Q3

State of the Market Report for PJM

January through September

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

11.15.2012

2012

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 *2012 Quarterly State of the Market Report for PJM: January through September.*

1 PJM Open Access Transmission Tariff (OATT) Attachment M (PJM Market Monitoring Plan) § VI.A. 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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Introduction

Q3 2012 In Review

The state of the PJM markets in the first three quarters of 2012 was good. The results of the energy market and the results of the capacity market were competitive.

The goal of a competitive power market is to provide power at the lowest possible price, consistent with cost. PJM markets met that goal in the first nine months of 2012. The test of a competitive power market is how it reacts to change. PJM markets have passed that test so far, but that test continues. The significant changes in the economic environment of PJM markets in 2011 continued in the first three quarters of 2012.

Continued success requires that market participants have access to all the information about the economic fundamentals of PJM markets necessary to make rational decisions. There are still areas where more transparency is required in order to permit markets to function effectively. The provision of clear, understandable information about market fundamentals matters.

Continued success requires markets that are flexible and adaptive. However, wholesale power markets are defined by complex rules. Markets do not automatically provide competitive and efficient outcomes. There are still areas of market design that need further improvement in order to ensure that the PJM markets continue to adapt successfully to changing conditions. The details of market design matter.

Both coal and natural gas prices decreased in the first nine months of 2012, although the decline in gas prices was substantially larger than the decline in coal prices. PJM LMPs were also substantially lower. The load-weighted average LMP was 29.2 percent lower in the first three quarters of 2012 than in the first three quarters of 2011, resulting in the lowest prices in the first nine months of a year since 2002.

The results of the energy market dynamics in January through September of 2012 were positive for new gas fired combined cycle units in some areas. The result of the changes in gas prices compared to coal prices was that the fuel cost of a new entrant combined cycle unit remained below the fuel cost of a new entrant coal plant in the first six months of 2012, but greater than the fuel cost of a coal plant for the months of July through September. The combination of lower energy prices, lower gas prices and lower coal prices resulted in lower energy net revenues for new entrant CC units in thirteen of seventeen zones and lower energy net revenues for the new entrant CT and CP unit in all zones in 2012.

Markets need accurate and understandable information about fundamental market parameters in order to function effectively. For example, the markets need better information about unit retirements in order to permit new entrants to address reliability issues. For example, the markets need better information about the reasons for operating reserve charges in order to permit market responses to persistent high payments of operating reserve credits.

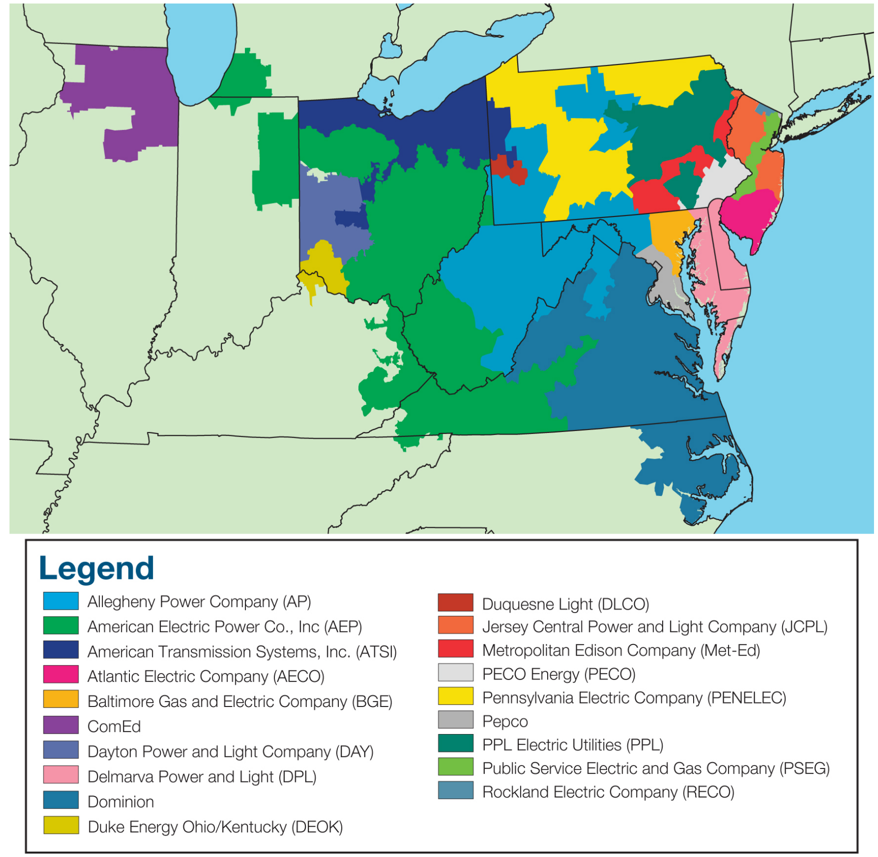
The market design should permit market prices to reflect underlying supply and demand fundamentals. Significant factors that result in capacity market prices failing to reflect fundamentals should be addressed, including better LDA definitions, the effectiveness of the transmission interconnection queue process, the 2.5 percent reduction in demand that suppresses market prices and the continued inclusion of inferior demand side products that also suppress market prices.

The PJM markets and PJM market participants from all sectors face significant challenges as a result of the changing economic environment. PJM and its market participants will need to continue to work constructively to address these challenges to ensure the continued effectiveness of PJM markets.

PJM Market Background

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of September 30, 2012, had installed generating capacity of 182,874 megawatts (MW) and about 800 market buyers, sellers and traders of electricity[1] in a region including more than 60 million people[2] 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 (Figure 1-1).[3] In the first nine months of 2012, PJM had total billings of $22.12 billion, down from $28.84 billion in the first three quarters of 2011. As part of the market operator function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

Figure 1-1 PJM's footprint and its 19 control zones[4] (See 2011 SOM, Figure 1-1)



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).

1 See "Company Overview." PJM.com. PJM Interconnection L.L.C. (Accessed November 13, 2012). <http://pjm.com/about-pjm/member-services/member-list.aspx>.

2 See "Company Overview." PJM.com. PJM Interconnection L.L.C. (Accessed November 13, 2012). <http://pjm.com/about-pjm/who-we-are.aspx>.

3 See the *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2011.

4 On January 1, 2012, the Duke Energy Ohio/Kentucky (DEOK) Control Zone joined the PJM footprint.

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 for the January through May 1999 period. 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.[5,6]

On January 1, 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone.

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first nine months of 2012, 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.

For each PJM market, market structure is evaluated as competitive or not competitive, and participant behavior is evaluated as competitive or not competitive. Most important, the outcome of each market, market performance, is evaluated as competitive or not competitive.

The MMU also evaluates the market design for each market. The market design serves as the vehicle for translating participant behavior within the market structure into market performance. This report evaluates the effectiveness of the market design of each PJM market in providing market performance consistent with competitive results.

Market structure refers to the ownership structure of the market. The three pivotal supplier test is the most relevant measure of market structure because it accounts for both the ownership of assets and the relationship between ownership among multiple entities and the market demand and it does so using actual market conditions reflecting both temporal and geographic granularity. Market shares and the related Herfindahl-Hirschman Index (HHI) are also measures of market structure.

Participant behavior refers to the actions of individual market participants, also sometimes referenced as participant conduct.

Market performance refers to the outcome of the market. Market performance reflects the behavior of market participants within a market structure, mediated by market design.

Market design means the rules under which the entire relevant market operates, including the software that implements the market rules. Market rules include the definition of the product, the definition of marginal cost, rules governing offer behavior, market power mitigation rules, and the definition of demand. Market design is characterized as effective, mixed or flawed. An effective market design provides incentives for competitive behavior and permits competitive outcomes. A mixed market design has significant issues that constrain the potential for competitive behavior to result in competitive market performance, and does not have adequate rules to mitigate market power or incent competitive behavior. A flawed market design produces inefficient outcomes which cannot be corrected by competitive behavior.

5 See also the *2011 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."
6 Analysis of 2012 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. In June 2011, the American Transmission Systems, Inc. (ATSI) Control Zone joined PJM. In January 2012, the Duke Energy Ohio/Kentucky Control Zone joined PJM. 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 prior to 2012, see the *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

The MMU concludes the following for the first nine months of 2012:

Table 1-1 The Energy Market results were competitive (See 2011 SOM, Table 1-1)

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

- The aggregate market structure was evaluated as competitive because the calculations for hourly HHI (Herfindahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market during the first nine months of 2012 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1234 with a minimum of 927 and a maximum of 1657 in the first nine months of 2012.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test mitigated local market power and forced competitive offers, correcting for structural issues created by local transmission constraints.

  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.[7] 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.[8]

Table 1-2 The Capacity Market results were competitive (See 2011 SOM, Table 1-2)

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior: Local Market	Competitive	
Market Performance	**Competitive**	**Mixed**

- The aggregate market structure was evaluated as not competitive. The entire PJM region failed the preliminary market structure screen (PMSS), which is conducted by the MMU prior to each Base Residual Auction (BRA), for every planning year for which a BRA has been run to date. For almost all auctions held from 2007 to the present, the PJM region failed the Three Pivotal Supplier Test (TPS), which is conducted at the time of the auction.[9]
- The local market structure was evaluated as not competitive. All modeled Locational Deliverability Areas (LDAs) failed the PMSS, which is conducted by the MMU prior to each Base Residual Auction, for every planning year for which a BRA has been run to date. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[10]
- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded

7 OATT Attachment M

8 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.

9 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.

10 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test.

the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a new resource or uprate that was below the Minimum Offer Price Rule (MOPR) threshold.

- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design, there are several features of the RPM design which threaten competitive outcomes. These include the 2.5 percent reduction in demand in Base Residual Auctions and the definition of DR which permits inferior products to substitute for capacity.

Table 1-3 The Regulation Market results were not competitive[11] (See 2011 SOM, Table 1-3)

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Not Competitive	Flawed

- The Regulation Market structure was evaluated as not competitive because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 44 percent of the hours in January through September 2012.[12]
- Participant behavior was evaluated as competitive because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in anti-competitive behavior.
- Market performance was evaluated as not competitive, despite competitive participant behavior, 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 in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic.[13]
- Market design was evaluated as flawed because while PJM has improved the market by modifying the schedule switch determination, the lost opportunity cost calculation is inconsistent with economic logic and there are additional issues with the order of operation in the assignment of units to provide regulation prior to market clearing.

Table 1-4 The Synchronized Reserve Markets results were competitive (See 2011 SOM, Table 1-4)

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Effective

- The Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration and inelastic demand. The Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 24 percent of the hours in January through September of 2012.
- Participant behavior was evaluated as competitive because the market rules require competitive, cost based offers.

11 As Table 1-3 indicates, the Regulation Market results are not the result of the offer behavior of market participants, which was 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 in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic. 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 a combination of the competitive offers from market participants and 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 or lower opportunity cost than its owner does, depending on the direction the unit was dispatched to provide regulation. If the market rules and/or their implementation produce inefficient outcomes, then no amount of competitive behavior will produce a competitive outcome.

12 These TPS results reflect MMU estimates for the period between May 6 and July 21, 2012, when the TPS test was not correctly applied by PJM.

13 PJM agrees that the definition of opportunity cost should be consistent across all markets and should, in all markets, be based on the offer schedule accepted in the market. This would require a change to the definition of opportunity cost in the Regulation Market which is the change that the MMU has recommended. The MMU also agrees that the definition of opportunity cost should be consistent across all markets.

- Market performance was evaluated as competitive because the interaction of the participant behavior with the market design results in prices that reflect marginal costs.
- Market design was evaluated as effective because market power mitigation rules result in competitive outcomes despite high levels of supplier concentration.

Table 1-5 The Day-Ahead Scheduling Reserve Market results were competitive (See 2011 SOM, Table 1-5)

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Mixed	
Market Performance	Competitive	Mixed

- The Day-Ahead Scheduling Reserve Market structure was evaluated as competitive because the market did not fail the three pivotal supplier test.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs (zero), about 17 percent of offers reflected economic withholding, with offer prices above $5.00.
- Market performance was evaluated as competitive because there were adequate offers at reasonable levels in every hour to satisfy the requirement and the clearing price reflected those offers.
- Market design was evaluated as mixed because while the market is functioning effectively to provide DASR, the three pivotal supplier test and cost-based offer capping when the test is failed, should be added to the market to ensure that market power cannot be exercised at times of system stress.

Table 1-6 The FTR Auction Markets results were competitive (see 2011 SOM, Table 1-6)

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Effective

- The market structure was evaluated as competitive because the FTR auction is voluntary and the ownership positions resulted from the distribution of ARRs and voluntary participation.
- Participant behavior was evaluated as competitive because there was no evidence of anti-competitive behavior.
- Performance was evaluated as competitive because it reflected the interaction between participant demand behavior and FTR supply, limited by PJM's analysis of system feasibility.
- Market design was evaluated as effective because the market design provides a wide range of options for market participants to acquire FTRs and a competitive auction mechanism.

Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.[14] These functions are interrelated and overlap. The PJM Market Monitoring Plan establishes these functions, providing that the MMU is responsible for monitoring: compliance with the PJM Market Rules; actual or potential design flaws in the PJM Market Rules; structural problems in the PJM Markets that may inhibit a robust and competitive market; the actual or potential exercise of market power or violation of the market rules by a Market Participant; PJM's implementation of the PJM Market Rules or operation of the PJM Markets; and such matters as are necessary to prepare reports.[15]

14 18 CFR § 35.28(g)(3)(ii); *see also Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶31,281 (2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶31,292 (2009), *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).
15 OATT Attachment M § IV; 18 CFR § 1c.2.

