planning period's Annual and Monthly Balance of Planning Period FTR Auctions generated a surplus of $69.4 million in auction net revenue through December 31, 2009, above the amount needed to pay 100 percent of ARR target allocations. The whole 2008 to 2009 planning period's Annual and Monthly Balance of Planning Period FTR Auctions generated a surplus of $128.3 million in auction net revenue, above the amount needed to pay 100 percent of ARR target allocations.

Table 8-24 ARR revenue adequacy (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010

	2008/2009	2009/2010
Total FTR auction net revenue	$2,489.6	$1,342.9
Annual FTR Auction net revenue	$2,422.6	$1,329.8
Monthly Balance of Planning Period FTR Auction net revenue*	$67.1	$13.1
ARR target allocations	$2,361.3	$1,273.5
ARR credits	$2,361.3	$1,273.5
Surplus auction revenue	$128.3	$69.4
ARR payout ratio	100%	100%
FTR payout ratio*	100%	97.7%

* Shows twelve months for 2008/2009 and seven months ended 31-Dec-09 for 2009/2010

ARR Proration

During the annual ARR allocation process, all ARRs must be simultaneously feasible to ensure that the physical transmission system can support the approved set of ARRs. If all the ARR requests made during the annual ARR allocation process are not feasible, then ARRs are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.[44,45]

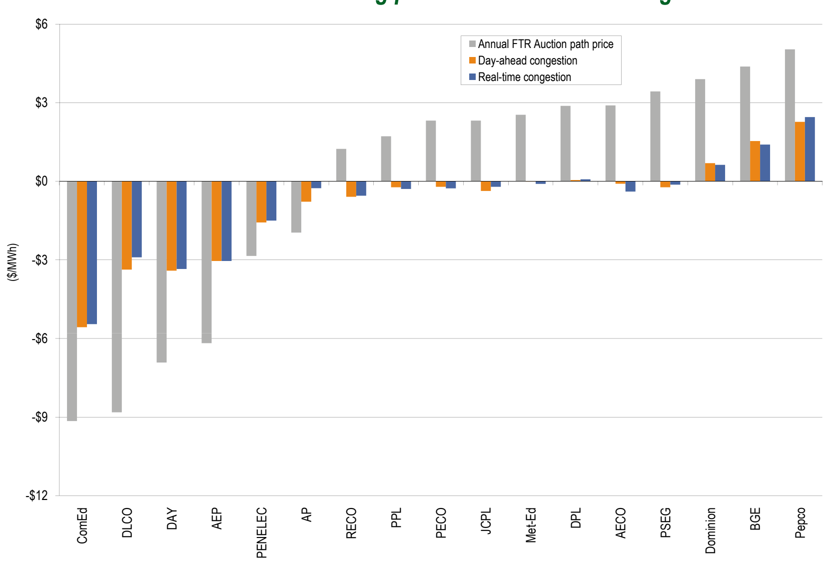
When ARRs were allocated for the 2009 to 2010 planning period, some of the requested ARRs were prorated in Stage 2 in order to ensure simultaneous feasibility. No ARRs were prorated in Stage 1A and Stage 1B since there were no constraints affecting the ARR allocation in these two stages.

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 8-11 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone for the 2009 to 2010 planning period through December 31, 2009. The day-ahead and real-time congestion are based on the difference between zonal congestion prices and Western Hub congestion prices. The figure shows, for example, that an FTR from the Western Hub to the PECO Control Zone cost $2.32 per MWh in the Annual FTR Auction and that about -$0.21 per MWh of day-ahead congestion and -$0.27 per MWh of real-time congestion existed between the Western Hub and the PECO Control Zone. The data show that congestion costs, approximated in this way, were only positive for the Dominion, BGE and Pepco control zones and negative for all other PJM control zones. This is in contrast to prior years when congestion costs, approximated in this way, were positive for most control zones located east of the Western Hub. The Annual FTR Auction prices exceeded the price differential for every zone, again in contrast to prior years.

Figure 8-11 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2009 to 2010 through December 31, 2009



44 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 24-25.
45 See the *2009 State of the Market Report for PJM*, Volume II, Appendix G, "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining the ARR prorating method.

Effectiveness of ARRs as a Hedge against Congestion

One measure of the effectiveness of ARRs as a hedge against congestion is a comparison of the revenue received by the holders of ARRs and the congestion across the corresponding paths. The revenue which serves as a hedge for ARR holders comes from the FTR auctions while the hedge for FTR holders is provided by the congestion payments derived directly from the Day-Ahead Energy Market and the balancing energy market. Thus, ARRs are an indirect hedge against actual congestion in both the Day-Ahead Energy Market and the balancing energy market.

The comparison between the revenue received by ARR holders and the actual congestion experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market is presented by control zone in Table 8-25. ARRs and self scheduled FTRs that sink at an aggregate are assigned to a control zone if applicable.[46] Total revenue equals the ARR credits and the FTR credits from ARRs which are self scheduled as FTRs. The ARR credits do not include the credits for the portion of any ARR that was self scheduled as an FTR since ARR holders purchase self scheduled FTRs in the Annual FTR Auction and that revenue is then paid back to the ARR holders, netting the transaction to zero. ARR credits are calculated as the product of the ARR MW (excludes any self scheduled FTR MW) and the sink-minus-source price difference for the ARR path from the Annual FTR Auction.

FTR credits equal FTR target allocations adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and the congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are paid to FTR holders and, depending on market conditions, may be less than the target allocation. The FTR payout ratio equals the percentage of the target allocation that FTR holders actually receive as credits. The FTR payout ratio was 100 percent of the target allocation for the 2008 to 2009 planning period.

The “Congestion” column shows the amount of congestion in each control zone from the Day-Ahead Energy Market and the balancing energy market and includes only the congestion costs incurred by the organizations that hold ARRs or self scheduled FTRs. The last column shows the difference between the total revenue and the congestion for each ARR control zone sink.

Data shown are for the 2008 to 2009 planning period summed by ARR control zone sink. For example, the table shows that for the 2008 to 2009 planning period, ARRs allocated to the JCPL Control Zone received a total of $70.1 million in revenue which was the sum of $64.5 million in ARR credits and $5.6 million in credits for self scheduled FTRs. This total revenue was $15.7 million less than the congestion costs of $85.8 million from the Day-Ahead Energy Market and the balancing energy market incurred by organizations in the JCPL Control Zone that held ARRs or self scheduled FTRs.

46 For Table 8-25 through Table 8-28, aggregates are separated into their individual bus components and each bus is assigned to a control zone. The “PJM” Control Zone does not include all the buses in PJM, but does include all aggregate sinks that are external to PJM or buses that cannot otherwise be assigned to a specific control zone.

Table 8-25 ARR and self scheduled FTR congestion hedging by control zone: Planning period 2008 to 2009

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Hedged
AECO	$26,640,842	$5,126,844	$31,767,686	$87,321,948	($55,554,262)	36.4%
AEP	$4,952,682	$231,856,718	$236,809,400	$210,288,401	$26,520,999	>100%
AP	$50,310,148	$512,353,151	$562,663,299	$334,688,945	$227,974,354	>100%
BGE	$93,238,869	$4,134,804	$97,373,673	$2,288,903	$95,084,770	>100%
ComEd	$15,791,877	$12,658,294	$28,450,171	$164,815,901	($136,365,730)	17.3%
DAY	$9,353,214	$1,119,768	$10,472,982	$6,769,503	$3,703,479	>100%
DLCO	$4,691,151	$0	$4,691,151	$31,730,929	($27,039,778)	14.8%
Dominion	$24,970,748	$4,221,089	$29,191,837	$48,544,486	($19,352,649)	60.1%
DPL	$6,990,231	$246,078,596	$253,068,827	$108,153,653	$144,915,174	>100%
JCPL	$64,463,301	$5,636,585	$70,099,886	$85,816,579	($15,716,693)	81.7%
Met-Ed	$220,814	$28,242,556	$28,463,370	$48,289,989	($19,826,619)	58.9%
PECO	$4,336,906	$55,831,240	$60,168,146	($18,644,822)	$78,812,968	>100%
PENELEC	$49,024,464	$24,861,452	$73,885,916	$54,514,680	$19,371,236	>100%
Pepco	$58,344,157	$648,017	$58,992,174	$289,001,211	($230,009,037)	20.4%
PJM	$10,528,746	($9,203,133)	$1,325,613	$9,855,465	($8,529,852)	13.5%
PPL	$1,841,709	$63,076,348	$64,918,057	$32,505,809	$32,412,248	>100%
PSEG	$119,733,671	$17,949,360	$137,683,031	($3,415,832)	$141,098,863	>100%
RECO	$0	$0	$0	$6,870,494	($6,870,494)	0.0%
Total	$545,433,530	$1,204,591,689	$1,750,025,219	$1,499,396,241	$250,628,978	>100%

During the 2008 to 2009 planning period, congestion costs associated with the 112,011 MW of allocated ARRs were $1,499.4 million. As Table 8-8 indicates, 72,851 MW of ARRs were converted into FTRs through the self scheduling option, with 39,160 MW remaining as ARRs. The 39,160 MW of remaining ARRs provided $545.4 million of ARR credits, representing a hedge of 36.4 percent of the $1,499.4 million in congestion costs incurred, while the self scheduled FTRs provided $1,204.6 million of revenue, hedging an additional 80.3 percent of congestion costs. Total congestion was fully hedged by both. (See Table 8-25) The effectiveness of ARRs as a hedge depends both on the ARR value which is a function of the FTR auction prices, on congestion patterns in the Day-Ahead and Real-Time Energy Markets and on the FTR payout ratio.

Effectiveness of FTRs as a Hedge against Congestion

FTRs provide a direct hedge against congestion costs. Table 8-26 compares the total FTR credits and the total FTR auction revenues that sink in each control zone and the congestion costs in each control zone for the 2008 to 2009 planning period. FTRs that sink at an aggregate or a bus are assigned to a control zone if applicable. The "FTR Credits" column represents the total FTR target allocations for FTRs that sink in each control zone from the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any FTRs that were self scheduled from ARRs, adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR

MW and the congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are the product of the FTR target allocations and the FTR payout ratio. The FTR payout ratio was 100 percent of the target allocation for the 2007 to 2008 planning period. The "FTR Auction Revenue" column shows the amount paid for FTRs that sink in each control zone in the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any self scheduled FTRs. The FTR hedge is the difference between the FTR credits and the FTR auction revenue. The "Congestion" column shows the total amount of congestion in the Day-Ahead Energy Market and the balancing energy market in each control zone. The last column shows the difference between the FTR hedge and the congestion for each control zone.

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. That is, 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. For example, the table shows that for the 2008 to 2009 planning period, all FTRs sunk in the Pepco Control Zone received a total of $204.6 million in FTR credits (with -$26.0 million from counter flow FTRs and $230.6 million from prevailing flow FTRs) while these FTRs cost $260.9 million in the FTR auctions (with -$52.4 million from counter flow FTRs and $313.3 million from prevailing flow FTRs) resulting in a loss of -$56.3 million. This was not the case in every control zone. For example, the FTR credits received exceeded the cost of FTRs in the AEP Control Zone. Given that the cost of FTRs exceeded the FTR credits received, FTRs did not provide a hedge against congestion for this period. In the Pepco Control Zone, the total FTR position was $206.8 million less than the cost of congestion in the Day-Ahead Energy Market and the balancing energy market. All FTRs provided a hedge of -$741.4 million against $1,422.1 million in congestion costs incurred.[47]

47 The congestion costs in Table 8-25 are the congestion costs for organizations that held ARRs while the congestion costs in Table 8-26, Table 8-27 and Table 8-28 (2008 to 2009 planning period) are the congestion costs for all organizations. The congestion costs in Table 8-25 do not equal the congestion costs in Table 8-26, Table 8-27 and Table 8-28 (2008 to 2009 planning period) because the congestion costs in Table 8-25 include congestion only for organizations that held ARRs.

Table 8-26 FTR congestion hedging by control zone: Planning period 2008 to 2009

Control Zone	FTR Direction	FTR Credits	FTR Auction Revenue	FTR Hedge	Congestion	FTR Hedge - Congestion Difference	Percent Hedged
AECO	Counter Flow	($2,104,717)	($9,736,127)	$7,631,410			
	Prevailing Flow	$38,963,612	$42,669,675	($3,706,064)			
	Total	$36,858,894	$32,933,548	$3,925,346	$43,970,115	($40,044,770)	8.9%
AEP	Counter Flow	($66,608,764)	($112,426,082)	$45,817,317			
	Prevailing Flow	$276,411,670	$316,511,145	($40,099,475)			
	Total	$209,802,906	$204,085,063	$5,717,843	$155,842,889	($150,125,047)	3.7%
AP	Counter Flow	($37,785,200)	($52,972,978)	$15,187,778			
	Prevailing Flow	$565,711,180	$833,217,106	($267,505,926)			
	Total	$527,925,980	$780,244,128	($252,318,148)	$298,746,849	($551,064,997)	<0%
BGE	Counter Flow	($13,378,212)	($24,751,969)	$11,373,757			
	Prevailing Flow	$52,323,115	$81,912,465	($29,589,350)			
	Total	$38,944,903	$57,160,496	($18,215,593)	$89,929,323	($108,144,916)	<0%
ComEd	Counter Flow	($40,127,883)	($36,435,643)	($3,692,239)			
	Prevailing Flow	$13,975,621	$32,115,569	($18,139,948)			
	Total	($26,152,262)	($4,320,075)	($21,832,187)	$264,565,267	($286,397,454)	<0%
DAY	Counter Flow	($5,562,537)	($7,323,185)	$1,760,648			
	Prevailing Flow	$7,307,409	$5,296,615	$2,010,794			
	Total	$1,744,872	($2,026,571)	$3,771,443	$5,493,146	($1,721,704)	68.7%
DLCO	Counter Flow	($16,801,149)	($22,611,480)	$5,810,330			
	Prevailing Flow	$7,459,145	$6,325,094	$1,134,051			
	Total	($9,342,004)	($16,286,386)	$6,944,382	$14,972,671	($8,028,289)	46.4%
Dominion	Counter Flow	($24,949,028)	($64,995,263)	$40,046,235			
	Prevailing Flow	$369,161,337	$587,519,630	($218,358,294)			
	Total	$344,212,309	$522,524,367	($178,312,059)	$254,898,027	($433,210,086)	<0%
DPL	Counter Flow	($10,925,470)	($10,885,580)	($39,890)			
	Prevailing Flow	$61,148,336	$53,699,473	$7,448,863			
	Total	$50,222,866	$42,813,893	$7,408,973	$79,599,656	($72,190,683)	9.3%
JCPL	Counter Flow	($14,281,610)	($31,473,090)	$17,191,480			
	Prevailing Flow	$20,011,860	$135,728,462	($115,716,602)			
	Total	$5,730,251	$104,255,372	($98,525,121)	$92,985,545	($191,510,667)	<0%
Met-Ed	Counter Flow	($1,749,069)	($17,057,141)	$15,308,072			
	Prevailing Flow	$38,291,273	$77,247,955	($38,956,682)			
	Total	$36,542,204	$60,190,813	($23,648,610)	($1,271,642)	($22,376,968)	<0%
PECO	Counter Flow	($1,689,120)	($20,496,906)	$18,807,786			
	Prevailing Flow	$67,235,084	$97,218,293	($29,983,209)			
	Total	$65,545,964	$76,721,387	($11,175,423)	($47,350,955)	$36,175,533	<0%
PENELEC	Counter Flow	($51,999,686)	($96,975,856)	$44,976,170			
	Prevailing Flow	$170,697,684	$231,308,984	($60,611,300)			
	Total	$118,697,998	$134,333,128	($15,635,130)	$112,271,697	($127,906,827)	<0%
Pepco	Counter Flow	($26,020,597)	($52,417,603)	$26,397,006			
	Prevailing Flow	$230,620,973	$313,328,160	($82,707,187)			
	Total	$204,600,376	$260,910,557	($56,310,182)	$150,501,458	($206,811,640)	<0%
PJM	Counter Flow	($6,601,308)	($12,860,773)	$6,259,465			
	Prevailing Flow	$2,797,949	$15,856,630	($13,058,681)			
	Total	($3,803,359)	$2,995,857	($6,799,216)	($119,445,094)	$112,645,878	<0%
PPL	Counter Flow	($10,080,144)	($15,198,354)	$5,118,210			
	Prevailing Flow	$84,990,420	$97,234,669	($12,244,249)			
	Total	$74,910,276	$82,036,315	($7,126,039)	$4,627,831	($11,753,870)	<0%
PSEG	Counter Flow	($10,194,108)	($24,945,718)	$14,751,609			
	Prevailing Flow	$81,949,642	$173,322,349	($91,372,706)			
	Total	$71,755,534	$148,376,631	($76,621,097)	$15,850,146	($92,471,243)	<0%
RECO	Counter Flow	($99,442)	($139,574)	$40,132			
	Prevailing Flow	$103,319	$2,800,521	($2,697,202)			
	Total	$3,877	$2,660,947	($2,657,070)	$5,941,446	($8,598,516)	<0%
Total	Counter Flow	($340,958,046)	($613,703,323)	$272,745,277			
	Prevailing Flow	$2,089,159,629	$3,103,312,795	($1,014,153,166)			
	Total	$1,748,201,583	$2,489,609,472	($741,407,889)	$1,422,128,376	($2,163,536,265)	<0%

Effectiveness of ARRs and FTRs as a Hedge against Congestion

Table 8-27 compares the revenue for ARR and FTR holders and the congestion in both the Day-Ahead Energy Market and the balancing energy market for the 2008 to 2009 planning period. This compares the total hedge provided by all ARRs and all FTRs to the total congestion costs within each control zone. ARRs and FTRs that sink at an aggregate or a bus are assigned to a control zone if applicable. ARR credits are calculated as the product of the ARR MW and the price difference (sink minus source) for the ARR path from the Annual FTR Auction. The "FTR Credits" column represents the total FTR target allocation for FTRs that sink in each control zone from the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any FTRs that were self scheduled from ARRs, adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are the product of the FTR target allocations and the FTR payout ratio. The FTR payout ratio was 100 percent of the target allocation for the 2008 to 2009 planning period. The "FTR Auction Revenue" column shows the amount paid for FTRs that sink in each control zone in the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any ARRs that were self scheduled as FTRs. ARR holders that self schedule FTRs purchased the FTRs in the Annual FTR Auction and that revenue was then paid back to those ARR holders through ARR credits on a monthly basis throughout the planning period, ultimately netting the transaction to zero. The total ARR and FTR hedge is the sum of the ARR credits and the FTR credits minus the FTR auction revenue. The "Congestion" column shows the total amount of congestion in the Day-Ahead Energy Market and the balancing energy market in each control zone. The last column shows the difference between the total ARR and FTR hedge and the congestion cost for each control zone.

The results indicate that the value of ARRs and FTRs together were higher than total congestion costs by about $130.2 million because the positive value of the ARRs exceeded the net negative value of the FTRs.

During the 2008 to 2009 planning period, the 112,011 MW of cleared ARRs produced $2,361.3 million of ARR credits while the total of all FTR credits was $1,748.2 million. Together, the ARR credits and FTR credits provided $4,109.5 million in total revenue. When calculating the total ARR and FTR hedge, the cost to obtain the FTRs must be subtracted from the total ARR and FTR revenue. This cost is the sum of the FTR auction revenues, which was $2,489.6 million for the 2008 to 2009 planning period. The total ARR and FTR value equals $1,619.9 million, which is in excess of the $1,422.1 million of congestion in the Day-Ahead Energy Market and the balancing energy market. For example, the table shows that all ARRs and FTRs that sink in the AP Control Zone received $786.1 million in ARR credits and $527.9 million in FTR credits. After subtracting the cost of the FTRs, the FTR auction revenue of $780.2 million, the total ARR and FTR hedge was $533.8 million. The total value of the ARRs and FTRs was $235.1 million higher than the $298.7 million of congestion in the Day-Ahead Energy Market and the balancing energy market.

Table 8-27 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%

Table 8-28 shows that for the 2008 to 2009 planning period, the total value of the ARR and FTR positions was $130.2 million higher than the total congestion within PJM. All ARRs and FTRs fully covered the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM. For the first seven months of the 2009 to 2010 planning period, the FTR payout ratio was 97.7 percent of the target allocation. All ARRs and FTRs covered 93.5 percent of the total congestion costs within PJM for the first seven months of the 2009 to 2010 planning period. The total value of the ARR and FTR positions was less than the cost of congestion by $23.4 million.

Table 8-28 TARR and FTR congestion hedging: Planning periods 2008 to 2009 and 2009 to 2010[48]

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
2008/2009	$2,361,292,807	$1,748,201,585	$2,489,609,470	$1,619,884,922	$1,489,647,665	$130,237,257	>100%
2009/2010*	$747,598,320	$388,741,220	$799,140,566	$337,198,974	$360,608,751	($23,409,777)	93.5%

* Shows seven months ended 31-Dec-09

48 The FTR credits do not include after-the-fact adjustments. For the 2009 to 2010 planning period, the ARR credits were the total credits allocated to all ARR holders for the first seven months (June through December 2009) of this planning period, and the FTR Auction Revenue includes the net revenue in the Monthly Balance of Planning Period FTR Auctions for the first seven months of this planning period and the portion of Annual FTR Auction revenue distributed to the first seven months.

ARRs and FTRs as a Hedge against Total Real Time Energy Charges

The hedge provided by ARRs and self scheduled FTRs 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 direct measure of the net price of energy rather than a comparison of the ARR/FTR credits to an accounting measure of congestion. This is a measure of the value of the hedge against real time energy costs provided by ARRs received by loads during this period. Table 8-29 shows the results of this measure by control zone for January through December 2009. As an example, Table 8-29 shows the total value of ARR and self-scheduled FTR credits in the AP Control Zone was $204.6 million, which was 11.3 percent of the $1,815.0 in total real time energy charges in the AP Control Zone.

Table 8-29 ARRs and self-scheduled FTR credits as a hedge against energy charges by control zone: January through December, 2009

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Hedge	Total Energy Charges	Percent of Energy Charges Covered by ARR and Self-Scheduled FTR Credits
AECO	$20,597,972	$437,541	$21,035,513	$461,146,506	4.6%
AEP	$4,561,042	$144,550,225	$149,111,267	$4,521,818,925	3.3%
AP	$47,461,725	$157,111,180	$204,572,905	$1,814,978,586	11.3%
BGE	$65,812,175	$1,640,293	$67,452,468	$1,462,148,148	4.6%
ComEd	$15,063,621	$35,377,358	$50,440,979	$2,937,210,035	1.7%
DAY	$7,508,653	$624,238	$8,132,891	$579,595,373	1.4%
DLCO	$3,377,699	$1,324	$3,379,023	$468,046,410	0.7%
Dominion	$6,488,260	$109,517,031	$116,005,290	$3,930,796,513	3.0%
DPL	$19,933,162	$962,469	$20,895,631	$795,666,592	2.6%
JCPL	$43,154,697	$2,212,990	$45,367,687	$983,469,839	4.6%
Met-Ed	$155,199	$10,011,872	$10,167,070	$634,581,943	1.6%
PECO	$2,926,977	$14,173,419	$17,100,396	$1,691,108,089	1.0%
PENELEC	$33,746,839	$9,827,605	$43,574,444	$643,838,042	6.8%
Pepco	$36,917,119	$1,021,829	$37,938,948	$1,391,452,420	2.7%
PJM	$8,886,304	($9,087,024)	($200,719)	NA	NA
PPL	$1,408,223	$12,857,478	$14,265,700	$1,686,349,753	0.8%
PSEG	$98,728,236	$4,960,710	$103,688,945	$1,900,334,329	5.5%
RECO	($24,305)	$0	($24,305)	$61,457,329	(0.0%)
Total	$416,703,596	$496,200,538	$912,904,134	$26,008,223,006	3.5%

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. This is a direct measure of the net price of energy rather than a comparison of the FTR credits to an accounting measure of congestion. This is a measure of the value of the hedge against real time energy costs provided by FTRs purchased for this period. Table 8-30 shows the results of this measure by control zone for January through

December 2009. When the purchase cost of the FTRs exceeds the FTR credits, the hedge is negative.

Table 8-30 FTRs as a hedge against energy charges by control zone: January through December, 2009

Control Zone	FTR Credits (Excluding Self-Scheduled FTRs)	FTR Auction Revenue (Excluding Self-Scheduled FTRs)	Total FTR Hedge (Excluding Self-Scheduled FTRs)	Total Energy Charges	Percent of Energy Charges Covered by FTR Credits (Excluding Self-Scheduled FTRs)
AECO	$5,416,677	$24,348,793	($18,932,116)	$461,146,506	(4.1%)
AEP	$12,430,993	($32,434,705)	$44,865,698	$4,521,818,925	1.0%
AP	$19,798,820	$35,860,828	($16,062,008)	$1,814,978,586	(0.9%)
BGE	$28,212,716	$40,599,207	($12,386,491)	$1,462,148,148	(0.8%)
ComEd	$8,590,467	($7,760,858)	$16,351,326	$2,937,210,035	0.6%
DAY	$1,451,205	($1,579,623)	$3,030,828	$579,595,373	0.5%
DLCO	($1,702,295)	($9,462,717)	$7,760,422	$468,046,410	1.7%
Dominion	$19,609,059	$45,984,131	($26,375,072)	$3,930,796,513	(0.7%)
DPL	$13,767,438	$34,571,957	($20,804,519)	$795,666,592	(2.6%)
JCPL	$2,432,397	$51,098,545	($48,666,149)	$983,469,839	(4.9%)
Met-Ed	$3,262,702	$7,491,200	($4,228,498)	$634,581,943	(0.7%)
PECO	$3,116,099	$7,595,873	($4,479,775)	$1,691,108,089	(0.3%)
PENELEC	$41,509,540	$56,165,056	($14,655,516)	$643,838,042	(2.3%)
Pepco	$91,130,294	$150,832,795	($59,702,501)	$1,391,452,420	(4.3%)
PJM	$938,250	($6,595,056)	$7,533,305	NA	NA
PPL	$5,431,156	$8,745,511	($3,314,355)	$1,686,349,753	(0.2%)
PSEG	$21,897,739	$107,264,636	($85,366,897)	$1,900,334,329	(4.5%)
RECO	($510,771)	($473,088)	($37,684)	$61,457,329	(0.1%)
Total	$276,782,485	$512,252,486	($235,470,001)	$26,008,223,006	(0.9%)

Table 8-31 combines the results for the ARR related hedge and the FTR related hedge by zone. This is a measure of the total value of ARRs received by those who pay for the transmission system plus the total value of FTRs received by those who purchased FTRs in the FTR auctions. The combined ARR plus FTR credits covers the largest percentage of total energy charges in the AP Control Zone (10.4 percent), and the lowest percentage of total energy charges in the Pepco Control Zone (-1.6 percent).

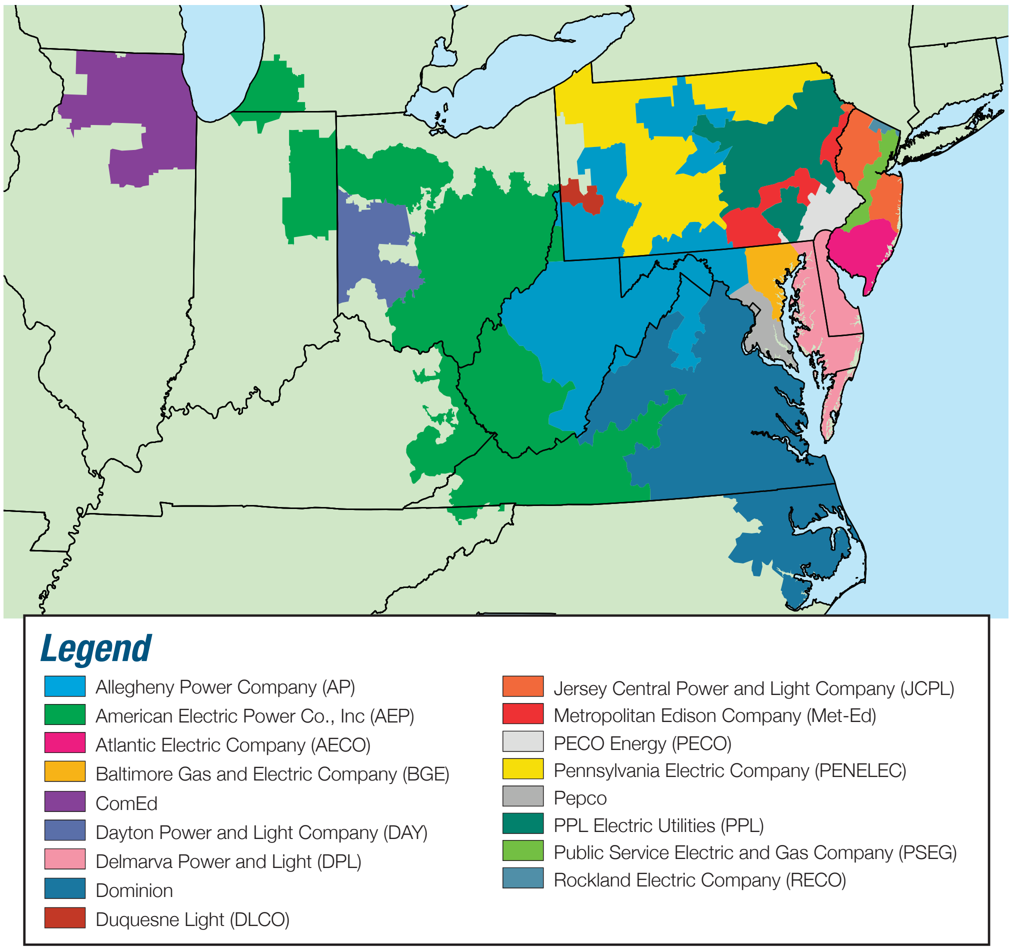
Table 8-31 ARRs and FTRs as a hedge against energy charges by control zone: Calendar year 2009

Control Zone	ARR Related Hedge (Including Self-Scheduled FTRs)	FTR Hedge (Excluding Self-Scheduled FTRs)	Total ARR and FTR Hedge	Total Energy Charges	Percent of Energy Charges Covered by ARR and FTR Credits
AECO	$21,035,513	($18,932,116)	$2,103,396	$461,146,506	0.5%
AEP	$149,111,267	$44,865,698	$193,976,965	$4,521,818,925	4.3%
AP	$204,572,905	($16,062,008)	$188,510,897	$1,814,978,586	10.4%
BGE	$67,452,468	($12,386,491)	$55,065,978	$1,462,148,148	3.8%
ComEd	$50,440,979	$16,351,326	$66,792,305	$2,937,210,035	2.3%
DAY	$8,132,891	$3,030,828	$11,163,719	$579,595,373	1.9%
DLCO	$3,379,023	$7,760,422	$11,139,445	$468,046,410	2.4%
Dominion	$116,005,290	($26,375,072)	$89,630,218	$3,930,796,513	2.3%
DPL	$20,895,631	($20,804,519)	$91,111	$795,666,592	0.0%
JCPL	$45,367,687	($48,666,149)	($3,298,461)	$983,469,839	(0.3%)
Met-Ed	$10,167,070	($4,228,498)	$5,938,573	$634,581,943	0.9%
PECO	$17,100,396	($4,479,775)	$12,620,622	$1,691,108,089	0.7%
PENELEC	$43,574,444	($14,655,516)	$28,918,928	$643,838,042	4.5%
Pepco	$37,938,948	($59,702,501)	($21,763,553)	$1,391,452,420	(1.6%)
PJM	($200,719)	$7,533,305	$7,332,586	NA	NA
PPL	$14,265,700	($3,314,355)	$10,951,346	$1,686,349,753	0.6%
PSEG	$103,688,945	($85,366,897)	$18,322,048	$1,900,334,329	1.0%
RECO	($24,305)	($37,684)	($61,989)	$61,457,329	(0.1%)
Total	$912,904,134	($235,470,001)	$677,434,133	$26,008,223,006	2.6%

APPENDIX A – PJM GEOGRAPHY

During 2009, the PJM geographic footprint encompassed 17 control zones located in Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

Figure A-1 PJM's footprint and its 17 control zones



Analysis of 2009 market results requires comparison to 2008 and certain other prior years. During calendar years 2006 through 2009 the PJM footprint was stable. During calendar years 2004 and 2005, however, PJM integrated five new control zones, three in 2004 and two in 2005. When making comparisons involving this period, the 2004, 2005 and 2006 state of the market reports referenced phases, each corresponding to market integration dates:[1]

1 See the *2004 State of the Market Report* (March 8, 2005) for more detailed descriptions of Phases 1, 2 and 3 and the *2005 State of the Market Report* (March 8, 2006) for more detailed descriptions of Phases 4 and 5.