Reporting

The MMU performs its reporting function by issuing and filing annual and quarterly state of the market reports, and reports on market issues. The state of the market reports provide a comprehensive analysis of the structure, behavior and performance of PJM markets. The reports evaluate whether the market structure of each PJM Market is competitive or not competitive; whether participant behavior is competitive or not competitive; and, most importantly, whether the outcome of each market, the market performance, is competitive or not competitive. The MMU also evaluates the market design for each market. Market design translates participant behavior within the market structure into market performance. The MMU evaluates whether the market design of each PJM market provides the framework and incentives for competitive results. State of the market reports and other reports are intended to inform PJM, the PJM Board, FERC, other regulators, other authorities, market participants, stakeholders and the general public about how well PJM markets achieve the competitive outcomes necessary to realize the goals of regulation through competition, and how the markets can be improved.

The MMU's quarterly state of the market reports supplement the annual state of the market report for the prior year, and extend the analysis into the current year. Readers of the quarterly state of the market reports should refer to the prior annual report for detailed explanation of reported metrics and market design.

The MMU's reports on market issues cover specific topics in depth. For example, the MMU issues reports on RPM auctions. In addition, the MMU's reports frequently respond to the needs of FERC, state regulators, or other authorities, in order to assist policy development, decision making in regulatory proceedings, and in support of investigations.

Monitoring

To perform its monitoring function, the MMU screens and monitors the conduct of Market Participants under the MMU's broad purview to monitor, investigate, evaluate and report on the PJM Markets.[16] The MMU has direct, confidential access to the FERC.[17] The MMU may also refer matters to the attention of State commissions.[18]

The MMU monitors market behavior for violations of FERC Market Rules.[19] The MMU will investigate and refer "Market Violations," which refers to any of "a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation,[20] or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies..."[21] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[22]

The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation.[23] If the problem or violation involves a market participant, the MMU discusses the matter with the participant(s) involved and analyzes relevant market data. If that investigation produces sufficient credible evidence of a violation, the MMU prepares a formal referral[24] and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff.[25] If the problem involves an existing or proposed law, rule or practice that exposes PJM markets to the risk that market power or market manipulation could compromise the integrity of the markets, the MMU explains the issue, as appropriate, to the FERC, state regulators, stakeholders or other authorities.

16 OATT Attachment M § IV.
17 OATT Attachment M § IV.K.3.
18 OATT Attachment M § IV.H.
19 OATT Attachment M § II(d)&(q) ("FERC Market Rules" mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish... "PJM Market Rules" mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.").
20 The FERC defines manipulation as engaging "in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity." 18 CFR § 1c.2(a)(3). Manipulation may involve behavior that is consistent with the letter of the rules, but violates their spirit. An example is market behavior that is economically meaningless, such as equal and opposite transactions, which may entitle the transacting party to a benefit associated with volume. Unlike market power or rule violations, manipulation must be intentional. The MMU must build its case, including an inference of intent, on the basis of market data.
21 OATT Attachment M § II(h-1).
22 OATT Attachment M § IV.C.
23 OATT Attachment M § IV.I.1.
24 *Id.*
25 *Id.*

The MMU may also participate as a party or provide information or testimony in regulatory or other proceedings.

Another important component of the monitoring function is the review of inputs to mitigation. The actual or potential exercise of market power is addressed in part through *ex ante* mitigation rules incorporated in PJM's market clearing software for the energy market, the capacity market and the regulation market. If a market participant fails the TPS test in any of these markets its offer is set to the lower of its price based or cost based offer. This prevents the exercise of market power and ensures competitive pricing, provided that the cost based offer accurately reflects short run marginal cost. Cost based offers for the energy market and the regulation market are based on incremental costs as defined in the PJM Cost Development Guidelines (PJM Manual 15).[26] The MMU evaluates every offer in each capacity market (RPM) auction using data submitted to the MMU through web-based data input systems developed by the MMU.[27]

The MMU also reviews operational parameter limits included with unit offers,[28] evaluates compliance with the requirement to offer into the energy and capacity markets,[29] evaluates the economic basis for unit retirement requests,[30] and evaluates and compares offers in the Day-Ahead and Real-Time Energy Markets.[31]

Market Design

In order to perform its role in PJM market design, the MMU evaluates existing and proposed PJM Market Rules and the design of the PJM Markets.[32] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[33] In support of this function, the MMU engages in discussions with stakeholders, State Commissions, PJM Management, and the PJM Board; participates in PJM stakeholder meetings or working groups regarding market design matters; publishes proposals, reports or studies on such market design issues; and makes filings with the Commission on market design issues.[34] The MMU also recommends changes to the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[35] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[36]

Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes,"[37] the MMU recommends specific enhancements to existing market 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. In this *2012 Quarterly State of the Market Report for PJM: January through September*, the recommendations from the *2011 State of the Market Report for PJM* and subsequent 2012 quarterly state of the market reports remain MMU recommendations.

The following are new recommendations since the last quarterly report.

From Section 3, "Operating Reserve":

- The MMU recommends that PJM should, on an expedited basis, request that the tariff be modified to permit allocation of day-ahead operating reserve charges consistent with the prior allocation of these charges in real time. This would be a short term solution to the issue created by shifting operating reserve charges to the Day-Ahead Energy Market and therefore changing the allocation of those charges. In addition, PJM should start a stakeholder process to consider the market design and cost allocation issues in detail and propose a permanent tariff change that results from the process.

26 *See* OATT Attachment M–Appendix § II.A.
27 OATT Attachment M–Appendix § II.E.
28 OATT Attachment M–Appendix § II.B.
29 OATT Attachment M–Appendix § II.C.
30 OATT Attachment M–Appendix § IV.
31 OATT Attachment M–Appendix § VII.
32 OATT Attachment M § IV.D.
33 *Id.*
34 *Id.*
35 *Id.*
36 OATT Attachment M § VI.A.
37 18 CFR § 35.28(g)(3)(ii)(A); *see also* OATT Attachment M § IV.D.

- The MMU recommends that this stakeholder process address three areas of incorrect allocation that are directly related to and part of the current issue. These areas are related to reactive service costs, black start service costs and the inclusion of no load costs in the lost opportunity cost calculation.[38,39,40] As part of the stakeholder process, the MMU recommends that PJM clearly identify and classify the reasons for operating reserve credits in the Day-Ahead and the Real-Time Energy Markets in order to ensure the correct allocation of the corresponding charges.

From Section 4, "Capacity":

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. The MMU also recommends that the notification requirement for deactivations be modified to include required notification of six to twelve months prior to an auction in which the unit will not be offered due to deactivation. The purpose of this deadline is to allow adequate time for potential Capacity Market Sellers to offer new capacity in the auction. The currently proposed related deadline of 120 days prior to an RPM Auction for requesting exemption to the RPM Must Offer Obligation is a step in the right direction.[41] All notification recommendations assume that the generation owner has the required knowledge in the defined time frame.
- The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened.[42]
- The MMU recommends that generation capacity resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. All revenues should be at risk under the peak hour availability charge.
- The MMU recommends that 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 MMU recommends that all generation types face the same performance incentives.
- The MMU recommends elimination of the exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.
- The MMU recommends elimination of the exception related to a unit that runs less than 50 hours during the RPM peak period.
- The MMU recommends that PJM eliminate all Out of Management Control (OMC) outages from use in planning or capacity markets.

From Section 8, "Interchange Transactions":

- The MMU recommends the termination of the existing PJM/PEC (Progress Energy Carolinas) JOA, as some of the assumptions used in the development of the JOA were based on explicit assumptions about the Progress generation fleet, and its dispatch. Those assumptions are no longer correct, as is evident by the Progress/DUK joint dispatch agreement, and thus the PJM/PEC JOA should be terminated.

From Section 9, "Ancillary Services":

- The MMU recommends that PJM reevaluate its use of the Tier 1 bias factor and define explicit and transparent rules for calculating available Tier 1 MW and calculating required Tier 2 MW.

38 See the *2012 Quarterly State of the Market Report for PJM: January through September*, Section 3, "Operating Reserve" at "Black Start and Voltage Support Units".
39 See the *2012 Quarterly State of the Market Report for PJM: January through September*, Section 3, "Operating Reserve" at "Reactive Service Credits and Operating Reserve Credits".
40 See the *2012 Quarterly State of the Market Report for PJM: January through September*, Section 3, "Operating Reserve" at "Lost Opportunity Cost Calculation".
41 In order to make an offer in a BRA, planned generation must be in a generation queue, have completed a Feasibility Study and have a signed Impact Study Agreement. Planned generation must be in the queue at least six months prior to the month of the BRA, or by October 31 of the calendar year preceding the auction, in order to ensure timely completion of the Feasibility Study and Impact Study Agreement. Given these requirements of the queue process, a notification period of nine months prior to the BRA would be required to allow planned generation time to enter the queue in response to a notice of deactivation.
42 For more details on the reasons for these recommendations, see the IMM's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, *"Capacity in the PJM Market,"* <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012)

Highlights

The following presents highlights of each of the sections of the *2012 Quarterly State of the Market Report for PJM: January through September:*

Section 2, Energy Market

- Average offered supply increased by 10,571, or 6.6 percent, from 159,826 MW in the first nine months of 2011 to 170,397 MW in the first nine months of 2012. The increase in offered supply was in part the result of the integration of the Duke Energy Ohio/Kentucky (DEOK) Transmission Zone in the first quarter of 2012 and the integration of the American Transmission Systems, Inc. (ATSI) Transmission Zone in the second quarter of 2011. In addition, 1,898 MW of nameplate capacity were added to PJM in the first nine months of 2012. The increases in supply were partially offset by the deactivation of 43 units (6,722 MW) since January 1, 2012. (See page 20)
- In January through September 2012, coal units provided 41.8 percent, nuclear units 34.1 percent and gas units 19.6 percent of total generation. Compared to January through September 2011, generation from coal units decreased 10.0 percent, generation from nuclear units increased 5.3 percent, while generation from natural gas units increased 45.4 percent, and generation from oil units increased 96.5 percent. (See page 21)
- The PJM system peak load for the first nine months of 2012 was 154,344 MW, which was 3,672 MW, or 2.3 percent, lower than the PJM peak load for the first nine months of 2011.[43] The DEOK Transmission Zone accounted for 5,360 MW in the peak hour of the first nine months of 2012. The peak load in 2012 excluding the DEOK Transmission Zone was 148,984 MW, a decrease of 9,032 MW, or 5.7 percent, from the peak load for the first nine months 2011. (See page 23)
- PJM average real-time load increased in the first nine months of 2012 by 5.9 percent from the first nine months of 2011, from 83,762 MW to 88,680 MW. The PJM average real-time load would have decreased in the first nine months of 2012 by 0.9 percent from the first nine months of 2011, from 83,762 MW to 82,970 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison for the months in 2011 when they were not part of PJM.[44] (See page 35)
- PJM average day-ahead load, including DECs and up-to congestion transactions, increased in the first nine months of 2012 by 16.5 percent from the first nine months of 2011, from 113,724 MW to 132,494 MW. PJM average day-ahead load would have increased in the first nine months of 2012 by 10.7 percent from the first nine months of 2011, from 113,724 MW to 125,917 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison for the months in 2011 when they were not part of PJM. The day-ahead load growth was 179.7 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions. (See page 40)
- PJM average real-time generation increased in the first nine months of 2012 by 3.9 percent from the first nine months of 2011, from 86,966 MW to 90,367 MW. PJM average real-time generation would have decreased in the first nine months of 2012 by 1.6 percent from the first nine months of 2011, from 86,966 MW to 85,532 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison for the months in 2011 when they were not part of PJM. (See page 43)
- PJM average day-ahead generation, including INCs and up-to congestion transactions, increased in the first nine months of 2012 by 15.6 percent from the first nine months of 2011, from 116,988 MW to 135,213 MW. PJM average day-ahead generation would have increased 11.5 percent from the first nine months of 2011, from 116,988 MW to 135,213 MW if the DEOK and ATSI transmission zones were excluded from the comparison for the months in 2011 when they were not part of PJM. The day-ahead generation growth was 300.0 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions. (See page 44)
- PJM Real-Time Energy Market prices decreased in the first nine months of 2012 compared to the first nine months of 2011. The load-weighted

43 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2011 State of the Market Report for PJM*, Appendix I, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

44 The ATSI Transmission Zone was excluded from this comparison and similar comparisons for the first 5 months of 2012 because it did not join PJM until June 1, 2011. The DEOK Transmission Zone was excluded from this comparison for all of the months of 2012 because it did not join PJM until January 1, 2012.

average LMP was 29.2 percent lower in the first nine months of 2012 than in the first nine months of 2011, $35.02 per MWh versus $49.48 per MWh. (See page 47)

- PJM Day-Ahead Energy Market prices decreased in the first nine months of 2012 compared to the first nine months of 2011. The load-weighted average LMP was 29.1 percent lower in the first nine months of 2012 than in the first nine months of 2011, $34.29 per MWh versus $48.34 per MWh. (See page 51)
- Based on average spot fuel prices, the fuel cost of a new entrant combined cycle unit ($19.54/MWh) was lower than the fuel cost of a new entrant coal plant ($19.83/MWh) in the first nine months of 2012. (See page 48)
- Levels of offer capping for local market power remained low. In the first nine months of 2012, 1.6 percent of unit hours and 1.0 percent of MW were offer capped in the Real-Time Energy Market and 0.2 percent of unit hours and 0.2 percent of MW were offer capped in the Day-Ahead Energy Market. (See page 25)
- Of the 131 units that were eligible to include a Frequently Mitigated Unit (FMU) or Associated Unit (AU) adder in their cost-based offer during the first nine months of 2012, 44 (33.6 percent) qualified in all months, and 26 (19.9 percent) qualified in only one month of the first nine months of 2012. (See page 34)