- **Phase 1 (2004).** The four-month period from January 1, through April 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones,[2] and the Allegheny Power Company (AP) Control Zone.[3]

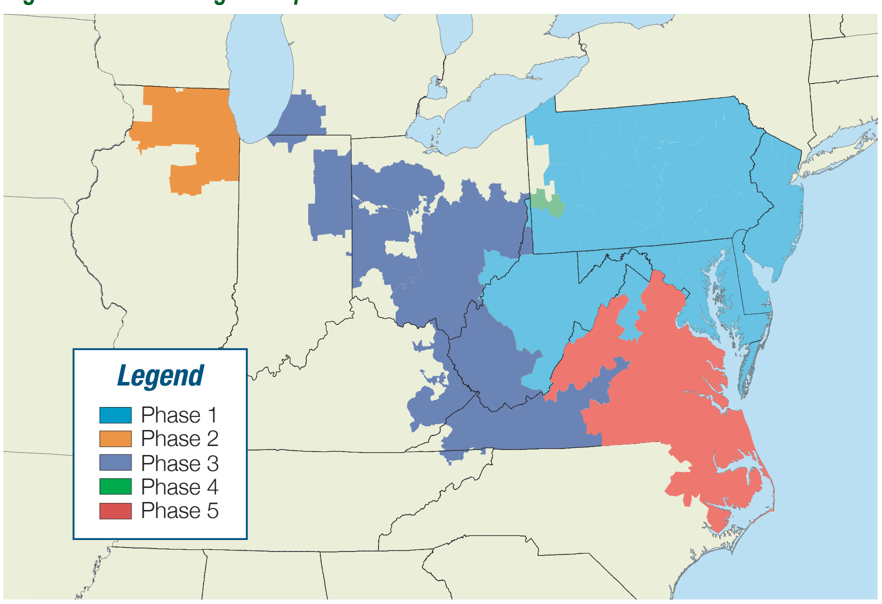
- **Phase 2 (2004).** The five-month period from May 1, through September 30, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Area.[4]

- **Phase 3 (2004).** The three-month period from October 1, through December 31, 2004, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone and the ComEd Control Zone plus the American Electric Power Control Zone (AEP) and The Dayton Power & Light Company Control Zone (DAY). The ComEd Control Area became the ComEd Control Zone on October 1.

- **Phase 4 (2005).** The four-month period from January 1, through April 30, 2005, during which PJM was comprised of the Mid-Atlantic Region, including its 11 zones, the AP Control Zone, the ComEd Control Zone, the AEP Control Zone and the DAY Control Zone plus the Duquesne Light Company (DLCO) Control Zone which was integrated into PJM on January 1, 2005.

- **Phase 5 (2005).** The eight-month period from May 1, through December 31, 2005, during which PJM was comprised of the Phase 4 elements plus the Dominion Control Zone which was integrated into PJM on May 1, 2005.

Figure A-2 PJM integration phases



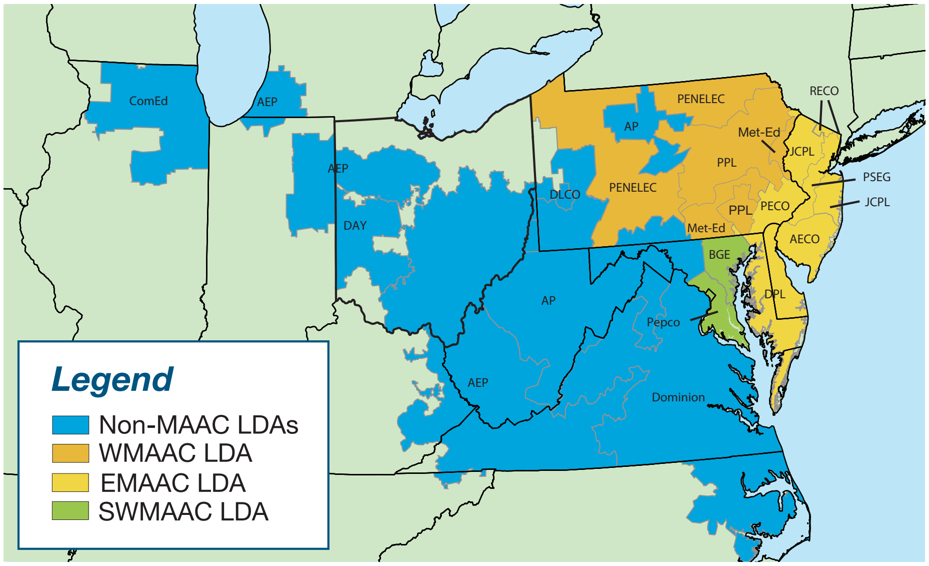
2 The Mid-Atlantic Region is comprised of the AECO, BGE, DPL, JCPL, Met-Ed, PECO, PENELEC, Pepco, PPL, PSEG and RECO control zones.

3 Zones, control zones and control areas are geographic areas that customarily bear the name of a large utility service provider operating within their boundaries. Names apply to the geographic area, not to any single company. The geographic areas did not change with the formalization of these concepts during PJM integrations. For simplicity, zones are referred to as control zones for all phases. The only exception is ComEd which is called the ComEd Control Area for Phase 2 only.

4 During the five-month period May 1, through September 30, 2004, the ComEd Control Zone (ComEd) was called the Northern Illinois Control Area (NICA).

A locational deliverability area (LDA) is a geographic area within PJM that has limited transmission capability to import capacity in the RPM design to satisfy its reliability requirements, as determined by PJM in connection with the preparation of the Regional Transmission Expansion Plan (RTEP) and as specified in Schedule 10.1 of the PJM "Reliability Assurance Agreement with Load-Serving Entities."[5]

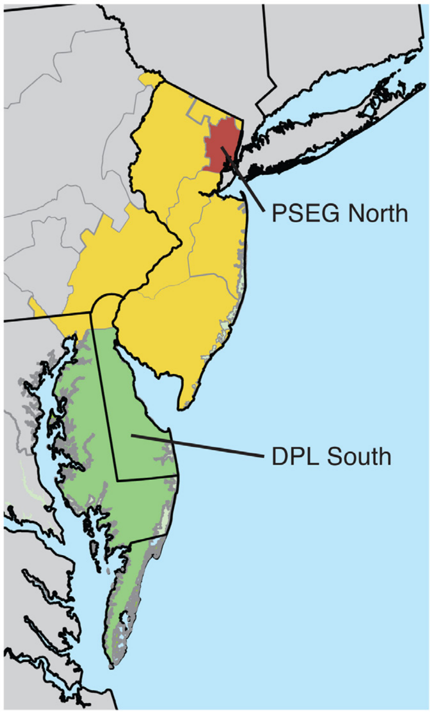
Figure A-3 PJM locational deliverability areas



In PJM's Reliability Pricing Model (RPM) Auctions, markets are defined dynamically by LDA. The regional transmission organization (RTO) market comprises the entire PJM footprint, unless an LDA is constrained. Each constrained LDA or group of LDAs is a separate market with a separate clearing price and the RTO market is the balance of the footprint.

For the 2007/2008 and 2008/2009 Base Residual Auctions, the defined markets were RTO, EMAAC and SWMAAC. For the 2009/2010 Base Residual Auction, the defined markets were RTO, MAAC+APS and SWMAAC. The MAAC+APS LDA consists of the WMAAC, EMAAC, SWMAAC LDAs, as shown in Figure A-3, plus the Allegheny Power System (APS or AP) zone as shown in Figure A-1. For the 2010/2011 Base Residual Auction, the defined markets were RTO and DPL South. The DPL South LDA is shown in Figure A-4. For the 2011/2012 Base Residual Auction, the only defined market was RTO. For the 2012/2013 Base Residual Auction, the defined markets were RTO, MAAC, EMAAC, PSEG North, and DPL South. The PSEG North LDA is shown in Figure A-4.

Figure A-4 PJM RPM EMAAC locational deliverability area markets, including PSEG North and DPL South



APPENDIX B – PJM MARKET MILESTONES

Year	Month	Event
1996	April	FERC Order 888, "Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities"
1997	April	Energy Market with cost-based offers and market-clearing prices
	November	FERC approval of ISO status for PJM
1998	April	Cost-based Energy LMP Market
1999	January	Daily Capacity Market
	March	FERC approval of market-based rates for PJM
	March	Monthly and Multimonthly Capacity Market
	March	FERC approval of Market Monitoring Plan
	April	Offer-based Energy LMP Market
	April	FTR Market
2000	June	Regulation Market
	June	Day-Ahead Energy Market
	July	Customer Load-Reduction Pilot Program
2001	June	PJM Emergency and Economic Load-Response Programs
2002	April	Integration of AP Control Zone into PJM Western Region
	June	PJM Emergency and Economic Load-Response Programs
	December	Spinning Reserve Market
	December	FERC approval of RTO status for PJM
2003	May	Annual FTR Auction
2004	May	Integration of ComEd Control Area into PJM
	October	Integration of AEP Control Zone into PJM Western Region
	October	Integration of DAY Control Zone into PJM Western Region
2005	January	Integration of DLCO Control Zone into PJM
	May	Integration of Dominion Control Zone into PJM
2006	May	Balance of Planning Period FTR Auction
2007	April	First RPM Auction
	June	Marginal loss component in LMPs
2008	June	Day Ahead Scheduling Reserve (DASR) Market
	August	Independent, External MMU created as Monitoring Analytics, LLC
	October	Long Term FTR Auction
	December	Modified Operating Reserve Accounting Rules
	December	Three Pivotal Supplier Test in Regulation Market

APPENDIX C – ENERGY MARKET

This appendix provides more detailed information about load, locational marginal prices (LMP) and offer-capped units.

Load

Frequency Distribution of Load

Table C-1 provides the frequency distributions of PJM accounting load by hour, for the calendar years 2005 to 2009.[1] The table shows the number of hours (frequency) and the cumulative percent of hours (cumulative percent) when the load was between 0 GWh and 20 GWh and then within a given 5-GWh load interval, or for the cumulative column, within the interval plus all the lower load intervals. The integrations of the AP Control Zone during 2002, the ComEd, AEP and DAY control zones during 2004 and the DLCO and Dominion control zones during 2005 mean that annual comparisons of load frequency are significantly affected by PJM's geographic growth.[2]

The frequency distribution of load in 2005 reflects the phased integrations of the DLCO and Dominion control zones. The most frequently occurring load interval was 75 GWh to 80 GWh at 16.1 percent of the hours. The next most frequently occurring interval was 65 GWh to 70 GWh at 13.4 percent of the hours. Load was less than 85 GWh for 72.9 percent of the time, less than 100 GWh for 88.2 percent of the time and less than 130 GWh for all but 22 hours.

For the year 2006, the most frequently occurring load interval was 75 GWh to 80 GWh at 17.1 percent of the hours. The next most frequently occurring interval was 80 GWh to 85 GWh at 15.3 percent of the hours. Load was less than 85 GWh for 70.9 percent of the hours, less than 100 GWh for 91.5 percent of the hours and less than 130 GWh for all but 50 hours.

During 2007, the most frequently occurring load interval was 80 GWh to 85 GWh at 15.3 percent of the hours. The next most frequently occurring interval was 75 GWh to 80 GWh at 14.0 percent of the hours. Load was less than 85 GWh for 62.6 percent of the hours, less than 100 GWh for 88.8 percent of the hours and less than 130 GWh for all but 15 hours.

During 2008, the most frequently occurring load interval was 75 GWh to 80 GWh at 17.5 percent of the hours. The next most frequently occurring interval was 80 GWh to 85 GWh at 13.8 percent of the hours. Load was less than 85 GWh for 68.8 percent of the hours, less than 100 GWh for 91.9 percent of the hours and less than 130 GWh for all hours.

During 2009, the most frequently occurring load interval was 75 GWh to 80 GWh at 17.0 percent of the hours. The next most frequently occurring interval was 70 GWh to 75 GWh at 15.3 percent of the hours. Load was less than 85 GWh for 76.2 percent of the hours, less than 100 GWh for 95.4 percent of the hours and less than 125 GWh for all hours.

1 The definitions of load are discussed in the *2009 State of the Market Report for PJM*, Volume II, Appendix I, "Load Definitions."

2 See the *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

Table C-1 Frequency distribution of PJM real-time, hourly load: Calendar years 2005 to 2009

	2005		2006		2007		2008		2009	
Load (GWh)	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
0 to 20	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
20 to 25	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
25 to 30	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
30 to 35	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
35 to 40	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
40 to 45	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
45 to 50	71	0.81%	2	0.02%	0	0.00%	0	0.00%	15	0.17%
50 to 55	286	4.08%	129	1.50%	79	0.90%	127	1.45%	376	4.46%
55 to 60	636	11.34%	504	7.25%	433	5.84%	517	7.33%	738	12.89%
60 to 65	843	20.96%	689	15.11%	637	13.12%	667	14.92%	836	22.43%
65 to 70	1,170	34.32%	967	26.15%	890	23.28%	941	25.64%	915	32.88%
70 to 75	1,089	46.75%	1,079	38.47%	878	33.30%	1,048	37.57%	1,342	48.20%
75 to 80	1,407	62.81%	1,501	55.61%	1,227	47.31%	1,535	55.04%	1,488	65.18%
80 to 85	887	72.93%	1,337	70.87%	1,338	62.58%	1,208	68.80%	966	76.21%
85 to 90	557	79.29%	943	81.63%	981	73.78%	916	79.22%	742	84.68%
90 to 95	453	84.46%	569	88.13%	741	82.24%	655	86.68%	549	90.95%
95 to 100	330	88.23%	295	91.50%	577	88.82%	457	91.88%	388	95.38%
100 to 105	308	91.75%	215	93.95%	382	93.18%	292	95.21%	205	97.72%
105 to 110	283	94.98%	161	95.79%	223	95.73%	181	97.27%	121	99.10%
110 to 115	169	96.91%	145	97.44%	179	97.77%	133	98.78%	48	99.65%
115 to 120	113	98.20%	102	98.61%	106	98.98%	58	99.44%	26	99.94%
120 to 125	93	99.26%	45	99.12%	43	99.47%	35	99.84%	5	100.00%
125 to 130	43	99.75%	27	99.43%	31	99.83%	14	100.00%	0	0.00%
130 to 135	22	100.00%	19	99.65%	12	99.97%	0	0.00%	0	0.00%
135 to 140	0	0.00%	19	99.86%	3	100.00%	0	0.00%	0	0.00%
> 140	0	0.00%	12	100.00%	0	0.00%	0	0.00%	0	0.00%

Off-Peak and On-Peak Load

Table C-2 presents summary load statistics for 1998 to 2009 for the off-peak and on-peak hours, while Table C-3 shows the percent change in load on a year-to-year basis. The on-peak period is defined for each weekday (Monday to Friday) as the hour ending 0800 to the hour ending 2300 Eastern Prevailing Time (EPT), excluding North American Electric Reliability Council (NERC) holidays. Table C-2 shows that on-peak load was 22.7 percent higher than off-peak load in 2009. Average load during on-peak hours in 2009 was 4.1 percent lower than in 2008. Off-peak load in 2009 was 4.8 percent lower than in 2008.[3](See Table C-3)

3 The increase in on-peak median load for 2006 was incorrectly reported as 3.2 percent in the *2006 State of the Market Report* rather than the 2.8 percent shown here.

Table C-2 Off-peak and on-peak load (MW): Calendar years 1998 to 2009

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	25,269	32,344	1.28	24,729	31,081	1.26	4,091	4,388	1.07
1999	26,454	33,269	1.26	25,780	31,950	1.24	4,947	4,824	0.98
2000	26,917	33,797	1.26	26,313	32,757	1.24	4,466	4,181	0.94
2001	26,804	34,303	1.28	26,433	33,076	1.25	4,225	4,851	1.15
2002	31,734	40,314	1.27	30,590	38,365	1.25	6,111	7,464	1.22
2003	33,598	41,755	1.24	32,973	40,802	1.24	5,545	5,424	0.98
2004	44,631	56,020	1.26	43,028	56,578	1.31	10,845	12,595	1.16
2005	70,291	87,164	1.24	68,049	82,503	1.21	12,733	15,236	1.20
2006	71,810	88,323	1.23	70,300	84,810	1.21	11,348	12,662	1.12
2007	73,499	91,066	1.24	71,751	88,494	1.23	11,501	11,926	1.04
2008	72,175	87,915	1.22	70,516	85,431	1.21	11,378	11,205	0.98
2009	68,745	84,337	1.23	67,159	81,825	1.22	10,924	10,523	0.96

Table C-3 Multiyear change in load: Calendar years 1998 to 2009

	Average			Median			Standard Deviation		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
1998	NA	NA	NA	NA	NA	NA	NA	NA	NA
1999	4.7%	2.9%	(1.6%)	4.3%	2.8%	(1.6%)	20.9%	9.9%	(8.4%)
2000	1.8%	1.6%	0.0%	2.1%	2.5%	0.0%	(9.7%)	(13.3%)	(4.1%)
2001	(0.4%)	1.5%	1.6%	0.5%	1.0%	0.8%	(5.4%)	16.0%	22.3%
2002	18.4%	17.5%	(0.8%)	15.7%	16.0%	0.0%	44.6%	53.9%	6.1%
2003	5.9%	3.6%	(2.4%)	7.8%	6.4%	(0.8%)	(9.3%)	(27.3%)	(19.7%)
2004	32.8%	34.2%	1.6%	30.5%	38.7%	5.6%	95.6%	132.2%	18.4%
2005	57.5%	55.6%	(1.6%)	58.2%	45.8%	(7.6%)	17.4%	21.0%	3.4%
2006	2.2%	1.3%	(0.8%)	3.3%	2.8%	0.0%	(10.9%)	(16.9%)	(6.7%)
2007	2.4%	3.1%	0.8%	2.1%	4.3%	1.7%	1.3%	(5.8%)	(7.1%)
2008	(1.8%)	(3.5%)	(1.6%)	(1.7%)	(3.5%)	(1.6%)	(1.1%)	(6.0%)	(5.8%)
2009	(4.8%)	(4.1%)	0.8%	(4.8%)	(4.2%)	0.8%	(4.0%)	(6.1%)	(2.0%)

Locational Marginal Price (LMP)

In assessing changes in LMP over time, the Market Monitoring Unit (MMU) examines three measures: simple LMP, load-weighted LMP and fuel-cost-adjusted, load-weighted LMP. Simple LMP measures the change in reported price. Load-weighted LMP measures the change in reported price weighted by the actual hourly MWh load to reflect what customers actually pay for energy. Fuel-cost-adjusted, load-weighted LMP measures the change in reported price actually paid by load after accounting for the change in price that reflects shifts in underlying fuel prices.[4]

Real-Time LMP

Frequency Distribution of Real-Time LMP

Table C-4 provides frequency distributions of PJM real-time hourly LMP for the calendar years 2005 to 2009. The table shows the number of hours (frequency) and the cumulative percent of hours (cumulative percent) when the hourly PJM LMP was within a given $10 per MWh price interval and lower than $300 per MWh, or within a given $100 per MWh price interval and higher than $300 per MWh, or for the cumulative column, within the interval plus all the lower price intervals.

In 2005, LMP occurred in the $30 per MWh to $40 per MWh interval most frequently at 20.5 percent of the time and in the $20 per MWh to $30 per MWh interval at 14.7 percent of the time. In 2005, LMP was less than $60 per MWh for 63.2 percent of the hours, less than $100 per MWh for 87.4 percent of the hours and LMP was $200 per MWh or greater for 35 hours (0.4 percent of the hours). In 2006, LMP was in the $20 per MWh to $30 per MWh interval most frequently (22.4 percent of the time) and in the $30 per MWh to $40 per MWh interval next most frequently (21.0 percent of the hours). In 2007, LMP was in the $20 per MWh to $30 per MWh interval most frequently (17.9 percent of the time) and in the $30 per MWh to $40 per MWh interval next most frequently (16.8 percent of the hours). In 2007, LMP was $60 per MWh or less for 60.7 percent of the hours and was $100 per MWh or less for 91.0 percent of the hours. LMP was more than $200 per MWh for 35 hours (0.4 percent of the hours). In 2008, LMP was in the $40 per MWh to $50 per MWh interval most frequently (17.5 percent of the time) and in the $30 per MWh to $40 per MWh interval next most frequently (16.4 percent of the hours). In 2009, LMP was in the $20 per MWh to $30 per MWh interval most frequently (33.9 percent of the hours) and in the $30 per MWh to $40 per MWh interval next most frequently (33.7 percent of the hours).

4 See the *2009 State of the Market Report for PJM*, Volume II, Appendix H, "Calculating Locational Marginal Price."

Table C-4 Frequency distribution by hours of PJM Real-Time Energy Market LMP (Dollars per MWh): Calendar years 2005 to 2009

	2005		2006		2007		2008		2009	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	142	1.62%	85	0.97%	56	0.64%	94	1.07%	117	1.34%
$10 to $20	259	4.58%	247	3.79%	185	2.75%	129	2.54%	218	3.82%
$20 to $30	1,290	19.30%	1,958	26.14%	1,571	20.68%	490	8.12%	2,970	37.73%
$30 to $40	1,793	39.77%	1,840	47.15%	1,470	37.47%	1,443	24.54%	2,951	71.42%
$40 to $50	1,172	53.15%	1,405	63.18%	1,108	50.11%	1,533	42.00%	1,269	85.90%
$50 to $60	877	63.16%	1,040	75.06%	931	60.74%	1,212	55.79%	555	92.24%
$60 to $70	730	71.50%	662	82.61%	827	70.18%	845	65.41%	276	95.39%
$70 to $80	568	77.98%	479	88.08%	726	78.47%	709	73.49%	151	97.11%
$80 to $90	453	83.15%	347	92.04%	646	85.84%	502	79.20%	95	98.20%
$90 to $100	374	87.42%	230	94.67%	451	90.99%	385	83.58%	62	98.90%
$100 to $110	297	90.81%	162	96.52%	240	93.73%	352	87.59%	30	99.25%
$110 to $120	208	93.18%	95	97.60%	178	95.76%	265	90.61%	21	99.49%
$120 to $130	159	95.00%	61	98.30%	110	97.02%	199	92.87%	15	99.66%
$130 to $140	110	96.26%	46	98.82%	76	97.89%	144	94.51%	7	99.74%
$140 to $150	94	97.33%	27	99.13%	53	98.49%	111	95.78%	9	99.84%
$150 to $160	53	97.93%	16	99.32%	26	98.79%	102	96.94%	3	99.87%
$160 to $170	57	98.58%	11	99.44%	29	99.12%	68	97.71%	3	99.91%
$170 to $180	51	99.17%	6	99.51%	18	99.33%	52	98.30%	5	99.97%
$180 to $190	22	99.42%	3	99.54%	9	99.43%	45	98.82%	0	99.97%
$190 to $200	16	99.60%	5	99.60%	15	99.60%	29	99.15%	1	99.98%
$200 to $210	12	99.74%	3	99.63%	6	99.67%	20	99.37%	1	99.99%
$210 to $220	10	99.85%	7	99.71%	4	99.71%	11	99.50%	1	100.00%
$220 to $230	5	99.91%	1	99.73%	4	99.76%	14	99.66%	0	0.00%
$230 to $240	1	99.92%	1	99.74%	2	99.78%	10	99.77%	0	0.00%
$240 to $250	1	99.93%	1	99.75%	5	99.84%	2	99.80%	0	0.00%
$250 to $260	3	99.97%	1	99.76%	2	99.86%	5	99.85%	0	0.00%
$260 to $270	2	99.99%	0	99.76%	4	99.91%	4	99.90%	0	0.00%
$270 to $280	0	99.99%	3	99.79%	0	99.91%	1	99.91%	0	0.00%
$280 to $290	1	100.00%	1	99.81%	0	99.91%	1	99.92%	0	0.00%
$290 to $300	0	0.00%	0	99.81%	0	99.91%	0	99.92%	0	0.00%
$300 to $400	0	0.00%	11	99.93%	2	99.93%	6	99.99%	0	0.00%
$400 to $500	0	0.00%	2	99.95%	4	99.98%	1	100.00%	0	0.00%
$500 to $600	0	0.00%	1	99.97%	1	99.99%	0	0.00%	0	0.00%
$600 to $700	0	0.00%	1	99.98%	1	100.00%	0	0.00%	0	0.00%
> $700	0	0.00%	2	100.00%	0	0.00%	0	0.00%	0	0.00%

Off-Peak and On-Peak, PJM Real-Time, Load-Weighted LMP: 2008 to 2009

Table C-5 shows load-weighted, average LMP for 2008 and 2009 during off-peak and on-peak periods. In 2009, the on-peak, load-weighted LMP was 30.2 percent higher than the off-peak LMP, while in 2008, it was 45.8 percent higher. On-peak, load-weighted, average LMP in 2009 was 47.6 percent lower than in 2008. Off-peak, load-weighted LMP in 2009 was 41.3 percent lower than in 2008. The on-peak median LMP was lower in 2009 than in 2008 by 47.6 percent; off-peak median LMP was lower in 2009 than in 2008 by 35.4 percent. Dispersion in load-weighted LMP, as indicated by standard deviation, was 56.0 percent lower in 2009 than in 2008 during on-peak hours and was 53.6 percent lower during off-peak hours. Since the mean was above the median during on-peak and off-peak hours, both showed a positive skewness. The mean was, however, proportionately higher than the median in 2009 as compared to 2008 during on-peak periods (14.3 percent in 2009 compared to 14.2 percent in 2008).

Table C-5 Off-peak and on-peak, PJM load-weighted, average LMP (Dollars per MWh): Calendar years 2008 to 2009

	2008			2009			Difference 2008 to 2009		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
Average	$57.55	$83.90	1.46	$33.76	$43.95	1.30	(41.3%)	(47.6%)	(10.7%)
Median	$45.43	$73.47	1.62	$29.33	$38.46	1.31	(35.4%)	(47.6%)	(18.9%)
Standard deviation	$36.64	$40.72	1.11	$16.99	$17.93	1.06	(53.6%)	(56.0%)	(5.0%)

Off-Peak and On-Peak, Real-Time, Fuel-Cost-Adjusted, Load-Weighted, Average LMP

In a competitive market, changes in LMP result from changes in demand and changes in supply. As competitive offers are equivalent to the marginal cost of generation and fuel costs make up about 88 percent of marginal cost on average for marginal units, fuel cost is a key factor affecting supply and, therefore, the competitive clearing price. In a competitive market, if fuel costs increase and nothing else changes, the competitive price also increases.

The impact of fuel cost on LMP depends on the fuel burned by the marginal units. To account for differences in the impact of fuel costs on prices between different time periods, the fuel-cost-adjusted, load-weighted LMP is used to compare load-weighted LMPs using fuel costs from a base period.[5]

Table C-6 shows the real-time, load-weighted, average LMP for 2008 and the real-time, fuel-cost-adjusted, load-weighted, average LMP for 2009 for on-peak and off-peak hours. During on-peak hours, the real-time, fuel-cost-adjusted, load-weighted, average LMP in 2009 decreased by 13.3 percent over the real-time, load-weighted LMP in 2008. The real-time, fuel-cost-adjusted, load-weighted LMP in 2009 decreased by 6.3 percent in the off-peak hours compared to the real-time, load-weighted LMP in 2008.

5 See the *2009 State of the Market Report for PJM*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table C-6 On-peak and off-peak real-time PJM fuel-cost-adjusted, load-weighted, average LMP (Dollars per MWh): Calendar year 2009

	2008 Load-Weighted LMP	2009 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
On Peak	$83.90	$72.70	(13.3%)
Off Peak	$57.55	$53.92	(6.3%)

PJM Real-Time, Load-Weighted LMP during Constrained Hours

Table C-7 shows that the PJM load-weighted, average LMP during constrained hours was 43.9 percent lower in 2009 than it had been in 2008.[6] The load-weighted, median LMP during constrained hours was 40.9 percent lower in 2009 than in 2008 and the standard deviation was 54.6 percent lower in 2009 than in 2008.[7]

Table C-7 PJM real-time load-weighted, average LMP during constrained hours (Dollars per MWh): Calendar years 2008 to 2009

	2008	2009	Difference
Average	$72.90	$40.88	(43.9%)
Median	$60.53	$35.75	(40.9%)
Standard deviation	$41.92	$19.02	(54.6%)

Table C-8 provides a comparison of PJM load-weighted, average LMP during constrained and unconstrained hours for 2008 and 2009. In 2009, load-weighted, average LMP during constrained hours was 25.0 percent higher than load-weighted, average LMP during unconstrained hours. The comparable number for 2008 was 22.5 percent.[8]

Table C-8 PJM load-weighted, average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar years 2008 to 2009

	2008			2009		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$59.49	$72.90	22.5%	$32.71	$40.88	25.0%
Median	$53.52	$60.53	13.1%	$29.95	$35.75	19.3%
Standard deviation	$31.68	$41.92	32.3%	$13.26	$19.02	43.4%

6 A constrained hour, or a constraint hour, is any hour during which one or more facilities are congested. Since the *2006 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 has been measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is also consistent with the way in which PJM reports real-time congestion. In the *2005 State of the Market Report for PJM*, an hour was considered constrained if one or more facilities were constrained for four or more of the 12 five-minute intervals in that hour. In the *2004 State of the Market Report for PJM*, this appendix defined a congested hour as one in which the difference in LMP between at least two buses in that hour was greater than $1.00.

7 The average real-time, load-weighted LMP in constrained hours for 2008 changed from $72.28 to $72.90, the median changed from $60.00 to $60.53, and the standard deviation changed from $41.58 to $41.92, compared to what was reported in the 2008 State of the Market Report for PJM due to an increase in the number of constrained hours. The change resulted from the correction of a data error.

8 The average real-time, load-weighted LMP on unconstrained hours in 2008 changed from $64.94 to $59.49, the median changed from $56.52 to $53.52, and the standard deviation changed from $36.89 to $31.68, compared to what was reported in the *2008 State of the Market Report for PJM* due to an increase in the number of constrained hours. The change resulted from the correction of a data error.

Table C-9 shows the number of hours and the number of constrained hours during each month in 2008 and 2009. There were 6,657 constrained hours in 2009 and 7,606 in 2008, an decrease of approximately 12.5 percent. Table C-9 also shows that the average number of constrained hours per month was lower in 2009 than in 2008, with 555 per month in 2009 versus 634 per month in 2008.[9]

Table C-9 PJM real-time constrained hours: Calendar years 2008 to 2009

	2008 Constrained Hours	2009 Constrained Hours	Total Hours
Jan	638	701	744
Feb	507	571	696
Mar	560	596	743
Apr	671	552	720
May	638	439	744
Jun	697	557	720
Jul	711	536	744
Aug	648	623	744
Sep	673	494	720
Oct	718	562	744
Nov	591	520	721
Dec	554	506	744
Avg	634	555	732

Day-Ahead and Real-Time LMP

On average, prices in the Real-Time Energy Market in 2009 were slightly higher than those in the Day-Ahead Energy Market and real-time prices showed greater dispersion. This pattern of system average LMP distribution for 2009 can be seen by comparing Table C-4 and Table C-10. Table C-10 shows frequency distributions of PJM day-ahead hourly LMP for the calendar years 2005 to 2009. Together the tables show the frequency distribution by hours for the two markets. In PJM's Real-Time Energy Market, the most frequently occurring price interval was the $20 per MWh to $30 per MWh with 33.9 percent of the hours in 2009. In the PJM Day-Ahead Energy Market, the most frequently occurring price interval was the $30 per MWh to $40 per MWh interval with 36.8 percent of the hours in 2009. The standard deviation of the simple average real-time LMP is higher than that of simple average day-ahead LMP ($17.12 and $13.39) and the standard deviation of the load-weighted real-time LMP is higher than that of load-weighted day-ahead LMP ($18.21 and $14.03). In the Real-Time Energy Market, prices were above $100 per MWh for 96 hours (1.1 percent of the hours), reaching a high for the year of $212.14 per MWh on January 16, 2009, during the hour ending 700 EPT. In the Day-Ahead Energy Market, prices were above $100 per MWh for 27 hours (0.3 percent of the hours) and reached a high for the year of $123.59 per MWh on March 3, 2009, during the hour ending 800 EPT.

9 The average number of constrained hours in July, 2008 changed from 513 to 711, compared to what was reported in the *2008 State of the Market Report for PJM*. The change resulted from the correction of a data error.

Table C-10 Frequency distribution by hours of PJM Day-Ahead Energy Market LMP (Dollars per MWh): Calendar years 2005 to 2009

	2005		2006		2007		2008		2009	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
$10 and less	47	0.54%	11	0.13%	3	0.03%	0	0.00%	23	0.26%
$10 to $20	162	2.39%	147	1.80%	88	1.04%	19	0.22%	343	4.18%
$20 to $30	1,022	14.05%	1,610	20.18%	1,291	15.78%	320	3.86%	2,380	31.35%
$30 to $40	1,753	34.06%	1,747	40.13%	1,495	32.84%	1,148	16.93%	3,221	68.12%
$40 to $50	1,382	49.84%	1,890	61.70%	1,221	46.78%	1,546	34.53%	1,717	87.72%
$50 to $60	1,102	62.42%	1,364	77.27%	1,266	61.23%	1,491	51.50%	557	94.08%
$60 to $70	812	71.69%	905	87.60%	1,301	76.08%	1,107	64.11%	253	96.96%
$70 to $80	686	79.52%	524	93.58%	939	86.80%	942	74.83%	138	98.54%
$80 to $90	524	85.50%	237	96.29%	504	92.56%	682	82.59%	68	99.32%
$90 to $100	388	89.93%	145	97.95%	264	95.57%	542	88.76%	33	99.69%
$100 to $110	263	92.93%	65	98.69%	155	97.34%	289	92.05%	19	99.91%
$110 to $120	207	95.30%	38	99.12%	104	98.53%	193	94.25%	6	99.98%
$120 to $130	151	97.02%	11	99.25%	59	99.20%	131	95.74%	2	100.00%
$130 to $140	102	98.18%	8	99.34%	33	99.58%	112	97.02%	0	0.00%
$140 to $150	64	98.92%	8	99.43%	13	99.73%	67	97.78%	0	0.00%
$150 to $160	46	99.44%	7	99.51%	8	99.82%	54	98.39%	0	0.00%
$160 to $170	27	99.75%	6	99.58%	7	99.90%	46	98.92%	0	0.00%
$170 to $180	11	99.87%	6	99.65%	3	99.93%	23	99.18%	0	0.00%
$180 to $190	8	99.97%	3	99.68%	4	99.98%	20	99.41%	0	0.00%
$190 to $200	1	99.98%	3	99.71%	1	99.99%	16	99.59%	0	0.00%
$200 to $210	2	100.00%	3	99.75%	1	100.00%	8	99.68%	0	0.00%
$210 to $220	0	0.00%	3	99.78%	0	0.00%	9	99.78%	0	0.00%
$220 to $230	0	0.00%	1	99.79%	0	0.00%	4	99.83%	0	0.00%
$230 to $240	0	0.00%	3	99.83%	0	0.00%	3	99.86%	0	0.00%
$240 to $250	0	0.00%	2	99.85%	0	0.00%	2	99.89%	0	0.00%
$250 to $260	0	0.00%	1	99.86%	0	0.00%	0	99.89%	0	0.00%
$260 to $270	0	0.00%	2	99.89%	0	0.00%	4	99.93%	0	0.00%
$270 to $280	0	0.00%	1	99.90%	0	0.00%	0	99.93%	0	0.00%
$280 to $290	0	0.00%	1	99.91%	0	0.00%	2	99.95%	0	0.00%
$290 to $300	0	0.00%	1	99.92%	0	0.00%	2	99.98%	0	0.00%
>$300	0	0.00%	7	100.00%	0	0.00%	2	100.00%	0	0.00%

Off-Peak and On-Peak, Day-Ahead and Real-Time, Simple Average LMP

Table C-11 shows PJM simple average LMP during off-peak and on-peak periods for the Day-Ahead and Real-Time Energy Markets during calendar year 2009. On-peak, day-ahead and real-time, average LMPs were 34.9 percent and 33.2 percent higher, than the corresponding off-peak average LMPs. Since the mean was above the median in these markets, both showed a positive skewness. The mean was, however, proportionately higher than the median in the Real-Time Energy Market as compared to the Day-Ahead Energy Market during both on-peak and off-peak periods (13.8 percent and 12.6 percent compared to 7.9 percent and 9.6 percent). The differences reflect larger positive skewness in the Real-Time Energy Market.

Figure C-1 and Figure C-2 show the difference between real-time and day-ahead LMP during calendar year 2009 during the on-peak and off-peak hours. The difference between real-time and day-ahead average LMP during on-peak hours was $0.14 per MWh. (Day-ahead LMP was higher than real-time LMP.) During the off-peak hours, the difference between real-time and day-ahead average LMP was $0.28 per MWh. (Day-ahead LMP was lower than real-time LMP.)

Table C-11 Off-peak and on-peak, simple average LMP (Dollars per MWh): Calendar year 2009

	Day Ahead			Real Time			Difference in Real Time Relative to Day Ahead		
	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak	Off Peak	On Peak	On Peak/ Off Peak
Average	$31.81	$42.91	1.35	$32.10	$42.76	1.33	0.9%	(0.3%)	(1.2%)
Median	$29.02	$39.78	1.37	$28.49	$37.58	1.32	(1.8%)	(5.5%)	(3.8%)
Standard deviation	$11.82	$12.60	1.07	$15.63	$16.98	1.09	32.2%	34.7%	1.9%

Figure C-1 Hourly real-time LMP minus day-ahead LMP (On-peak hours): Calendar year 2009

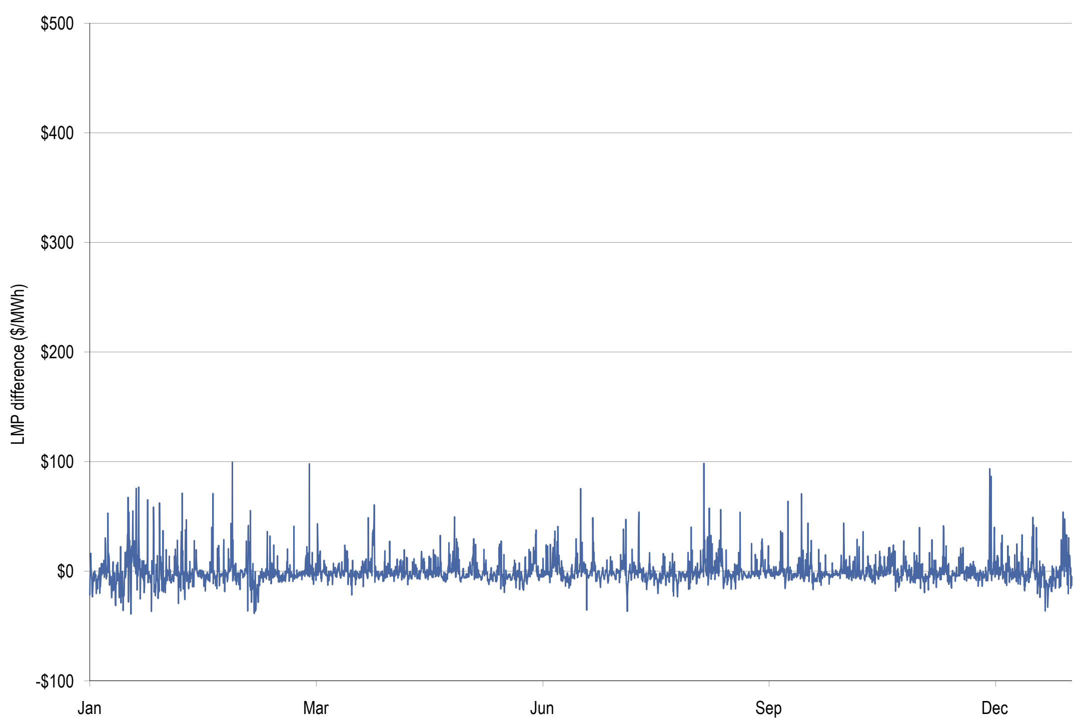
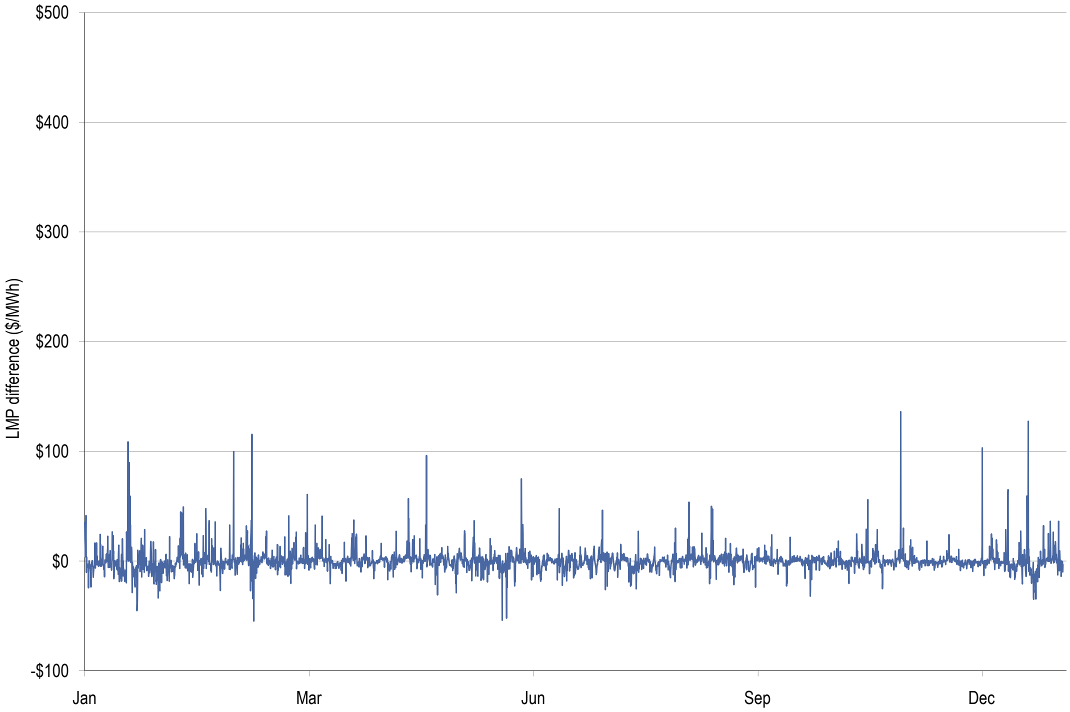


Figure C-2 Hourly real-time LMP minus day-ahead LMP (Off-peak hours): Calendar year 2009



On-Peak and Off-Peak, Zonal, Day-Ahead and Real-Time, Simple Average LMP

Table C-12 and Table C-13 show the on-peak and off-peak, simple average LMPs for each zone in the Day-Ahead and Real-Time Energy Markets during calendar year 2009. The zone with the maximum difference between on-peak real-time and day-ahead LMP was the AECO Control Zone with a real-time, on-peak, zonal LMP that was $1.24 lower than its day-ahead, on-peak, zonal LMP. The AEP Control Zone had the smallest difference with its real-time, on-peak, zonal LMP $0.12 lower than its day-ahead, on-peak, zonal LMP. (See Table C-12) The DLCO Control Zone had the largest difference between off-peak zonal, real-time and day-ahead LMP, with real-time LMP that was $0.94 higher than day-ahead LMP. The zone with the smallest difference between off-peak, zonal, real-time and day-ahead LMP was the PENELEC Control Zone with a real-time LMP that was $0.02 higher than day-ahead LMP. (See Table C-13)

Table C-12 On-peak, zonal, simple average day-ahead and real-time LMP (Dollars per MWh): Calendar year 2009

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$47.98	$46.73	($1.24)	(2.66%)
AEP	$38.29	$38.17	($0.12)	(0.33%)
AP	$43.38	$43.97	$0.58	1.33%
BGE	$49.14	$48.03	($1.11)	(2.32%)
ComEd	$35.24	$35.39	$0.15	0.41%
DAY	$37.91	$38.30	$0.40	1.03%
DLCO	$37.59	$37.36	($0.23)	(0.62%)
Dominion	$46.25	$45.51	($0.74)	(1.62%)
DPL	$48.14	$47.40	($0.74)	(1.55%)
JCPL	$47.81	$47.19	($0.62)	(1.32%)
Met-Ed	$46.51	$46.00	($0.51)	(1.12%)
PECO	$46.96	$45.80	($1.16)	(2.53%)
PENELEC	$42.63	$42.09	($0.54)	(1.28%)
Pepco	$49.19	$48.65	($0.54)	(1.10%)
PPL	$46.08	$45.38	($0.70)	(1.55%)
PSEG	$48.42	$47.73	($0.70)	(1.46%)
RECO	$47.27	$46.88	($0.39)	(0.84%)

Table C-13 Off-peak, zonal, simple average LMP (Dollars per MWh): Calendar year 2009

	Day Ahead	Real Time	Difference	Difference as Percent Real Time
AECO	$35.71	$35.35	($0.35)	(1.00%)
AEP	$29.18	$29.64	$0.46	1.54%
AP	$32.90	$33.30	$0.40	1.21%
BGE	$36.79	$36.17	($0.63)	(1.74%)
ComEd	$23.41	$23.48	$0.07	0.28%
DAY	$28.57	$29.27	$0.70	2.39%
DLCO	$27.71	$28.65	$0.94	3.29%
Dominion	$35.60	$35.16	($0.44)	(1.26%)
DPL	$36.11	$35.81	($0.29)	(0.82%)
JCPL	$35.69	$35.42	($0.27)	(0.75%)
Met-Ed	$34.93	$34.61	($0.32)	(0.92%)
PECO	$35.38	$34.90	($0.48)	(1.38%)
PENELEC	$32.23	$32.25	$0.02	0.06%
Pepco	$36.70	$35.92	($0.77)	(2.15%)
PPL	$34.46	$34.22	($0.24)	(0.70%)
PSEG	$36.06	$35.60	($0.45)	(1.28%)
RECO	$35.34	$34.63	($0.71)	(2.06%)

PJM Day-Ahead and Real-Time, Simple Average LMP during Constrained Hours

Table C-14 shows the number of constrained hours for the Day-Ahead and Real-Time Energy Markets and the total number of hours in each month for 2009. Overall, there were 6,657 constrained hours in the Real-Time Energy Market and 8,485 constrained hours in the Day-Ahead Energy Market. Table C-14 shows that in every month of calendar year 2009, excluding month of June, the number of constrained hours in the Day-Ahead Energy Market exceeded those in the Real-Time Energy Market. Over the year, the Day-Ahead Energy Market had 27.5 percent more constrained hours than the Real-Time Energy Market.

Table C-14 PJM day-ahead and real-time, market-constrained hours: Calendar year 2009

	DA Constrained Hours	RT Constrained Hours	Total Hours
Jan	744	701	744
Feb	672	571	672
Mar	741	596	743
Apr	720	552	720
May	741	439	744
Jun	552	557	720
Jul	744	536	744
Aug	744	623	744
Sep	720	494	720
Oct	736	562	744
Nov	681	520	721
Dec	690	506	744
Avg	707	555	730

Table C-15 shows PJM simple average LMP during constrained and unconstrained hours in the Day-Ahead and Real-Time Energy Markets. In the Day-Ahead Energy Market, average LMP during constrained hours was 1.5 percent higher than average LMP during unconstrained hours.[10] In the Real-Time Energy Market, average LMP during constrained hours was 24.6 percent higher than average LMP during unconstrained hours. Average LMP during constrained hours was 5.2 percent higher in the Real-Time Energy Market than in the Day-Ahead Energy Market and LMP during unconstrained hours was 14.3 percent lower in the Real-Time Energy Market than in the Day-Ahead Energy Market.

10 This comparison is of limited usefulness as there were only 275 day-ahead unconstrained hours.

Table C-15 PJM simple average LMP during constrained and unconstrained hours (Dollars per MWh): Calendar year 2009

	Day Ahead			Real Time		
	Unconstrained Hours	Constrained Hours	Difference	Unconstrained Hours	Constrained Hours	Difference
Average	$36.47	$37.02	1.5%	$31.25	$38.93	24.6%
Median	$36.63	$35.13	(4.1%)	$29.14	$34.34	17.8%
Standard deviation	$12.21	$13.43	9.9%	$12.71	$17.90	40.9%

Taken together, the data show that simple average LMP in the Day-Ahead Energy Market during constrained hours was $0.02 (0.1 percent) higher than the overall simple average LMP for the Day-Ahead Energy Market, while simple average LMP during unconstrained hours was $0.53 (1.4 percent) lower although these comparisons are of limited usefulness as there were only 275 unconstrained hours in the Day-Ahead Energy Market.[11] In the Real-Time Energy Market, simple average LMP during constrained hours was $1.85 (5.0 percent) higher than the overall simple average LMP for the Real-Time Energy Market, while simple average LMP during unconstrained hours was $5.83 (15.7 percent) lower.

Offer-Capped Units

PJM's market power mitigation goals have focused on market designs that promote competition and that limit market power mitigation to situations where market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this situation occurs primarily in the case of local market power. Offer capping occurs only as a result of structurally noncompetitive local markets and noncompetitive offers in the Day-Ahead and Real-Time Energy Markets.

PJM has clear rules limiting the exercise of local market power.[12] The rules provide for offer capping when conditions on the transmission system create a structurally noncompetitive local market, when units in that local market have made noncompetitive offers and when such offers would set the price above the competitive level in the absence of mitigation. Offer caps are set at the level of a competitive offer. Offer-capped units receive the higher of the market price or their offer cap. Thus, if broader market conditions lead to a price greater than the offer cap, the unit receives the higher market price. The rules governing the exercise of local market power recognize that units in certain areas of the system would be in a position to extract monopoly profits, but for these rules.

Under existing rules, PJM suspends offer capping when structural market conditions, as determined by the three pivotal supplier test, indicate that suppliers are reasonably likely to behave in a competitive manner.[13] The goal is to apply a clear rule to limit the exercise of market power by generation owners in load pockets, but to apply the rule in a flexible manner in real time and to lift offer capping when the exercise of market power is unlikely based on the real-time application of the market structure screen.

11 See the *2009 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market, Part 1" for a discussion of load and LMP.
12 See PJM. "Amended and Restated Operating Agreement (OA)," Schedule 1, Section 6.4.2 (January 19, 2007).
13 See the *2009 State of the Market Report for PJM*, Volume II, Appendix L, "Three Pivotal Supplier Test."

Levels of offer capping have generally been low and stable over the last five years. Table C-16 through Table C-19 show offer capping by month, including the number of offer-capped units and the level of offer-capped MW in the Day-Ahead and Real-Time Energy Markets.

Table C-16 Average day-ahead, offer-capped units: Calendar years 2005 to 2009

	2005		2006		2007		2008		2009	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	0.4	0.0%	0.1	0.0%	0.2	0.0%	0.5	0.0%	0.7	0.1%
Feb	0.4	0.0%	0.2	0.0%	0.8	0.1%	0.2	0.0%	0.3	0.0%
Mar	0.6	0.1%	0.7	0.1%	0.9	0.1%	0.0	0.0%	0.6	0.1%
Apr	0.4	0.0%	0.2	0.0%	0.2	0.0%	0.2	0.0%	0.0	0.0%
May	0.2	0.0%	0.1	0.0%	0.2	0.0%	0.6	0.1%	0.1	0.0%
Jun	0.4	0.0%	0.7	0.1%	0.8	0.1%	1.5	0.1%	0.3	0.0%
Jul	0.9	0.1%	4.1	0.4%	0.6	0.1%	1.7	0.2%	0.4	0.0%
Aug	1.1	0.1%	4.7	0.5%	1.0	0.1%	0.4	0.0%	0.2	0.0%
Sep	0.2	0.0%	0.6	0.1%	0.2	0.0%	0.4	0.0%	0.1	0.0%
Oct	0.3	0.0%	0.3	0.0%	0.8	0.1%	0.4	0.0%	0.3	0.0%
Nov	0.2	0.0%	0.3	0.0%	0.0	0.0%	0.5	0.1%	0.0	0.0%
Dec	0.7	0.1%	0.5	0.0%	0.1	0.0%	1.3	0.1%	0.0	0.0%

Table C-17 Average day-ahead, offer-capped MW: Calendar years 2005 to 2009

	2005		2006		2007		2008		2009	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	87	0.1%	4	0.0%	23	0.0%	16	0.0%	98	0.1%
Feb	75	0.1%	6	0.0%	57	0.1%	11	0.0%	30	0.0%
Mar	57	0.1%	51	0.1%	86	0.1%	2	0.0%	47	0.1%
Apr	34	0.0%	31	0.0%	11	0.0%	31	0.0%	0	0.0%
May	14	0.0%	22	0.0%	38	0.0%	15	0.0%	9	0.0%
Jun	28	0.0%	164	0.2%	28	0.0%	91	0.1%	42	0.0%
Jul	52	0.0%	518	0.5%	45	0.0%	110	0.1%	35	0.0%
Aug	63	0.1%	398	0.4%	58	0.1%	49	0.0%	10	0.0%
Sep	13	0.0%	51	0.1%	14	0.0%	70	0.1%	3	0.0%
Oct	16	0.0%	25	0.0%	77	0.1%	39	0.0%	29	0.0%
Nov	26	0.0%	15	0.0%	4	0.0%	53	0.1%	0	0.0%
Dec	48	0.0%	30	0.0%	4	0.0%	187	0.2%	0	0.0%

Table C-18 Average real-time, offer-capped units: Calendar years 2005 to 2009

	2005		2006		2007		2008		2009	
	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent	Avg. Units Capped	Percent
Jan	2.5	0.3%	1.9	0.2%	1.2	0.1%	3.1	0.3%	2.4	0.2%
Feb	1.3	0.1%	2.1	0.2%	4.2	0.4%	2.6	0.3%	1.1	0.1%
Mar	1.4	0.2%	2.3	0.2%	1.9	0.2%	2.7	0.3%	1.8	0.2%
Apr	1.2	0.1%	1.5	0.2%	1.3	0.1%	3.1	0.3%	1.8	0.2%
May	0.8	0.1%	3.4	0.3%	1.9	0.2%	2.1	0.2%	1.0	0.1%
Jun	10.0	1.0%	2.5	0.3%	6.0	0.6%	8.7	0.8%	1.3	0.1%
Jul	13.9	1.4%	8.6	0.9%	4.4	0.4%	5.7	0.6%	1.1	0.1%
Aug	13.7	1.4%	9.5	1.0%	9.6	0.9%	2.1	0.2%	3.0	0.3%
Sep	7.9	0.8%	1.8	0.2%	5.5	0.5%	4.8	0.5%	1.6	0.1%
Oct	7.9	0.8%	1.7	0.2%	5.0	0.5%	2.5	0.2%	1.2	0.1%
Nov	3.3	0.3%	1.1	0.1%	2.9	0.3%	2.3	0.2%	0.6	0.1%
Dec	4.4	0.4%	1.0	0.0%	4.7	0.5%	2.4	0.2%	1.3	0.1%

Table C-19 Average real-time, offer-capped MW: Calendar years 2005 to 2009

	2005		2006		2007		2008		2009	
	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent	Avg. MW Capped	Percent
Jan	209	0.3%	42	0.1%	50	0.1%	99	0.1%	158	0.2%
Feb	145	0.2%	67	0.1%	125	0.1%	92	0.1%	92	0.1%
Mar	74	0.1%	88	0.1%	142	0.2%	117	0.2%	147	0.2%
Apr	59	0.1%	75	0.1%	48	0.1%	125	0.2%	151	0.2%
May	78	0.1%	136	0.2%	68	0.1%	59	0.1%	64	0.1%
Jun	652	0.7%	160	0.2%	190	0.2%	415	0.5%	103	0.1%
Jul	819	0.9%	506	0.5%	160	0.2%	202	0.2%	74	0.1%
Aug	908	1.0%	518	0.6%	314	0.3%	114	0.1%	137	0.2%
Sep	477	0.6%	69	0.1%	218	0.3%	186	0.2%	95	0.1%
Oct	337	0.5%	49	0.1%	153	0.2%	177	0.3%	105	0.2%
Nov	129	0.2%	31	0.0%	104	0.1%	164	0.2%	60	0.1%
Dec	156	0.2%	12	0.0%	146	0.2%	200	0.2%	128	0.2%

In order to help understand the frequency of offer capping in more detail, Table C-20 through Table C-24 show the number of generating units that met the specified criteria for total offer-capped run hours and percentage of offer-capped run hours for the years 2005 through 2009.

Table C-20 Offer-capped unit statistics: Calendar year 2005

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2005 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	12	1	0	1	2	2
80% and < 90%	7	6	0	6	7	10
75% and < 80%	0	1	3	3	8	3
70% and < 75%	0	0	1	2	4	4
60% and < 70%	1	0	3	2	8	9
50% and < 60%	0	0	2	0	2	10
25% and < 50%	2	9	1	3	10	49
10% and < 25%	0	0	1	0	6	33

Table C-21 Offer-capped unit statistics: Calendar year 2006

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2006 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	3	0	0	1	2	0
80% and < 90%	1	5	1	4	3	7
75% and < 80%	0	1	0	2	6	10
70% and < 75%	0	0	0	2	6	18
60% and < 70%	0	1	1	3	5	27
50% and < 60%	0	2	0	0	0	12
25% and < 50%	0	2	1	2	1	31
10% and < 25%	0	0	0	3	9	41

Table C-22 Offer-capped unit statistics: Calendar year 2007

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2007 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2	1	3	2	6	0
80% and < 90%	15	3	0	14	13	6
75% and < 80%	0	0	0	0	2	4
70% and < 75%	0	0	2	0	1	3
60% and < 70%	0	0	0	1	3	24
50% and < 60%	1	0	0	0	0	21
25% and < 50%	0	0	0	0	0	51
10% and < 25%	0	0	0	3	12	37

Table C-23 Offer-capped unit statistics: Calendar year 2008

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2008 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	1	1	4
80% and < 90%	0	0	1	0	4	10
75% and < 80%	0	0	5	4	4	11
70% and < 75%	1	0	1	2	4	9
60% and < 70%	1	0	0	4	4	30
50% and < 60%	0	0	2	3	3	20
25% and < 50%	0	5	10	11	10	57
10% and < 25%	1	0	1	0	6	48

Table C-24 Offer-capped unit statistics: Calendar year 2009

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	2009 Offer-Capped Hours					
	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	0	1	6
80% and < 90%	0	0	0	1	2	13
75% and < 80%	0	0	0	1	0	6
70% and < 75%	0	0	0	1	1	9
60% and < 70%	0	0	0	0	1	21
50% and < 60%	0	0	0	0	1	19
25% and < 50%	0	1	1	2	3	56
10% and < 25%	1	0	0	0	6	53

APPENDIX D – INTERCHANGE TRANSACTIONS

In competitive wholesale power markets, market participants' decisions to buy and sell power are based on actual and expected prices. If contiguous wholesale power markets incorporate security constrained nodal pricing, well designed interface pricing provides economic signals for import and export decisions by market participants, although those signals may be attenuated by a variety of institutional arrangements.

In order to understand the data on imports and exports, it is important to understand the institutional details of completing import and export transactions. These include the Open Access Real-time Information System (OASIS), North American Electric Reliability Council (NERC) Tags, neighboring balancing authority check out processes, and transaction curtailment rules.

Transactions Background

OASIS Products

The OASIS products available for reservation include firm, network, non-firm and spot import service. The product type designated on the OASIS reservation determines when and how the transaction can be curtailed.

- **Firm.** Transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency, and unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility, or the Office of the Interconnection.

- **Network.** Transmission service that is for the sole purpose of serving network load. Network transmission service is only eligible to network customers.

- **Non-Firm.** Point-to-point transmission service under the PJM tariff that is reserved and scheduled on an as available basis and is subject to curtailment or interruption. Non-firm point-to-point transmission service is available on a stand alone basis for periods ranging from one hour to one month.

- **Spot Import.** PJM introduced spot market imports with the introduction of the Energy Market on April 1, 1997 (Marginal Clearing Price). It was introduced as an option for non-load serving entities to offer into the PJM spot market at the border/interface as price takers, providing access to the PJM energy markets and reducing the cost of energy through increased competition. Prior to April 2007, PJM did not limit spot import service, preferring to let market prices ration the use of the service which is not physically limited. However, in 2007 PJM interpreted its Joint Operating Agreement (JOA) with the Midwest ISO (MISO) to require a limitation on spot import service in order to limit the impact of such transactions on selected external flowgates. In 2007, spot imports were added to the OASIS to account for the impacts of this network service on flowgates external to the PJM Transmission System. Effective April 2007, the availability of spot import service was limited by the Available Transmission Capacity (ATC) on the transmission path.

Source and Sink

For a real-time import energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, the source defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is DUK and the POD is PJM, the source would initially default to DUK's Interface Pricing point (i.e. SouthIMP). At the time the energy is scheduled, if the Generation Control Area (GCA) on the NERC Tag represents physical flow entering PJM at an interface other than the SouthIMP Interface, the source would then default to that new interface. The sink bus is selected by the market participant at the time the OASIS reservation is made and can be any bus in the PJM footprint. The selection of the sink bus determines the explicit congestion charge that the market participant is exposed to, as congestion is calculated as the difference in LMP from the sink to the source.

For a real-time export energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, the sink defaults to the associated interface price as defined by the POR/POD path. For example, if the selected POR is PJM and the POD is DUK, the sink would initially default to DUK's Interface Pricing point (i.e. SouthEXP). At the time the energy is scheduled, if the Load Control Area (LCA) on the NERC Tag represents physical flow leaving PJM at an interface other than the SouthEXP Interface, the sink would then default to that new interface. The source bus is selected by the market participant at the time the OASIS reservation is made and can be any bus in the PJM footprint. The selection of the source bus determines the explicit congestion charge that the market participant is exposed to, as congestion is calculated as the difference in LMP from the sink to the source.

For a real-time wheel through energy transaction, when a market participant selects the Point of Receipt (POR) and Point of Delivery (POD) on their OASIS reservation, both the source and sink default to the associated interface prices as defined by the POR/POD path. For example, if the selected POR is DUK and the POD is NYIS, the source would initially default to DUK's Interface Pricing point (i.e. SouthIMP), and the sink would initially default to NYIS's Interface Pricing point (i.e. NYIS). At the time the energy is scheduled, if the GCA on the NERC Tag represents physical flow entering PJM at an interface other than the SouthIMP Interface, the source would then default to that new interface. Similarly, if the LCA on the NERC Tag represents physical flow leaving PJM at an interface other than the NYIS Interface, the sink would then default to that new interface.

NERC Tagging

A NERC Tag is required for all external energy transactions. A NERC Tag can be created only after a valid transmission reservation is acquired. If a ramp reservation has been made in advance, the market participant can enter the ramp reservation ID on the NERC Tag. If no ramp reservation has been created, upon submission of the NERC Tag, PJM will create a ramp reservation if there is available ramp. If there is no ramp available to match the tagged energy profile, the NERC Tag will be denied.

The NERC Tag requires that the complete path be specified from the GCA to the LCA. This complete path is utilized by PJM to determine the interface pricing point which PJM will associate with the transaction. The path specified in the OASIS reflects only the path of energy into or out of PJM to one neighboring balancing authority.

Neighboring Balancing Authority Checkout

PJM operators must verify all requested energy schedules with PJM's neighboring balancing authorities. Only if the neighboring balancing authority agrees with the expected interchange will the transaction flow. If there is a disagreement in the expected interchange for any 15 minute interval, the system operators must work to resolve the difference. It is important that both balancing authorities enter the same values in their Energy Management Systems (EMS) to avoid inadvertent energy from flowing between balancing authorities.

With the exception of the New York Independent System Operator (NYISO), all neighboring balancing authorities handle transaction requests in the same way as PJM (i.e. via the NERC Tag). This helps facilitate interchange transaction checkouts, as all balancing authorities are receiving the same information. While the NYISO also requires NERC Tags, the NYISO utilizes their Market Information System (MIS) as their primary scheduling tool. The NYISO's real-time commitment (RTC) tool evaluates all bids and offers each hour, and performs a least cost economic dispatch solution. The NYISO accepts or denies individual transactions in whole or in part based on this evaluation. Upon market clearing, the NYISO implements NERC Tag adjustments to match the output of the RTC. PJM and the NYISO can verify interchange transactions once the NYISO Tag adjustments are sent and approved. The results of the adjustments made by the NYISO affect PJM operations, as the adjustments often cause large swings in expected ramp for the next hour.

Curtailment of Transactions

Once a transaction has been implemented, energy flows between balancing authorities. Transactions can be curtailed based on economic and reliability considerations. There are three types of economic curtailments: curtailments of dispatchable schedules based on price; curtailments of transactions based on their OASIS designation as not willing to pay congestion; and self curtailments by market participant. Reliability curtailments are implemented by the balancing authorities and are termed TLRs or transmission loading relief.

A dispatchable external energy transaction (also known as "real-time with price") is one in which the market participant designates a floor or ceiling price on their external transaction. For example, an import dispatchable schedule specifies that the market participant only wishes to load the transaction if the LMP at the interface where the transaction is entering the PJM footprint reaches a specified limit (the minimum LMP at which they are willing to sell). An export dispatchable schedule specifies the maximum LMP at the interface where the market participant wishes to purchase the power from PJM.

PJM system operators evaluate dispatchable transactions 30 minutes prior to the start of every hour of the energy profile. If the system operator expects the floor (or ceiling) price to be realized over the next hour, they contact the market participant informing them that they are loading the transaction. Once loaded, the dispatchable transaction will run for the next hour. If at any time the system operator does not believe that the transaction will be economic for the next hour, they will elect to curtail the dispatchable transaction. Dispatchable schedules can be viewed as a generation offer, with a minimum run time of one hour. For import dispatchable schedules, if the transaction is loaded and then curtailed, or if the hourly integrated LMP falls below the price specified, the transaction will be made whole through payment of operating reserve credits.

Not willing to pay congestion transactions will be curtailed if there is realized congestion between the designated source and sink.

Transactions utilizing spot import service will be curtailed if the interface price where the transaction enters PJM reaches zero.