Section 3, Operating Reserve

- Operating reserve charges decreased $42.8 million, or 8.9 percent, from $479.8 million in the first nine months of 2011, to $437.0 million in the first nine months of 2012. Day-ahead operating reserve charges increased $17.8 million, or 26.3 percent to $85.3 million and balancing operating reserve charges decreased $59.9 million, or 14.5 percent to $351.7 million. (See page 67)
- Balancing operating reserve charges for reliability decreased by $5.3 million, or 7.1 percent compared to the first nine months of 2011. Balancing operating reserve charges for deviations decreased by $47.4 million, or 27.6 percent. (See page 68)
- The reduction in balancing operating reserve charges was comprised of a decrease of $52.7 million in generator and real-time import transactions balancing operating reserve charges, a decrease of $9.8 million in lost opportunity costs, a decrease of $2.6 million in canceled resources and an increase of $5.2 million in charges to participants requesting resources to control local constraints. (See page 69)
- Generators and real-time transactions balancing operating reserve charges were $194.2 million, 55.2 percent of all balancing operating reserve charges. Balancing operating reserve charges were allocated 35.8 percent as reliability charges and 64.2 percent as deviation charges. Lost opportunity cost charges were $146.5 million or 41.7 percent of all balancing charges. The remaining 3.1 percent of balancing operating reserve charges were comprised of 0.9 percent canceled resources charges and 2.2 percent of local constraints control charges. (See page 69)
- The concentration of operating reserve credits among a small number of units remains high. The top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 21.1 percent of total operating reserve credits in the first nine months of 2012, compared to 29.7 percent in the first nine months of 2011. HHI for day-ahead operating reserve credits was 3868, for balancing operating reserve credits was 2847 and for lost opportunity cost credits was 3832. (See page 83)
- The regional concentration of operating reserves remained high in the first nine months of 2012. In the first nine months of 2012, 47.1 percent of all operating reserve credits were paid to resources in the top three zones, a decrease of 13.5 percentage points from the first nine months of 2011. (See page 79)

Section 4, Capacity

- During the period January 1, through September 30, 2012, PJM installed capacity increased 4,019.4 MW or 2.2 percent from 178,854.1 MW on January 1 to 182,873.5 MW on September 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis. (See page 98)

- The 2013/2014 RPM Second Incremental Auction and the 2014/2015 RPM First Incremental Auction were conducted in the third quarter of 2012. In the 2013/2014 RPM Second Incremental Auction, the rest of RTO clearing price was $7.01 per MW-day. In the 2014/2015 RPM First Incremental Auction, the rest of RTO clearing price for Annual and Extended Summer Resources was $5.54 per MW-day. (See page 105)
- Capacity in the RPM load management programs was 7,118.5 MW for June 1, 2012 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2012/2013 Delivery Year (9,407.0 MW) less replacement capacity (2,288.5 MW). (See page 102)
- Annual weighted average capacity prices increased from a Capacity Credit Market (CCM) weighted average price of $5.73 per MW-day in 2006 to an RPM weighted-average price of $164.71 per MW-day in 2010 and then declined to $148.33 per MW-day in 2015. (See page 107)
- Combined cycle units ran more often in January through September 2012, than in the same period in 2011, increasing from a 47.1 percent capacity factor in 2011 to a 63.8 percent capacity factor in 2012. Combined cycle units had a higher capacity factor than steam units, for which the capacity factor decreased from 54.0 percent in 2011 to 45.5 percent in January through September 2012. (See page 108)
- The average PJM equivalent demand forced outage rate (EFORd) decreased from 7.6 percent in the first nine months of 2011 to 6.8 percent in the first nine months of 2012. (See page 109)
- The PJM aggregate equivalent availability factor (EAF) increased from 84.9 percent in January through September 2011 to 85.5 percent for the same period in 2012. The equivalent maintenance outage factor (EMOF) increased from 2.8 percent to 3.5 percent, the equivalent planned outage factor (EPOF) decreased from 7.1 percent to 6.3 percent, and the equivalent forced outage factor (EFOF) decreased from 5.3 percent to 4.7 percent. (See page 104)

Section 5, Demand Response

- In January through September 2012, the total MWh of load reduction under the Economic Load Response Program increased by 84,620 MWh compared to the same period in 2011, from 15,376 MWh in 2011 to 99,996 MWh in 2012, a 550 percent increase. Total payments under the Economic Program increased by $4,896,597, from $1,943,507 in the first nine months of 2011 to $6,840,104 in 2012, a 252 percent increase, as a result of the implementation of Order 745 on April 1, 2012. The increased payments were concentrated in the summer months of 2012. (See page 120)
- In January through September 2012, total capacity payments to demand response resources under the PJM Load Management (LM) Program, which integrated Emergency Load Response Resources into the Reliability Pricing Model, decreased by $118.2 million, or 31.0 percent, compared to the same period in 2011, from $381 million in 2011 to $263 million in 2012. The decrease in capacity credits in 2012 was the result of a decrease in RPM clearing prices in the rest of RTO region. While prices increased for MAAC zones, the rest of the PJM RTO cleared at $16.46 in the 2012/2013 delivery year, an 85 percent decrease from the RTO wide $110.04 clearing price in the 2011/2012 delivery year. (See page 126)

Section 6, Net Revenue

- Average real time LMP decreased by 29.1 percent in the first nine months of 2012 over the first nine months of 2011. (See page 47)
- Natural gas prices decreased by more than coal prices in the first nine months of 2012 compared to the first nine months of 2011. The price of Northern Appalachian coal was 15.5 percent lower; the price of Central Appalachian coal was 19.4 percent lower; and the price of Powder River Basin coal was 34.1 percent lower. The price of eastern natural gas was 40.5 percent lower; and the price of western natural gas was 37.1 percent lower.[45] (See page 48)

45 Eastern natural gas and Western natural gas prices are the average of daily fuel price indices in the PJM footprint. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

- While average net revenues for all three technologies declined, only new entrant combined cycle units had net revenue increases in some zones. Comparing the first nine months of 2012 to the first nine months of 2011, energy net revenues for the new entrant combustion turbine unit were down 36.8 percent, energy net revenues for the new entrant combined cycle unit were down 8.7 percent, and energy net revenues for the new entrant coal unit were down 69.1 percent.[46] (See page 129)

Section 7, Environmental and Renewables

- In a decision dated August 21, 2012, the U.S. Court of Appeals for the D.C. Circuit vacated the Cross State Air Pollution Rule (CSAPR).[47] The court had found "fatal flaws" in the prior rule, the Clean Air Interstate Rule (CAIR), but allowed it to remain in effect until replaced.[48] The EPA filed a petition for review en banc with the court on October 5, 2012. CAIR remains in place, as does the requirement to replace it. (See page 134)
- On March 27, 2012, the EPA proposed a Carbon Pollution Standard for new fossil-fired electric utility generating units. The proposed standard would limit emissions from new electric generating units to 1,000 pounds of CO_2 per MWh. In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the GHG rule, rejecting challenges brought by industry groups and a number of states.[49] (See page 134)
- The EPA proposed to exempt certain small reciprocating engines participating in DR programs as behind-the-meter generation from otherwise applicable run time restrictions. On May 22, 2012, the EPA proposed to increase the existing 15-hour exemption to 100 hours. EPA justified this exemption based on concerns about the impact on reliability and efficient operation of the wholesale energy markets.[50] The Market Monitor testified on this issue explaining that such concerns are unwarranted, and that, by providing a special exemption to units participating in demand response programs, the exemption would harm efficiency and reliability.[51] (See page 135)
- NO_x and SO_2 emission prices declined in January through September 2012, compared to 2011, while RGGI CO_2 prices increased. NO_x prices declined 75.9 percent in 2012 compared to 2011, and SO_2 prices declined 55.2 percent in 2012 compared to 2011. Spot average RGGI CO_2 prices increased by 2.6 percent in 2012 compared to 2011, partially as a result of the increase in the price floor for RGGI CO_2 allowances. (See page 136)
- The auction price of RGGI CO_2 allowances remained at the floor price of $1.93 during January through September 2012, and as of January 1, 2012, the state of New Jersey no longer participates in the RGGI program. (See page 136)
- Generation from wind units increased from 7,924.5 GWh in January through September 2011 to 8,944.7 GWh in January through September 2012, an increase of 12.9 percent. Generation from solar units increased from 37.9 GWh in January through September 2011 to 192.7 GWh in January through September 2012, an increase of 408.7 percent. (See page 141)

Section 8, Interchange Transactions

- During the first nine months of 2012, PJM was a net exporter of energy in the Real-Time Energy Market in January, August and September, and a net importer of energy in the remaining months. During the first nine months of 2011, PJM was a net importer of energy in the Real-Time Energy Market in January, and a net exporter of energy in the remaining months. (See page 147)
- During the first nine months of 2012, PJM was a net exporter of energy in the Day-Ahead Energy Market in January through April and July through September, and a net importer of energy in May and June. During the first nine months of 2011, PJM was a net importer of energy in the Day-Ahead Energy Market in January through May, and a net exporter of energy in July through September. (See page 147)

46 Changes are simple zonal averages.
47 EME Homer City Generation, L.P. v. EPA, et al., No. 11-1302.
48 State of North Carolina, et al. v. EPA, 531 F.3d 896 (D.C. Cir. 2008), *order on reh'g*, 550 F.3d 1176 (2008).
49 Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.
50 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines, Proposed Rule*, EPA Docket No. EPA-HQ-OAR-2008-0708, 77 Fed. Reg. 33812 (June 7, 2012).
51 Comments of the Independent Market Monitor for PJM, filed in EPA Docket No. EPA-HQ-OGC-2011-1030 (February 16, 2012).

- The direction of power flows was not consistent with real-time energy market price differences in 55 percent of hours at the border between PJM and MISO and in 48 percent of hours at the border between PJM and NYISO during the first nine months of 2012. (See page 165)
- During the first nine months of 2012, net scheduled interchange was 1,051 GWh and net actual interchange was 801 GWh, a difference of 251 GWh. During the first nine months of 2011, net scheduled interchange was -4,176 GWh and net actual interchange was -4,524 GWh, a difference of 348 GWh. (See page 169)
- PJM initiated 29 TLRs during the first nine months of 2012, a reduction from the 58 TLRs initiated during the first nine months of 2011. (See Page 170)
- The average daily volume of up-to congestion bids increased from 26,553 bids per day, during the first nine months of 2011, to 58,273 bids per day during the first nine months of 2012. (See page 171)
- During the first nine months of 2012, there were no balancing operating reserve credits paid to dispatchable transactions, a decrease from $1.3 million for the first nine months of 2011. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and that dispatchable schedules were only submitted on three days during the first nine months of 2012. (See page 179)

Section 9, Ancillary Services

- The weighted average Regulation Market clearing price, including opportunity cost, for January through September 2012 was $14.92 per MW.[52] This was a decrease of $2.11, or 12.4 percent, from the average price for regulation in January through September 2011. The total cost of regulation decreased by $12.13 from $32.71 per MW in January through September 2011, to $20.58, or 37.1 percent. In January through September 2012, the weighted Regulation Market clearing price was 72 percent of the total regulation cost per MW, compared to 52 percent of the total regulation cost per MW in January through September 2011. (See page 188)
- The weighted average Tier 2 Synchronized Reserve Market clearing price in the Mid-Atlantic Subzone was $7.06 per MW in January through September 2012, a $4.94 per MW decrease from January through September 2011.[53] The total cost of synchronized reserves per MW in January through September 2012, was $10.96, a 23 percent decrease from the total cost of synchronized reserves ($14.21) during January through September 2011. The weighted average Synchronized Reserve Market clearing price was 64 percent of the weighted average total cost per MW of synchronized reserve in January through September 2012. The price to cost ratio was 84 percent in January through September 2011. (See page 196)
- The weighted DASR market clearing price was $0.91 per MW in January through September 2012. In January through September 2011, the weighted price of DASR was $1.04 per MW. The average hourly purchased DASR was 7,042 MW, an increase from 6,622 MW during the same period of 2011, reflecting PJM's larger footprint with the integration of DEOK on January 1, 2012. (See page 200)
- Black start zonal charges in January through September 2012 ranged from $0.02 per MW in the ATSI zone to $1.80 per MW in the BGE zone. (See page 202)

Section 10, Congestion and Marginal Losses

- Marginal loss costs decreased by $395.0 million or 34.3 percent, from $1,152.6 million in the first nine months of 2011 to $757.6 million in the first nine months of 2012 (Table 10-10). (See page 208)
- Day-ahead marginal loss costs decreased by $415.0 million or 34.8 percent, from $1,191.1 million in the first nine months of 2011 to $776.0 million in the first nine months of 2012 (Table 10-12). (See page 209)
- Balancing marginal loss costs increased by $20.0 million or 52.0 percent, from $38.5 million in the first nine months of 2011 to -$18.5 million in the first nine months of 2012 (Table 10-12). (See page 209)
- The marginal loss credits (loss surplus) decreased by $188.7 million or 37.6 percent, from $502.1 million in the first nine months of 2011 to $313.4 million in the first nine months of 2012. (Table 10-13). (See page 209)

52 The term "weighted" when applied to clearing prices in the Regulation Market means clearing prices weighted by the MW of cleared regulation.

53 The term "weighted" when applied to clearing prices in the Synchronized Reserve Market means clearing prices weighted by the MW of cleared synchronized reserve.