A market participant may curtail their own transactions. All self curtailments must be requested on 15 minute intervals. In order for PJM to approve a self curtailment request, there must be available ramp for the modification.

Transmission Loading Relief (TLR)

TLRs are called to control flows on transmission facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

There are seven TLR levels and additional sublevels, determined by the severity of system conditions and whether the interchange transactions contributing to congestion on the impacted flowgates are using firm or non-firm transmission. Reliability coordinators are not required to implement TLRs in order. The TLR levels are described below.[1]

- **TLR Level 0 – TLR concluded:** A TLR Level 0 is initiated when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violations are mitigated and the system is returned to a reliable state**.** Upon initiation of a TLR Level 0, transactions with the highest transmission priorities are reestablished first when possible. The purpose of a TLR Level 0 is to inform all affected parties that the TLR has been concluded.

- **TLR Level 1 – Potential SOL or IROL Violations:** A TLR Level 1 is initiated when the transmission system is still in a secure state but a reliability coordinator anticipates a transmission or generation contingency or other operating problem that could lead to a potential violation. No actions are required during a TLR Level 1. The purpose of a TLR Level 1 is to inform other reliability coordinators of a potential SOL or IROL.

- **TLR Level 2 – Hold transfers at present level to prevent SOL or IROL Violations:** A TLR Level 2 is initiated when the transmission system is still in a secure state but one or more transmission facilities are expected to approach, are approaching or have reached their SOL or

1 Additional details regarding the TLR procedure can be found in NERC. "Standard IRO-006-4 – Reliability Coordination – Transmission Loading Relief" (October 23, 2007) (Accessed January 26, 2010) <http://www.nerc.com/files/IRO-006-4.pdf> (KB).

IROL. The purpose of a TLR Level 2 is to prevent additional transactions that have an adverse affect on the identified transmission facility(ies) from starting.

- **TLR Level 3a – Reallocation of transmission service by curtailing interchange transactions using non-firm point-to-point transmission service to allow interchange transactions using higher priority transmission service:** A TLR Level 3a is initiated when the transmission system is secure but one or more transmission facilities are expected to approach, or are approaching their SOL or IROL, when there are transactions using non-firm point-to-point transmission service that have a greater than 5 percent effect on the facility and when there are transactions using a higher priority point-to-point transmission reservation that wish to begin. Curtailments to transactions in a TLR 3a begin on the top of the hour only. The purpose of TLR Level 3a is to curtail transactions using lower priority non-firm point-to-point transmission to allow transactions using higher priority transmission to flow.

- **TLR Level 3b – Curtail interchange transactions using non-firm transmission service arrangements to mitigate a SOL or IROL violation:** A TLR Level 3b is initiated when one or more transmission facilities is operating above their SOL or IROL; such operation is imminent and it is expected that facilities will exceed their reliability limits if corrective action is not taken; or one or more transmission facilities will exceed their SOL or IROL upon the removal from service of a generating unit or other transmission facility and transactions are flowing that are using non-firm point-to-point transmission service and have a greater than 5 percent impact on the facility. Curtailments of transactions in a TLR 3b can occur at any time within the operating hour. The purpose of a TLR Level 3b is to curtail transactions using non-firm point-to-point transmission service which impact the constraint by greater than 5 percent in order to mitigate a SOL or IROL.

- **TLR Level 4 – Reconfigure Transmission:** A TLR Level 4 is initiated when one or more transmission facilities are above their SOL or IROL limits or such operation is imminent and it is expected that facilities will exceed their reliability limits if corrective action is not taken. Upon issuance of a TLR Level 4, all transactions using non-firm point-to-point transmission service, in the current and next hour, with a greater than 5 percent impact on the facility, have been curtailed under the TLR 3b. The purpose of a TLR Level 4 is to request that the affected transmission operators reconfigure transmission on their system, or arrange for reconfiguration on other transmission systems, to mitigate the constraint if a SOL or IROL violation is imminent or occurring.

- **TLR Level 5a – Reallocation of transmission service by curtailing interchange transactions using firm point-to-point transmission service on a pro rata basis to allow additional interchange transactions using firm point-to-point transmission service:** A TLR Level 5a is initiated when one or more transmission facilities are at their SOL or IROL; all interchange transactions using non-firm point-to-point transmission service that affect the constraint by greater than 5 percent have been curtailed; no additional effective transmission configuration is available; and a transmission provider has been requested to begin an interchange transaction using previously arranged firm point-to-point transmission service. Curtailments to transactions in a TLR 5a begin on the top of the hour only. The purpose of a TLR Level 5a is to curtail existing interchange transactions, which are using firm point-to-point transmission service, on a pro rata basis to allow for the newly requested interchange transaction, also using firm point-to-point transmission service, to flow.

- **TLR Level 5b – Curtail transactions using firm point-to-point transmission service to mitigate an SOL or IROL violation:** A TLR Level 5b is initiated when one or more transmission facilities are operating above their SOL or IROL or such operation is imminent; one or more transmission facilities will exceed their SOL or IROL upon removal of a generating unit or another transmission facility; all interchange transactions using non-firm point-to-point transmission service that affect the constraint by greater than 5 percent have been curtailed; and no additional effective transmission configuration is available. Unlike a TLR 5a, curtailments to transactions in a TLR 5b can occur at any time within the operating hour. The purpose of a TLR Level 5b is to curtail transactions using firm point-to-point transmission service to mitigate a SOL or IROL.

- **TLR Level 6 – Emergency Procedures:** A TLR Level 6 is initiated when all interchange transactions using both non-firm and firm point-to-point transmission have been curtailed and one or more transmission facilities are above their SOL or IROL, or will exceed their SOL or IROL upon removal of a generating unit or other transmission facility. The purpose of a TLR Level 6 is to instruct balancing authorities and transmission providers to redispatch generation, reconfigure transmission or reduce load to mitigate the critical condition.

Table D-1 below shows the historic number of TLRs, by level, issued by reliability coordinators in the Eastern Interconnection since 2004.

Table D-1 TLRs by level and reliability coordinator: Calendar years 2004 through 2009

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2004	EES	47	15	88	1	3	0	154
	FPL	0	1	0	0	0	0	1
	IMO	33	2	0	0	0	0	35
	MAIN	8	3	0	0	0	0	11
	MISO	650	210	409	9	3	0	1,281
	PJM	270	115	35	4	5	0	429
	SOCO	1	0	0	0	0	0	1
	SWPP	185	107	14	5	6	0	317
	TVA	56	17	0	0	1	0	74
	VACN	8	1	0	0	0	0	9
Total		1,258	471	546	19	18	0	2,312
2005	EES	49	10	101	6	3	1	170
	IMO	57	2	0	0	0	0	59
	MISO	776	296	200	5	14	0	1,291
	PJM	201	94	29	1	1	0	326
	SWPP	193	78	19	4	2	0	296
	TVA	172	61	12	2	3	0	250
	VACN	0	3	0	0	0	0	3
	VACS	2	2	0	1	0	0	5
Total		1,450	546	361	19	23	1	2,400
2006	EES	71	20	93	5	1	0	190
	ICTE	11	6	14	0	1	0	32
	IMO	1	0	0	0	0	0	1
	MISO	414	214	136	17	19	0	800
	ONT	27	3		0	0	0	30
	PJM	88	30	18	0	0	0	136
	SWPP	189	121	201	11	13	0	535
	TVA	90	52	31	1	2	0	176
	VACS	0	1	0	0	0	0	1
Total		891	447	493	34	36	0	1,901
2007	ICTE	95	42	139	19	10	0	305
	MISO	414	273	89	17	26	0	819
	ONT	47	4	1	0	0	0	52
	PJM	46	31	1	1	1	0	80
	SWPP	777	935	35	53	24	0	1,824
	TVA	45	40	25	2	2	0	114
	VACS	4	1	0	0	0	0	5
Total		1428	1326	290	92	63	0	3199
2008	ICTE	132	41	112	43	25	0	353
	MISO	320	235	21	8	15	0	599
	ONT	153	7	1	0	0	0	161
	PJM	55	92	2	0	1	0	150
	SWPP	687	1,077	11	59	44	0	1,878
	TVA	48	72	29	5	4	0	158
Total		1,395	1,524	176	115	89	0	3,299
2009	ICTE	82	35	55	75	18	1	266
	MISO	199	140	2	15	25	0	381
	NYIS	101	8	0	0	0	0	109
	ONT	169	0	0	0	0	0	169
	PJM	61	68	0	0	0	0	129
	SWPP	383	1,466	33	77	24	0	1,983
	TVA	8	22	29	0	0	0	59
	VACS	0	1	0	0	0	0	1
Total		1,003	1,740	119	167	67	1	3,097

NYISO Issues

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-ISO power flows, and those price differentials.[2]

There are institutional differences between PJM and the NYISO markets that are relevant to observed differences in border prices.[3] The NYISO requires hourly bids or offer prices for each export or import transaction and clears its market for each hour based on hourly bids.[4] Import transactions to the NYISO are treated by the NYISO as generator bids at the NYISO/PJM proxy bus. Export transactions are treated by the NYISO as price-capped load offers. Competing bids and offers are evaluated along with other NYISO resources and a proxy bus price is derived. Bidders are notified of the outcome. This process is repeated, with new bids and offers each hour. A significant lag exists between the time when offers and bids are submitted to the NYISO and the time when participants are notified that they have cleared. The lag is a result of the functioning of the RTC system and the fact that transactions can only be scheduled at the beginning of the hour.

As a result of the NYISO's RTC timing, market participants must submit bids or offers by no later than 75 minutes before the operating hour. The bid or offer includes the MW volume desired and, for imports into NYISO, the asking price or, for exports out of the NYISO, the price the participants are willing to pay. The required lead time means that participants make price and MW bids or offers based on expected prices. Transactions are accepted only for a single hour.

Under PJM operating practices, in the Real-Time Market, participants must make a request to import or export power at one of PJM's interfaces at least 20 minutes before the desired start which can be any quarter hour.[5] The duration of the requested transaction can vary from 45 minutes to an unlimited amount of time. Generally, PJM market participants provide only the MW, the duration and the direction of the real-time transaction. While bid prices for transactions are allowed in PJM, less than 1 percent of all transactions submit an associated price. Transactions are accepted, with virtually no lag, in order of submission, based on whether PJM has the capability to import or export the requested MW. If transactions do not submit a price, the transactions are priced at the real-time price for their scheduled imports or exports. As in the NYISO, the required lead time means that participants must make offers to buy or sell MW based on expected prices, but the required lead time is substantially shorter in the PJM market.

The NYISO rules provide that the RTC results should be available 45 minutes before the operating hour. Winning bidders then have 25 minutes from the time when the RTC results indicate that their transaction will flow to meet PJM's 20-minute notice requirement. To get a transaction cleared with

2 See also the discussion of these issues in the *2005 State of the Market Report*, Section 4, "Interchange Transactions" (March 8, 2006).
3 See the *2005 State of the Market Report* (March 8, 2006), pp. 195-198.
4 See NYISO. "NYISO Transmission Services Manual," Version 2.0 (February 1, 2005) (Accessed January 26, 2010) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/tran_ser_mnl.pdf> (463 KB).
5 See PJM. "Manual 41: Managing Interchange" (November 24, 2008) (Accessed January 26, 2010) <http://www.pjm.com/documents/~/media/documents/manuals/m41.ashx> (291 KB).

PJM, the market participant must have a valid NERC Tag, an OASIS reservation and a PJM ramp reservation. Each of these requirements takes time to process.

The length of required lead times in both markets may be a contributor to the observed relationship between price differentials and flows. Market conditions can change significantly in a relatively short time. The resulting uncertainty could weaken the observed relationship between contemporaneous interface prices and flows.

Consolidated Edison Company (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts

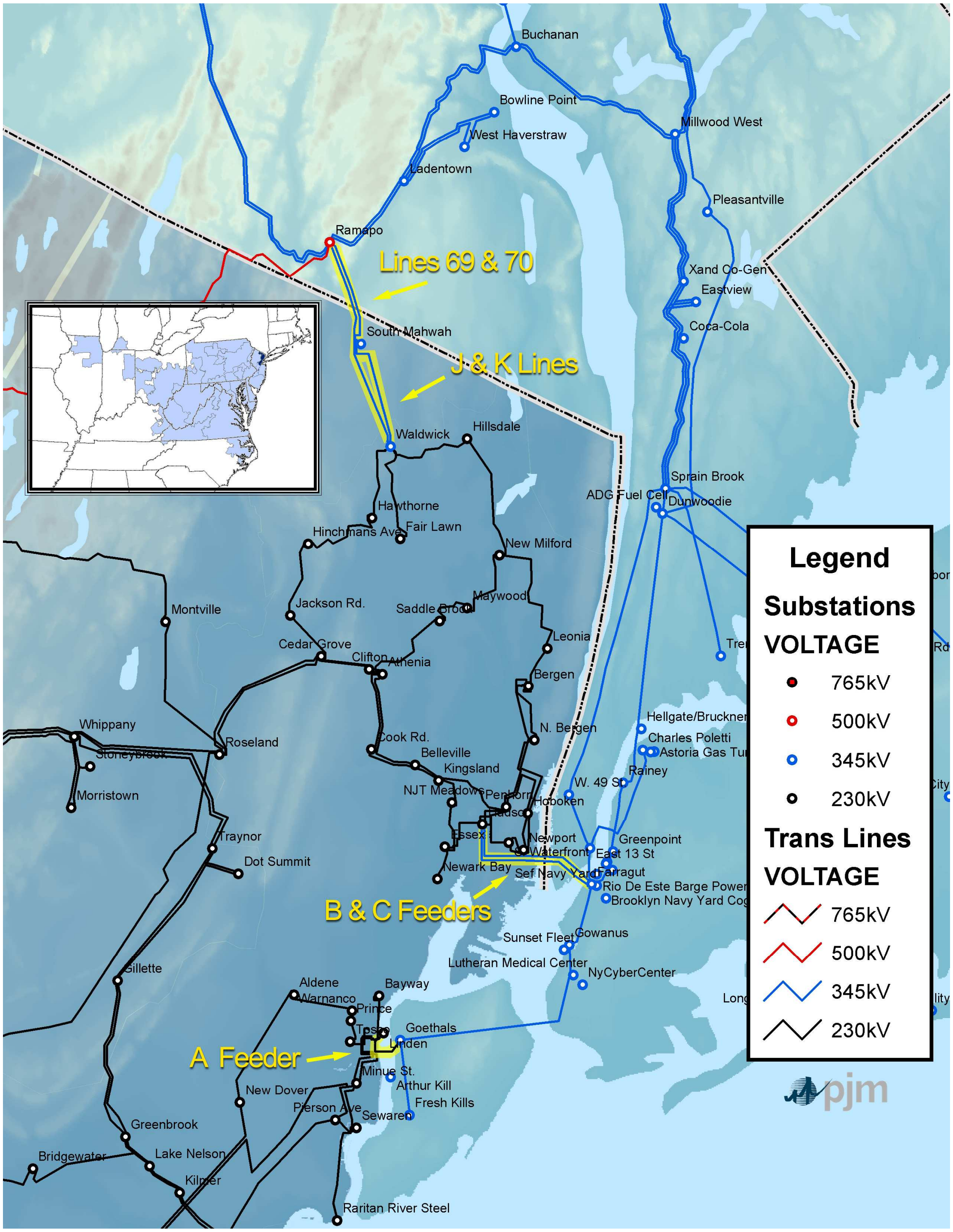
To help meet the demand for power in New York City, Con Edison uses electricity generated in upstate New York and wheeled through New York and New Jersey. A common path is through Westchester County using lines controlled by the NYISO. Another path is through northern New Jersey using lines controlled by PJM. This wheeled power creates loop flow across the PJM system. The Con Edison/PSE&G contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001. In May 2005, the FERC issued an order setting out a protocol developed by the two companies, PJM and the NYISO.[6] In July 2005, the protocol was implemented. Con Edison filed a protest with the FERC regarding the delivery performance in January 2006.[7]

The contracts provide for the delivery of up to 1,000 MW of power from Con Edison's Ramapo Substation in Rockland County, New York, to PSE&G at its Waldwick Switching Substation in Bergen County, New Jersey. PSE&G wheels the power across its system and delivers it to Con Edison across lines connecting directly into New York City. (See Figure D-1.) Two separate contracts cover these wheeling arrangements. A 1975 agreement covers delivery of up to 400 MW through Ramapo (New York) to PSE&G's Waldwick Switching Station (New Jersey) then to the New Milford Switching Station (New Jersey) via the J line and ultimately from the Linden Switching Station (New Jersey) to the Goethals Substation (New York) and from the Hudson Generating Station (New Jersey) to the Farragut Switching Station (New York), via the A and B feeders, respectively. A 1978 agreement covers delivery of up to an additional 600 MW through Ramapo to Waldwick then to Fair Lawn, via the K line, and ultimately through a second Hudson-to-Farragut line, the C feeder. In 2001, Con Edison alleged that PSE&G had under delivered on the agreements and asked the FERC to resolve the issue.

6 111 FERC ¶ 61,228 (2005).

7 Protest of the Consolidated Edison Company of New York, Inc., Protest, Docket No. EL02-23 (January 30, 2006).

Figure D-1 Con Edison and PSE&G wheel



Initial Implementation of the FERC Protocol

In May 2005, the FERC issued an order setting out a protocol developed by the four parties to address the issues raised by Con Edison.[8] The protocol was implemented in July 2005.

The Day-Ahead Energy Market Process

The protocol allows Con Edison to elect up to the flow specified in each contract through the PJM Day-Ahead Energy Market. These elections are transactions in the PJM Day-Ahead Energy Market. The 600 MW contract is for firm service and the 400 MW contract has a priority higher than non-firm service but less than firm service. These elections obligate PSE&G to pay congestion costs associated with the daily elected level of service under the 600 MW contract and obligate Con Edison to pay congestion costs associated with the daily elected level of service under the 400 MW contract. The interface prices for this transaction are not defined PJM interface prices, but are defined in the protocol based on the actual facilities governed by the protocol.

Under the FERC order, PSE&G is assigned FTRs associated with the 600 MW contract. The PSE&G FTRs are treated like all other FTRs. In 2009, PSE&G's revenues were less than its congestion charges by $5,417 after adjustments. (Revenues exceeded its charges by $13,768 in 2008.) Under the FERC order, Con Edison receives credits on an hourly basis for its elections under the 400 MW contract from a pool containing any excess congestion revenue after hourly FTRs are funded. In 2009, Con Edison's congestion credits were $232,744 less than its day-ahead congestion charges. Con Edison also had a day-ahead congestion credit. With appropriate adjustments accounted for, the result was that Con Edison's total charges exceeded its congestion credits by $251,102. (Credits had been $213,535 less than charges in 2008.) Table D-2 shows the monthly details for both PSE&G and Con Edison.

The protocol states:

> If there is congestion in PJM that affects the portion of the wheel that is associated with the 400 MW contract, PJM shall re-dispatch for the portion of the 400 MW contract for which ConEd specified it was willing to pay congestion, and ConEd shall pay for the re-dispatch. ConEd will be credited back for any congestion charges paid in the hour to the extent of any excess congestion revenues collected by PJM that remain after congestion credits are paid to all other firm transmission customers. Such credits to ConEd shall not exceed congestion payments owed or made by it.[9]

In effect, Con Edison has been given congestion credits that are the equivalent of a class of FTRs covering positive congestion with subordinated rights to revenue. However, Con Edison is not treated as having an FTR when congestion is negative. An FTR holder in that position would pay the negative congestion credits, but Con Edison does not. The protocol's provisions about congestion payments clearly cover congestion charges and offsetting congestion credits, but are not explicit on the treatment of Con Edison's negative congestion credits, which were -$251,102 in 2009. The parties should address this issue.

8 111 FERC ¶ 61,228 (2005).

9 PJM Interconnection, L.L.C., Operating Protocol for the Implementation of Commission Opinion No. 476, Docket No. EL02-23-000 (Phase II) (Effective: July 1, 2005), Original Sheet No. 6 <http://www.pjm.com/~/media/documents/agreements/20050701-attachment-iv-operating-protocol.ashx> (327 KB).

The Real-Time Energy Market Process

Under the terms of the protocol, Con Edison can make a real-time election of its desired flow for each hour in the Real-Time Energy Market. If this election differs from its day-ahead schedule, the company is subject to the resultant charges or credits based on the difference between day-ahead and real-time prices. The real-time election differed from the day-ahead schedule in 2 percent of the hours in 2009.

Table D-2 Con Edison and PSE&G wheel settlements data: Calendar year 2009

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
January	Congestion Charge	$279,940	($1,167)	$278,773	$841,794	$0	$841,794
	Congestion Credit			$280,235			$857,942
	Adjustments			$0			$1,013
	Net Charge			($1,462)			($17,161)
February	Congestion Charge	$0	$0	$0	$572,117	$0	$572,117
	Congestion Credit			$0			$572,117
	Adjustments			$0			($761)
	Net Charge			$0			$761
March	Congestion Charge	$123,847	($43)	$123,804	$328,334	$0	$328,334
	Congestion Credit			$65,759			$327,917
	Adjustments			($106,433)			($979)
	Net Charge			$164,478			$1,396
April	Congestion Charge	$269,027	($878)	$268,149	$426,910	$0	$426,910
	Congestion Credit			$269,259			$427,130
	Adjustments			$106,536			($728)
	Net Charge			($107,646)			$508
May	Congestion Charge	$162,299	$4,223	$166,522	$559,648	$0	$559,648
	Congestion Credit			$162,483			$559,648
	Adjustments			$485,456			$14,944
	Net Charge			($481,417)			($14,944)
June	Congestion Charge	$84,657	($235)	$84,422	$234,068	$0	$234,068
	Congestion Credit			$86,653			$234,068
	Adjustments			($1,377)			($1,610)
	Net Charge			($854)			$1,610

		Con Edison			PSE&G		
		Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
July	Congestion Charge	$151,152	$0	$151,152	$235,874	$0	$235,874
	Congestion Credit			$151,425			$235,874
	Adjustments			$0			$6,556
	Net Charge			($273)			($6,556)
August	Congestion Charge	$114,764	$0	$114,764	$180,342	$0	$180,342
	Congestion Credit			$64,770			$174,463
	Adjustments			$0			($2,591)
	Net Charge			$49,994			$8,470
September	Congestion Charge	$117,182	($68)	$117,115	$297,200	$0	$297,200
	Congestion Credit			$34,064			$262,288
	Adjustments			($7)			($1,281)
	Net Charge			$83,058			$36,194
October	Congestion Charge	$102,161	($485)	$101,676	$235,756	$0	$235,756
	Congestion Credit			$50,080			$209,886
	Adjustments			$357			($45)
	Net Charge			$51,239			$25,915
November	Congestion Charge	$33,790	$0	$33,790	$77,978	$0	$77,978
	Congestion Credit			$34,798			$79,076
	Adjustments			$209			($30)
	Net Charge			($1,217)			($1,067)
December	Congestion Charge	$49,561	($453)	$49,107	$129,195	$0	$129,195
	Congestion Credit			$56,109			$159,405
	Adjustments			$0			($501)
	Net Charge			($7,002)			($29,709)
Total	Congestion Charge	$1,488,379	$894	$1,489,274	$4,119,216	$0	$4,119,216
	Congestion Credit			$1,255,635			$4,099,812
	Adjustments			$484,741			$13,987
	Net Charge			($251,102)			$5,417

APPENDIX E – CAPACITY MARKET

Background

PJM and its members have long relied on capacity obligations as one of the methods to ensure reliability. Under the Reliability Assurance Agreement (RAA) governing the Capacity Market operated by the PJM regional transmission organization (RTO), each load-serving entity (LSE) must own or purchase capacity resources greater than, or equal to, its capacity obligation.

On June 1, 2007, the Reliability Pricing Model (RPM) Capacity Market design was implemented in PJM, replacing the Capacity Credit Market (CCM) Capacity Market design. This appendix explains certain key features of the RPM design in more detail.[1]

Demand

VRR Curves

Under RPM, PJM establishes variable resource requirement (VRR) curves for the PJM RTO and for each constrained locational deliverability area (LDA). The VRR curve is a demand curve based on three price-quantity points. The demand curve quantities are based on negative and positive adjustments to the reliability requirement. The demand curve prices are based on multipliers applied to the net cost of new entry (CONE). Net CONE is CONE minus the energy and ancillary service revenue offset (E&AS).[2]

The PJM reliability requirement, measured as unforced capacity, is the RTO peak load forecast multiplied by the RTO forecast pool requirement (FPR) less the sum of any unforced capacity (UCAP) obligations served by fixed resource requirement (FRR) entities. The FPR is calculated as (1 + Installed Reserve Margin) times (1 - Pool Wide Average EFORd), where the Installed Reserve Margin (IRM) is the level of installed capacity needed to maintain an acceptable level of reliability. The PJM reliability requirement represents the target level of reserves required to meet PJM reliability standards.

Load Obligations

Participation by LSEs in the RPM for load served in PJM control zones is mandatory, except for those LSEs that have elected the FRR alternative.[3] Under RPM, each LSE that serves load in a PJM zone during the delivery year is responsible for paying a locational reliability charge equal to its daily unforced capacity obligation in the zone multiplied by the final zonal capacity price. LSEs may choose to hedge their locational reliability charge obligations by directly offering resources in

1 This section relies upon the cited PJM manuals where additional detail may be found.
2 See PJM. "Manual 18: PJM Capacity Market," Revision 8 (Effective January 1, 2010), p. 16 <http://www.pjm.com/~/media/documents/manuals/m18.ashx> (1.27 MB).
3 See "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Substitute Original Sheet No. 40 (Effective June 1, 2007), Schedule 8.1.

the Base Residual Auction (BRA) and Second Incremental Auction or by designating self-supplied resources (resources directly owned or resources contracted for through unit-specific bilateral purchases) as self-scheduled to cover their obligation in the Base Residual Auction.

Base UCAP Obligations

A base RTO UCAP obligation is determined after the clearing of the BRA and is posted with the BRA results. The base RTO UCAP obligation is equal to the sum of the UCAP obligation satisfied through the BRA plus the forecast RTO interruptible load for reliability (ILR) obligation, for delivery years prior to 2012/2013, or plus the RTO Short-Term Resource Procurement Target for the delivery years 2012/2013 and forward. Base zonal UCAP obligations are defined for each zone as an allocation of the RTO UCAP obligation based on zonal, peak-load forecasts and zonal ILR obligations, for delivery years prior to 2012/2013, or the zonal Short-Term Resource Procurement Target for the delivery years 2012/2013 and forward. The zonal UCAP obligation is equal to the zonal, weather-normalized summer peak for the summer four years prior to the delivery year multiplied by the base zonal RPM scaling factor and the FPR plus the forecast zonal ILR obligation, for delivery years prior to 2012/2013, or plus the zonal Short-Term Resource Procurement Target for the delivery years 2012/2013 and forward.

Final UCAP Obligation

Prior to the 2009/2010 delivery year, the final RTO UCAP obligation is determined after the clearing of the Second Incremental Auction (IA) and is posted with the second IA results.[4] For the 2009/2010 through 2011/2012 delivery years, the final RTO UCAP obligations are determined after the clearing of the Third IA. Effective with the 2012/2013 delivery year, the final RTO UCAP obligations are determined after the clearing of the final incremental auction. Prior to the 2012/2013 delivery year, the final RTO UCAP obligation is equal to the sum of the UCAP obligation satisfied through the BRA and the second IA plus the forecast RTO ILR obligation. Effective with the 2012/2013 delivery year, the final RTO UCAP obligation is equal to the total MW cleared in PJM Buy Bids in RPM Auctions, including cleared MW in the BRA, less the total MW cleared in PJM Sell Offers in RPM Auctions for the given delivery year. Prior to the 2009/2010 delivery year, the final zonal UCAP obligation is equal to the base zonal UCAP obligation plus the RTO UCAP obligation satisfied in the second IA multiplied by the zone's percentage allocation of the obligation satisfied in the second IA. For the 2009/2010 through 2011/2012 delivery years, the final zonal UCAP obligation is equal to the zonal allocation of the RTO UCAP obligation satisfied in the BRA and second IA plus the zonal forecast ILR obligation. The allocation of the RTO UCAP obligation satisfied in the BRA and second IA to zones is on a pro rata basis based on the final zonal peak load forecasts. For the 2012/2013 delivery year and beyond, the final zonal UCAP obligation is equal to the zonal allocation of the final RTO UCAP obligation. The allocation of the final RTO UCAP obligation to zones is on a pro rata basis based on the final RTO and zonal peak load forecasts for the delivery year.

LSE Daily UCAP Obligation

Obligation peak load is the peak load value on which LSEs' UCAP obligations are based. The obligation peak load allocation for a zone is constant and effective for the entire delivery year. The

4 See PJM. "Manual 18: PJM Capacity Market," Revision 8 (Effective January 1, 2010), p. 86 <http://www.pjm.com/~/media/documents/manuals/m18.ashx> (1.27 MB).

daily UCAP obligation of an LSE in a zone/area equals the LSE's obligation peak load in the zone/area multiplied by the final zonal RPM scaling factor and the FPR.

Capacity Resources

Capacity resources may consist of generation resources, load management resources and qualifying transmission upgrades, all of which must meet specific criteria.[5] Generation resources may be located within or outside of PJM, but they must be committed to serving load within PJM and must pass tests regarding the capability of generation to serve load and to deliver energy.

Generation Resources

Generation resources may consist of existing generation, planned generation, and bilateral contracts for unit-specific capacity resources. Existing generation located within or outside PJM is eligible to be offered into RPM Auctions or traded bilaterally if it meets defined requirements.[6] Planned generation that is participating in PJM's Regional Transmission Expansion Planning (RTEP) Process is eligible to be offered into RPM Auctions if it meets defined requirements.

Load Management Resources

Load management is the ability to reduce metered load upon request.[7] A load management resource is eligible to be offered as a demand resource (DR) or, prior to the 2012/2013 delivery year, interruptible load for reliability (ILR). DR is a load resource that is offered into an RPM Auction as capacity and receives the relevant LDA or RTO resource clearing price. ILR is a load resource that is not offered into the RPM Auction, but receives the final zonal ILR price determined after the close of the second incremental auction. DR and ILR resources must meet defined requirements.

Energy Efficiency Resources

Existing or planned Energy Efficiency (EE) resources may be offered in an RPM auction starting with the 2012/2013 delivery year and receive the relevant LDA or RTO resource clearing price. An EE resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak periods) reduction in electric energy consumption that is not reflected in the peak load forecast prepared for the delivery year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such delivery year, without any requirement of notice, dispatch, or operator intervention.[8]

5 See PJM. "Manual 18: PJM Capacity Market," Revision 8 (Effective January 1, 2010), p. 29 <http://www.pjm.com/~/media/documents/manuals/m18.ashx> (1.27 MB).
6 See PJM. "Manual 18: PJM Capacity Market," Revision 8 (January 1, 2010), p. 22 <http://www.pjm.com/~/media/documents/manuals/m18.ashx> (1.27 MB).
7 See PJM. "Manual 18: PJM Capacity Market," Revision 8 (Effective January 1, 2010), p. 28 <http://www.pjm.com/~/media/documents/manuals/m18.ashx> (1.27 MB).
8 See PJM. "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," First Revised Sheet No. 35C (Effective March 27, 2009), Schedule 6, section M.

Qualified Transmission Upgrades

A qualifying transmission upgrade may be offered into the BRA to increase import capability into a transmission-constrained LDA. Such transmission upgrades must meet the identified requirements.[9]

Obligations of Generation Capacity Resources

The sale of a generating unit as a capacity resource within PJM entails obligations for the generation owner. The first four of these requirements, listed below, are essential to the definition of a capacity resource and contribute directly to system reliability.

- **Energy Recall Right.** PJM rules specify that when a generation owner sells capacity resources from a unit, the seller is contractually obligated to allow PJM to recall the energy generated by that unit if the energy is sold outside of PJM. This right enables PJM to recall energy exports from capacity resources when it invokes emergency procedures. The recall right establishes a link between capacity and actual delivery of energy when it is needed. Thus, PJM can call upon energy from all capacity resources to serve load. When PJM invokes the recall right, the energy supplier is paid the PJM Real-Time Energy Market price.

- **Day-Ahead Energy Market Offer Requirement.** Market sellers owning or controlling the output of a generation capacity resource that was committed in an FRR Capacity Plan, self-supplied, offered and cleared in any RPM auction, or designated as replacement capacity, and that is not unavailable due to an outage are required to offer into PJM's Day-Ahead Energy Market.[10] When LSEs purchase capacity, they ensure that resources are available to provide energy on a daily basis, not just in emergencies. Since day-ahead offers are financially binding, PJM capacity resource owners must provide the offered energy at the offered price if the offer is accepted in the Day-Ahead Energy Market. This energy can be provided by the specific unit offered, by a bilateral energy purchase, or by an energy purchase from the Real-Time Energy Market.

- **Deliverability.** To qualify as a PJM capacity resource, energy from the generating unit must be deliverable to load in PJM. Capacity resources must be deliverable, consistent with a loss of load expectation as specified by the reliability principles and standards, to the total system load, including portion(s) of the system that may have a capacity deficiency.[11] In addition, for external capacity resources used to meet an accounted for obligation within PJM, capacity and energy must be delivered to the metered, PJM boundaries through firm transmission service.

- **Generator Outage Reporting Requirement.** Owners of PJM capacity resources are required to submit historical outage data to PJM pursuant to Schedule 12 of the RAA.[12]

9 See PJM. "Manual 18: PJM Capacity Market," Revision 8 (Effective January 1, 2010), p. 38 <http://www.pjm.com/~/media/documents/manuals/m18.ashx> (1.27 MB).
10 See PJM. "Operating Agreement of PJM Interconnection, L.L.C.," Sixth Revised Sheet No. 93 (Effective June 1, 2008), Schedule 1, section 1.10.1A (d).
11 Deliverable per PJM. "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Original Sheet No. 50 (Effective June 1, 2007), Schedule 10.
12 See PJM. "Reliability Assurance Agreement among Load-Serving Entities in the PJM Region," Original Sheet No. 53 (Effective June 1, 2007), Schedule 11.

CETO/CETL

Since the ability to import energy and capacity into LDAs may be limited by the existing transmission capability, PJM conducts a load deliverability analysis for each LDA.[13,14] The first step in this process is to determine the transmission import requirement into an LDA, called the capacity emergency transfer objective (CETO). This value, expressed in MW, is the transmission import capability required for each LDA to meet the area reliability criterion of loss of load expectation due to insufficient import capability alone, of one occurrence in 25 years when the LDA is experiencing a localized capacity emergency.

The second step is to determine the transmission import limit for an LDA, called the capacity emergency transfer limit (CETL), which is also expressed in MW. The CETL is the ability of the transmission system to deliver energy into the LDA when it is experiencing the localized capacity emergency used in the CETO calculation.

If CETL is less than CETO, capacity-related transmission constraints may result in locational price differences in the RPM.[15] This will also trigger the planning of transmission upgrades under the RTEP Process. Prior to the 2012/2013 delivery year, only an LDA with CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. Effective with the 2012/2013 delivery year, an LDA with CETL less than 1.15 times CETO is modeled as a constrained LDA in RPM. Starting with the 2012/2013 delivery year, regardless of the CETO/CETL results, separate VRR curves will be established for any LDA with a locational price adder in one or more of the three immediately preceding BRAs, any LDA that PJM determines in a preliminary analysis is likely to have a locational price adder based on historic offer price levels, and EMAAC, SWMAAC, and MAAC LDAs.

Generator Performance: NERC OMC Outage Cause Codes

Table E-1 includes a list of the North American Electric Reliability Council (NERC) GADS cause codes that PJM deems outside management control (OMC). PJM does not automatically include cause codes 9200-9299 as outside management control for the purposes of calculating unforced capacity, with the exception of code 9250 under certain conditions.

13 See PJM. "Manual 14B: PJM Region Transmission Planning Process," Attachment C: PJM Deliverability Testing Methods," Revision 14 (Effective February 1, 2010), p. 45 <http://www.pjm.com/~/media/documents/manuals/m14b.ashx> (887.15 KB). PJM Manual 14B indicates that all "electrically cohesive load areas" are tested.

14 See PJM. "Manual 20: PJM Resource Adequacy Analysis," Revision 3 (Effective June 1, 2007), p. 32 <http://www.pjm.com/~/media/documents/manuals/m20.ashx> (662.90 KB).

15 See PJM. "Manual 18: PJM Capacity Market," Revision 8 (Effective January 1, 2010), p. 10, <http://www.pjm.com/~/media/documents/manuals/m18.ashx> (1.27 MB).

Table E-1 NERC GADS cause codes that PJM deems outside management control[16] (OMC)

Cause Code	Reason for Outage
3600	Switchyard transformers and associated cooling systems - external
3611	Switchyard circuit breakers - external
3612	Switchyard system protection devices - external
3619	Other switchyard equipment - external
3710	Transmission line (connected to powerhouse switchyard to 1st Substation)
3720	Transmission equipment at the 1st substation (see code 9300 if applicable)
3730	Transmission equipment beyond the 1st substation (see code 9300 if applicable)
9000	Flood
9010	Fire, not related to a specific component
9020	Lightning
9025	Geomagnetic disturbance
9030	Earthquake
9035	Hurricane
9036	Storms (ice, snow, etc)
9040	Other catastrophe
9130	Lack of fuel (water from rivers or lakes, coal mines, gas lines, etc) where the operator is not in control of contracts, supply lines, or delivery of fuels
9135	Lack of water (hydro)
9150	Labor strikes company-wide problems or strikes outside the company's jurisdiction such as manufacturers (delaying repairs) or transportation (fuel supply) problems
9250	Low Btu coal
9300	Transmission system problems other than catastrophes (do not include switchyard problems in this category; see codes 3600 to 3629, 3720 to 3730)
9320	Other miscellaneous external problems
9500	Regulatory (nuclear) proceedings and hearings - regulatory agency initiated
9502	Regulatory (nuclear) proceedings and hearings - intervener initiated
9504	Regulatory (environmental) proceedings and hearings - regulatory agency initiated
9506	Regulatory (environmental) proceedings and hearings - intervenor initiated
9510	Plant modifications strictly for compliance with new or changed regulatory requirements (scrubbers, cooling towers, etc.)
9590	Miscellaneous regulatory (this code is primarily intended for use with event contribution code 2 to indicate that a regulatory-related factor contributed to the primary cause of the event)

16 See NERC. "Generator Availability Data System Data Reporting Instructions," Appendix K <http://www.nerc.com/files/Appendix_K_Outside_Plant_Management_Control.pdf> (149 KB).

APPENDIX F – ANCILLARY SERVICE MARKETS

This appendix covers two areas related to Ancillary Service Markets: area control error and the details of regulation availability and price determination.

Area Control Error (ACE)

Area control error (ACE) is a real-time metric used by PJM operators to measure the instantaneous MW imbalance between load plus net interchange and generation within PJM.[1] PJM dispatchers seek to ensure grid reliability by balancing ACE. A dispatcher's success in doing so is measured by control performance standard 1 (CPS1) and balancing authority ACE limit (BAAL) performance. These measurements are mandated by the North American Electric Reliability Council (NERC).

In the absence of a severe grid disturbance, the primary tool used by dispatchers to minimize ACE is regulation. Regulation is defined as a variable amount of energy under automatic control which is independent of economic cost signal and is obtainable within five minutes. Regulation contributes to maintaining the balance between load and generation by moving the output of selected generators up and down via an automatic generation control (AGC) signal.[2]

Resources wishing to participate in the Regulation Market must pass certification and submit to random testing. Certification requires that resources be capable of and responsive to AGC. After receiving certification, all participants in the Regulation Market are tested to ensure that regulation capacity is fully available at all times. Testing occurs at times of minimal load fluctuation. During testing, units must respond to a regulation test pattern for 40 minutes and must reach their offered regulation capacity levels, up and down, within five minutes. Units whose monitored response is less than their offered regulation capacity have their regulating capacity reduced by PJM.[3]

During 2008 an experimental battery-powered regulation unit was installed at the PJM facility. Observation of this unit reveals that new types of units will require that PJM's regulation unit certification testing procedure as administered by PJM's Performance Compliance group be modified, perhaps tailored to the specific unit types. The test as it is now designed measures the ability of the unit to respond to its regulation min/max within five minutes. This has always been the critical regulating metric for steam and CT units. But other types of units can meet this criterion easily yet still be inadequate for regulation because they lack the capacity to regulate for the entire hour in the event that regulation is almost completely above or below the regulation set point. Such units might include battery, pumped hydro, and inertial regulation units.

Control Performance Standard (CPS) and Balancing Authority ACE Limit (BAAL)

Two control performance standards are established by NERC for evaluating ACE control. One measure is a statistical measure of ACE variability and its relationship to frequency error. The

1 "Two additional terms may be included in ACE under certain conditions – time error bias and manual add (a PJM dispatcher term). These provide for automatic inadvertent interchange payback and error compensation, respectively." See PJM. "Manual 12: Balancing Operations," Revision 20 (October 5, 2009), Section 3, "System Control" p. 11.

2 Regulation Market business rules are defined in PJM. "Manual 11: Scheduling Operations," Revision 44 (January 1, 2010), pp. 38-44.

3 See PJM. "Manual 12: Balancing Operations," Revision 20 (October 5, 2009), Section 4, pp. 45-47.

purpose of the new BAAL standard is to maintain interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal), to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection.

- **CPS1.** NERC requires that the first CPS measure provide a measure of the balancing authority's performance. The measure is intended to provide the balancing authority with a frequency-sensitive evaluation of how well it has met its demand requirements. A minimum passing score for CPS1 is 100 percent.[4]

- **CPS2.** NERC also requires that the second CPS measure provide a measure of 10-minute ACE averages. CPS2 provides a control measure of excessive, unscheduled power flows that could result from large ACEs. CPS2 is measured by counting the number of 10-minute periods during a month when the 10-minute average of PJM's ACE is within defined limits known as L_{10}. The specific, 10-minute periods of each hour are those ending at 10, 20, 30, 40, 50 and 60 minutes after the hour. A passing score for CPS2 is achieved when 90 percent of these 10-minute periods during a single month are within L_{10}. From January 1, through December 31, 2009, PJM's L_{10} standard was 278.2 MW.

- **BAAL.** Since August 1, 2005, PJM has participated in the NERC "Balancing Standard Proof-of-Concept Field Test" which has established a new metric, balancing authority ACE limit (BAAL), as a possible substitute for CPS2. Participants in the field test have a waiver from meeting the CPS2 requirement for the duration of the field test. As a substitute, the field test participants are required to comply with BAAL limits, which have been established on a trial basis.[5] PJM measures the total number of minutes the BAAL limit is exceeded (high or low) compared to the total number of minutes for a month, with a passing level for this goal being set at 98 percent.

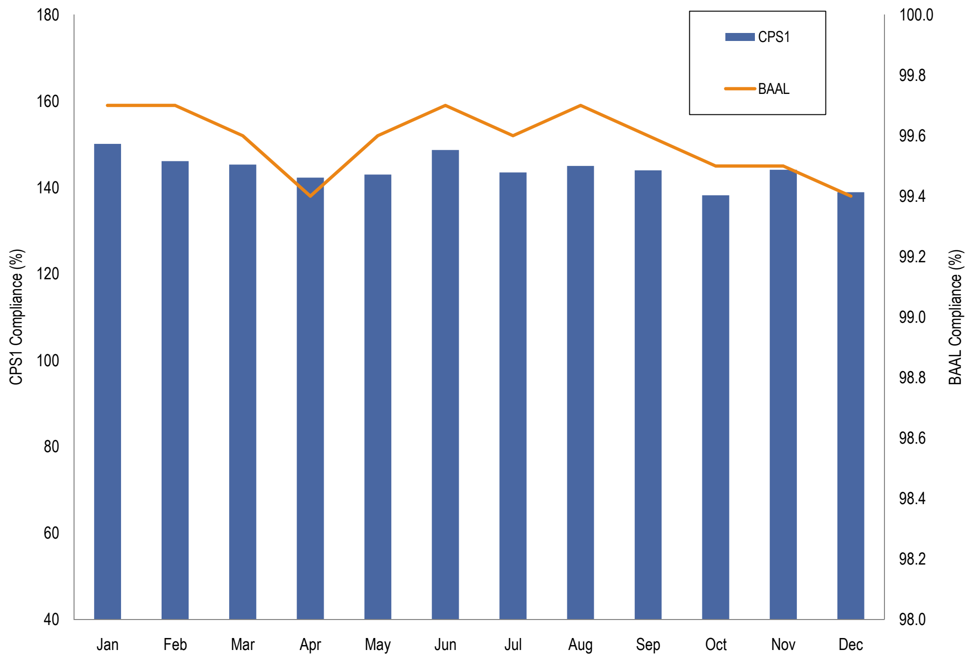
4 For more information about the definition and calculation of CPS, see PJM. "Manual 12: Balancing Operations," Revision 20 (October 5, 2009), pp. 80-90. The formal definition of CPS1 can be found in NERC's "Performance Standards Reference Document," Version 2 (November 21, 2002), Section B.1.1.1. The formal definition of CPS2 can be found in NERC's "Performance Standards Reference Document," Version 2 (November 21, 2002), Section B.1.1.2.

5 See PJM. "Manual 12: Balancing Operations," Revision 20 (October 5, 2009), pp. 80-90.

PJM's CPS/BAAL Performance

As Figure F-1 shows, PJM's performance relative to both the CPS1 and BAAL metrics was acceptable in calendar year 2009.

Figure F-1 PJM CPS1 and BAAL performance: Calendar year 2009



PJM dispatchers have to balance both ACE and frequency. Meeting the CPS1 standard requires balancing ACE and frequency on a monthly, running-average basis. Meeting the BAAL standard requires PJM dispatchers to maintain interconnection frequency within a predefined frequency profile under all conditions (normal and abnormal) to prevent frequency-related instability, unplanned tripping of load or generation, or uncontrolled separation or cascading outages that adversely impact the reliability of the interconnection.

PJM's DCS Performance

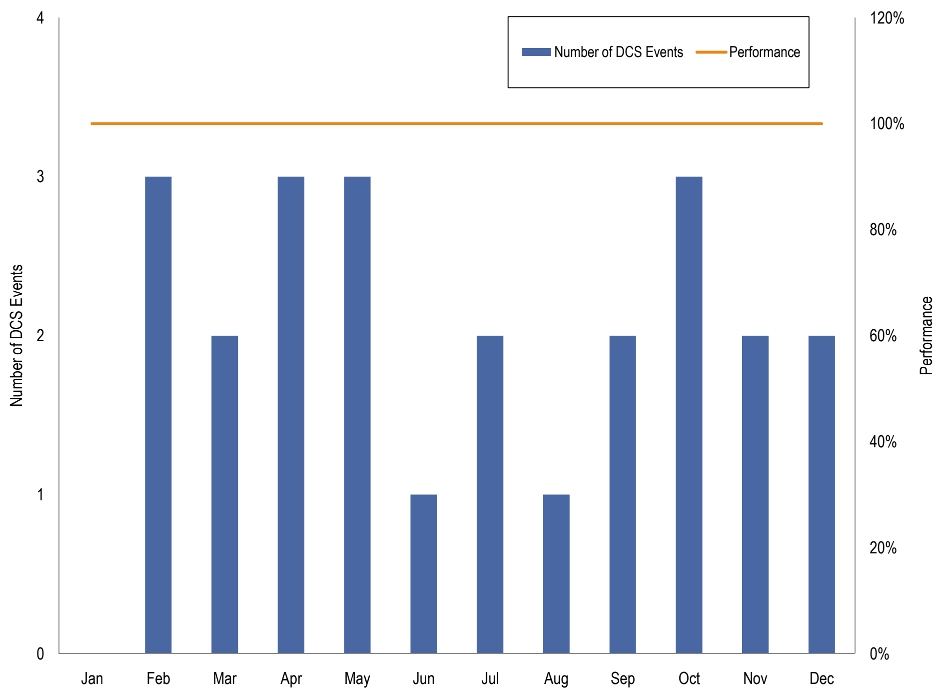
A dispatch performance metric that is directly related to synchronized reserve is the disturbance control standard (DCS).[6] DCS measures how well PJM dispatch recovers from a disturbance. A disturbance is defined as any ACE deviation greater than, or equal to, 80 percent of the magnitude of PJM's most severe single contingency loss. PJM currently interprets this to be any ACE deviation

6 For more information on the NERC DCS, see "Standard BAL-002-0 — Disturbance Control Performance" (April 1, 2005) <www.nerc.com/files/BAL-002-0.pdf> (61 KB).

greater than 800 MW. Compliance with the NERC DCS is recovery to zero or predisturbance level within 15 minutes.

PJM experienced 24 DCS events during calendar year 2009 and successfully recovered from all of them. All events were caused by the tripping of a major unit. Recovery times ranged from four minutes to 13 minutes. Figure F-2 illustrates the event count and performance by month. All of the events resulted in low ACE. The solution in 16 of the 24 events was to declare a 100 percent spinning event. The other events were addressed using redispatch or reserve sharing with NYISO.

Figure F-2 DCS event count and PJM performance (By month): Calendar year 2009



Regulation Capacity, Daily Offers, Offered and Eligible, Hourly Assigned

The regulation market-clearing price (RMCP) is determined algorithmically by the PJM Market Operations Group. The market clearing software (SPREGO) creates a regulation supply curve as part of a two product, and two constraint simultaneous solution. The price of the most expensive unit required to satisfy the regulation requirement is the RMCP. Calculating the supply curves for two products (regulation and synchronized reserve) with two constraints (energy and operating reserves) interactively is complicated, but necessary to achieve the lowest overall cost after first taking into account units that self schedule. In the event it is not possible to satisfy both regulation and synchronized reserve, regulation has the higher priority.

- **Regulation Capacity.** The sum of the regulation MW capability of all generating units which have qualified to participate in the Regulation Market is the theoretical maximum regulation capacity. This maximum regulation capacity varies over time because units that are certified for regulation may be decommissioned, fail regulation testing or be removed from the Regulation Market by their owners.

- **Regulation Offers.** All owners of generating units qualified to provide regulation may, but are not required to, offer their regulation capacity daily into the Regulation Market using the PJM market user interface. Regulating units may also self-schedule. Self-scheduled units have zero lost opportunity cost (LOC) and are the first to be assigned. Demand resources were eligible to offer regulation although during 2009 none qualified to do so. Demand resources have an LOC of zero. Under PJM rules, no more than 25 percent of the total regulation requirement may be supplied by demand resources. Total regulation offers are the sum of all regulation-capable units that offer regulation into the market for the day and that are not out of service or fully committed to provide energy. Owners of units that have entered offers into the PJM market user interface system have the ability to set unit status to “unavailable” for regulation for the day, or for a specific hour or set of hours. They also have the ability to change the amount of regulation MW offered in each hour. Unit owners do not have the ability to change their regulation offer price during a day. Starting in December, 2008, the PJM Market Users Interface allows regulation owners to enter cost data. For cost-based offers above $12 per MWh owners are required to enter cost data. All regulation offers are summed to calculate the total daily regulation offered, a figure that changes each hour.

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

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

For each offered and eligible unit in the regulation supply, the regulation total offer price is calculated using the sum of the unit's regulation cost-based offer and the opportunity cost based on the forecast LMP, unit economic minimum and economic maximum, regulation minimum and regulation maximum, startup costs and relevant offer schedule.[7] Based on this result, SPREGO determines if the period has three or fewer pivotal suppliers. If it does, all owners who are pivotal have their offers limited to the lesser of their cost or price offer. SPREGO uses price-based offers for those operators not offer capped and re-solves. This solution is final. The MW offered and the calculated regulation offered prices are used to create a regulation supply curve. The Regulation and Synchronized Reserve Markets are cleared interactively with the Energy Market and operating reserve requirements to minimize the cost of the combined products subject to reactive limits, resource constraints, unscheduled power flows, interarea transfer limits, resource distribution factors, self-scheduled resources, limited fuel resources, bilateral transactions, hydrological constraints, generation requirements and reserve requirements.

- **Cleared Regulation.** Regulation actually assigned by SPREGO is cleared regulation. The clearing price established by SPREGO becomes the final clearing price. In real time, units that have been assigned regulation and synchronized reserve are expected to provide regulation and synchronized reserve for the designated hour. At any time before or during the hour, PJM dispatchers can redispatch units for reliability reasons. Such redispatch leads to a disparity between cleared regulation and settled regulation.

- **Settled Regulation.** Units providing regulation are compensated at the clearing price times their actual MW provided (as opposed to cleared MW) plus any actual lost opportunity costs associated with providing regulation. The cost per MW of settled regulation can be higher than the regulation clearing price because there can be a difference between actual and cleared MW, as well as real-time versus forecast nodal prices.

7 See the *2009 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Services" for a discussion of opportunity cost.

APPENDIX G – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

Appendix G provides examples of topics related to Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs):

- The sources of total congestion revenue and the determination of FTR target allocations and congestion receipts;
- The procedure for prorating ARRs when transmission capability limits the number of ARRs that can be allocated; and
- The establishment of ARR target allocations and credits through the Annual FTR Auction.

FTR Target Allocations and Congestion Revenue

Table G-1 shows an example of the sources of total congestion revenue and the determination of FTR target allocations and congestion receipts.

Table G-1 Congestion revenue, FTR target allocations and FTR congestion credits: Illustration

Day-Ahead Congestion Revenue						
Pricing Node	Day-Ahead Congestion Price	Day-Ahead Load	Load Congestion Payments	Day-Ahead Generation	Generation Congestion Credits	Transmission Congestion Charges
A	$10	0	$0	100	$1,000	($1,000)
B	$15	50	$750	0	$0	$750
C	$20	50	$1,000	100	$2,000	($1,000)
D	$25	50	$1,250	0	$0	$1,250
E	$30	50	$1,500	0	$0	$1,500
Total		200	$4,500	200	$3,000	$1,500
Balancing Congestion Revenue						
Pricing Node	Real-Time Congestion Price	Load Deviation	Load Congestion Payments	Generation Deviation	Generation Congestion Credits	Transmission Congestion Charges
A	$8	0	$0	0	$0	$0
B	$18	0	$0	0	$0	$0
C	$25	3	$75	5	$125	($50)
D	$20	(5)	($100)	0	$0	($100)
E	$40	7	$280	0	$0	$280
Total		5	$255	5	$125	$130
Transmission congestion charges accounting						
Balancing transmission congestion charges						$130
+ Day-ahead transmission congestion charges						$1,500
= Total transmission congestion charges						$1,630
FTR Target Allocations						
Path	Day-Ahead Path Price	FTR MW	FTR Target Allocations	Positive FTR Target Allocations	Negative FTR Target Allocations	
A-C	$10	50	$500	$500	$0	
A-D	$15	50	$750	$750	$0	
D-B	($10)	25	($250)	$0	($250)	
B-E	$15	50	$750	$750	$0	
Total		175	$1,750	$2,000	($250)	
Congestion accounting						
Transmission congestion charges						$1,630
+ Negative FTR target allocations						$250
= Total congestion charges						$1,880
Positive FTR target allocations				$2,000		
- FTR congestion credits				$1,880		
= Congestion credit deficiency				$120		
FTR payout ratio				0.94		

ARR Prorating Procedure

Table G-2 shows an example of the prorating procedure for ARRs. If line A-B has a 100 MW rating, but ARR requests from two customers together would impose 175 MW of flow on it, the service request would exceed its capability by 75 MW. The first customer's ARR request (ARR #1) is for a total of 300 MW with a 0.50 impact on the constrained line. It would thus impose 150 MW of flow on the line. The second customer's request (ARR #2) is for a total of 100 MW with a 0.25 impact and would impose an additional 25 MW on the constrained line.

Table G-2 ARR allocation prorating procedure: Illustration

Line A-B Rating = 100 MW						
ARR #	Path	Per MW Effect on Line A-B	Requested ARRs	Resulting Line A-B Flow	Prorated ARRs	Prorated Line A-B Flow
1	C-D	0.50	300	150	150	75
2	E-F	0.25	100	25	100	25
Total			400	175	250	100

Equation G-1 Calculation of prorated ARRs

Individual prorated MW =
(Line capability) • (Individual requested MW / Total requested MW) • (1 / per MW effect on line).

The equation would then be solved for each request as follows:

ARR #1 prorated MW award = (100 MW) • (300 MW / 400 MW) • (1 / 0.50) = 150 MW; and

ARR #2 prorated MW award = (100 MW) • (100 MW / 400 MW) • (1 / 0.25) = 100 MW.

Together the prorated, awarded ARRs would impose a flow equal to line A-B's capability
(150 MW • 0.50) + (100 MW • 0.25) = 100 MW.

ARR Credits

Table G-3 shows an example of how ARR target allocations are established, how FTR auction revenue is generated and how ARR credits are determined. The purchasers of FTRs pay and the holders of ARRs are paid based on cleared nodal prices from the Annual FTR Auction. If total revenue from the auction is greater than the sum of the ARR target allocations, then the surplus is used to offset any FTR congestion credit deficiencies occurring in the hourly Day-Ahead Energy Market. For example, the FTR auction revenue is only $75 for the ARR on line A-D while the ARR target allocation is $150. The surplus FTR auction revenue from the other ARR paths is enough to cover the $75 deficiency and fulfill the ARR target allocation of $150.

Table G-3 ARR credits: Illustration

Path	Annual FTR Auction Path Price	ARR MW	ARR Target Allocation	FTR MW	FTR Auction Revenue	ARR Credits
A-C	$10	10	$100	10	$100	$100
A-D	$15	10	$150	5	$75	$150
B-D	$10	0	$0	20	$200	$0
B-E	$15	10	$150	5	$75	$150
Total		30	$400	40	$450	$400
ARR payout ratio = ARR credits / ARR target allocations = $400 / $400 = 100%						
Surplus ARR revenue = FTR auction revenue - ARR credits = $450 - $400 = $50						

Self-Scheduled ARRs

Table G-4 shows an example of two ARR customers, one of which self schedules ARRs and one of which retains ARRs. During an Annual ARR Allocation, both ARR customers #1 and #2 are allocated 10 MW ARRs on line A-B. ARR customer #1 self schedules 10 MW ARRs on line A-B as FTRs during the subsequent Annual FTR Auction while ARR customer #2 retains 10 MW ARRs on line A-B. Based on cleared nodal prices from the Annual FTR Auction, ARRs on line A-B are valued at $10 per MW. Customer #2 will receive $100 in ARR credits. Customer #1 converts all of the 10 MW ARRs on line A-B to FTRs during the Annual FTR Auction and, as a result, this customer needs to pay $100 to purchase the associated self-scheduled FTRs although this cost will be fully offset by the same amount of ARR credits. Based on the difference in LMPs, FTRs on line A-B are valued at $15 per MW. Customer #1 will receive $150 in FTR credits. In summary, Customer #1 receives a net $150 in FTR credits as a result of self scheduling the 10 MW of allocated ARRs on line A-B as FTRs, while Customer #2 receives $100 in ARR credits as a result of retaining the 10 MW ARRs on line A-B.

Table G-4 Self-Scheduled ARR credits: Illustration

Customer #	Path	ARR MW	Annual FTR Auction Path Price	ARR Credits	Converted to FTRs?	Cost of Conversion to FTRs	Day-Ahead FTR Path Price	FTR Credits	Total Credits
1	A-B	10 MW	$10	$100	Yes	$100	$15	$150	$150
2	A-B	10 MW	$10	$100	No	$0	$15	$0	$100
Total credits = ARR credits - Cost of conversion to FTRs + FTR credits									

APPENDIX H – CALCULATING LOCATIONAL MARGINAL PRICE

In order to understand the relevance of various measures of locational marginal price (LMP), it is important to understand how average LMPs are calculated across time and across buses. This appendix explains how PJM calculates average LMP and load-weighted, average LMP for the system, for a zone and, by extension, for any aggregation of buses, for an hour, for a day and for a year.[1] This appendix also explains how the Market Monitoring Unit (MMU) calculates average LMP for states, consistent with the PJM method for other aggregates.

Real-Time Hourly Integrated LMP and Real-Time Hourly Integrated Load

In PJM a real-time LMP is calculated at every bus for every five-minute interval.

The system real-time, five-minute, average LMP is the load-weighted, average LMP for that five-minute interval, calculated using the five-minute LMP at each load bus and the corresponding five-minute load at each load bus in the system. The sum of the product of the five-minute LMP and the five-minute load at each bus, divided by the sum of the five-minute loads across the buses equals the system load-weighted, average LMP for that five-minute interval.

In PJM, the real-time hourly LMP at a bus is equal to the simple average of each hour's 12 five-minute interval LMPs at that bus. This is termed the hourly integrated LMP at the bus. The hourly load at a bus is also calculated as the simple average of each hour's 12 five-minute interval loads at that bus. This is termed the hourly integrated load at the bus. The hourly values for LMP and load are the basis of PJM's settlement calculations.

Day-Ahead Hourly LMP and Day-Ahead Hourly Load

The day-ahead LMP is calculated at every bus for every hour from the day-ahead dispatch required to meet estimated nodal loads derived from the distribution factors plus nodal load from decrement bids (DECs) and price-sensitive load and nodal supply from generation offers and increment offers (INCs). The result is a full set of day-ahead nodal LMPs and cleared, nodal loads.

This measure of nodal, day-ahead load is used in system load-weighted, average LMP calculations. This is termed nodal, total day-ahead load here. Zonal, day-ahead hourly aggregate load is assigned to buses in the relevant zone using zonal distribution factors.

Day-ahead zonal distribution factors are calculated from historical real-time, bus-level load distributions that were in effect at 8 AM seven days prior. The use of load data from a period seven days prior to the DA price calculations provides a week day match but the lack of adjustment for other factors that affect bus-specific loads, including temperature, introduces a potentially significant inaccuracy in the load data used to clear the day-ahead market. This would be an issue to the extent that weather or other factors changes the relative size of nodal loads.

1 The unweighted, average LMP is also referred to as the simple average LMP.

Zonal, day-ahead, load-weighted LMP is calculated from nodal day-ahead LMP using zonal distribution factors as the load weights. This measure of load weights excludes bus specific loads, such as DECs, that clear in the day-ahead market. The exclusion of bus specific loads from the calculation of day ahead load weighted LMP means that the zonal day-ahead load weighted prices reported by PJM do not reflect the load weighted price paid by all load in a zone, but instead reflect only the price paid by the load that settles at the day ahead hourly zonal price.

Factor distributed load, used in the calculation of state load weighted average LMP, is calculated by multiplying day-ahead zonal hourly load (fixed plus price-sensitive load only) by day-ahead distribution factors. The factor distributed load calculation provides bus specific load weights, derived directly from the day ahead zonal distribution factors, which are used to calculate day-ahead load and load weighted average LMP for states with load buses in multiple zones or parts of zones. This methodology is used because it results in weighted LMPs that are consistent with how zonal factor weighted prices are determined by PJM. This means that where the zone buses are the same as state buses, the result will be the same. For example, the state of Maryland contains buses from the AP, BGE, DPL and Pepco zones, but the areas encompassed by these aggregates, with the exception of BGE, extend beyond the borders of the state. AP, for example, extends past the western portion of Maryland into Pennsylvania, Ohio, West Virginia and Virginia. To provide Maryland specific results for load and LMP, a Maryland aggregate is calculated using only those AP, BGE, DPL and Pepco load buses that are physically within the geographic boundaries of the state of Maryland.

Load-Weighted, Average LMP

Real Time

The system real-time, load-weighted, average LMP for an hour is equal to the sum of the product of the hourly integrated bus LMPs for each load bus and the hourly integrated load for each load bus, for the hour, divided by the sum of the hourly integrated bus loads for the hour.

The zonal real-time, load-weighted, average LMP for an hour is equal to the sum of the product of the hourly integrated bus LMPs for each load bus in a zone and the hourly integrated load for each load bus in that zone, divided by the sum of the real-time hourly integrated loads for each load bus in that same zone.

The real-time, load-weighted, average LMP for an hour for a state is equal to the sum of the product of the hourly integrated bus LMPs for each load bus in a state and the hourly integrated load for each load bus in that state, divided by the sum of the real-time hourly integrated loads for each load bus in that state.

The system real-time, load-weighted, average LMP for a day is equal to the product of the hourly integrated LMPs for each load bus and the hourly integrated load for each load bus, for each hour, summed over every hour of the day, divided by the sum of the hourly integrated bus loads for the system for the day.

The zonal real-time, load-weighted, average LMP for a day is equal to the product of each of the hourly integrated LMPs for each load bus in a zone and the hourly integrated load for each load bus in that zone, for each hour, summed over every hour of the day, divided by the sum of the hourly integrated bus loads at each load bus in that zone for the day.

The real-time, load-weighted, average LMP for a day for a state is equal to the product of each of the hourly integrated LMPs for each load bus in a state and the hourly integrated load for each load bus in that state, for each hour, summed over every hour of the day, divided by the sum of the hourly integrated bus loads at each load bus in that state for the day.

The system real-time, load-weighted, average LMP for a year is equal to the product of the hourly integrated LMPs and hourly integrated load for each load bus, summed across every hour of the year, divided by the sum of the hourly integrated bus loads at each load bus in the system for each hour in the year.

The zonal real-time load-weighted, average LMP for a year is equal to the product of each of the hourly integrated bus LMPs and hourly integrated load for each load bus in a zone, summed across every hour of the year, divided by the sum of the hourly integrated bus loads at each load bus in that zone for each hour in the year.

The real-time load-weighted, average LMP for a year for a state is equal to the product of each of the hourly integrated bus LMPs and hourly integrated load for each load bus in a state, summed across every hour of the year, divided by the sum of the hourly integrated bus loads at each load bus in that state for each hour in the year.

Day Ahead

The system day-ahead, load-weighted, average LMP for an hour is equal to the sum of the product of the hourly LMP at each load bus and the corresponding nodal, total day-ahead hourly load at each load bus in the system, divided by the sum of the nodal, total day-ahead hourly loads across the buses.