- Congestion decreased by $449.7 million or 51.4 percent, from $874.9 million in the first nine months of 2011 to $425.2 million in the first nine months of 2012 (Table 10-15). (See page 212)
- Day-ahead congestion costs decreased by 460.0 million or 43.3 percent, from $1,063.2 million in the first nine months of 2011 to $603.2 million in the first nine months of 2012. (See page 212)
- Balancing congestion costs decreased by $10.3 million or 5.8 percent, from -$178.0 million in the first nine months of 2011 to -$188.3 million in the first nine months of 2012. (See page 212)

Section 11, Planning

- At September 30, 2012, 75,869 MW of capacity were in generation request queues to be in service through 2018, compared to an average installed capacity of 185,000 MW in 2012 including the January 1, 2012, DEOK integration. Wind projects account for 26,495 MW, 34.9 percent of the capacity in the queues, and combined-cycle projects account for 38,806 MW, 51.1 percent of the capacity in the queues. (See page 226)
- A total of 6,722 MW of generation capacity retired between January and October 1, 2012, and it is expected that a total of 19,142.8 MW will have retired from 2011 through 2019, with most of this capacity retiring by the end of 2015. Units that have retired through October 1, 2012, make up 35 percent of all retirements currently expected to occur from 2012 through 2019. (See page 225)

Section 12, Financial Transmission Rights and Auction Revenue Rights

- The total cleared FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2012 to 2013 planning period decreased by 15.2 percent from 1,067,015 MW to 904,797 MW compared to the first four months of the 2011 to 2012 planning period. (See page 240)
- FTRs were paid at 79.1 percent for the first four months of the 2012 to 2013 planning period. (See page 249)
- FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. FTRs were not profitable overall for physical entities but were profitable for financial entities in the period from January through September 2012. Total FTR profits were -$3.3 million for physical entities and $77.2 million for financial entities. Self-scheduled FTRs were the source of $134.0 million of the FTR profits for physical entities. (See page 251)

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, and transmission service, administrative fees, regulatory support fees and uplift charges billed through PJM systems. Table 1-7 provides the average price and total revenues paid, by component, for the first nine months of 2011 and 2012.

Table 1-7 shows that Energy, Capacity and Transmission Service Charges are the three largest components of the total price per MWh of wholesale power, comprising 95.0 percent of the total price per MWh in the first nine months of 2012.

Each of the components 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 Energy component is the real time load weighted average PJM locational marginal price (LMP).
- The Capacity component is the average price per MWh of Reliability Pricing Model (RPM) payments.

- The Transmission Service Charges component is the average price per MWh of network integration charges, and firm and non firm point to point transmission service.[54]
- The Operating Reserve (uplift) component is the average price per MWh of day ahead and real time operating reserve charges.[55]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[56]
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[57]
- 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 TrAIL and PATH projects.[58]
- The Day-Ahead Scheduling Reserve component is the average cost per MWh of Day-Ahead scheduling reserves procured through the Day-Ahead Scheduling Reserve Market.[59]
- 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.[60]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[61]
- The Black Start component is the average cost per MWh of black start service.[62]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[63]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[64]
- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.[65]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[66]

Table 1-7 Total price per MWh by category and total revenues by category: January through September 2011 and 2012 (See 2011 SOM, Table 1-7)

Category	Jan-Sep 2011 $/MWh	Jan-Sep 2012 $/MWh	Percent Change Totals	Jan-Sep 2011 Percent of Total	Jan-Sep 2012 Percent of Total
Load Weighted Energy	$49.47	$35.02	(29.2%)	74.3%	72.4%
Capacity	$10.19	$6.27	(38.5%)	15.3%	12.9%
Transmission Service Charges	$4.30	$4.69	9.0%	6.5%	9.7%
Operating Reserves (Uplift)	$0.90	$0.75	(15.8%)	1.3%	1.6%
Reactive	$0.38	$0.44	14.5%	0.6%	0.9%
PJM Administrative Fees	$0.38	$0.44	13.8%	0.6%	0.9%
Transmission Enhancement Cost Recovery	$0.28	$0.32	11.2%	0.4%	0.7%
Regulation	$0.36	$0.23	(34.8%)	0.5%	0.5%
Transmission Owner (Schedule 1A)	$0.09	$0.08	(7.4%)	0.1%	0.2%
Day Ahead Scheduling Reserve (DASR)	$0.07	$0.06	(11.0%)	0.1%	0.1%
Synchronized Reserves	$0.09	$0.03	(63.2%)	0.1%	0.1%
Black Start	$0.02	$0.02	26.7%	0.0%	0.1%
NERC/RFC	$0.02	$0.02	18.3%	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(5.8%)	0.0%	0.0%
Load Response	$0.01	$0.01	44.3%	0.0%	0.0%
Transmission Facility Charges	$0.00	$0.00	(20.1%)	0.0%	0.0%
Total	$66.58	$48.40	(27.3%)	100.0%	100.0%

54 OATT §§ 13.7, 14.5, 27A & 34.
55 OA Schedules 1 §§ 3.2.3 & 3.3.3.
56 OATT Schedule 2 and OA Schedule 1 § 3.2.3B.
57 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
58 OATT Schedule 12.
59 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
60 OATT Schedule 1A.
61 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
62 OATT Schedule 6A. The Black Start charges do not include Operating Reserve charges required for units to provide Black Start Service under the ALR option.
63 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
64 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
65 OA Schedule 1 § 3.6.
66 OA Schedule 1 § 5.3b.

Energy Market

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 the first nine months of 2012, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM Energy Market results were competitive in the first nine months of 2012.

Table 2-1 The Energy Market results were competitive (See 2011 SOM, Table 2-1)

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Effective

- The aggregate market structure was evaluated as competitive because the calculations for hourly HHI (Herndahl-Hirschman Index) indicate that by the FERC standards, the PJM Energy Market during the first nine months of 2012 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1234 with a minimum of 927 and a maximum of 1657 in the first nine months of 2012.
- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test mitigated local market power and forced competitive offers, correcting for structural issues created by local transmission constraints.

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.[3]

Highlights

- Average offered supply increased by 10,571, or 6.6 percent, from 159,826 MW in the first nine months of 2011 to 170,397 MW in the first nine months of 2012. The increase in offered supply was in part the result of the integration of the Duke Energy Ohio/Kentucky (DEOK) Transmission Zone in the first quarter of 2012 and the integration of the American Transmission Systems, Inc. (ATSI) Transmission Zone in the second quarter of 2011. In addition, 1,898 MW of nameplate capacity were added to PJM in the first nine months of 2012. The increases in supply were

1 Analysis of 2012 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. In June 2011, PJM integrated the American Transmission Systems, Inc. (ATSI) Control Zone. In January 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. 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 *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

2 OATT Attachment M

3 The market performance test means that offer capping is not applied if the offer does not exceed the competitive level and therefore market power would not affect market performance.

partially offset by the deactivation of 43 units (6,722 MW) since January 1, 2012.

- In January through September 2012, coal units provided 41.8 percent, nuclear units 34.1 percent and gas units 19.6 percent of total generation. Compared to January through September 2011, generation from coal units decreased 10.0 percent, generation from nuclear units increased 5.3 percent, while generation from natural gas units increased 45.4 percent, and generation from oil units increased 96.5 percent.
- The PJM system peak load for the first nine months of 2012 was 154,344 MW, which was 3,672 MW, or 2.3 percent, lower than the PJM peak load for the first nine months of 2011.[4] The DEOK Transmission Zone accounted for 5,360 MW in the peak hour of the first nine months of 2012. The peak load in 2012 excluding the DEOK Transmission Zone was 148,984 MW, a decrease of 9,032 MW, or 5.7 percent, from the peak load for the first nine months 2011.
- PJM average real-time load increased in the first nine months of 2012 by 5.9 percent from the first nine months of 2011, from 83,762 MW to 88,680 MW. The PJM average real-time load would have decreased in the first nine months of 2012 by 0.9 percent from the first nine months of 2011, from 83,762 MW to 82,970 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison for the months in 2011 when they were not part of PJM.[5]
- PJM average day-ahead load, including DECs and up-to congestion transactions, increased in the first nine months of 2012 by 16.5 percent from the first nine months of 2011, from 113,724 MW to 132,494 MW. PJM average day-ahead load would have increased in the first nine months of 2012 by 10.7 percent from the first nine months of 2011, from 113,724 MW to 125,917 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison for the months in 2011 when they were not part of PJM. The day-ahead load growth was 179.7 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions.
- PJM average real-time generation increased in the first nine months of 2012 by 3.9 percent from the first nine months of 2011, from 86,966 MW to 90,367 MW. PJM average real-time generation would have decreased in the first nine months of 2012 by 1.6 percent from the first nine months of 2011, from 86,966 MW to 85,532 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison for the months in 2011 when they were not part of PJM.
- PJM average day-ahead generation, including INCs and up-to congestion transactions, increased in the first nine months of 2012 by 15.6 percent from the first nine months of 2011, from 116,988 MW to 135,213 MW. PJM average day-ahead generation would have increased 11.5 percent from the first nine months of 2011, from 116,988 MW to 135,213 MW if the DEOK and ATSI transmission zones were excluded from the comparison for the months in 2011 when they were not part of PJM. The day-ahead generation growth was 300.0 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.
- PJM Real-Time Energy Market prices decreased in the first nine months of 2012 compared to the first nine months of 2011. The load-weighted average LMP was 29.2 percent lower in the first nine months of 2012 than in the first nine months of 2011, $35.02 per MWh versus $49.48 per MWh.
- PJM Day-Ahead Energy Market prices decreased in the first nine months of 2012 compared to the first nine months of 2011. The load-weighted average LMP was 29.1 percent lower in the first nine months of 2012 than in the first nine months of 2011, $34.29 per MWh versus $48.34 per MWh.
- Based on average spot fuel prices, the fuel cost of a new entrant combined cycle unit ($19.54/MWh) was lower than the fuel cost of a new entrant coal plant ($19.83/MWh) in the first nine months of 2012.

4 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2011 State of the Market Report for PJM*, Appendix I, "Glossary," for a definition of EPT and its relationship to Eastern Standard Time (EST) and Eastern Daylight Time (EDT).

5 The ATSI Transmission Zone was excluded from this comparison and similar comparisons for the first 5 months of 2012 because it did not join PJM until June 1, 2011. The DEOK Transmission Zone was excluded from this comparison for all of the months of 2012 because it did not join PJM until January 1, 2012.

- Levels of offer capping for local market power remained low. In the first nine months of 2012, 1.6 percent of unit hours and 1.0 percent of MW were offer capped in the Real-Time Energy Market and 0.2 percent of unit hours and 0.2 percent of MW were offer capped in the Day-Ahead Energy Market.
- Of the 131 units that were eligible to include a Frequently Mitigated Unit (FMU) or Associated Unit (AU) adder in their cost-based offer during the first nine months of 2012, 44 (33.6 percent) qualified in all months, and 26 (19.9 percent) qualified in only one month of the first nine months of 2012.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in the first nine months of 2012, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand-side response programs, loads and prices.

Aggregate hourly real-time supply offered increased by 10,571 MW in the first nine months of 2012 compared to the first nine months of 2011, while aggregate peak load decreased by 3,672 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. In the Day-Ahead Energy Market, average load in the first nine months of 2012 increased from the first nine months of 2011, from 113,724 MW to 132,494 MW, or 16.5 percent. In the Real-Time Energy Market, average load in the first nine months of 2012 increased from the first nine months of 2011, from 83,762 MW to 88,680 MW, or 5.9 percent. Market concentration levels remained moderate. 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 in each hour. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price. Energy Market results for the first nine months of 2012 generally reflected supply-demand fundamentals.

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.[6] 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 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.

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 can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not

6 The MMU reviews PJM's application of the TPS test and brings issues to the attention of PJM.

required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. 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. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Nonetheless, with a market design that includes a direct and explicit scarcity pricing revenue true up mechanism, 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. Any such market design modification should occur only after scarcity pricing for price signals has been implemented and sufficient experience has been gained to permit a well calibrated and gradual change in the mix of revenues. The MMU concludes that the PJM Energy Market results were competitive in the first nine months of 2012.

Market Structure

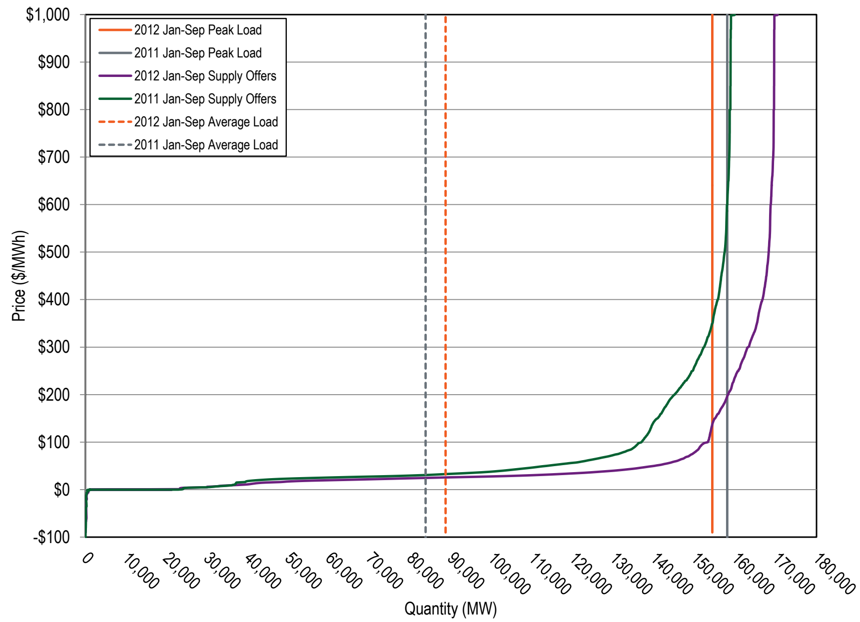
Supply

Average offered supply increased by 10,571 MW, or 6.6 percent, from 159,826 MW in the first nine months of 2011 to 170,397 MW in the first nine months of 2012.[7] The increase in offered supply was in part the result of the integration of the DEOK Transmission Zone in the first quarter of 2012 and the integration of the ATSI Transmission Zone in the second quarter of 2011. In addition, 1,898 MW of nameplate capacity were added to PJM in the first nine months of 2012. This includes six large plants (over 500 MW) that began generating in PJM between January 1, 2011, and September 30, 2012. The increases in supply were partially offset by the deactivation of 43 units (6,722 MW) since January 1, 2012.

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

Figure 2-1 shows the average PJM aggregate supply curves, peak load and average load for the first nine months of 2011 and 2012.

Figure 2-1 Average PJM aggregate supply curves: January through September, 2011 and 2012 (See 2011 SOM, Figure 2-1)



Energy Production by Fuel Source

Compared to January through September, 2011, generation from coal units decreased 10.0 percent and generation from natural gas units increased 44.4 percent (Table 2-2). If the impact of the increased coal from the newly integrated ATSI and DEOK zones is eliminated, generation from coal units decreased 19.1 percent in the first three quarters of 2012 compared to the first three quarters of 2011.

Table 2-2 PJM generation (By fuel source (GWh)): January through September 2011 and 2012[8] (See 2011 SOM, Table 2-2)

	Jan-Sep 2011		Jan-Sep 2012		
	GWh	Percent	GWh	Percent	Change in Output
Coal	279,501.2	48.0%	251,591.7	41.8%	(10.0%)
Standard Coal	270,273.8	46.4%	244,258.0	40.5%	(9.3%)
Waste Coal	9,227.4	1.6%	7,333.6	1.2%	(0.7%)
Nuclear	195,196.7	33.5%	205,503.9	34.1%	5.3%
Gas	82,130.5	14.1%	118,328.2	19.6%	44.1%
Natural Gas	80,774.5	13.9%	116,649.9	19.4%	44.4%
Landfill Gas	1,355.9	0.2%	1,678.0	0.3%	23.8%
Biomass Gas	0.1	0.0%	0.4	0.0%	175.0%
Wind	7,924.5	1.4%	8,944.7	1.5%	12.9%
Hydroelectric	11,379.8	2.0%	9,768.1	1.6%	(14.2%)
Waste	4,254.8	0.7%	3,894.1	0.6%	(8.5%)
Solid Waste	3,318.0	0.6%	3,156.5	0.5%	(4.9%)
Miscellaneous	936.8	0.2%	737.6	0.1%	(21.3%)
Oil	2,207.7	0.4%	4,337.1	0.7%	96.5%
Heavy Oil	1,844.8	0.3%	4,122.7	0.7%	123.5%
Light Oil	334.3	0.1%	201.3	0.0%	(39.8%)
Diesel	15.9	0.0%	8.2	0.0%	(48.2%)
Kerosene	12.7	0.0%	4.9	0.0%	(61.8%)
Jet Oil	0.1	0.0%	0.0	0.0%	(29.1%)
Solar	37.9	0.0%	192.7	0.0%	408.7%
Battery	0.2	0.0%	0.2	0.0%	15.6%
Total	582,633.3	100.0%	602,560.9	100.0%	3.4%

Table 2-3 PJM Generation (By fuel source (GWh)): January through September 2011 and 2012; excluding ATSI and DEOK zones[9] (See 2011 SOM, Table 2-2)

	Jan-Sep 2011		Jan-Sep 2012		
	GWh	Percent	GWh	Percent	Change in Output
Coal	279,501.2	48.0%	226,139.4	39.8%	(19.1%)
Standard Coal	270,273.8	46.4%	218,805.8	38.5%	(18.4%)
Waste Coal	9,227.4	1.6%	7,333.6	1.3%	(0.7%)
Nuclear	195,196.7	33.5%	198,293.7	34.9%	1.6%
Gas	82,130.5	14.1%	116,771.4	20.5%	42.2%
Natural Gas	80,774.5	13.9%	115,161.1	20.3%	42.6%
Landfill Gas	1,355.9	0.2%	1,609.9	0.3%	18.7%
Biomass Gas	0.1	0.0%	0.4	0.0%	175.0%
Hydroelectric	11,379.8	2.0%	9,768.1	1.7%	(14.2%)
Wind	7,924.5	1.4%	8,944.7	1.6%	12.9%
Waste	4,254.8	0.7%	3,894.1	0.7%	(8.5%)
Solid Waste	3,318.0	0.6%	3,156.5	0.6%	(4.9%)
Miscellaneous	936.8	0.2%	737.6	0.1%	(21.3%)
Oil	2,207.7	0.4%	4,334.0	0.8%	96.3%
Heavy Oil	1,844.8	0.3%	4,122.7	0.7%	123.5%
Light Oil	334.3	0.1%	198.9	0.0%	(40.5%)
Diesel	15.9	0.0%	7.5	0.0%	(52.8%)
Kerosene	12.7	0.0%	4.9	0.0%	(61.8%)
Jet Oil	0.1	0.0%	0.0	0.0%	(29.1%)
Solar	37.9	0.0%	192.7	0.0%	408.7%
Battery	0.2	0.0%	0.2	0.0%	15.6%
Total	582,633.3	100.0%	568,338.3	100.0%	(2.5%)

Generator Offers

The generator offers are categorized by dispatchable and self-scheduled MW and are shown in Table 2-4 and Table 2-5.[10,11] Table 2-4 shows the average hourly distribution of MW for dispatchable units by offer prices for the first nine months of 2012. Table 2-5 shows the average hourly distribution of MW for self-scheduled units by offer prices for the first nine months of 2012. Of the dispatchable MW offered by combustion turbines (CT), 25.8 percent were dispatchable at an offered range of $600 to $800. Only wind and solar units have negative offer prices. Of all the MW offered, 74.1 percent are offered in

8 Hydroelectric generation is total generation output and does not net out the MWh used at pumped storage facilities to pump water. Battery generation is total generation output and does not net out MWh absorbed.

9 ATSI Zone is included only for the months of June through September 2011 and June through September 2012.

10 Each range in the tables is greater than or equal to the lower value and less than the higher value.

11 The unit type battery is not included in these tables because batteries do not make energy offers.

the $0 to $200 range, 42 percent are dispatchable and 32.1 percent are self scheduled.

Table 2-4 Distribution of MW for dispatchable unit offer prices: January through September of 2012 (See 2011 SOM, Table 2-3)

	Dispatchable (Range)						
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Total
CC	0.0%	60.6%	11.7%	3.0%	4.6%	1.2%	81.1%
CT	0.0%	44.1%	15.5%	10.8%	25.8%	3.3%	99.5%
Diesel	0.0%	7.6%	56.9%	7.0%	1.2%	0.8%	73.5%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	10.0%	0.0%	0.0%	0.0%	0.0%	10.0%
Pumped Storage	0.0%	52.7%	0.0%	0.0%	0.0%	0.0%	52.7%
Solar	0.0%	56.9%	0.0%	0.0%	0.0%	0.0%	56.9%
Steam	0.0%	49.5%	11.2%	0.5%	0.1%	0.1%	61.4%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	23.8%	28.1%	0.0%	0.0%	0.0%	0.0%	51.8%
All Dispatchable Offers	0.5%	42.0%	9.8%	2.9%	6.1%	0.9%	62.1%

Table 2-5 Distribution of MW for self-scheduled unit offer prices: January through September of 2012 (See 2011 SOM, Table 2-3)

	Self-Scheduled (Range)						
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Total
CC	0.0%	17.9%	0.8%	0.0%	0.0%	0.2%	18.9%
CT	0.0%	0.4%	0.0%	0.0%	0.0%	0.1%	0.5%
Diesel	0.0%	26.3%	0.1%	0.0%	0.0%	0.2%	26.5%
Hydro	0.0%	99.0%	0.0%	0.0%	0.0%	1.0%	100.0%
Nuclear	0.0%	90.0%	0.0%	0.0%	0.0%	0.0%	90.0%
Pumped Storage	0.0%	47.3%	0.0%	0.0%	0.0%	0.0%	47.3%
Solar	20.5%	22.6%	0.0%	0.0%	0.0%	0.0%	43.1%
Steam	0.0%	26.0%	12.1%	0.0%	0.4%	0.1%	38.6%
Transaction	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	10.0%	38.2%	0.0%	0.0%	0.0%	0.0%	48.2%
All Self-Scheduled Offers	0.2%	32.1%	5.3%	0.0%	0.2%	0.1%	37.9%

Demand

The PJM system peak load for the first nine months of 2012 was 154,344 MW in the HE 1700 on July 17, 2012, which was 3,672 MW, or 2.3 percent, lower than the PJM peak load for the first nine months of 2011, which was 158,016 MW in the HE 1700 on July 21, 2011. The DEOK Transmission Zone accounted for 5,360 MW in the peak hour of the first nine months of 2012. The peak load excluding the DEOK Transmission Zone was 148,984 MW, also occurring on July 17, 2012, HE 1700, a decrease of 9,032 MW, or 5.7 percent, from the first nine months 2011 peak load.

Table 2-6 shows the coincident peak loads for the first nine months of years 2003 through 2012.

Table 2-6 Actual[12,13] PJM footprint peak loads: January through September of 2003 to 2012 (See 2011 SOM, Table 2-4)

(Jan - Sep)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
2003	Fri, August 22	16	61,499	NA	NA
2004	Tue, August 03	17	77,887	16,387	26.6%
2005	Tue, July 26	16	133,761	55,875	71.7%
2006	Wed, August 02	17	144,644	10,883	8.1%
2007	Wed, August 08	16	139,428	(5,216)	(3.6%)
2008	Mon, June 09	17	130,100	(9,328)	(6.7%)
2009	Mon, August 10	17	126,798	(3,302)	(2.5%)
2010	Tue, July 06	17	136,460	9,662	7.6%
2011	Thu, July 21	17	158,016	21,556	15.8%
2012 (with DEOK)	Tue, July 17	17	154,344	(3,672)	(2.3%)
2012 (without DEOK)	Tue, July 17	17	148,984	(9,032)	(5.7%)

Figure 2-2 shows the peak loads for the first nine months of years 2003 through 2012.

Figure 2-2 PJM[14] footprint first nine months peak loads: 2003 to 2012 (See 2011 SOM, Figure 2-2)

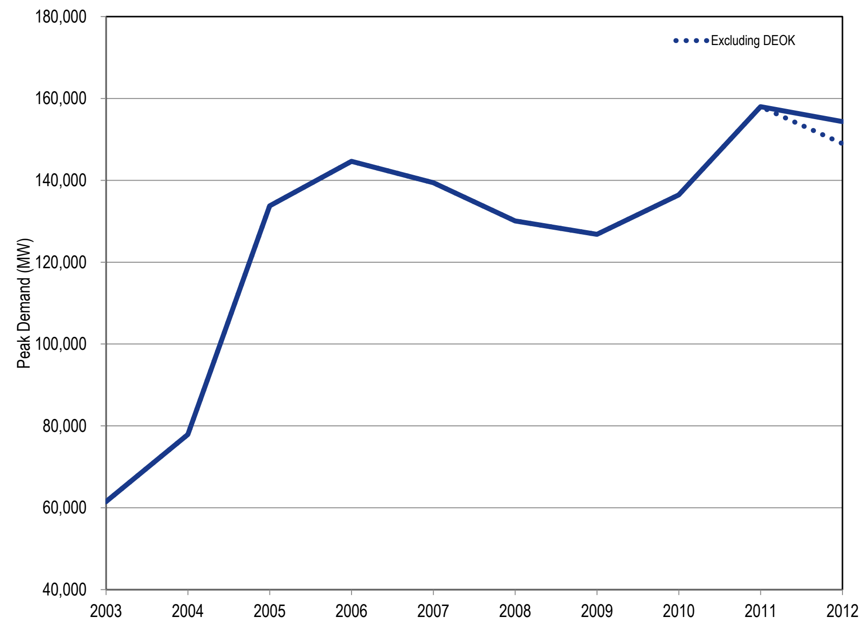


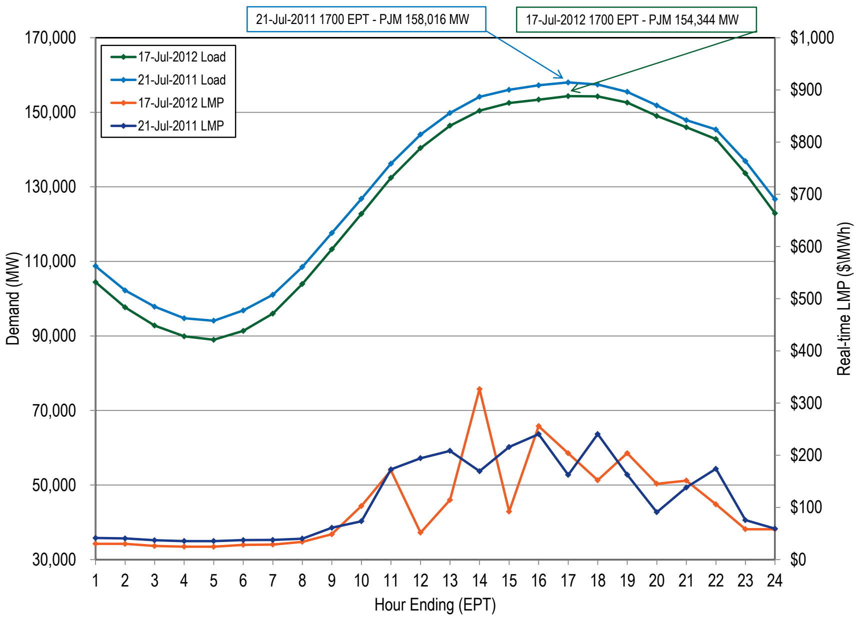
Figure 2-3 compares the peak load days in the first nine months of 2011 and 2012. In every hour on July 21, 2011, the average hourly real-time load was higher than the average hourly real-time load on July 17, 2012. The average hourly real-time LMP peaked at $326.72 on July 17, 2012 and peaked at $240.42 on July 21, 2011.

12 Peak loads shown are eMTR load. See the *MMU Technical Reference* for the PJM Markets, at "Load Definitions" for detailed definitions of load.

13 The ATSI Transmission Zone was excluded from this comparison and similar comparisons for the first 5 months of 2012 because it did not join PJM until June 1, 2011. The DEOK Transmission Zone was excluded from this comparison for all of the months of 2012 because it did not join PJM until January 1, 2012.