The zonal day-ahead, load-weighted, average LMP for an hour is equal to the sum of the product of the hourly bus LMPs for each load bus in a zone and the hourly estimated load distribution factors for each load bus in that zone. The zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

The day-ahead, load-weighted, average LMP for an hour for a state is equal to the sum of the product of the hourly bus LMPs for each load bus in a state and the hourly factor distributed load, from each contributing zone, for each load bus in that state. The state specific day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

The system day-ahead, load-weighted, average LMP for a day is equal to the product of the hourly day-ahead LMPs for each load bus and the nodal, total hourly day-ahead load for each load bus, for each hour, summed over every hour of the day, divided by the sum of the nodal, total hourly day-ahead loads for the system for the day.

The zonal day-ahead, load-weighted, average LMP for a day is equal to the product of each of the hourly day-ahead LMPs for each load bus in a zone and the hourly estimated load distribution factors for each load bus in that zone and the hourly day-ahead load for the zone, summed over every hour of the day, and divided by the corresponding estimated total zonal load for the day. The zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

The day-ahead, load-weighted, average LMP for a day for a state is equal to the product of each of the hourly day-ahead LMPs for each load bus in a state and the hourly factor distributed load, from each contributing zone, for each load bus in that state, summed over every hour of the day, and divided by the corresponding estimated total hourly factor distributed load for the day. The zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

The system day-ahead, load-weighted, average LMP for a year is equal to the product of the hourly LMPs and nodal, total hourly load for each load bus, summed across every hour of the year, divided by the sum of the nodal, total hourly bus loads at each load bus in the system for each hour in the year.

The zonal day-ahead, load-weighted, average LMP for a year is equal to the product of each of the hourly LMPs for each load bus in a zone and the hourly estimated load distribution factors for each load bus in that zone and the hourly day-ahead load for the zone, summed over every hour of the year, and divided by the total estimated zonal load for the year. The zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

The day-ahead, load-weighted, average LMP for a year for a state is equal to the product of each of the hourly LMPs for each load bus in a zone and the hourly factor distributed load, from each contributing zone, for each load bus in that state, summed over every hour of the year, and divided by the corresponding estimated total hourly factor distributed load for the year. The zonal day-ahead, load-weighted, average LMP does not use the full nodal, total day-ahead hourly loads used in the other calculations of day-ahead average LMP.

Equation H-1 LMP calculations

	i = 5-minute interval	h = 12 intervals = hour i = 1..12	d = 24 hours = day h = 1..24	y = 365 days = 8,760 hours = year d = 1..365
Bus average	LMP_{bi}	$LMP_{bh} = \frac{\sum_{i=1}^{12} LMP_{bi}}{12}$	$LMP_{bd} = \frac{\sum_{h=1}^{24} LMP_{bh}}{24}$	$LMP_{by} = \frac{\sum_{h=1}^{8760} LMP_{bh}}{8760}$
Bus load-weighted average			$lwLMP_{bd} = \frac{\sum_{h=1}^{24} (LMP_{bh} \bullet Load_{bh})}{\sum_{h=1}^{24} Load_{bh}}$	$lwLMP_{by} = \frac{\sum_{h=1}^{8760} (LMP_{bh} \bullet Load_{bh})}{\sum_{h=1}^{8760} Load_{bh}}$
System average	$LMP_{si} = \frac{\sum_{b=1}^{B} LMP_{bi}}{B}$	$LMP_{sh} = \frac{\sum_{b=1}^{B} LMP_{bh}}{B}$	$LMP_{sd} = \frac{\sum_{h=1}^{24} \frac{\sum_{b=1}^{B} (LMP_{bh} \bullet Load_{bh})}{\sum_{b=1}^{B} Load_{bh}}}{24}$	$LMP_{sy} = \frac{\sum_{h=1}^{8760} \frac{\sum_{b=1}^{B} (LMP_{bh} \bullet Load_{bh})}{\sum_{b=1}^{B} Load_{bh}}}{8760}$
System load-weighted average	$lwLMP_{si} = \frac{\sum_{b=1}^{B} (LMP_{bi} \bullet Load_{bi})}{\sum_{b=1}^{B} Load_{bi}}$	$lwLMP_{sh} = \frac{\sum_{b=1}^{B} (LMP_{bh} \bullet Load_{bh})}{\sum_{b=1}^{B} Load_{bh}}$	$lwLMP_{sd} = \frac{\sum_{h=1}^{24} \sum_{b=1}^{B} (LMP_{bh} \bullet Load_{bh})}{\sum_{h=1}^{24} \sum_{b=1}^{B} Load_{bh}}$	$lwLMP_{sy} = \frac{\sum_{h=1}^{8760} \sum_{b=1}^{B} (LMP_{bh} \bullet Load_{bh})}{\sum_{h=1}^{8760} \sum_{b=1}^{B} Load_{bh}}$

APPENDIX I – LOAD DEFINITIONS

PJM measures load in a number of ways. The Market Monitoring Unit (MMU) makes use of two basic measures of load in its analysis of the PJM market: peak load and accounting load. In the *2009 State of the Market Report for PJM*, both measures of load are used, as appropriate for the specific analysis. The measures of load and their applications changed after PJM's June 1, 2007, implementation of marginal losses.

Peak Load

PJM uses eMTR data for both peak loads and as the basis for accounting loads. eMTR data is supplied by PJM electricity distribution companies (EDCs) and generators and is based on the metered MWh values of tie lines and the metered values of generation MWh. For PJM Western Region and Southern Region EDCs (ComEd, AEP, DAY, DLCO, AP and Dominion), eMTR load values implicitly include local, EHV (extra-high-voltage) and non-EHV losses. eMTR load values for PJM Mid-Atlantic Region EDCs implicitly include local and non-EHV losses plus an explicit allocation of metered Mid-Atlantic Region EHV losses. PJM uses this eMTR load data to measure peak loads. This measure of load provides the total amount of generation output and net energy imports required to meet the peak demand on the system. It is not strictly a measure of load, but rather a measure of the output and imports necessary to meet load.

Accounting Load

PJM uses eMTR load data, excluding losses, as accounting load in the settlement process. Prior to June 1, 2007, accounting load for all EDCs was equal to eMTR load and thus included losses. Since the implementation of marginal losses on June 1, 2007, accounting load without losses is calculated by subtracting State Estimator losses from eMTR load and allocating the net amount to load buses based on State Estimator loads. Since June 1, 2007, accounting load without losses has represented the actual retail customer load and is referred to here as accounting load.

Accounting load is used in the *2009 State of the Market Report for PJM* to measure daily, monthly and annual load. Accounting load is also used in the *2009 State of the Market Report for PJM* to weight LMP in load-weighted LMP calculations. Prior to June 1, 2007, accounting load included losses and after June 1 accounting load excludes losses. Prior to June 1, 2007, LMP did not include losses. After June 1, 2007, LMP includes losses.

APPENDIX J – MARGINAL LOSSES

On June 1, 2007, PJM revised its methodology for determining transmission losses from average losses to nodal, marginal losses. Marginal loss pricing is based on the incremental losses that result from an increase in output. Marginal loss pricing is designed to permit more efficient system dispatch and decreased total production cost.

Under the new methodology, PJM's locational marginal price (LMP) at a bus *i* is comprised of three distinct components: system marginal price (SMP), marginal losses component of LMP at bus *i* (L_i) and the congestion component of LMP at bus *i* ($CLMP_i$).

Equation J-1 shows the components of LMP at bus *i*.

Equation J-1 LMP components

$$LMP_i = SMP + L_i + CLMP_i$$

SMP is calculated at the distributed load reference bus, where the loss and CLMP contribution to LMP are zero. The LMP at bus *i* is comprised of losses and congestion effects, either positive or negative, that are determined by the bus's location on the system relative to the SMP at the load weighted reference bus.

Total, Average and Marginal Losses

Total transmission losses are equal the product of the square of the current flowing across the line (*I*) and the resistance of the line (*R*). The materials constituting the conductors and other elements of the transmission system exhibit a characteristic impedance to the flow of power. Total transmission losses over a line can also be expressed as the product of the resistance of the line (*R*) times the square of the power consumed by the load (*P*), divided by the square of the voltage (*V*).[1] While this relationship differs somewhat in an alternating current (AC) as compared to a direct current (DC) system, the magnitude of losses can be approximated by the equation:

Equation J-2 Total transmission losses

Total Losses = $I^2 \cdot R = (P^2 \cdot R) / V^2$,

Defining $a = R / V^2$ and substituting into Equation J-2 results in:

Equation J-3 Total transmission losses

Total Losses = $a \cdot P^2$.

Average transmission losses per MW from a given power flow *P* across a transmission element are:

1 Equation J-2 incorporates the substitution of the relationship *I=P/V*, derived from Ohm's Law, for the variable *I*.

Equation J-4 Average transmission losses

$$\text{Average Losses} = \left(a \cdot P^2 / P\right) = a \cdot P .$$

Marginal transmission losses are the incremental losses resulting from an increase in power flow P across the transmission element and are equal to the first derivative of total losses with respect to power flow P:

Equation J-5 Marginal losses

$$\text{Marginal Losses} = \frac{d}{dP}\left(a \cdot P^2\right) = 2 \cdot a \cdot P .$$

For a given power flow P, the marginal losses for an increase in P are, therefore, equal to twice the average losses for the associated total flow P.

Effect of Marginal Losses on LMP

The following equations illustrate the effect of marginal losses on least cost dispatch. In this simple example, the least cost dispatch problem involves meeting system load and the losses associated with serving that load.

Equation J-6 defines the total cost of generation (C_T), which is a function of generator output (P) of units i though N.

Equation J-6 Total cost of generation

$$C_T = \sum_{i=1}^{N} \left[C_i(P_i)\right]$$

Equation J-7 is the power balance constraint, where total injections ($\sum_i^N P_i$) must equal total withdrawals (P_{load}) plus total losses (P_{loss}), where losses are a function of ($\sum_i^N P_i$).

Equation J-7 Power Balance Constraint

$$P_{load} + P_{loss}\left(\sum_{i=1}^{N} P_i\right) = \sum_{i=1}^{N} P_i$$

Together, equation Equation J-6 and Equation J-7 form a system of equations which can be represented by a Lagrangian (ζ), as defined in Equation J-8.

Equation J-8 System

$$\zeta(P_i) = \sum_{i=1}^{N} C_i(P_i) + \lambda_i \bullet (P_{load} + P_{loss}(\sum_i^N P_i) - \sum_{i=1}^{N} P_i)$$

Optimizing Equation J-8 for $P_{i...n}$ results in Equation J-9 and Equation J-7:

Equation J-9 Lambda

$$\frac{dC}{dP_i} \bullet \frac{1}{(1 - \frac{dP_{loss}}{dP_i})} = \lambda_i$$

Equation J-10 Power Balance Constraint (from above)

$$P_{load} + P_{loss}\left(\sum_{i=1}^{N} P_i\right) = \sum_{i=1}^{N} P_i$$

Note, that Equation J-9 shows that the optimal dispatch of each generator *i* must account for losses associated with using that unit to meet load. This measure of losses is the marginal loss penalty factor (Pf_f) for incremental power from generator *i* to serve system load:

Equation J-11 Penalty factor

$$Pf_i = \frac{1}{\left(1 - \frac{\partial P_{loss}}{\partial P_i}\right)}.$$

The incremental cost of using output from generator *i* to meet load includes incremental losses.[2]

The term $\frac{\partial P_{loss}}{\partial P_i}$ is called the loss factor and represents the change in system losses for a change in output from generator *i* to meet load.

If an increase in power from generator *i* results in an incremental increase in losses, then the loss factor is positive:

$$0 < \frac{\partial P_{loss}}{\partial P_i} < 1,$$

and the resultant penalty factor at bus_i would be greater than one:

$$Pf_i = \frac{1}{\left(1 - \frac{\partial P_{loss}}{\partial P_i}\right)} > 1.$$

Conversely, if an increase in power results in a decrease in losses, then the loss factor is negative:

$$-1 < \frac{\partial P_{loss}}{\partial P_i} < 0,$$

and the resultant penalty factor at bus *i* would be less than one: $Pf_i = \frac{1}{\left(1 - \frac{\partial P_{loss}}{\partial P_i}\right)} < 1$.

2 Note, as presented here, the marginal effect is on total losses, not losses at any particular load bus.

The unit offer curve of a generator is multiplied by the respective penalty factor for serving the load. (See Equation J-11) To the system operator, seeking to minimize the costs of serving a given level of load, the existence of losses modifies the relative costs of output from the unit relative to the case where losses are not accounted for. If the relevant penalty factor is greater than one, system losses would be made greater by increasing the output of that generator to serve load, and the unit offer curve, from the system operator perspective, would be shifted upward relative to the case where losses were not accounted for. Similarly, if the penalty factor associated with generator i delivering power to load is less than one, system losses associated with serving system load would be reduced by increasing the output of generator *i* , and the unit offer curve would shift downward relative to the case where losses are not accounted for.

These marginal loss related adjustments in relative costs will affect the optimal dispatch, and the resulting LMPs, for any given level of load relative to the case where marginal losses are not accounted for. LMPs at specific load buses will reflect the fact that marginal generators must produce more (or less) energy due to losses to serve that bus than is needed to serve the load weighted reference bus. The LMP at any bus is a function of the SMP, losses and congestion. Relative to the system marginal price (SMP) at the load weighted reference bus, the loss factor can be either positive or negative.

Loss Revenue Surplus

As demonstrated in Equation J-5, revenues resulting from marginal losses are approximately twice those collected from average losses. As demonstrated in Equation J-2, losses are equal to the square of the power, *P.* As such, two loads of equal size at the same location, served simultaneously, result in losses four times greater than the losses incurred in serving either of them separately. By utilizing the penalty factor in the dispatch, losses are paid based on marginal losses rather than based on average losses. Other than the effect on the optimal dispatch point, LMP at the marginal generator bus, and therefore the payment to the generator, is not affected. By paying for losses based on marginal instead of average losses at the load bus, a revenue over collection occurs. Using the example of two loads, of equal size at the same location, being served simultaneously, the marginal losses associated with the combined effect of the loads are greater than the sum of the losses incurred by each load separately, thus resulting in an over collection.

Properly accounting for marginal losses allows for an optimal, least cost solution to the system of equations that make up the market to serve load. Over collection is a direct outcome of marginal cost pricing and not a cause for concern. Prices set on this basis reflect the true incremental cost of serving load at any bus, and provide efficient incremental resource signals. Of concern under these circumstances is what is done with the over collection and how it is distributed among the market participants. These disbursements should be provided to the market participants that pay for the marginal losses in their energy charges, in this case the loads. To maintain an efficient price signal, any reallocation of the excess revenues must not interfere with the price signal at the margin. The solution to this problem generally takes the form of lump sum payments to market participants. The next issue is how to distribute the payments among the loads. To the extent that the causality of total marginal losses related costs are not generally directly attributable to specific load serving entities, the actual allocation methodology used to distribute the lump sum payments, while important from a policy perspective, is more a question of equity than market outcome efficiency. Under these circumstances, where there are common costs attributable to providing a service to a number of parties, it is general accepted practice to allocate the common costs, or benefits, to participants in proportion to their contribution to total load. This is the approach adopted by PJM. Under PJM's tariff, excess total loss related revenues are allocated to transmission users based on load plus export ratio shares:

Equation J-12 Excess loss revenue allocation

$$\text{Loss Credit} = (\text{Total Loss Surplus}) + \left(\frac{\text{Customer total MWh delivered to load} \ + \ \text{exports}}{\text{Total PJM MWh delivered to load} \ + \ \text{exports}}\right).$$

APPENDIX K – CALCULATION AND USE OF GENERATOR SENSITIVITY/ UNIT PARTICIPATION FACTORS

Sensitivity factors define the impact of each marginal unit on locational marginal price (LMP) at every bus on the system. The availability of sensitivity factor data permits the refinement of analyses in areas where the goal is to calculate the impact of unit characteristics or behavior on LMP.[1] These factors include the impact on LMP of the cost of fuel by type, the cost of emissions allowances by type, frequently mitigated unit adders and unit markup by unit characteristics.[2]

Generator sensitivity factors, or unit participation factors (UPFs), are calculated within the least-cost, security-constrained optimization program. For every five-minute system solution, UPFs describe the incremental amount of output that would have to be provided by each of the current set of marginal units to meet the next increment of load at a specified bus while maintaining total system energy balance. A UPF is calculated from each marginal unit to each load bus for every five-minute interval. In the absence of marginal losses, the UPFs associated with the set of marginal units in any given interval, for a particular load bus, always sum to 1.0. UPFs can be either positive or negative. A negative UPF for a unit with respect to a specific load bus indicates that the unit would have to be backed down for the system to meet the incremental load at the load bus.

Within the security-constrained, least-cost dispatch solution for an interval, during which the LMP at the marginal unit's bus equals the marginal unit's offer, consistent with its output level, LMP at each load bus is equal to each marginal unit's offer price, multiplied by its UPF, relative to that load bus. In some cases, the bus price for the marginal unit may not equal the calculated price based on the offer curve of the marginal unit. These differences are the result of the LPA marginal unit offer being overridden with its UDS LMP or ex-ante dispatch rate. When overridden, the LPA marginal unit's current offer is replaced by the UDS LMP and this sets the price. The UDS LMP does not reflect the LPA marginal unit's offer curve and does not represent the offer behavior of the marginal units in the LPA whose offers are overridden. The UDS LMP is a result of the marginal units in UDS and reflects the offer curve and behavior of these units. Any difference between the price based on the offer curve and the actual bus price when no override occurs is categorized as "dispatch differential." When an override occurs and the price difference cannot be explained with the UDS solution, the difference is categorized as "UDS override differential." In addition, final LMPs calculated using UPFs may differ slightly from PJM's posted LMPs as a result of rounding and missing data. Such differentials are identified as not available (NA).

Table K-1 shows the relationship between marginal generator offers and the LMP at a specific load bus X in a given five-minute interval.

Table K-1 LMP at bus X

Generator	UPF Bus X	Offer	Generator Contribution to LMP at X	Generator Contribution to LMP at X (Percentage)
A	0.5	$200.00	$100.00	85%
B	0.4	$40.00	$16.00	14%
C	0.1	$10.00	$1.00	1%
			LMP at X	
			$117.00	100%

1 The PJM Market Monitoring Unit (MMU) identified applications for sensitivity factors and began to save sensitivity factors in 2006.

2 Before the *2006 State of the Market Report*, state of the market reports had shown the impact of each marginal unit on load and on LMP based on engineering estimates whenever there were multiple marginal units.

Table K-1 shows three hypothetical, marginal generators at three different buses (A, B and C); each affects LMP at load bus X. Each generator's effect on LMP at X is measured by the UPF of that unit with respect to X. The UPF for generator A is 0.5 relative to load bus X, meaning that 50 percent of marginal Unit A's offer price contributes directly to the LMP at X. Since A has an offer price of $200, generator A contributes $100, or UPF times the offer, to the LMP at load bus X. The UPFs from all the marginal units to the load bus must sum to 1.0, so that the marginal units explain 100 percent of the load bus LMP. Generators B and C have UPFs of 0.4 and 0.1, respectively, and offer prices of $40 and $10, respectively, and therefore contribute $16 and $1, respectively, to the LMP at X. Together, the marginal units' offers multiplied by their UPFs with respect to load bus X explain the interval LMP at the load bus.

Hourly Integrated LMP Using UPF

Table K-1 describes the relationship between LMP and UPFs for a five-minute interval. Since PJM charges loads and credits generators on the basis of hourly integrated LMP, the relationship among marginal unit offers, UPFs and the hourly integrated LMP must be specified.

The relevant variables and notation are defined as follows:

h = hour,

i = five-minute interval,

t = year, where t designates the current year and t-1 designates the previous year,

b = a specified load bus, where b ranges from 1 to B,

g = a specified marginal generator, where g ranges from 1 to G, and

L = interval-specific load.

The hourly integrated load at a bus is the simple average of the 12 interval loads at a bus in a given hour:

Equation K-1 Hourly integrated load at a bus

$$Load_{bh} = \frac{\sum_{i=1}^{12} L_{bi}}{12}.$$

Load bus *LMP* is determined on a five-minute basis and is a function of marginal unit offers and *UPF*s in that interval:

Equation K-2 Load bus LMP

$$LMP_{bi} = \sum_{g=1}^{G} \left(Offer_{gi} \bullet UPF_{gbi}\right).$$

The hourly integrated *LMP* at a bus is the simple average of the 12 interval LMPs at a bus in a given hour:

Equation K-3 Hourly integrated LMP at a bus

$$LMP_{bh} = \frac{\sum_{i=1}^{12} LMP_{bi}}{12}.$$

Total cost (*TC*) of the system in the hour is equal to the product of the hourly integrated LMP and the hourly integrated load at each bus summed across all buses in the hour:

Equation K-4 Hourly total system cost

$$TC_h = \sum_{b=1}^{B} \left(LMP_{bh} \bullet Load_{bh} \right).$$

System load-weighted LMP for the hour ($LMPSYS_h$) is equal to the total hourly system cost (*TC*) divided by the sum of a bus's simple 12 interval average loads in the hour:

Equation K-5 Hourly load-weighted LMP

$$LMPSYS_h = \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}}.$$

The system annual, load-weighted, average (S*LW*) LMP for the year is:

Equation K-6 System annual, load-weighted, average LMP

$$Annual\_SLW\_LMP = \sum_{h=1}^{8760} \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}}.$$

Hourly Integrated Markup Using UPFs

Markup is defined as the difference between the price from the price-based offer curve and the cost from the cost-based offer curve at the operating point of a specific marginal unit. UPFs can be used to calculate the impact of marginal unit markup behavior on the LMP at any individual load bus and of the LMP at any aggregation of load buses including the system LMP. The resultant markup component of LMP is a measure of market power, a market performance metric. The markup component of LMP is based on the markup of the actual marginal units and is not based on a redispatch of the system using cost-based offers.

To determine the impact of marginal unit markup behavior on system LMP on an hourly integrated basis, the following steps are required.

Total cost (*TC*) of the system in the hour is equal to the product of the average LMP and the average load at each bus summed across all buses in the hour which, using the definitions above, can be expressed in terms of marginal unit offers and UPFs:

Equation K-7 UPF-based system hourly total cost

$$TC_h = \sum_{b=1}^{B} \left(LMP_{bh} \bullet Load_{bh}\right) = \sum_{b=1}^{B} \left[Load_{bh} \bullet \frac{\sum_{i=1}^{12} \sum_{g=1}^{G} \left(Offer_{gi} \bullet UPF_{gbi}\right)}{12} \right].$$

System load-weighted LMP for the hour is equal to total hourly system cost divided by the sum of the bus's simple 12 interval average loads in the hour:

Equation K-8 System load-weighted LMP

$$LMPSYS_h = \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B} \left[Load_{bh} \bullet \frac{\sum_{i=1}^{12} \sum_{g=1}^{G} \left(Offer_{gi} \bullet UPF_{gbi}\right)}{12} \right]}{\sum_{b=1}^{B} Load_{bh}}.$$

Holding dispatch and marginal units constant, the system, hourly load-weighted LMP based on cost offers of the marginal units, shown in Equation K-9, is found by substituting the marginal unit cost offers into Equation K-8**:**

Equation K-9 Cost-based offer system, hourly load-weighted LMP

$$LMPSYSCost_h = \frac{TC_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B} \left[Load_{bh} \bullet \frac{\sum_{i=1}^{12} \sum_{g=1}^{G} \left(CostOffer_{gi} \bullet UPF_{gbi}\right)}{12} \right]}{\sum_{b=1}^{B} Load_{bh}}.$$

The contribution of the markup by marginal units to system LMP for the hour is shown in Equation K-10 below:

Equation K-10 Impact of marginal unit markup on LMP

$$MarkUp_h = LMPSYS_h - LMPSYSCost_h.$$

UPF–Weighted, Marginal Unit Markup

The price-cost markup index for a marginal unit provides a measure of market power based on the behavior of a single unit of an individual generator:

Equation K-11 Price-cost markup index

$$MarkUp_{gi} = \frac{Offer_{gi} - CostOffer_{gi}}{Offer_{gi}}.$$

The UPF load-weighted, marginal unit markup (measure of unit behavior) provides a measure of market power for a given hour for the system or any aggregation of load buses. This measure of system performance equals the weighted-average markup index for all marginal units, which is a measure of unit behavior:

Equation K-12 UPF load-weighted, marginal unit markup

$$lwMarkUp_h = \frac{\sum_{b=1}^{B}\left[\frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(MarkUp_{gi} \bullet UPF_{gbi}\right)}{12} \bullet Load_{bh}\right]}{\sum_{b=1}^{B} Load_{bh}}.$$

Hourly Integrated Historical, Cost-Adjusted, Load-Weighted LMP Using UPFs

UPFs can be used to calculate historical, cost-adjusted, load-weighted LMP for a specific time period. This method is used to disaggregate the various components of LMP, including all the separate components of unit marginal cost and unit markup, and to calculate the contributions of each component to system LMP.

The extent to which fuel cost, emission allowance cost, variable operation and maintenance cost (VOM) and markup affect the offers of marginal units depends on the share of the offer that each component represents. The percentage of a unit's offer that is based on each of the components is given as the following:

Fuel: $\%Fuel_{gi}$

SO_2: $\%SO_{2\,gi}$

NO_x: $\%NO_{x\,gi}$

VOM: $\%VOM_{gi}$

Markup: $\%MarkUp_{gi}$

The proportion of specific components of unit offers is calculated on an interval and on a unit-specific basis. Cost components are determined for each marginal unit for the relevant time periods:

Delivered fuel cost per MWh: FC_{gt}.

Sulfur dioxide, emission-related cost per MWh: $SO_{2\,gt}$.

Nitrogen oxide, emission-related cost per MWh: $NO_{x\,gt}$.

Fuel costs (*FC)* are specific to the unit's location, the unit's fuel type and the time period in question. For example:

FC_{gt} = Avg *FC* in specified "Current Year's Period" (e.g., April 1, 2008); and

FC_{gt-1} = Avg *FC* in specified "Previous Year's Period" (e.g., April 1, 2007).

Fuel-Cost-Adjusted LMP

The portion of a marginal generator's offer that is related to fuel costs for a specified period is adjusted to reflect the previous period's fuel costs. Subtracting the proportional fuel-cost adjustment from the marginal generator's interval-specific offer provides the fuel-cost-adjusted offer (*FCA)*:

Equation K-13 Fuel-cost-adjusted offer

$$FCAOffer_{gi} = Offer_{gi} \bullet \left[1 - \%Fuel_{gi} \bullet \left(\frac{FC_{gt} - FC_{gt-1}}{FC_{gt}}\right)\right].$$

Using $FCAOffer_{gi}$ for all marginal units in place of the unadjusted offers ($offer_{gi}$) in Equation K-8 (i.e., the system load-weighted LMP equation), results in the hourly fuel-cost-adjusted, load-weighted LMP:

Equation K-14 Fuel-cost-adjusted, load-weighted LMP

$$LWFCAsysLMP_h = \frac{TCFCA_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B}\left[Load_{bh} \bullet \frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(FCAOffer_{gi} \bullet UPF_{gbi}\right)}{12}\right]}{\sum_{b=1}^{B} Load_{bh}}.$$

The systemwide annual, fuel-cost-adjusted, load-weighted (*SFCALW*) LMP for the year is given by the following equation:

Equation K-15 Systemwide annual, fuel-cost-adjusted, load-weighted LMP

$$Annual\_SFCALW\_LMP = \sum_{h=1}^{8760} \frac{TCFCA_h}{\sum_{b=1}^{B} Load_{bh}}.$$

Cost-Adjusted LMP

Summing the unit's specific historical, cost-adjusted component effects and subtracting that sum from the unit's unadjusted offer provides the historical, cost-adjusted offer of the unit (*HCAOffer*):

Equation K-16 Unit historical, cost-adjusted offer

$$HCAOffer_{gi} = Offer_{gi} \bullet \left[1 - \%Fuel_{gi} \bullet \left(\frac{FC_{gt} - FC_{gt-1}}{FC_{gt}}\right) - \%NOx_{gi} \bullet \left(\frac{NOx_{gt} - NOx_{gt-1}}{NOx_{gt}}\right) - \%SO2_{gi} \bullet \left(\frac{SO2_{gt} - SO2_{gt-1}}{SO2_{gt}}\right)\right].$$

Using each unit's $HCAOffer_{gi}$ in place of its unadjusted offers ($offer_{gi}$) in Equation K-8 (i.e., the system load-weighted LMP equation) results in the following historical, cost-adjusted, load-weighted LMP for the hour in question:

Equation K-17 Unit historical, cost-adjusted, load-weighted LMP

$$LWHCAsysLMP_h = \frac{TCHCA_h}{\sum_{b=1}^{B} Load_{bh}} = \frac{\sum_{b=1}^{B}\left[Load_{bh} \bullet \frac{\sum_{i=1}^{12}\sum_{g=1}^{G}\left(HCAOffer_{gi} \bullet UPF_{gbi}\right)}{12}\right]}{\sum_{b=1}^{B} Load_{bh}}.$$

The annual systemwide, historical, cost-adjusted, load-weighted (*annual SHCALW*) LMP for the year is given by the following equation:

Equation K-18 Systemwide, historical, cost-adjusted, load-weighted LMP

$$Annual\_SHCALW\_LMP = \sum_{h=1}^{8760} \frac{TCHCA_h}{\sum_{b=1}^{B} Load_{bh}}.$$

Components of LMP

Table K-2 Components of PJM annual, load-weighted, average LMP: Calendar year 2009

Element	Contribution to LMP	Percent
Coal	$20.53	52.6%
Natural Gas	$12.10	31.0%
10% Cost Adder	$3.73	9.6%
VOM	$2.50	6.4%
Oil	$0.88	2.3%
NO_x	$0.80	2.1%
SO_2	$0.76	1.9%
CO_2	$0.61	1.6%
FMU Adder	$0.17	0.4%
Offline CT Adder	$0.03	0.1%
Municipal Waste	$0.02	0.0%
NA	$0.01	0.0%
Unit LMP Differential	$0.00	0.0%
Shadow Price Limit Adder	($0.01)	(0.0%)
M2M Adder	($0.14)	(0.3%)
Dispatch Differential	($0.15)	(0.4%)
UDS Override Differential	($0.43)	(1.1%)
Markup	($2.38)	(6.1%)
LMP	$39.05	100.0%

There are several components of LMP that are not directly a function of individual unit characteristics:

- **Offline CT Adder.** Offline CTs that are marginal in the UDS solution have $3 added to their operational offer. This is reflected at the CT unit bus and is propagated through the UDS system solution to the LPA marginal unit buses whose offers have been overridden with their respective UDS LMP. The purpose of this adder was to impose a penalty for selecting offline CTs in UDS in order to avoid UDS switching between online CTs and offline CTs. The implementation of Look Ahead UDS (LA UDS) in February 2009 eliminated the occurrence of offline CTs on the margin in UDS and therefore the offline CT adder.[3]

  The offline CT adder is the contribution of this adder to the annual average, load weighted LMP.

- **UDS Override Differential.** The LPA preprocessor determines the set of units eligible to set price in the LPA solution every five minutes. In order to determine eligible units, the preprocessor takes input from UDS in the form of desired MW, unit specific dispatch rates (UDS LMP), zonal dispatch rates, and unit operating limits. The UDS LMP is the dispatch rate calculated based on where units are being dispatched to 15 minutes from the present. The UDS LMP is

3 In January 2009, there were 1,355 intervals where an offline CT was marginal in UDS and a UDS override set the LPA marginal unit bus LMP. In February 2009, there were 5 intervals where an offline CT was marginal in UDS and a UDS override set the LPA marginal unit bus LMP. In April 2009, there was 1 interval where an offline CT was marginal in UDS and a UDS override set the LPA marginal unit bus LMP. There were no offline CTs marginal in the remaining months of 2009.

calculated respecting all transmission and operating constraints and is calculated based on a set of marginal units in the UDS solution. These marginal units set the UDS LMP in UDS in the same way that the LPA marginal units set the LMP.

The LPA preprocessor evaluates each unit against several thresholds designed to measure the extent to which units are currently following the dispatch signals provided by UDS. Units are eligible to set price in the LPA if they meet all the criteria in the preprocessor. A unit's current offer is calculated based on the unit's offer curve and the current state estimated solution. If a unit is following dispatch and its offer is less than or equal to the UDS LMP, the unit is eligible to set price based on its current offer. If a unit's current offer is greater than the UDS LMP and the unit is not a CT, the unit's current offer is automatically overridden with the UDS LMP. When overridden, the unit's current offer becomes the UDS LMP and the unit is again eligible to set price, but it sets price based on the UDS LMP and the characteristics of the UDS marginal units rather than based on the characteristics of the LPA unit. The UDS LMP does not reflect the LPA unit's offer curve and does not represent the offer behavior of the LPA units whose offers are overridden. The LMPs resulting from the LPA calculations do reflect the network characteristics of the LPA marginal unit, including the UPF and DFAX. However, when a UDS override occurs and the overridden unit is marginal in the LPA, the UDS solution marginal units have a direct effect on the LPA marginal prices.