14 For additional information on the "PJM Integration Period", see the *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

Figure 2-3 PJM peak-load comparison: Tuesday, July 17, 2012, and Thursday, July 21, 2011 (See 2011 SOM, Figure 2-3)



Market Concentration

Analyses of supply curve segments of the PJM Energy Market for the first nine months of 2012 indicate moderate concentration in the base load segment, but high concentration in the intermediate and peaking segments.[15] 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 generally effective in preventing the exercise of market power in these areas during the first nine months of 2012. 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.

Hourly PJM Energy Market HHIs were calculated based on the real-time energy output of generators, adjusted for hourly net imports by owner (Table 2-7).

Hourly Energy Market HHIs by supply curve segment were calculated based on hourly Energy Market shares, unadjusted for imports.

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during the first nine months of 2012 was moderately concentrated (Table 2-7).

Table 2-7 PJM hourly Energy Market HHI: January through September 2011[16] and 2012 (See 2011 SOM, Table 2-5)

	Hourly Market HHI (Jan - Sep, 2011)	Hourly Market HHI (Jan - Sep, 2012)
Average	1200	1234
Minimum	889	927
Maximum	1564	1657
Highest market share (One hour)	30%	32%
Average of the highest hourly market share	21%	23%
# Hours	6,551	6,575
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 2-8 includes 2012 HHI values by supply curve segment, including base, intermediate and peaking plants.

15 A unit is classified as base load if it runs for more than 50 percent of the total hours, as intermediate if it runs for less than 50 percent but greater than 10 percent of the total hours, and as peak if it runs for less than 10 percent of the total hours.

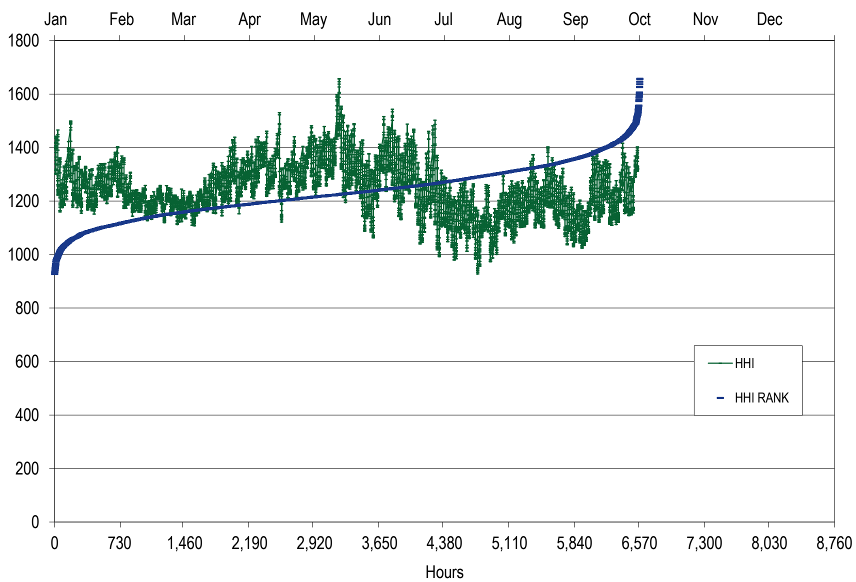
16 This analysis includes all hours in the first nine months of 2012, regardless of congestion.

Table 2-8 PJM hourly Energy Market HHI (By supply segment): January through September 2011 and 2012 (See 2011 SOM, Table 2-6)

	Jan - Sep, 2011			Jan - Sep, 2012		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	1035	1219	1529	1082	1268	1691
Intermediate	842	2801	9467	849	1919	8301
Peak	613	5720	10000	619	5699	10000

Figure 2-4 presents the 2012 hourly HHI values in chronological order and an HHI duration curve.

Figure 2-4 PJM hourly Energy Market HHI: January through September 2012 (See 2011 SOM, Figure 2-4)



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.

Levels of offer capping have historically been low in PJM, as shown in Table 2-9.

Table 2-9 Offer-capping statistics: January through September from 2008 to 2012 (See 2011 SOM, Table 2-7)

	Real Time		Day Ahead	
(Jan - Sep)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2008	1.0%	0.2%	0.2%	0.0%
2009	0.5%	0.1%	0.1%	0.0%
2010	1.2%	0.3%	0.3%	0.1%
2011	0.9%	0.3%	0.1%	0.0%
2012	1.6%	1.0%	0.2%	0.2%

Table 2-10 presents data on the frequency with which units were offer capped in the first nine months of 2011 and 2012.

Table 2-10 Real-time offer-capped unit statistics: January through September 2012 (See 2011 SOM, Table 2-8)

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	(Jan - Sep)	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2012	0	0	1	0	1	1
	2011	0	0	0	4	9	5
80% and < 90%	2012	0	2	0	0	2	4
	2011	0	0	1	1	4	9
75% and < 80%	2012	0	0	0	0	2	0
	2011	0	0	0	0	3	3
70% and < 75%	2012	1	0	0	0	0	4
	2011	0	0	0	0	2	6
60% and < 70%	2012	1	0	0	1	1	8
	2011	0	1	0	1	1	23
50% and < 60%	2012	5	0	1	0	1	9
	2011	0	0	0	1	10	24
25% and < 50%	2012	12	1	2	1	8	42
	2011	1	0	0	3	14	77
10% and < 25%	2012	1	2	0	5	3	55
	2011	5	1	1	1	1	51

Table 2-10 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.

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 the first nine months of 2012, the AEP, AP, ATSI, BGE, ComEd, DEOK, DLCO, Dominion, DPL, Met-Ed, Pepco and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 75 or more hours. Actual competitive conditions in the Real-Time Energy Market associated with each of these frequently binding constraints were analyzed using the three pivotal supplier results for the first nine months of 2012.[17] The AECO, DAY, JCPL, PECO, PENELEC, PPL and RECO Control Zones were not affected by constraints binding for 75 or more hours.

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, 2012, through September 30, 2012. The three pivotal supplier test is applied every time the system solution indicates that out of merit resources are needed to relieve a transmission constraint. Only uncommitted resources, which would be started to relieve the transmission constraint, are subject to offer capping. Already committed units that can provide incremental relief cannot be offer capped. The results of the TPS test are shown for tests that could have resulted in offer capping and tests that resulted in offer capping.

Table 2-11 provides the number of tests applied, the number and percentage of tests with one or more passing owners, and the number and percentage of tests with one or more failing owners.

17 See the *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for a more detailed explanation of the three pivotal supplier test.

Table 2-11 Three pivotal supplier results summary for regional constraints: January through September 2012 (See 2011 SOM, Table 2-9)

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	2,058	489	24%	1,805	88%
	Off Peak	1,021	525	51%	715	70%
AEP-DOM	Peak	824	32	4%	815	99%
	Off Peak	437	24	5%	429	98%
AP South	Peak	3,167	405	13%	3,045	96%
	Off Peak	1,525	249	16%	1,456	95%
Bedington - Black Oak	Peak	1,074	169	16%	1,007	94%
	Off Peak	282	38	13%	270	96%
Central	Peak	27	6	22%	26	96%
	Off Peak	NA	NA	NA	NA	NA
Eastern	Peak	160	69	43%	107	67%
	Off Peak	NA	NA	NA	NA	NA
Western	Peak	528	114	22%	470	89%
	Off Peak	39	14	36%	31	79%

Table 2-12 shows the average constraint relief required on the constraint, the average effective supply available to relieve the constraint, the average number of owners with available relief in the defined market and the average number of owners passing and failing for the regional 500 kV constraints.

Table 2-12 Three pivotal supplier test details for regional constraints: January through September 2012 (See 2011 SOM, Table 2-10)

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	332	484	16	4	13
	Off Peak	247	478	16	8	9
AEP-DOM	Peak	276	373	8	0	8
	Off Peak	214	353	9	0	8
AP South	Peak	376	557	11	1	10
	Off Peak	364	583	12	1	10
Bedington - Black Oak	Peak	93	133	10	1	9
	Off Peak	114	102	9	1	8
Central	Peak	347	451	15	2	13
	Off Peak	NA	NA	NA	NA	NA
Eastern	Peak	426	656	15	8	7
	Off Peak	NA	NA	NA	NA	NA
Western	Peak	754	837	17	4	13
	Off Peak	849	976	15	5	10

Table 2-13 provides, for the identified seven regional constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping uncommitted units.

Table 2-13 Summary of three pivotal supplier tests applied for regional constraints: January through September 2012 (See 2011 SOM, Table 2-11)

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
5004/5005 Interface	Peak	2,058	104	5%	25	1%	24%
	Off Peak	1,021	21	2%	3	0%	14%
AEP-DOM	Peak	824	49	6%	26	3%	53%
	Off Peak	437	22	5%	18	4%	82%
AP South	Peak	3,167	77	2%	15	0%	19%
	Off Peak	1,525	24	2%	5	0%	21%
Bedington - Black Oak	Peak	1,074	36	3%	3	0%	8%
	Off Peak	282	8	3%	0	0%	0%
Central	Peak	27	0	0%	0	0%	0%
	Off Peak	NA	NA	NA	NA	NA	NA
Eastern	Peak	160	9	6%	4	3%	44%
	Off Peak	NA	NA	NA	NA	NA	NA
Western	Peak	528	47	9%	11	2%	23%
	Off Peak	39	6	15%	0	0%	0%

Ownership of Marginal Resources

Table 2-14 shows the contribution to PJM real-time, annual, load-weighted LMP by individual marginal resource owner.[18] The contribution of each marginal resource to price at each load bus is calculated for January through September, 2012, and summed by the company that offers the marginal resource into the Real-Time Energy Market. The results show that, during the first nine months of 2012, the offers of one company contributed 21 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 51 percent of the real-time, load-weighted, average PJM system LMP.

Table 2-14 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): January through September 2012 (See 2011 SOM, Table 2-12)

Company	Percent of Price
1	21%
2	13%
3	8%
4	8%
5	8%
6	6%
7	6%
8	5%
9	4%
Other (54 companies)	20%

Table 2-15 shows the contribution to PJM day-ahead, load-weighted LMP by individual marginal resource owner.[19] The contribution of each marginal resource to price at each load bus is calculated for the January through

18 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

19 See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

September, 2012, period and summed by the company that offers the marginal resource into the Day-Ahead Energy Market.

Table 2-15 Marginal unit contribution to PJM day-ahead, load-weighted LMP (By parent company): January through September, 2012 (See 2011 SOM, Table 2-13)

Company	Percent of Price
1	15%
2	11%
3	7%
4	6%
5	5%
6	5%
7	5%
8	4%
9	4%
Other (132 companies)	40%

Type of Marginal Resources

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources generally determine system LMPs, based on their offers. Marginal resource designation is not limited to physical resources, particularly in the Day-Ahead Market. INC offers, DEC bids and up-to congestion transactions are dispatchable injections and withdrawals in the Day-Ahead Market that can set price via their offers and bids.

Table 2-16 shows the type of fuel used by marginal resources in the Real-Time Energy Market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first nine months of 2012, coal units were 58 percent and natural gas units were 31 percent of the total marginal resources.

Table 2-16 Type of fuel used (By real-time marginal units): January through September, 2012 (See 2011 SOM, Table 2-14)

Fuel Type	Jan - Sep, 2012
Coal	58%
Gas	31%
Municipal Waste	0%
Oil	6%
Other	1%
Uranium	0%
Wind	4%

Table 2-17 shows the type, and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first nine months of 2012, Up-to Congestion transactions were 87 percent of the total marginal resources.

Table 2-17 Day-ahead marginal resources by type/fuel: January through September, 2012 (See 2011 SOM, Table 2-15)

Type/Fuel	Jan - Sep, 2012
Up-to Congestion Transaction	87%
DEC	5%
INC	4%
Coal	2%
Gas	1%
Dispatchable Transaction	0%
Price Sensitive Demand	0%
Oil	0%
Wind	0%
Diesel	0%
Municipal Waste	0%
Total	100%

Market Conduct: Markup

The markup index is a summary measure of participant offer behavior or conduct for individual marginal units. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[20] 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. This index calculation

20 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.

method weights the impact of individual unit markups using sensitivity factors, to reflect their relative importance in the system dispatch solution. The markup index does not measure the impact of unit markup on total LMP.

Real-Time Mark Up Conduct

Table 2-18 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category. A unit is assigned to a price category for each dispatch solution associated with the interval in which it was marginal, based on its offer price at that time. The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point.

Table 2-18 Average, real-time marginal unit markup index (By offer price category): January through September (See 2011 SOM, Table 2-16)

Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.08)	($3.01)	30.8%
$25 to $50	(0.04)	($2.07)	48.6%
$50 to $75	0.06	$2.27	4.4%
$75 to $100	0.33	$29.22	0.6%
$100 to $125	0.21	$21.35	0.6%
$125 to $150	0.17	$23.44	0.3%
>= $150	0.04	$9.65	5.5%

Day-Ahead Mark Up Conduct

Table 2-19 shows the average markup index of marginal units in Day-Ahead Energy 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 2-19 Average marginal unit markup index (By offer price category): January through September, 2012 (See 2011 SOM, Table 2-17)

Offer Price Category	Average Markup Index	Average Dollar Markup	Freqency
< $25	(0.09)	($3.00)	32.2%
$25 to $50	(0.05)	($2.58)	64.2%
$50 to $75	0.09	$4.13	3.1%
$75 to $100	0.45	$36.25	0.2%
$100 to $125	0.00	$0.00	0.0%
$125 to $150	0.04	$4.99	0.1%
>= $150	0.03	$4.84	0.2%

Market Performance

Markup

The markup index, which is a measure of participant conduct for individual marginal units, does not measure the impact of participant 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.[21]

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 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

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

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

Markup Component of Real-Time Price by Fuel, Unit Type

The markup component of price is the difference between the system price, when the system price is determined by marginal units with price-based offers, and the system price, based on the cost-based offers of those marginal units.

Table 2-20 shows the annual average unit markup component of LMP for marginal units, by unit type and primary fuel. The markup component of LMP is a measure of the impact of the markups of marginal units shown in Table 2-18 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 2-18.

Table 2-20 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type[22]: January through September 2012 (See 2011 SOM, Table 2-18)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($1.60)	343.2%
Gas	CC	$0.89	(191.3%)
Gas	CT	$0.32	(68.9%)
Gas	Diesel	$0.03	(6.6%)
Gas	Steam	($0.03)	7.1%
Municipal Waste	Diesel	$0.00	0.0%
Municipal Waste	Steam	$0.02	(5.0%)
Oil	CT	$0.01	(2.9%)
Oil	Diesel	$0.01	(1.7%)
Oil	Steam	($0.12)	24.8%
Other	Solar	$0.00	(0.0%)
Uranium	Steam	$0.00	0.0%
Wind	Wind	($0.01)	1.3%
Total		($0.47)	100.0%

Markup Component of Real-Time System Price

Table 2-21 shows the markup component of average prices and of average monthly on-peak and off-peak prices. In the first nine months of 2012, -$0.47 per MWh of the PJM real-time, load-weighted average LMP was attributable to markup. In first nine months of 2012, the markup component of LMP was -$2.27 per MWh off peak and $1.22 per MWh on peak.

Table 2-21 Monthly markup components of real-time load-weighted LMP: January through September 2012 (See 2011 SOM, Table 2-19)

	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($2.49)	($2.53)	($2.46)
Feb	($1.95)	($2.74)	($1.19)
Mar	($1.26)	($1.85)	($0.72)
Apr	($2.56)	($3.38)	($1.78)
May	$0.25	($2.63)	$2.85
Jun	($1.67)	($2.73)	($0.73)
Jul	$4.21	($1.55)	$9.66
Aug	($0.00)	($1.90)	$1.49
Sep	($0.14)	($1.40)	$1.24
Total	($0.47)	($2.27)	$1.22

22 The Unit Type Diesel refers to power generation using reciprocating internal combustion engines. Such Diesel units can use a variety of fuel types including diesel, natural gas, oil and municipal waste.

Markup Component of Real-Time Zonal Prices

The annual average real-time price component of unit markup is shown for each zone in Table 2-22. The smallest zonal all hours average markup component for the first nine months of 2012 was in the PPL Control Zone, -$0.79 per MWh, while the highest all hours' average zonal markup component for the first nine months of 2012 was in the Pepco Control Zone, $0.21 per MWh. Off peak, the smallest average zonal markup for the first nine months of 2012 was in the ATSI Control Zone, -$2.58 per MWh, while the highest annual average zonal markup was in the BGE Control Zone, -$1.74 per MWh. On peak, the smallest annual average zonal markup was in the PPL Control Zone, $0.71 per MWh, while the highest annual average zonal markup was in the Pepco Control Zone, $2.11 per MWh.

Table 2-22 Average real-time zonal markup component: January through September 2012 (See 2011 SOM, Table 2-20)

	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	($0.27)	($2.03)	$1.42
AEP	($0.78)	($2.36)	$0.75
AP	($0.57)	($2.36)	$1.13
ATSI	($0.77)	($2.58)	$0.92
BGE	($0.12)	($1.74)	$1.42
ComEd	($0.54)	($2.35)	$1.13
DAY	($0.74)	($2.49)	$0.88
DEOK	($0.68)	($2.39)	$0.94
Dominion	$0.06	($1.89)	$1.90
DPL	($0.57)	($2.49)	$1.27
DLCO	($0.48)	($2.42)	$1.34
JCPL	$0.02	($2.23)	$2.05
Met-Ed	($0.71)	($2.44)	$0.88
PECO	($0.42)	($2.12)	$1.17
PENELEC	($0.75)	($2.58)	$0.95
Pepco	$0.21	($1.86)	$2.11
PPL	($0.79)	($2.40)	$0.71
PSEG	($0.27)	($2.30)	$1.58
RECO	($0.04)	($2.35)	$1.93

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 2-23 shows the average markup component of observed prices when the PJM system LMP was in the identified price range.

Table 2-23 Average real-time markup component (By LMP category): January through September 2012 (See 2011 SOM, Table 2-21)

LMP Category	Average Markup Component	Frequency
< $25	($0.74)	27.9%
$25 to $50	($1.52)	61.7%
$50 to $75	$0.47	4.4%
$75 to $100	$0.33	1.4%
$100 to $125	$0.20	0.7%
$125 to $150	$0.17	0.3%
>= $150	$0.63	0.6%

Day-Ahead Markup

Markup Component of Day-Ahead Price 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 2-24.

Table 2-24 Markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through September, 2012 (See 2011 SOM, Table 2-22)

Fuel Type	Unit Type	Markup Component of LMP	Percent
Coal	Steam	($1.68)	89.9%
Diesel	Diesel	$0.00	0.0%
Gas	CT	$0.09	(4.6%)
Gas	Diesel	$0.00	0.0%
Gas	Steam	($0.20)	10.5%
Municipal Waste	Steam	($0.00)	0.1%
Oil	Steam	($0.08)	4.0%
Wind	Wind	$0.00	0.0%
Total		($1.87)	100.0%

Markup Component of Day-Ahead System Price

The markup component of day-ahead price is the difference between the day-ahead system price, when the day-ahead system price is determined by marginal units with price-based offers, and the day-ahead system price, based on the cost-based offers of those marginal units.

Table 2-25 shows the markup component of average prices and of average monthly on-peak and off-peak prices.

Table 2-25 Monthly markup components of day-ahead, load-weighted LMP: January through September, 2012 (See 2011 SOM, Table 2-23)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($2.77)	($2.22)	($3.30)
Feb	($3.04)	($3.66)	($2.39)
Mar	($2.29)	($2.00)	($2.61)
Apr	($2.67)	($2.36)	($2.99)
May	($1.51)	($1.11)	($1.95)
Jun	($1.94)	($1.11)	($2.89)
Jul	$0.41	$2.73	($2.07)
Aug	($1.86)	($0.96)	($3.04)
Sep	($1.75)	($1.37)	($2.11)
Total	($1.87)	($1.19)	($2.59)

Markup Component of Day-Ahead Zonal Prices

The annual average price component of unit markup is shown for each zone in Table 2-26.

Table 2-26 Day-ahead, average, zonal markup component: January through September, 2012 (See 2011 SOM, Table 2-24)

	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($1.49)	($0.57)	($2.49)
AEP	($1.95)	($1.35)	($2.58)
AP	($1.81)	($1.34)	($2.32)
ATSI	($1.99)	($1.42)	($2.62)
BGE	($1.86)	($1.22)	($2.55)
ComEd	($1.83)	($1.30)	($2.41)
DAY	($1.89)	($1.24)	($2.60)
DEOK	($1.83)	($1.22)	($2.48)
DLCO	($1.76)	($1.11)	($2.48)
Dominion	($1.80)	($1.07)	($2.58)
DPL	($1.61)	($0.77)	($2.50)
JCPL	($1.45)	($0.55)	($2.48)
Met-Ed	($1.82)	($1.08)	($2.64)
PECO	($1.68)	($0.97)	($2.45)
PENELEC	($2.14)	($1.68)	($2.63)
Pepco	($1.89)	($1.32)	($2.49)
PPL	($2.07)	($1.49)	($2.72)
PSEG	($1.54)	($0.53)	($2.69)
RECO	($1.47)	($0.52)	($2.61)

Markup by Day-Ahead System Price Levels

The annual average markup component of the identified price range and its frequency are shown in Table 2-27.

Table 2-27 shows the average markup component of observed price when the PJM day-ahead, system LMP was in the identified price range.

Table 2-27 Average, day-ahead markup (By LMP category): January through September, 2012 (See 2011 SOM, Table 2-25)

LMP Category	Average Markup Component	Frequency
< $25	($3.42)	25%
$25 to $50	($2.77)	71%
$50 to $75	$2.51	3%
$75 to $100	$6.96	1%
$100 to $125	$18.93	0%
$125 to $150	$4.54	0%
>= $150	$19.06	0%

Frequently Mitigated Units and Associated Units

An FMU is a frequently mitigated unit. FMU designations were created to provide additional compensation as a form of scarcity pricing in 2005.[23] 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.[24] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.[25,26]

An AU, or associated unit, is a unit that is physically, electrically and economically identical to an FMU, but does not qualify for the same FMU adder. 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. The AU designation was implemented 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.

23 110 FERC ¶ 61,053 (2005).
24 OA, Schedule 1 § 6.4.2.
25 114 FERC ¶ 61, 076 (2006).
26 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).

FMUs and AUs are designated monthly, where a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[27]

Table 2-28 shows the number of FMUs and AUs in the first nine months of 2011 and 2012. For example, in June 2012, there were 22 FMUs and AUs in Tier 1, 13 FMUs and AUs in Tier 2, and 48 FMUs and AUs in Tier 3.

Table 2-28 Number of frequently mitigated units and associated units (By month): January through September, 2012 (See 2011 SOM, Table 2-26)

	FMUs and AUs							
	2011				2012			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	46	22	66	134	26	21	52	99
February	34	43	60	137	26	22	47	95
March	30	46	66	142	25	17	47	89
April	34	45	62	141	23	17	46	86
May	37	48	59	144	23	14	47	84
June	31	50	61	142	22	13	48	83
July	45	32	43	120	25	11	50	86
August	33	14	44	91	25	23	43	91
September	18	19	55	92	17	6	33	56
October	31	24	53	108				
November	20	28	49	97				
December	20	26	51	97				

Figure 2-5 shows the total number of FMUs and AUs that qualified for an adder since the inception of the business rule in February, 2006.

27 OA, Schedule 1 § 6.4.2. In 2007, the FERC approved OA revisions to clarify the AU criteria.

Figure 2-5 Frequently mitigated units and associated units (By month): February, 2006 through September, 2012 (See 2011 SOM, Figure 2-5)

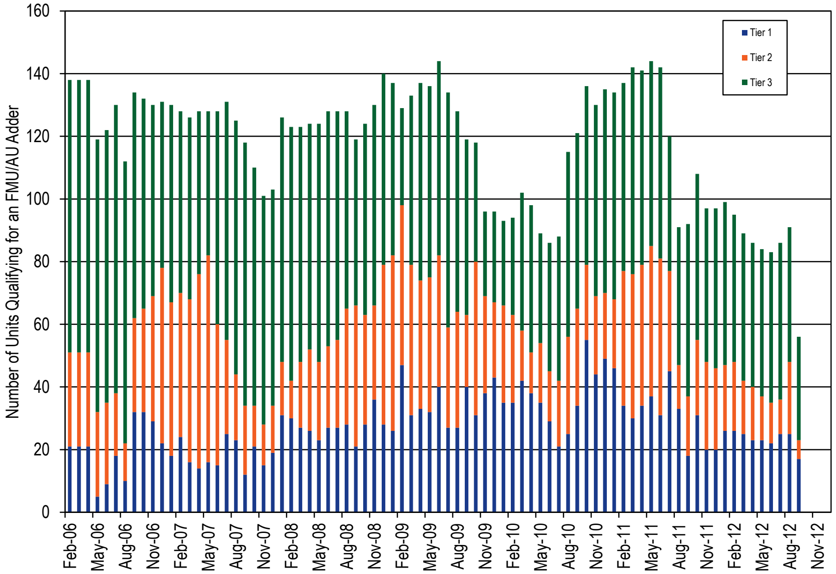


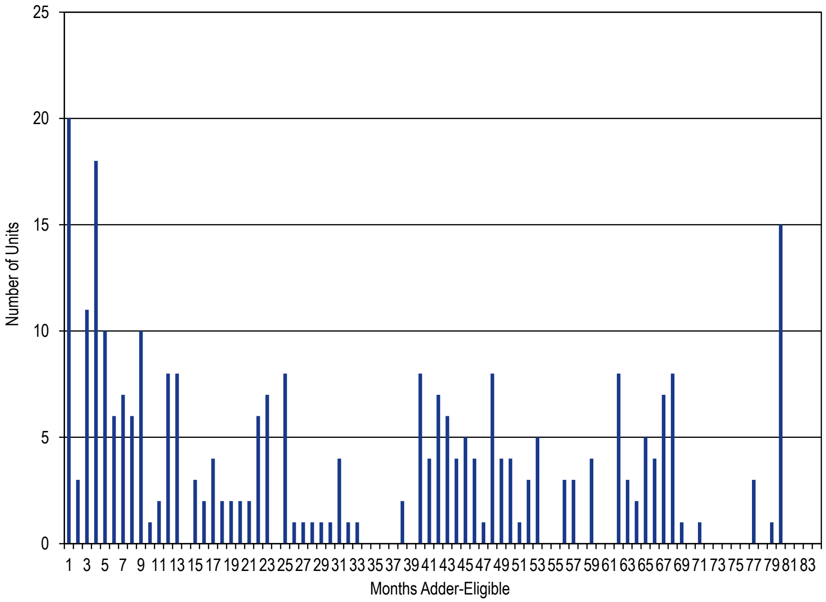
Table 2-29 shows the number of months FMUs and AUs that were eligible for any adder (Tier 1, Tier 2 or Tier 3) during the first nine months of 2011 and 2012. Of the 131 units eligible in at least one month during the first nine months of 2012, 44 units (33.6 percent) were FMUs or AUs for all nine months, and 26 (19.9 percent) qualified in only one month of 2012.