In addition to the automatic overrides, another type of override occurs when the PJM LMP Operator manually overrides the LPA marginal unit bus LMP with its respective UDS LMP. This type of override occurs less frequently and is generally used to ensure that LMPs reflect how the UDS redispatches units for a transmission constraint. For example, if the LPA is selecting a raise help unit to relieve a constraint and the UDS is selecting a lower help unit to relieve the same constraint, the PJM LMP Operator will place the raise help unit on its UDS LMP. This action will either cause the lower help unit to be marginal in the LPA or the raise help unit to be marginal on its UDS LMP. Either of these actions will result in the same LMPs in the LPA and be consistent with the controlling action used in the UDS.

Table K-3 shows the percentage of five minute intervals and the percentage of all marginal units where a UDS override occurred during calendar year 2009. In 2009, 91 percent of all five minute intervals had at least one marginal unit whose offer was automatically overridden with its respective UDS LMP. Two percent of all five minute intervals had at least one marginal unit whose offer was manually overridden with its respective UDS LMP. In 2009, 81 percent of all marginal units had their offer automatically overridden with its respective UDS LMP. One percent of all marginal units had their offer manually overridden with its respective UDS LMP.

Table K-3 Percentage of five minute intervals and marginal units having a UDS LMP override: Calendar year 2009

Type	Percent of 5 Minute Intervals Overriden with UDS LMP	Percent of Marginal Units Overriden with UDS LMP
Automatic	91%	81%
Manual	2%	1%
Total	93%	82%

When an override occurs and the price difference cannot be explained with the UDS solution as a result of missing data, the difference is categorized as "UDS override differential." The UDS override differential is calculated as the difference between the UDS LMP at the LPA marginal unit bus and the actual offer of the LPA marginal unit. The UDS override differential is the contribution of these differentials to annual average, load weighted LMP.

- **Dispatch Differential.** Measures any difference between the bus LMP and the LPA operational offer or the UDS LMP at the UDS marginal unit and its operational offer based on desired MW. The dispatch differential is the contribution of this difference to the annual average, load weighted LMP.

- **M2M Adder.** The M2M adder occurs when PJM uses the shadow price calculated by the Midwest ISO as stated in the Joint Operating Agreement between PJM and the Midwest ISO.[4] When PJM uses the Midwest ISO shadow price, a marginal unit inside PJM is not identified for the M2M constraint. In order to reflect the cost of the M2M constraint in the ex ante LMP at each generator, the shadow price is multiplied by the DFAX of each generator to the M2M constraint. The result of this multiplication is also equal to the congestion component of the ex ante LMP at each generator bus relative to the M2M constraint. When a UDS override occurs and the LPA marginal unit offer is set equal to the ex ante LMP, the M2M adder reflects the contribution of the M2M constraint, rather than the UDS marginal unit, to the annual average, load weighted LMP.

- **Shadow Price Limit Adder.** PJM uses shadow price limits for constraints and the RT UDS economic dispatch algorithm enforces these limits. The procedures for setting the shadow price limits are flexible and the exact rationale for setting the limits is not clearly stated. When a shadow price limit is enforced on a constraint a marginal unit is not identified for the constraint and the transmission constraint is treated as the marginal resource in the least cost dispatch solution. The marginal cost of using this resource is equal to the shadow price limit for the constraint. In order to reflect the cost of the constraint in the ex ante LMP at each generator, the shadow price is multiplied by the DFAX of each generator to the constraint. The result of this multiplication is also equal to the congestion component of the ex ante LMP at each generator bus. When a UDS override occurs and the LPA marginal unit offer is set equal to the ex ante LMP, the shadow price limit adder reflects the contribution of the constraint at its shadow price limit, rather than the UDS marginal unit, to the annual average, load weigUnit LMP differential. Where the product of the UDS UPFs and UDS marginal unit operational offers does not equal the LPA marginal unit bus LMP, this component measures that difference. The unit LMP differential is the contribution of this difference to the annual average, load weighted LMP.

- **NA.** NA is the net difference between the UPF load weighted LMP calculation and the accounting load weighted LMP. NA is the contribution of this difference to the annual average, load weighted LMP.

4 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> (1,534 KB).

APPENDIX L – THREE PIVOTAL SUPPLIER TEST

PJM markets are designed to promote competitive outcomes. Market design is the primary means of achieving and promoting competitive outcomes in the PJM markets. One of the Market Monitoring Unit's (MMU's) primary goals is to identify actual or potential market design flaws.[1] PJM's market power mitigation goals have focused on market designs that promote competition (i.e., a structural basis for competitive outcomes) and on limiting market power mitigation to instances where 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.

The structural test for implementing offer capping set forth in the PJM Amended and Restated Operating Agreement (OA) Schedule 1, Sections 6.4.1(e) and (f) is the three pivotal supplier test. The three pivotal supplier test is applied by PJM on an ongoing basis in order to determine whether offer capping is required for any transmission constraint. The three pivotal supplier test defined in the OA represents a significant evolution in accuracy because the test is applied in real time using the actual data used by the dispatchers to dispatch the system including transmission constraints and the real-time details of incremental generator availability.

As a result of PJM's implementation of the three pivotal supplier test in real time, the actual competitive conditions associated with each binding constraint are analyzed in real time as they arise. The three pivotal supplier test replaced the prior approach which was to offer cap all units required to resolve a binding constraint. The application of the three pivotal supplier test has meant a reduction in the application of offer capping. As a result of the application of the three pivotal supplier test, offer capping is applied only at times when the local market structure is not competitive and only to those participants with structural market power.

Three Pivotal Supplier Test: Background

By order issued April 18, 2005, the United States Federal Energy Regulatory Commission (FERC) set for hearing, in Docket No. EL04-121-000, PJM's proposal: a) to exempt the AP South Interface from PJM's offer-capping rules; and b) to conduct annual competitive analyses to determine whether additional exemptions from offer capping are warranted. By order issued July 5, 2005, the FERC also set for hearing, in Docket No. EL03-236-006, PJM's three pivotal supplier test. The Commission further set for hearing issues related to the appropriateness of implementing scarcity pricing in PJM. In the July order, the Commission consolidated Docket No. EL04-121-000 and Docket No. EL03-236-006.

On November 16, 2005, PJM filed a "Settlement Agreement" resolving all issues set for hearing in Dockets Nos. EL04-121-000 and ER03-236-006, which included the application of the three pivotal supplier ("TPS") test, provisions for scarcity pricing, offer caps for frequently mitigated units and

1 PJM. "Open Access Transmission Tariff (OATT)," "Attachment M: Market Monitoring Plan," Third Revised Sheet No. 452 (Effective July 17, 2006).

competitive issues associated with certain of PJM's internal interfaces. The Commission approved this settlement on January 27, 2006, and the TPS test was implemented shortly thereafter.[2]

On January 15, 2008 the Maryland Public Service Commission filed a complaint against PJM requesting that the Commission remove PJM's market rule provisions that exempt certain generation resources from energy offer price mitigation and that the Commission initiate an investigation to determine whether generators exempt from mitigation have exercised market power and provide retroactive relief where appropriate. By order issued May 16, 2008, the Commission granted the request to remove the mitigation exemptions, but also established a Section 206 investigation and paper hearing in Docket No. EL08-47-000 to consider the justness and reasonableness of PJM's the mitigation program adopted in settlement ("May 16th Order").[3] The hearing was held in abeyance pending the earlier of either the conclusion of the ongoing stakeholder process conducted primarily in the Three Pivotal Supplier Task Force convened to evaluate the performance of the TPS test and its potential application to the Regulation Market.

PJM filed a report on the status of stakeholder progress on the issue on September 5, 2008, explaining that no consensus had been reached, but that the process had provided stakeholders a greater understanding of the theory behind and the implementation of the TPS test. PJM declined to propose any revisions to the TPS test.

On October 6, 2008, numerous parties including the MMU filed comments on the merits of the TPS test and alternatives. A smaller group filed reply comments on November 5, 2008. The MMU filed on November 25, 2008 a supplemental response.

On February 2, 2009, the Commission issued an initial order in its investigation finding that "there is not sufficient evidence to meet the Federal Power Act section 206 burden to show that the three-pivotal-supplier test … is unjust and unreasonable as it relates to assessing the structural competitiveness of the PJM energy market."[4] The Commission, however, found that "because default bids do not clearly and explicitly provide for the inclusion of opportunity costs, especially for energy and environmentally-limited resources, the mitigation measures related to determining default bids are unjust and unreasonable."[5] The Commission, therefore, required PJM "to make a compliance filing that proposes an approach for addressing the incorporation of opportunity costs in mitigated offers" on or before July 31, 2009.[6] The Commission also provided that "within 30 days after that filing, other parties may provide comments on the PJM proposal or submit their own specific proposals for resolving this issue." [7]

Several parties requested rehearing of the May 16th Order, which the Commission denied on December 19, 2008.[8]

On October 1, 2008, in Docket No. ER09-13-000, PJM filed to add the TPS test to the Regulation Market. On October 20, 2008, numerous parties filed comments or protest, including the MMU, which supported PJM's proposal but indicated reservations about certain aspects of its implementation.

2 114 FERC ¶61,076 (2006).
3 123 FERC ¶ 61,169 (2008).
4 *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,145 at P 1.
5 *Id.* at P 42.
6 *Id.* at P 48.
7 *Id.*
8 125 FERC ¶ 61,340 (2008).

The MMU requested that the Commission direct the MMU to report on those aspects of PJM's proposal. On November 26, 2008, the Commission approved the application of the TPS test to the Regulation Market, directing the MMU to file the requested report by November 26, 2009.[9]

Market Structure Tests and Market Power Mitigation: Core Concepts

A test for local market power based on the number of pivotal suppliers has a solid basis in economics and is clear and unambiguous to apply in practice. There is no perfect test, but the three pivotal supplier test for local market power strikes a reasonable balance between the requirement to limit extreme structural market power and the goal of limiting intervention in markets when competitive forces are adequate. The three pivotal supplier test for local market power is also a reasonable application of the logic contained in the Commission's market power tests.

The Commission adopted market power screens and tests in the AEP Order.[10] The AEP Order defined two indicative screens and the more dispositive delivered price test. The Commission's delivered price test for market power defines the relevant market as all suppliers who offer at or below the clearing price times 1.05 and, using that definition, applies pivotal supplier, market share and market concentration analyses. These tests are failed if, in the relevant market, the supplier in question is pivotal, has a market share in excess of 20 percent or if the Herfindahl-Hirschman Index (HHI) exceeds 2500. The Commission also recognized that there are interactions among the results of each screen under the delivered price test and that some interpretation is required and, in fact, is encouraged.[11]

The three pivotal supplier test, as implemented, is consistent with the Commission's market power tests, encompassed under the delivered price test. The three pivotal supplier test is an application of the delivered price test to the Real-Time Energy Market, the Day-Ahead Energy Market and the Reliability Pricing Model (RPM) Capacity 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 three pivotal supplier test includes more competitors in its definition of the relevant market than the Commission's delivered price test. While the Commission's delivered price test defines the relevant market to include all offers with costs less than, or equal to, 1.05 times the market price, the three pivotal supplier test includes all offers with costs less than, or equal to, 1.50 times the clearing price for the local market.

The three pivotal supplier test is also consistent with the Commission's delivered price test in that it tests for the interaction between individual participant attributes and features of the relevant market structure. The three pivotal supplier test is an explicit test for the ability to exercise unilateral market power as well as market power via coordinated action, based on economic theory, which accounts simultaneously for market shares and the supply-demand balance in the market.

The results of the three pivotal supplier test can differ from the results of the HHI and market share tests. The three pivotal supplier test can show the existence of structural market power when the HHI is less than 2500 and the maximum market share is less than 20 percent. The three pivotal

9 125 FERC ¶ 61,231(2008).
10 107 FERC ¶ 61,018 (2004) (AEP Order).
11 107 FERC ¶ 61,018 (2004).

supplier test can also show the absence of market power when the HHI is greater than 2500 and the maximum market share is greater than 20 percent. The three pivotal supplier test is more accurate than the HHI and market share tests because it focuses on the relationship between demand and the most significant aspect of the ownership structure of supply available to meet it. A market share in excess of 20 percent does not matter if the holder of that market share is not jointly pivotal and is unlikely to be able to affect the market price. A market share less than 20 percent does not matter if the holder of that market share is jointly pivotal and is likely to be able to affect the market price. Similarly, an HHI in excess of 2500 does not matter if the relevant owners are not jointly pivotal and are unlikely to be able to affect the market price. An HHI less than 2500 does not matter if the relevant owners are jointly pivotal and are likely to be able to affect the market price.[12]

The three pivotal supplier test was designed in light of actual elasticity conditions in load pockets in wholesale power markets in PJM. The price elasticity of demand is a critical variable in determining whether a particular market structure is likely to result in a competitive outcome. A market with a specific set of market structure features is likely to have a competitive outcome under one range of demand elasticity conditions and a noncompetitive outcome under another set of elasticity conditions. It is essential that market power tests account for actual elasticity conditions and that evaluation of market power tests neither ignore elasticity nor make counterfactual elasticity assumptions. As the Commission stated, “In markets with very little demand elasticity, a pivotal supplier could extract significant monopoly rents during peak periods because customers have few, if any, alternatives.”[13] The Commission also stated:

> In both of these models, the lower the demand elasticity, the higher the mark-up over marginal costs. It must be recognized that demand elasticity is extremely small in electricity markets; in other words, because electricity is considered an essential service, the demand for it is not very responsive to price increases. These models illustrate the need for a conservative approach in order to ensure competitive outcomes for customers because many customers lack one of the key protections against market power: demand response.[14]

The Commission defines the relevant market under the delivered price test “by identifying potential suppliers based on market prices, input costs, and transmission availability, and calculates each supplier’s economic capacity for each season/load condition.” The Commission defines the relevant market to include suppliers with “costs less than or equal to 1.05 times the market price,” i.e. those “suppliers that could sell into the destination market at a price less than or equal to 5 percent over the market price.”[15] Thus, the relevant market includes all supply that is potentially competitive with the supplier and excludes supply that is not potentially competitive with the supplier.

The Commission’s market based rates analysis then applies the components of the delivered price test to the relevant market. A supplier fails if the supplier is pivotal (one pivotal supplier test), if it has a market share greater than or equal to 20 percent, or if the HHI in the relevant market is greater than or equal to 2500.[16] A supplier is pivotal under the market power test if demand in the relevant market cannot be met without its supply (one pivotal supplier test).

12 For detailed examples, see Joseph E. Bowring, PJM market monitor. “MMU Analysis of Combined Regulation Market,” PJM Market Implementation Committee Meeting (December 20, 2006).
13 107 FERC ¶ 61,018 (2004).
14 107 FERC ¶ 61,018 (2004).
15 AEP Order at App. F; *see also Inquiry Concerning the Commission’s Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶ 31,044, *mimeo* at 6 (1996), reconsideration denied, Order No. 592-A, 79 FERC ¶ 61,321 (1997) (“Merger Policy Statement”); Revised Filing Requirements Under Part 33 of the Commission’s Regulations, Order No. 642, FERC Stats. & Regs. ¶ 31,111 (2000), *order on reh’g*, Order No. 642-A, 94 FERC ¶ 61,289 (2001); Order No. 697 at P 108.
16 Order No. 697 at P 111.

The Commission recognizes the interactions among the multiple analyses under the delivered price test and "encourages the most complete analysis of competitive conditions in the market as the data allow."[17]

For example, passing a single-pivotal supplier test does not demonstrate the absence of structural market power because market participants can coordinate their behavior with other suppliers and can do so without overt interaction. The Commission stated:

> Concentration statistics can indicate the likelihood of coordinated interaction in a market. All else being equal, the higher the HHI, the more firms can extract excess profits from the market. Likewise a low HHI can indicate a lower likelihood of coordinated interactions among suppliers and could be used to support a claim of a lack of market power by a seller that is pivotal or does have a 20 percent or greater market share in some or all season/ load conditions. For example, a seller with a market share of 20 percent or greater could argue that … it would be unlikely to possess market power in an unconcentrated market (HHI less than 1000).[18]

In a market with an inelastic demand curve, the existence of two jointly pivotal suppliers, regardless of the amount of excess capacity available, does not provide a market structure that will result in a competitive outcome. The 20 percent market share and the HHI screen are also weak screens for structural market power on a stand-alone basis. A market share in excess of 20 percent does not demonstrate market power if the holder of that market share is not jointly pivotal and is unlikely to be able to affect the market price. A market share less than 20 percent does not demonstrate the absence of market power if the holder of that market share is jointly pivotal and is likely to be able to affect the market price. An HHI in excess of 2500 does not demonstrate market power if the relevant owners are not jointly pivotal and are unlikely to be able to affect the market price. An HHI less than 2500 does not demonstrate the absence of market power if the relevant owners are jointly pivotal and are likely to be able to affect the market price.[19]

The three pivotal supplier test is a reasonable application of the Commission's delivered price test to the case of load pockets that arise in a market based on security-constrained, economic dispatch with locational market pricing and extremely inelastic demand. The three pivotal supplier test also exists in the context of a local market power mitigation rule that relies on a structure test, a participant behavior test and a market impact test. The three pivotal supplier test explicitly incorporates the relationship between supply and demand in the definition of pivotal, and it provides a clear test for whether excess supply is adequate to offset other structural features of the market and results in an adequately competitive market structure. The greater the supply relative to demand, the less likely that three suppliers will be jointly pivotal, all else equal.

The three pivotal supplier test represents a significant modification of the previously existing PJM local market power rule, which did not include an explicit market structure test. The goal of applying a market structure test is to continue to limit the exercise of market power by generation owners in load pockets but to lift offer capping when the market structure makes the exercise of market power less likely. The goal of the three pivotal supplier test, proposed by PJM, was not to weaken

17 *See* Order No. 697 at PP 111–117; AEP Order at PP 111–12.
18 Order No. 697 at P 111.
19 For detailed examples, see Joseph E. Bowring, PJM market monitor. "MMU Analysis of Combined Regulation Market," PJM Market Implementation Committee Meeting (December 20, 2006).

the local market power rules but to make them more flexible by adding an explicit market structure test. As recognized by PJM when the local market power rule was proposed in 1997 and has continued to be the case, the local markets created by transmission constraints are generally not structurally competitive. Nonetheless, it is appropriate to have a clear test as to when a local market is adequately competitive to permit the relaxation of local market power mitigation. The three pivotal supplier test proposed by PJM is not a guarantee that suppliers will behave in a competitive manner in load pockets. The three pivotal supplier test is a structural test that is not a perfect predictor of actual behavior. The existence of this risk is the reason that the PJM Tariff language also includes the ability of the MMU to request that the Commission reinstate offer caps in cases where there is not a competitive outcome.

Three Pivotal Supplier Test: Mechanics

The three pivotal supplier test measures the degree to which the supply from three generation suppliers is required in order to meet the demand to relieve a constraint. Two key variables in the analysis are the demand and the supply. The demand consists of the incremental, effective MW required to relieve the constraint. The supply consists of the incremental, effective MW of supply available to relieve the constraint at a distribution factor (DFAX) greater than, or equal to, the DFAX used by PJM in operations.[20] For purposes of the test, incremental effective MW are attributed to specific suppliers on the basis of their control of the assets in question. Generation capacity controlled directly or indirectly through affiliates or through contracts with third parties are attributed to a single supplier.

The supply directly included as relevant to the market in the three pivotal supplier test consists of the incremental, effective MW of supply that are available at a price less than, or equal to, 1.5 times the clearing price (P_c) that would result from the intersection of demand (constraint relief required) and the incremental supply available to resolve the constraint. This measure of supply is termed the relevant effective supply (*S*) in the market for the relief of the constraint in question. In every case, incrementally available supply is measured as incremental effective MW of supply, as shown in Equation L-1, and the clearing price (P_c) is defined as shown in Equation L-2:

Equation L-1 Incremental effective MW of supply

$MW \bullet DFAX$; and

Equation L-2 Price of clearing offer

$$P_c = \frac{Offer_c - SMP}{DFAX_c}.$$

To be part of the relevant market, the effective offer of incremental supplier *i* must be less than, or equal to, 1.5 times P_c:

20 A unit's contribution toward effective, incrementally available supply is based on the DFAX of the unit relative to the constraint and the unit's incrementally available capacity over current load levels, to the extent that the capacity in question can be made available within an hour of the time the relief will be needed. Effective, incrementally available MW from an unloaded 100 MW 15-minute start combustion turbine (CT) with a DFAX of 0.05 to a constraint would be 5 MW relative to the constraint in question. Effective, incrementally available MW from a 200 MW steam unit, with 100 MW loaded, a 50 MW ramp rate and a DFAX of 0.5 to the constraint would be 25 MW.

Equation L-3 Relevant and effective offer

$$P_{ie} = \frac{Offer_i - SMP}{DFAX_i} \leq 1.5 \bullet P_c .$$

Where the effective incremental supply of supplier *i* is a function of price:

Equation L-4 Relevant and effective supply of supplier i

$$S_i = MW\left(P_{ie}\right) \bullet DFAX_i .$$

Where S_i is the relevant, incremental and effective supply of supplier *i*, total relevant, incremental and effective supply for suppliers *i*=1 to n is shown in Equation L-5:

Equation L-5 Total relevant, effective supply

$$S = \sum_{i=1}^{n} S_i .$$

Each effective supplier, from 1 to n, is ranked, from the largest to the smallest relevant effective supply, relative to the constraint for which it is being tested. In the first iteration of the test, the two largest suppliers are combined with the third largest supplier, and this combined supply is subtracted from total relevant effective supply. The resulting net amount of relevant effective supply is divided by the total relief required (*D*). Where *j* defines the supplier being tested in combination with the two largest suppliers (initially the third largest supplier with *j*=3), Equation L-6 shows the formula for the three pivotal supplier metric, i.e., the residual supply index for three pivotal suppliers (RSI3):

Equation L-6 Calculating the three pivotal supplier test

$$RSI3_j = \frac{\sum_{i=1}^{n} S_i - \sum_{i=1}^{2} S_i - S_j}{D} .$$

Where *j*=3, if $RSI3_j$ is less than, or equal to, 1.0, then the three largest suppliers in the market for the relief of the constraint fail the three pivotal supplier test. That is, the three largest suppliers are jointly pivotal for the local market created by the need to relieve the constraint using local, out-of-merit units. If $RSI3_j$ is greater than 1.0, then the three largest potential suppliers of relief MW pass the test and the remaining suppliers (*j*=4..n) pass the test. In the event of a failure of the three largest suppliers, further iterations of the test are needed, with each subsequent iteration testing a subsequently smaller supplier (*j*=4..n) in combination with the two largest suppliers. In each iteration, if $RSI3_j$ is less than 1.0, it indicates that the tested supplier, in combination with the two largest suppliers, has failed the test. Iterations of the test continue until the combination of the two largest suppliers and a supplier *j* result in $RSI3_j$ greater than 1.0. When the result of this process is that $RSI3_j$ is greater than 1.0, the remaining suppliers pass the test.

If a supplier fails the test for a constraint, units that are part of a supplier's relevant effective supply with respect to a constraint can have their offers capped at cost plus 10 percent, or cost plus relevant adders for frequently mitigated units and associated units. Offer capping only occurs to the extent that the units of this supplier's relevant, effective supply are offered at greater than cost plus 10 percent and are actually dispatched to contribute to the relief of the constraint in question.

Defining the market

The goal of defining the relevant market is to include those producers that actually compete to determine the market price or could actually compete to determine the market price. Conversely, the goal of defining the relevant market is to exclude those units that are not meaningful competitors and therefore do not have an impact on the clearing price. The existence of market power within that defined market depends on the ability of the firm to raise price while continuing to sell its output. A firm cannot successfully increase the market price above the competitive level if competitors would replace its output when it did so.

The Commission definition of the relevant market includes all suppliers which have costs less than or equal to 1.05 times the clearing price. The Commission definition means that, if the marginal unit sets the clearing price based on an offer of $200 per MWh, all units with costs less than, or equal to, $210 per MWh have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. The three pivotal supplier definition means that, if the marginal unit sets the clearing price based on an offer of $200 per MWh, all units with costs less than, or equal to, $300 per MWh have a competitive effect on the offer of the marginal unit. These units are all defined to be meaningful competitors in the sense that it is assumed that their behavior constrains the behavior of the marginal and inframarginal units. The three pivotal supplier test incorporates a definition of meaningful competitors that is at the extremely high end of inclusive. It is questionable whether a unit with a competitive offer price of $300 meaningfully constrains the offer of a $200 unit. This broad market definition is combined with the recognition that multiple owners can be jointly pivotal. The three pivotal supplier test includes three pivotal suppliers while the Commission test includes only one pivotal supplier.

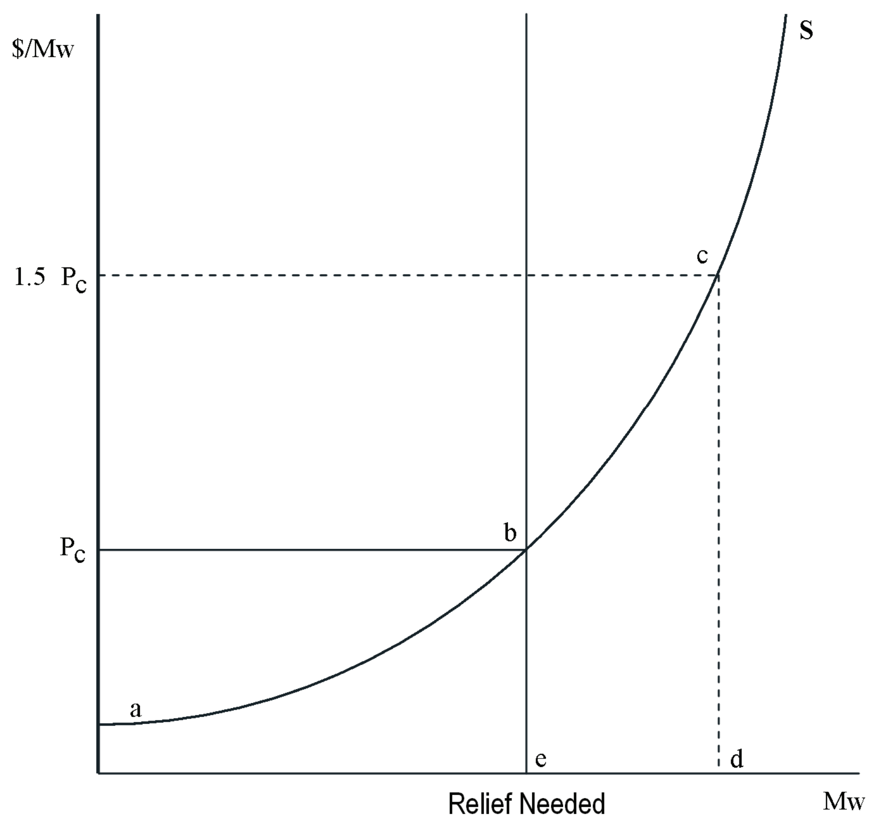
The three pivotal supplier test is designed to test the relevant market. For example, in the case of the market for out of merit generation needed to relieve a constraint in real time, the three pivotal supplier test examines the market specifically available to provide that relief. Under these conditions, the three pivotal supplier test measures the degree to which the supply from three generation suppliers, as defined by PJM's market solution software, is required in order to meet the demand to relieve a constraint. The market demand consists of the incremental, effective MW required to relieve the constraint. The market supply consists of the incremental, effective MW of supply available to relieve the constraint.[21] For purposes of the test, incremental effective MW are attributed to specific suppliers on the basis of their control of the assets in question. Generation capacity controlled directly or indirectly through affiliates or through contracts with third parties are attributed to a single supplier.

21 A unit's contribution toward effective, incrementally available supply is based on the DFAX of the unit relative to the constraint and the unit's incrementally available capacity over current load levels, if the capacity in question is available within an hour of the time the relief will be needed. Effective, incrementally available MW from an unloaded 100 MW 15-minute start combustion turbine (CT) with a DFAX of 0.05 to a constraint would be 5 MW relative to the constraint in question. Effective, incrementally available MW from a 200 MW steam unit, with 100 MW loaded, a 50 MW ramp rate and a DFAX of 0.5 to the constraint would be 25 MW.

The supply directly included as relevant to the market in the three pivotal supplier test consists of the incremental, effective MW of supply that are available at a price less than, or equal to, 1.5 times the clearing price (P_c) that would result from the intersection of demand (constraint relief required) and the incremental supply available to resolve the constraint. This measure of supply is termed the relevant effective supply (*S*) in the market for the relief of the constraint in question. In every case, incrementally available supply is measured as incremental effective MW of supply, as shown in Equation L-1, and the clearing price (P_c) is defined as shown in Equation L-1 above.

Figure L-1 illustrates the interaction between the relief requirement and the effective supply available, as recognized by PJM's solution software. The clearing price (P_c) is generated at the point of intersection of the relief required (D) and relevant effective supply (S). The effective cost and MW pairs from a particular participant are based on the lesser of the participant's cost or price schedule, if the unit is offline, or the current operational (price or cost) schedule if the unit is already being dispatched by PJM. The relief requirement can be fully met at the point of intersection (b) of (D) and (S) by the effective MW available at P_c (e). However, as indicated above, the market defined for the test also includes potentially effective MW in excess of what is needed to clear the market (d), defined as the effective MW available at a price less than, or equal to, 1.5 times the clearing price (P_c).

Figure L-1 Definition of relevant market



Unlike structural tests that define markets by geographic proximity, TPS makes explicit and direct use of the incremental, effective MW of supply available to relieve the constraint at a distribution factor (DFAX) greater than, or equal to, the DFAX used by PJM in operations. Only the supply that is part of the market as defined by the reality of the electric network as measured by unit characteristics and distribution factors is included in the three pivotal supplier test, to the extent that it is incremental, effective MW of supply that is available at a price less than, or equal to, 1.5 times the clearing price (P_c) that would result from the intersection of demand (constraint relief required) and the incremental supply available to resolve the constraint.

APPENDIX M – STANDARD MARKET METRICS

The Market Monitoring Unit (MMU) uses a number of measures of market structure, participant behavior and market performance. These metrics include, but are not limited to the residual supply index, markup, net revenue, market share and the Herfindahl-Hirschman Index.[1]

Residual Supply Index (RSI)

PJM utilizes the Three Pivotal Supplier (TPS) Test in the Regulation Market, the Capacity Market and the Energy Market to detect structural market power. The residual supply index is the metric used to determine the outcome of the TPS. Each supplier, from 1 to n, is ranked from the largest to the smallest offered MW of eligible regulation supply in each hour. Suppliers are then tested in order, starting with the three largest suppliers. In each iteration of the test, the two largest suppliers are combined with a third supplier, and the combined supply is subtracted from total effective supply. The resulting net amount of eligible supply is divided by the demand for the hour (*D*).

Where *j* defines the supplier being tested in combination with the two largest suppliers (initially the third largest supplier with *j*=3), Equation M-1 shows the formula for the residual supply index for three pivotal suppliers (RSI3):

Equation M-1 Calculating the three pivotal supplier test

$$RSI3_j = \frac{\sum_{i=1}^{n} S_i - \sum_{i=1}^{2} S_i - S_j}{D}$$

Where *j*=3, if $RSI3_j$ is less than or equal to 1.0, then the three suppliers are jointly pivotal and the suppliers being tested fail the three pivotal supplier test. Iterations of the test continue until the combination of the two largest suppliers and a supplier *j* result in $RSI3_j$ greater than 1.0. When the result of this process is that $RSI3_j$ is greater than 1.0, the remaining suppliers pass the test.

Markup

The price-cost markup index is a measure of conduct or behavior by the owners of generating units and not a measure of market impact. For marginal units, the markup index is a measure of market power. For units not on the margin, the markup index is a measure of the intent to exercise market power or, in cases where the markup results in higher-priced units replacing lower-priced units in the dispatch, also a measure of market power. A positive markup by marginal units results in a difference between the observed market price and the competitive market price. The goal of the markup analysis is both to calculate the actual markups by marginal units (market conduct) and to estimate the impact of those markups on the difference between the observed market price and the competitive market price (market impact or market performance). The results must be interpreted carefully, however, because the impact is not based on a full redispatch of the system. The markup index for each marginal unit is normalized and can vary from -1.00 when the offer price is less than

1 For a list of indices used by the MMU, see the Monitoring Analytics website: http://www.monitoringanalytics.com/reports/Market_Messages/Messages/MA_Market_Monitoring_Indices_20091214.pdf

marginal cost, to 1.00 when the offer price is higher than marginal cost. In the energy market, in order to normalize the index results (i.e., bound the results between +1.00 and -1.00), the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost. This index calculation method weights the impact of individual unit markups using sensitivity factors.[2]

Net Revenue

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 to serve PJM markets. Net revenue quantifies the contribution to capital cost 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 fixed costs of investing in new generating resources, 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. Zonal net revenue reflects differences in locational energy prices and differences in locational capacity prices. The zonal variation in net revenue illustrates the substantial impact of location on economic incentives.

Market Share

Market share is calculated based on participant specific volumes cleared in each iteration of the relevant market. For example, in the day-ahead energy market, the market clears every hour. Market shares are calculated in each hour based on each participant's cleared volumes in that hour.

A participant's market share is only calculated for those iterations of the market in which the participant cleared volume. For example, if Participant A delivered power only in hours 14 and 15 of a given day, Participant A's market share would be calculated only for hours 14 and 15. When calculating average market share for the day, Participant A's average market share would take the average of the market iterations within the day where Participant A cleared market volumes: hours 14 and 15. When calculating average market share for the year, Participant A's average market share would take the average of the market iterations within the year where Participant A cleared market volumes: hours 14 and 15. This ensures that participant specific market shares are examined within their relevant market space.

Herfindahl-Hirschman Index (HHI)

Concentration ratios are a summary measure of market share, a key element of market structure. High concentration ratios indicate that comparatively small numbers of sellers dominate a market; low concentration ratios mean larger numbers of sellers split market sales more equally. The best tests of market competitiveness are direct tests of the conduct of individual participants and their

2 Sensitivity factors define the impact of each marginal unit on LMP at every bus on the system. See the *2009 State of the Market Report for PJM*, Volume II, Appendix K, "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

impact on price. The price-cost markup index is one such test and direct examination of offer behavior by individual market participants is another. Low aggregate market concentration ratios establish neither that a market is competitive nor that participants are unable to exercise market power. High concentration ratios do, however, indicate an increased potential for participants to exercise market power.

Despite their significant limitations, concentration ratios provide useful information on market structure. The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market.

The "Merger Policy Statement" of the FERC states that a market can be broadly characterized as:

- **Unconcentrated.** Market HHI below 1000, equivalent to 10 firms with equal market shares;
- **Moderately Concentrated.** Market HHI between 1000 and 1800; and
- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.

APPENDIX N – GLOSSARY

Aggregate	Combination of buses or bus prices.
Ancillary Services	Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice..
Area Control Error (ACE)	Area Control Error of the PJM RTO is the actual net interchange minus the biased scheduling net interchange, including time error. It is the sum of tie-in errors and frequency errors.
Associated unit (AU)	A unit that is located at the same site as a frequently mitigated unit (FMU) and which has identical electrical and economic impacts on the transmission system as an FMU but which does not qualify for FMU status.
Auction Revenue Right (ARR)	A financial instrument entitling its holder to auction revenue from Financial Transmission Rights (FTRs) based on locational marginal price (LMP) differences across a specific path in the Annual FTR Auction.
Automatic Generation Control (AGC)	An automatic control system comprised of hardware and software. Hardware is installed on generators allowing their output to be automatically adjusted and monitored by an external signal and software is installed facilitating that output adjustment.
Average hourly LMP	An LMP calculated by averaging hourly LMP with equal hourly weights; also referred to as a simple average hourly LMP.
Avoidable cost rate (ACR)	The costs that a generation owner would not incur if the generating unit did not operate for one year, in particular the delivery year. The ACR calculation is based on the categories of cost that are specified in Section 6.8 of Attachment DD of the PJM Tariff.
Avoidable Project Investment Recovery Rate (APIR)	A component of the avoidable cost rate (ACR) calculation. Project investment is the capital reasonably required to enable a capacity resource to continue operating or improve availability during peak-hour periods during the delivery year.

Balancing energy market	Energy that is generated and financially settled during real time.
Base Residual Auction (BRA)	Reliability Pricing Model (RPM) auction held in May three years prior to the start of the delivery year. Allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation and allocates the cost of those commitments among the LSEs through the Locational Reliability Charge.
Bilateral agreement	An agreement between two parties for the sale and delivery of a service.
Black Start Unit	A generating unit with the ability to go from a shutdown condition to an operating condition and start delivering power without any outside assistance from the transmission system or interconnection.
Bottled generation	Economic generation that cannot be dispatched because of local operating constraints.
Burner tip fuel price	The cost of fuel delivered to the generator site equaling the fuel commodity price plus all transportation costs.
Bus	An interconnection point.
Capacity deficiency rate (CDR)	The CDR was designed to reflect the annual fixed costs of a new combustion turbine (CT) in PJM and the annual fixed costs of the associated transmission investment, including a return on investment, depreciation and fixed operation and maintenance expense, net of associated energy revenues. The CDR is used in applying penalties for capacity deficiencies. To express the CDR in terms of unforced capacity, it must be further divided by the quantity 1 minus the EFORd.
Capacity Emergency Transfer Limit (CETL)	The capability of the transmission system to support deliveries of electric energy to a given area experiencing a localized capacity emergency as determined in accordance with the PJM Manuals.
Capacity queue	A collection of Regional Transmission Expansion Planning (RTEP) capacity resource project requests received during a particular timeframe and designating an expected in-service date.

Combined Cycle (CC)	An electric generating technology in which electricity and process steam are produced from otherwise lost waste heat exiting from one or more combustion turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a conventional steam turbine in the production of electricity. This process increases the efficiency of the electric generating facility.
Combustion Turbine (CT)	A generating unit in which a combustion turbine engine is the prime mover for an electrical generator.
Congestion Management Process (CMP)	A process used between neighboring balancing authorities to coordinate the re-dispatch of resources to relieve transmission constraints.
Control Zone	An area within the PJM Control Area, as set forth in the PJM Open Access Transmission Tariff and the RAA. Schedule 16 of the RAA defines the distinct zones that comprise the PJM Control Area.
Decrement Bids (DEC)	An hourly bid, expressed in MWh, to purchase energy in the PJM Day-Ahead Energy Market if the Day-Ahead LMP is less than or equal to the specified bid price. This bid must specify hourly quantity, bid price and location (transmission zone, hub, aggregate or single bus).
Demand deviations	Hourly deviations in the demand category, equal to the difference between the sum of cleared decrement bids, day-ahead load, day-ahead sales, and day-ahead-exports, to the sum of real-time load, real-time sales, and real-time exports.
Demand Resource	A capacity resource with a demonstrated capability to provide a reduction in demand or otherwise control load. A Demand Resource may be an existing or planned resource.
Dispatch Rate	The control signal, expressed in dollars per MWh, calculated and transmitted continuously and dynamically to direct the output level of all generation resources dispatched by PJM in accordance with the Offer Data.
Disturbance Control Standard	A NERC-defined metric measuring the ability of a control area to return area control error (ACE) either to zero or to its predisturbance level after a disturbance such as a generator or transmission loss.

Eastern Prevailing Time (EPT)	Eastern Prevailing Time (EPT) is equivalent to Eastern Standard Time (EST) or Eastern Daylight Time (EDT) as is in effect from time to time.
Eastern Region	Defined region for purposes of allocating balancing operating reserve charges. Includes the BGE, Dominion, PENELEC, Pepco, Met-Ed, PPL, JCPL, PECO, DPL, PSEG, and RECO transmission zones.
Economic generation	Units producing energy at an offer price less than or equal to LMP.
End-use customer	Any customer purchasing electricity at retail.
Equivalent availability factor (EAF)	The proportion of hours in a year that a unit is available to generate at full capacity.
Equivalent demand forced outage rate (EFORd)	A measure of the probability that a generating unit will not be available due to forced outages or forced deratings when there is a demand on the unit to generate.
Equivalent forced outage factor (EFOF)	The proportion of hours in a year that a unit is unavailable because of forced outages.
Equivalent maintenance outage factor (EMOF)	The proportion of hours in a year that a unit is unavailable because of maintenance outages.
Equivalent planned outage factor (EPOF)	The proportion of hours in a year that a unit is unavailable because of planned outages.
External resource	A generation resource located outside metered boundaries of the PJM RTO.
Financial Transmission Right (FTR)	A financial instrument entitling the holder to receive revenues based on transmission congestion measured as hourly energy LMP differences in the PJM Day-Ahead Energy Market across a specific path.
Firm Point-to-Point Transmission Service	Transmission Service that is reserved and/or scheduled between specified Points of Receipt and Delivery.
Firm Transmission Service	Transmission service that is intended to be available at all times to the maximum extent practicable, subject to an emergency, and unanticipated failure of a facility, or other event beyond the control of the owner or operator of the facility, or the Office of the Interconnection.

Fixed Demand Bid	Bid to purchase a defined MW level of energy, regardless of LMP.
Fixed Resource Requirement (FRR)	An alternative method for a party to satisfy its obligation to provide Unforced Capacity. Allows an LSE to avoid direct participation in the RPM Auctions by meeting their fixed capacity resource requirement using internally owned capacity resources
Flowgate	A transmission facility or group of facilities that consist of the total interface between control areas, a partial interface, or an interface within a control area.
Frequently mitigated unit (FMU)	A unit that was offer-capped for more than a defined proportion of its real-time run hours in the most recent 12-month period. FMU thresholds are 60 percent, 70 percent and 80 percent of run hours. Such units are permitted a defined adder to their cost-based offers in place of the usual 10 percent adder.
Generation Control Area (GCA) and Load Control Area (LCA)	Designations used on a NERC Tag to describe the balancing authority where the energy is generated (GCA) and the balancing authority where the load is served (LCA). Note: the terms “Control Area” in these acronyms are legacy terms for balancing authority, and are expected to be changed in the future.
Generator deviations	Hourly deviations in the generator category, equal to the difference between a unit’s cleared day-ahead generation, and a unit’s hourly, integrated real-time generation.
Generation Offers	Schedules of MW offered and the corresponding offer price.
Generation owner	A PJM member that owns or leases, with rights equivalent to ownership, facilities for generation of electric energy that are located within PJM.
Gross export volume (energy)	The sum of all export transaction volume (MWh).
Gross import volume (energy)	The sum of all import transaction volume (MWh).
Gigawatt (GW)	A unit of power equal to 1,000 megawatts.
Gigawatt-day	One GW of energy flow or capacity for one day.
Gigawatt-hour (GWh)	One GWh is a gigawatt produced or consumed for one hour.

Herfindahl-Hirschman Index (HHI)	HHI is calculated as the sum of the squares of the market share percentages of all firms in a market.
Hertz (Hz)	Electricity system frequency is measured in hertz.
HRSG	Heat recovery steam generator. An air-to-steam heat exchanger.
Increment offers (INC)	Financial offers in the Day-Ahead Energy Market to supply specified amounts of MW at, or above, a given price.
Incremental Auction	Reliability Pricing Model (RPM) auction to allow for an incremental procurement of resource commitments to satisfy an increase in the region's unforced capacity obligation due to a load forecast increase or a decrease in the amount of resource commitments due to a resource cancellation, delay, derating, EFORd increase, or decrease in the nominated value of a Planned Demand Resource.
Inframarginal unit	A unit that is operating, with an accepted offer that is less than the clearing price.
Installed capacity	Installed capacity is the as-tested maximum net dependable capability of the generator, measured in MW.
Load	Demand for electricity at a given time.
Load Management	Previously known as ALM (Active Load Management). ALM was a term that PJM used prior to the implementation of RPM where end use customer load could be reduced at the request of PJM. The ability to reduce metered load, either manually by the customer, after a request from the resource provider which holds the Load management rights or its agent (for Contractually Interruptible), or automatically in response to a communication signal from the resource provider which holds the Load management rights or its agent (for Direct Load Control).
Load-serving entity (LSE)	Load-serving entities provide electricity to retail customers. Load-serving entities include traditional distribution utilities and new entrants into the competitive power market.
Locational Deliverability Area (LDA)	Sub-regions used to evaluate locational constraints. LDAs include EDC zones, sub-zones, and combination of zones.

Marginal unit	The last, highest cost, generation unit to supply power under a merit order dispatch system.
Market-clearing price	The price that is paid by all load and paid to all suppliers.
Market participant	A PJM market participant can be a market supplier, a market buyer or both. Market buyers and market sellers are members that have met creditworthiness standards as established by the PJM Office of the Interconnection.
Market user interface	A thin client application allowing generation sellers to provide and to view generation data, including bids, unit status and market results.
Maximum daily starts	The maximum number of times a unit can start in a day. An operating parameter incorporated in a unit's schedule.
Maximum weekly starts	The maximum number of times a unit can start in a week. An operating parameter incorporated in a unit's schedule.
Mean	The arithmetic average.
Median	The midpoint of data values. Half the values are above and half below the median.
Megawatt (MW)	A unit of power equal to 1,000 kilowatts.
Megawatt-day	One MW of energy flow or capacity for one day.
Megawatt-hour (MWh)	One MWh is a megawatt produced or consumed for one hour.
Megawatt-year	One MW of energy flow or capacity for one calendar year.
Minimum down time	The minimum amount of time that a unit has to stay off, or "down," before starting again. An operating parameter incorporated in a unit's schedule.
Minimum run time	The minimum amount of time that a unit has to stay on before shutting down. An operating parameter incorporated in a unit's schedule.
Monthly CCM	The capacity credits cleared each month through the PJM Monthly Capacity Credit Market (CCM).
Multimonthly CCM	The capacity credits cleared through PJM Multimonthly Capacity Credit Market (CCM).

Net excess (capacity)	The net of gross excess and gross deficiency, therefore the total PJM capacity resources in excess of the sum of load-serving entities' obligations.
Net exchange (capacity)	Capacity imports less exports.
Net interchange (energy)	Gross import volume less gross export volume in MWh.
Network Transmission Service	Transmission service that is for the sole purpose of serving network load. Network transmission service is only available to network customers.
Noneconomic generation	Units producing energy at an offer price greater than the LMP.
Non-Firm Transmission Service	Point-to-point transmission service under the PJM tariff that is reserved and scheduled on an as available basis and is subject to curtailment or interruption. Non-firm point to point transmission service is available on a stand-alone basis for periods ranging from one hour to one month.
North American Electric Reliability Council (NERC)	A voluntary organization of U.S. and Canadian utilities and power pools established to assure coordinated operation of the interconnected transmission systems.
Off peak	For the PJM Energy Market, off-peak periods are all NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) and weekend hours plus weekdays from the hour ending at midnight until the hour ending at 0700.
On peak	For the PJM Energy Market, on-peak periods are weekdays, except NERC holidays (i.e., New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day) from the hour ending at 0800 until the hour ending at 2300.
Opportunity cost	In general, the value of the opportunity foregone when a specific action is taken. In the ancillary services markets, the difference in compensation from the Energy Market between what a unit receives when providing regulation or synchronized reserve and what it would have received had it provided energy instead.

Parameter-limited schedule	A schedule for a unit that has parameters that are used when the unit fails the three pivotal supplier test, or in a maximum generation emergency event. These parameters are pre-determined by the MMU based on unit class, unless an exception is otherwise granted.
PJM member	Any entity that has completed an application and satisfies the requirements of the PJM Board of Managers to conduct business with PJM, including transmission owners, generating entities, load-serving entities and marketers.
PJM planning year	The calendar period from June 1 through May 31.
Point of Receipt (POR) and Point of Delivery (POD)	Designations used on a transmission reservation. The designations, when combined, determine the transmission reservations' market path.
Pool-scheduled resource	A generating resource that the seller has turned over to PJM for scheduling and control.
Price duration curve	graphic representation of the percent of hours that a system's price was at or below a given level during the year.
Price-sensitive bid	Purchases of a defined MW level of energy only up to a specified LMP. Above that LMP, the load bid is zero.
Primary operating interfaces	Primary operating interfaces are typically defined by a cross section of transmission paths or single facilities which affect a wide geographic area. These interfaces are modeled as constraints whose operating limits are respected in performing dispatch operations.
Ramp-limited desired (MW)	The achievable MW based on the UDS requested ramp rate.
Regional Transmission Expansion Planning (RTEP) Protocol	The process by which PJM recommends specific transmission facility enhancements and expansions based on reliability and economic criteria.

Reliability*First* Corporation	Reliability*First* Corporation (RFC) began operation January 1, 2006, as the successor to three other reliability organizations: the Mid-Atlantic Area Council (MAAC), the East Central Area Coordination Agreement (ECAR), and the Mid-American Interconnected Network (MAIN). PJM is registered with RFC to comply with its reliability standards for balancing authority (BA), planning coordinator (PC), reliability coordinator (RC), resource planner (RP), transmission operator (TOP), transmission planner (TP) and transmission service provider (TSP).
Reliability Pricing Model (RPM)	PJM's resource adequacy construct. The purpose of RPM is to develop a long term pricing signal for capacity resources and LSE obligations that is consistent with the PJM Regional Transmission Expansion Planning Process (RTEPP). RPM adds stability and a locational nature to the pricing signal for capacity.
Selective catalytic reduction (SCR)	NO_x reduction equipment usually installed on combined-cycle generators.
Self-scheduled generation	Units scheduled to run by their owners regardless of system dispatch signal. Self-scheduled units do not follow system dispatch signal and are not eligible to set LMP. Units can be submitted as a fixed block of MW that must be run, or as a minimum amount of MW that must run plus a dispatchable component above the minimum.
Shadow price	The constraint shadow price represents the incremental reduction in congestion cost achieved by relieving a constraint by 1 MW. The shadow price multiplied by the flow (in MW) on the constrained facility during each hour equals the hourly gross congestion cost for the constraint.
Short-Term Resource Procurement Target	The Short-Term Resource Procurement Target is equal to 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction for purposes of the First Incremental Auction, and 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction for purposes of the Second Incremental Auction. The stated rationale for this administrative reduction in demand is to permit short lead time resource procurement in later auctions for the delivery year.
Sources and sinks	Sources are the origins or the injection end of a transmission transaction. Sinks are the destinations or the withdrawal end of a transaction.

Spot Import Transmission Service	Transmission service introduced as an option for non-load serving entities to offer into the PJM spot market at the border/interface as price takers.Spot market Transactions made in the Real-Time and Day-Ahead Energy Market at hourly LMP.
Static Var compensator	A static Var compensator (SVC) is an electrical device for providing fast-acting, reactive power compensation on high-voltage electricity transmission networks.
Summer Net Capability	The Summer Net Capability of each unit or station shall be based on summer conditions and on the power factor level normally expected for that unit or station at the time of the PJM summer peak load. Summer conditions shall reflect the 50% probability of occurrence (approximated by the mean) of temperature and humidity conditions of the time of the PJM summer peak load. Conditions shall be based on local weather bureau records of the past 15 years, updated at 5 year intervals. When local weather records are not available, the values shall be estimated from the best data available. For steam units, summer conditions shall mean, where applicable, the probable intake water temperature of once-through or open cooling systems experienced in June, July, and August at the time of the PJM peak each weekday. For combustion turbine units, summer conditions shall mean, where applicable, the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak. The determination of the Summer Net Capability of hydro and pumped storage units shall be based on operational data or test results taken once each year at any time during the year. The same operational data or test results can be used for the determination of the Winter Net Capability. For combined-cycle units, summer conditions shall mean where applicable, the probable intake water temperature of once-through or open cooling systems experienced in June, July, and August at the time of the PJM peak each weekday, and the probable ambient air temperature and humidity condition experienced at the unit location at the time of the annual summer PJM peak.

Supply deviations	Hourly deviations in the supply category, equal to the difference between the sum of cleared increment offers, day-ahead purchases, and day-ahead imports, to the sum of real-time purchases and real-time imports.
Synchronized reserve	Reserve capability which is required in order to enable an area to restore its tie lines to the pre-contingency state within 10 minutes of a contingency that causes an imbalance between load and generation. During normal operation, these reserves must be provided by increasing energy output on electrically synchronized equipment, by reducing load on pumped storage hydroelectric facilities or by reducing the demand by demand-side resources. During system restoration, customer load may be classified as synchronized reserve.
System installed capacity	System total installed capacity measures the sum of the installed capacity (in installed, not unforced, terms) from all internal and qualified external resources designated as PJM capacity resources.
System lambda	The cost to the PJM system of generating the next unit of output.
Temperature-humidity index (THI)	A temperature-humidity index (THI) gives a single, numerical value reflecting the outdoor atmospheric conditions of temperature and humidity as a measure of comfort (or discomfort) during warm weather. THI is defined as: THI = $T_d - (0.55 - 0.55RH) * (T_d - 58)$ if T_d is > 58; else THI= T_d (where T_d is the dry-bulb temperature and RH is the percentage of relative humidity.)
Transmission Adequacy and Reliability Assessment (TARA)	An analysis tool that can calculate generation to load impacts. This tool is used to facilitate loop flow analysis across the Eastern Interconnection.
Turn down ratio	The ratio of dispatchable megawatts on a unit's schedule. Calculated by a unit's economic maximum MW divided by its economic minimum MW. An operating parameter of a unit's schedule.
Unforced capacity	Installed capacity adjusted by forced outage rates.
Western region	Defined region for purposes of allocating balancing operating reserve charges. Includes the AEP, AP, ComEd, DLCO, and DAY transmission zones.

Wheel-through	An energy transaction flowing through a transmission grid whose origination and destination are outside of the transmission grid.
Winter Weather Parameter (WWP)	WWP is wind speed adjusted temperature. WWP is defined as: WWP = T_d - (0.5 * (WIND -10) if WIND > 10 mph; WWP = T_d if WIND <= 10 mph (where T_d is the dry-bulb temperature and WIND is the wind speed.)
Zone	See “Control zone” (above).

APPENDIX O – LIST OF ACRONYMS

ACE	Area control error
ACR	Avoidable cost rate
AECI	Associated Electric Cooperative Inc.
AECO	Atlantic City Electric Company
AEG	Alliant Energy Corporation
AEP	American Electric Power Company, Inc.
AGC	Automatic generation control
ALM	Active load management
ALTE	Eastern Alliant Energy Corporation
ALTW	Western Alliant Energy Corporation
AMIL	Ameren - Illinois
AMRN	Ameren
AP	Allegheny Power Company
APIR	Avoidable Project Investment Recovery
ARR	Auction Revenue Right
ARS	Automatic reserve sharing
ATC	Available transfer capability
AU	Associated unit
BA	Balancing authority
BAAL	Balancing authority ACE limit
BGE	Baltimore Gas and Electric Company
BGS	Basic generation service
BME	Balancing market evaluation

BRA	Base Residual Auction
Btu	British thermal unit
C&I	Commercial and industrial customers
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CBL	Customer base line
CC	Combined cycle
CCM	Capacity Credit Market
CDR	Capacity deficiency rate
CDTF	Cost Development Task Force
CETL	Capacity emergency transfer limit
CETO	Capacity emergency transfer objective
CF	Coordinated flowgate under the Joint Operating Agreement between PJM and the Midwest Independent Transmission System Operator, Inc.
CILC	Central Illinois Light Company Interface
CILCO	Central Illinois Light Company
CIN	Cinergy Corporation
CLMP	Congestion component of LMP
CMP	Congestion management process
CMR	Congestion Management Report
ComEd	The Commonwealth Edison Company
Con Edison	The Consolidated Edison Company
CONE	Cost of new entry
CP	Pulverized coal-fired generator

CPL	Carolina Power & Light Company
CPS	Control performance standard
CRC	Central Repository for Curtailments
CSP	Curtailment service provider
CT	Combustion turbine
CTR	Capacity transfer right
DASR	Day-Ahead Scheduling Reserve
DAY	The Dayton Power & Light Company
DC	Direct current
DCS	Disturbance control standard
DEC	Decrement bid
DFAX	Distribution factor
DL	Diesel
DLCO	Duquesne Light Company
DPL	Delmarva Power & Light Company
DPLN	Delmarva Peninsula north
DPLS	Delmarva Peninsula south
DR	Demand response
DSR	Demand-side response
DUK	Duke Energy Corporation
EAF	Equivalent availability factor
ECAR	East Central Area Reliability Council
EDC	Electricity distribution company
EDT	Eastern Daylight Time

EE	Energy Efficiency
EEA	Emergency energy alert
EES	Enhanced Energy Scheduler
EFOF	Equivalent forced outage factor
EFORd	Equivalent demand forced outage rate
EHV	Extra-high-voltage
EKPC	East Kentucky Power Cooperative, Inc.
EMAAC	Eastern Mid-Atlantic Area Council
EMOF	Equivalent maintenance outage factor
EMS	Energy management system
EPOF	Equivalent planned outage factor
EPT	Eastern Prevailing Time
EST	Eastern Standard Time
ExGen	Exelon Generation Company, L.L.C.
FE	FirstEnergy Corp.
FERC	The United States Federal Energy Regulatory Commission
FFE	Firm flow entitlement
FMU	Frequently mitigated unit
FPA	Federal Power Act
FPR	Forecast pool requirement
FRR	Fixed resource requirement
FTR	Financial Transmission Right
GCA	Generation control area
GE	General Electric Company

GW	Gigawatt
GWh	Gigawatt-hour
HHI	Herfindahl-Hirschman Index
HRSG	Heat recovery steam generator
HVDC	High-voltage direct current
Hz	Hertz
IA	RPM Incremental Auction
ICAP	Installed capacity
ICCP	Inter-Control Center Protocol
IDC	Interchange distribution calculator
IESO	Ontario Independent Electricity System Operator
ILR	Interruptible load for reliability
INC	Increment offer
IP	Illinois Power Company
IPL	Indianapolis Power & Light Company
IPP	Independent power producer
IRM	Installed reserve margin
IRR	Internal rate of return
ISA	Interconnection service agreement
ISO	Independent system operator
JCPL	Jersey Central Power & Light Company
JOA	Joint operating agreement
JOU	Jointly owned units
JRCA	Joint Reliability Coordination Agreement

LAS	PJM Load Analysis Subcommittee
LCA	Load control area
LDA	Locational deliverability area
LGEE	LG&E Energy, L.L.C.
LIND	Linden Variable Frequency Transformer (VFT)
LM	Load management
LMP	Locational marginal price
LOC	Lost opportunity cost
LSE	Load-serving entity
MAAC	Mid-Atlantic Area Council
MAAC+APS	Mid-Atlantic Area Council plus the Allegheny Power System
MACRS	Modified accelerated cost recovery schedule
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MCP	Market-clearing price
MDS	Maximum daily starts
MDT	Minimum down time
MEC	MidAmerican Energy Company
MECS	Michigan Electric Coordinated System
Met-Ed	Metropolitan Edison Company
MICHFE	The pricing point for the Michigan Electric Coordinated System and FirstEnergy control areas
MIL	Mandatory interruptible load
MIS	Market information system

MISO	Midwest Independent Transmission System Operator, Inc.
MMU	PJM Market Monitoring Unit
Mon Power	Monongahela Power
MP	Market participant
MRC	Markets and reliability committee
MRT	Minimum run time
MUI	Market user interface
MW	Megawatt
MWh	Megawatt-hour
MWS	Maximum weekly starts
NAESB	North American Energy Standards Board
NCMPA	North Carolina Municipal Power Agency
NEPT	Neptune DC line
NERC	North American Electric Reliability Council
NICA	Northern Illinois Control Area
NIPSCO	Northern Indiana Public Service Company
NNL	Network and native load
NO_x	Nitrogen oxides
NUG	Non-utility generator
NYISO	New York Independent System Operator
OA	Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.
OASIS	Open Access Same-Time Information System
OATI	Open Access Technology International, Inc.
OATT	PJM Open Access Transmission Tariff

ODEC	Old Dominion Electric Cooperative
OEM	Original equipment manufacturer
OI	PJM Office of the Interconnection
Ontario IESO	Ontario Independent Electricity System Operator
OVEC	Ohio Valley Electric Corporation
PAR	Phase angle regulator
PE	PECO zone
PEC	Progress Energy Carolinas, Inc.
PECO	PECO Energy Company
PENELEC	Pennsylvania Electric Company
Pepco	Formerly Potomac Electric Power Company or PEPCO
PJM	PJM Interconnection, L.L.C.
PJM/AEPNI	The interface between the American Electric Power Control Zone and Northern Illinois
PJM/AEPPJM	The interface between the American Electric Power Control Zone and PJM
PJM/AEPVP	The single interface pricing point formed in March 2003 from the combination of two previous interface pricing points: PJM/American Electric Power Company, Inc. and PJM/Dominion Resources, Inc.
PJM/AEPVPEXP	The export direction of the PJM/AEPVP interface pricing point
PJM/AEPVPIMP	The import direction of the PJM/AEPVP interface pricing point
PJM/ALTE	The interface between PJM and the eastern portion of the Alliant Energy Corporation's control area
PJM/ALTW	The interface between PJM and the western portion of the Alliant Energy Corporation's control area

PJM/AMRN	The interface between PJM and the Ameren Corporation's control area
PJM/CILC	The interface between PJM and the Central Illinois Light Company's control area
PJM/CIN	The interface between PJM and the Cinergy Corporation's control area
PJM/CPLE	The interface between PJM and the eastern portion of the Carolina Power & Light Company's control area
PJM/CPLW	The interface between PJM and the western portion of the Carolina Power & Light Company's control area
PJM/CWPL	The interface between PJM and the City Water, Light & Power's (City of Springfield, IL) control area
PJM/DLCO	The interface between PJM and the Duquesne Light Company's control area
PJM/DUK	The interface between PJM and the Duke Energy Corp.'s control area
PJM/EKPC	The interface between PJM and the Eastern Kentucky Power Corporation's control area
PJM/FE	The interface between PJM and the FirstEnergy Corp.'s control area
PJMICC	PJM Industrial Customer Coalition
PJM/IP	The interface between PJM and the Illinois Power Company's control area
PJM/IPL	The interface between PJM and the Indianapolis Power & Light Company's control area
PJM/LGEE	The interface between PJM and the Louisville Gas and Electric Company's control area
PJM/LIND	The interface between PJM and the New York System Operator over the Linden VFT line
PJM/MEC	The interface between PJM and MidAmerican Energy Company's control area

PJM/MECS	The interface between PJM and the Michigan Electric Coordinated System's control area
PJM/MISO	The interface between PJM and the Midwest Independent System Operator
PJM/NEPT	The interface between PJM and the New York Independent System Operator over the Neptune DC line
PJM/NIPS	The interface between PJM and the Northern Indiana Public Service Company's control area
PJM/NYIS	The interface between PJM and the New York Independent System Operator
PJM/Ontario IESO	PJM/Ontario IESO pricing point
PJM/OVEC	The interface between PJM and the Ohio Valley Electric Corporation's control area
PJM/TVA	The interface between PJM and the Tennessee Valley Authority's control area
PJM/VAP	The interface between PJM and the Dominion Virginia Power's control area
PJM/WEC	The interface between PJM and the Wisconsin Energy Corporation's control area
PLS	Parameter limited schedule
PMSS	Preliminary market structure screen
PNNE	PENELEC's northeastern subarea
PNNW	PENELEC's northwestern subarea
POD	Point of delivery
POR	Point of receipt
PPL	PPL Electric Utilities Corporation
PSE&G	Public Service Electric and Gas Company (a wholly owned subsidiary of PSEG)
PSEG	Public Service Enterprise Group

PSN	PSEG north
PSNC	PSEG northcentral
RAA	Reliability Assurance Agreement among Load-Serving Entities
RCIS	Reliability Coordinator Information System
RECO	Rockland Electric Company zone
RFC	Reliability*First* Corporation
RLD (MW)	Ramp-limited desired (Megawatts)
RLR	Retail load responsibility
RMCP	Regulation market-clearing price
RMR	Reliability Must Run
RPM	Reliability Pricing Model
RSI	Residual supply index
RSI_x	Residual supply index, using “x” pivotal suppliers
RTC	Real-time commitment
RTEP	Regional Transmission Expansion Plan
RTO	Regional transmission organization
SCE&G	South Carolina Energy and Gas
SCPA	Southcentral Pennsylvania subarea
SCR	Selective catalytic reduction
SEPA	Southeast Power Administration
SEPJM	Southeastern PJM subarea
SERC	Southeastern Electric Reliability Council
SFT	Simultaneous feasibility test
SMECO	Southern Maryland Electric Cooperative

SMP	System marginal price
SNJ	Southern New Jersey
SO_2	Sulfur dioxide
SOUTHEXP	South Export pricing point
SOUTHIMP	South Import pricing point
SPP	Southwest Power Pool, Inc.
SPREGO	Synchronized reserve and regulation optimizer (market-clearing software)
SRMCP	Synchronized reserve market-clearing price
STD	Standard deviation
SVC	Static Var compensator
SWMAAC	Southwestern Mid-Atlantic Area Council
TARA	Transmission adequacy and reliability assessment
TDR	Turn down ratio
TEAC	Transmission Expansion Advisory Committee
THI	Temperature-humidity index
TLR	Transmission loading relief
TPS	Three pivotal supplier
TPSTF	Three Pivotal Supplier Task Force
TVA	Tennessee Valley Authority
UCAP	Unforced capacity
UDS	Unit dispatch system
UGI	UGI Utilities, Inc.
UPF	Unit participation factor
VACAR	Virginia and Carolinas Area

VAP	Dominion Virginia Power
VFT	Variable frequency transformer
VOM	Variable operation and maintenance expense
VRR	Variable resource requirement
WEC	Wisconsin Energy Corporation
WLR	Wholesale load responsibility
WPC	Willing to pay congestion