Table 2-29 Frequently mitigated units and associated units total months eligible: January through September, 2011 and 2012 (See 2011 SOM, Table 2-27)

Months Adder-Eligible	FMU & AU Count	
	2011	2012
1	20	26
2	5	11
3	7	5
4	2	9
5	8	2
6	30	2
7	26	14
8	20	18
9	58	44
Total	176	131

Figure 2-6 shows the number of months FMUs and AUs were eligible for any adder (Tier 1, Tier 2 or Tier 3) since the inception of FMUs effective February 1, 2006. From February 1, 2006, through September 30, 2012, there have been 293 unique units that have qualified for an FMU adder in at least one month. Of these 293 units, no unit qualified for an adder in all potential months. Fifteen units qualified in 80 of the 81 possible months, and 132 of the 293 units (45.1 percent) have qualified for an adder in more than half of the possible months.

Figure 2-6 Frequently mitigated units and associated units total months eligible: February, 2006 through September, 2012 (See 2011 SOM, Figure 2-6)



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

PJM average real-time load in the first nine months of 2012 increased by 5.9 percent from the nine six months of 2011, from 83,762 MW to 88,680 MW. The PJM average real-time load in the first nine months of 2012 would have decreased by 0.9 percent from the first nine months of 2011, from 83,762 MW to 86,680 MW, if the DEOK and ATSI Transmission Zones were excluded from the comparison for the months in 2011 when they were not part of PJM.[28]

PJM average day-ahead load, including DECs and up-to congestion transactions, in the first nine months of 2012 increased by 16.5 percent from the first nine months of 2011, from 113,724 MW to 132,494 MW. PJM average day-ahead load in the first nine months of 2012, including DECs and up-to congestion transactions, would have increased by 10.7 percent from the first nine months of 2011, from 113,724 MW 125,917 MW if the DEOK and ATSI Transmission Zones were excluded from the comparison for the months in 2011 when they were not part of PJM.

The day-ahead load growth was 179.7 percent higher than the real-time load growth because of the continued growth of up-to congestion transactions. If up-to congestion transactions had not grown in the first nine months of 2012 compared to the first nine months of 2011, the day-ahead load, including DECs and up-to congestion transactions, would have increased 1.8 percent instead of 16.5 percent. The day-ahead load growth would have been 69.5 percent lower than the real-time load growth.

Real-Time Load

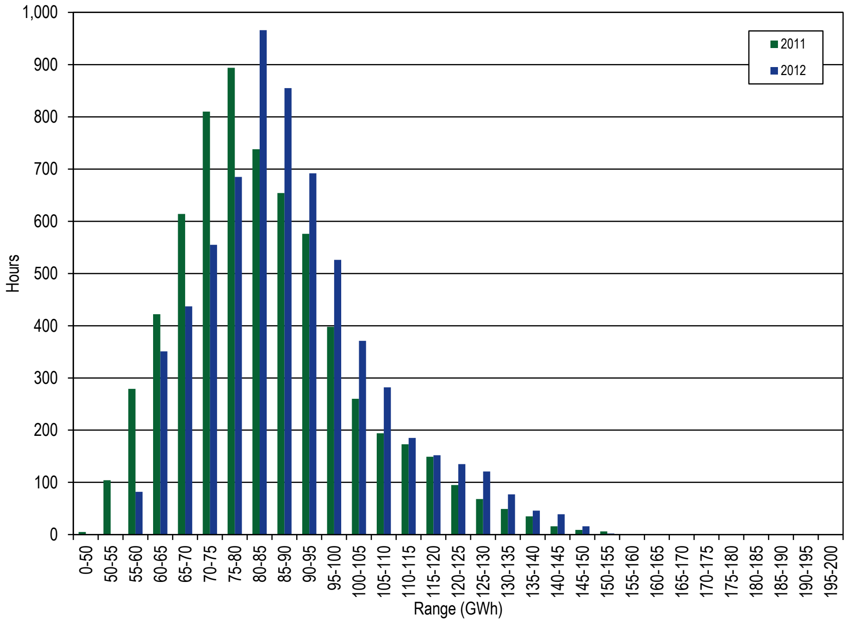
PJM Real-Time Load Duration

Figure 2-7 shows the hourly distribution of PJM real-time load for the first nine months of 2011 and 2012.[29]

28 The ATSI Transmission Zone was excluded from year to year comparisons for the first 5 months of 2012 because it did not join PJM until June 1, 2011. The DEOK Transmission Zone was excluded from this comparison for all of the months of 2012 because it did not join PJM until January 1, 2012.

29 All real-time load data in Section 2, "Energy Market," "Market Performance: Load and LMP" are based on PJM accounting load. See the *Technical Reference for PJM Markets*, Section 5, "Load Definitions," for detailed definitions of accounting load.

Figure 2-7 PJM real-time accounting load: January through September for years 2011 and 2012[30] (See 2011 SOM, Figure 2-7)



PJM Real-Time, Average Load

Table 2-30 presents summary real-time load statistics for the first nine months for the 15 year period 1998 to 2012. Before June 1, 2007, transmission losses were included in accounting load. After June 1, 2007, transmission losses were excluded from accounting load and losses were addressed through marginal loss pricing.[31]

Table 2-30 PJM real-time average hourly load: January through September for years 1998 through 2012[32] (See 2011 SOM, Table 2-28)

	PJM Real-Time Load (MWh)		Year-to-Year Change	
(Jan-Sep)	Average Load	Load Standard Deviation	Average Load	Load Standard Deviation
1998	29,112	5,780	NA	NA
1999	30,236	6,306	3.9%	9.1%
2000	30,266	5,765	0.1%	(8.6%)
2001	31,060	6,156	2.6%	6.8%
2002	35,715	8,688	15.0%	41.1%
2003	37,996	7,187	6.4%	(17.3%)
2004	45,294	10,512	19.2%	46.3%
2005	78,235	17,541	72.7%	66.9%
2006	80,717	15,568	3.2%	(11.2%)
2007	83,114	15,386	3.0%	(1.2%)
2008	80,611	14,389	(3.0%)	(6.5%)
2009	76,954	13,879	(4.5%)	(3.5%)
2010	81,068	16,209	5.3%	16.8%
2011	83,762	17,604	3.3%	8.6%
2012	88,680	17,432	5.9%	(1.0%)

30 Each range on the vertical axis includes the start value and excludes the end value.
31 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.

32 The version of this table in the *2012 Q1 State of the Market Report for PJM* incorrectly reported the standard deviation.

PJM Real-Time, Monthly Average Load

Figure 2-8 compares the real-time, monthly average hourly loads in the first nine months of 2012 with those in 2011.

Figure 2-8 PJM real-time monthly average hourly load: 2011 through September of 2012 (See 2011 SOM, Figure 2-8)

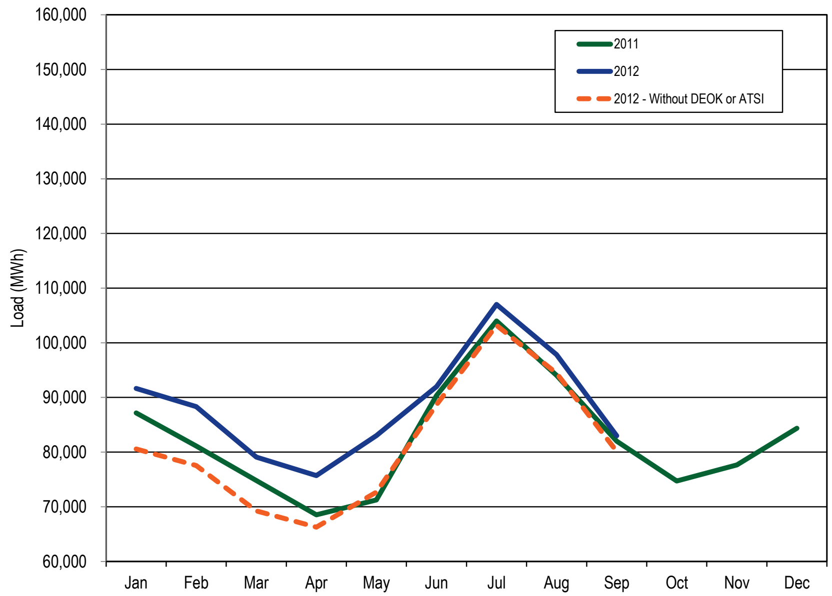


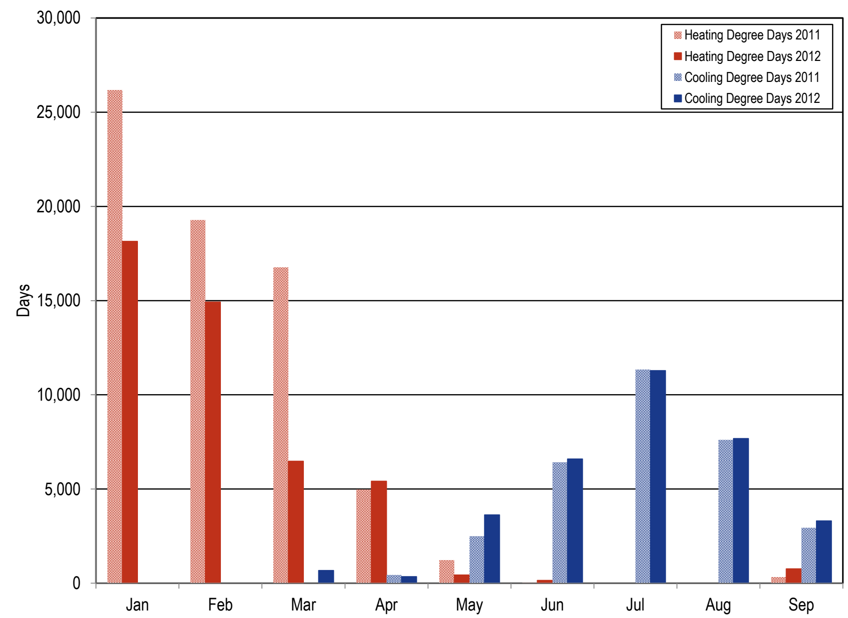
Table 2-31 shows the load weighted THI, WWP and average temperature for heating, cooling and shoulder seasons.[33]

Table 2-31 PJM annual Summer THI, Winter WWP and average temperature (Degrees F): cooling, heating and shoulder months of 2007 through June of 2012 (See 2011 SOM, Table 2-30)

	Summer THI	Winter WWP	Shoulder Average Temperature
2007	75.45	27.10	56.55
2008	75.35	27.52	54.10
2009	74.23	25.56	55.09
2010	77.36	24.28	57.22
2011	70.80	27.08	52.23
2012	70.22	36.06	58.40

Figure 2-9 compares the total PJM monthly heating and cooling degree days in the first nine months of 2012 with those in 2011.

Figure 2-9 PJM Heating and Cooling Degree Days for January through September for 2011 and 2012



33 The Summer THI is calculated by taking average of daily maximum THI in June, July, August and September. The Winter WWP is calculated by taking average of daily minimum WWP in January and February (December of each year is not included). 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 20 (June 28, 2012), Section 3, pp. 15-16. Load weighting using real-time zonal accounting load.

Day-Ahead Load

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

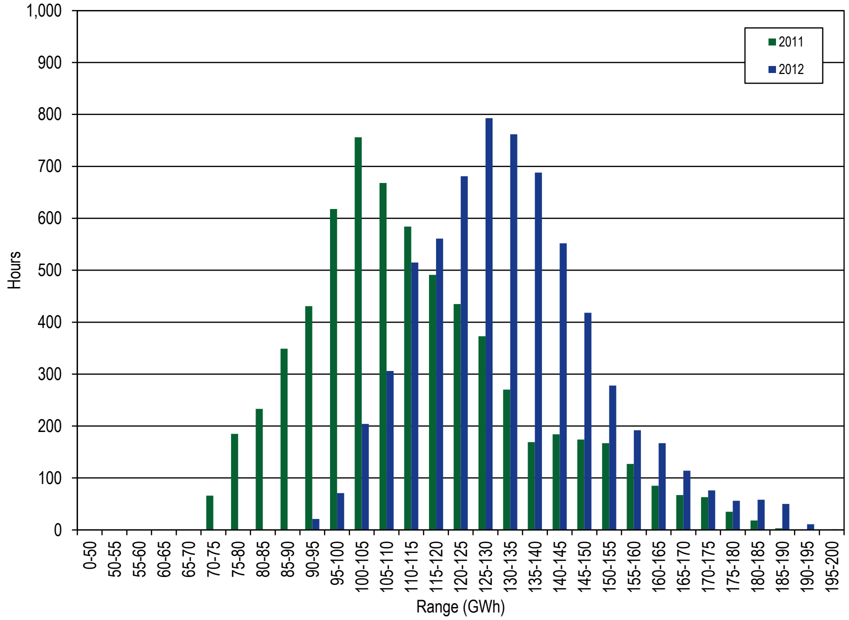
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** financial bid to purchase a defined MWh level of 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.
- **Up-to Congestion Transactions.** An up-to congestion transaction is a conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink.[34] In the PJM Day-Ahead Market, an up-to congestion transaction is evaluated and clears as a matched pair of injections and withdrawals analogous to a matched pair of INC offers and DEC bids. The DEC (sink) portion of each up-to congestion transaction is load in the Day-Ahead Energy Market. The INC (source) of each up-to congestion transaction is generation in the Day-Ahead Energy Market.

PJM day-ahead load is the hourly total of the four types of cleared demand bids.[35]

PJM Day-Ahead Load Duration

Figure 2-10 shows the hourly distribution of PJM day-ahead load for the first nine months of 2011 and 2012.

Figure 2-10 PJM day-ahead load: January through September for years 2011 and 2012 (See 2011 SOM, Figure 2-9)



34 Up-to congestion transactions are cleared based on the entire price difference between source and sink including the congestion and loss components of LMP.

35 Since an up-to congestion transaction is treated as analogous to a matched pair of INC offers and DEC bids, the DEC portion of the up-to congestion transaction contributes to the PJM day-ahead load, and the INC portion contributes to the PJM day-ahead generation.

PJM Day-Ahead, Average Load

Table 2-32 presents summary day-ahead load statistics for the first nine months of 12 year period 2001 to 2012.

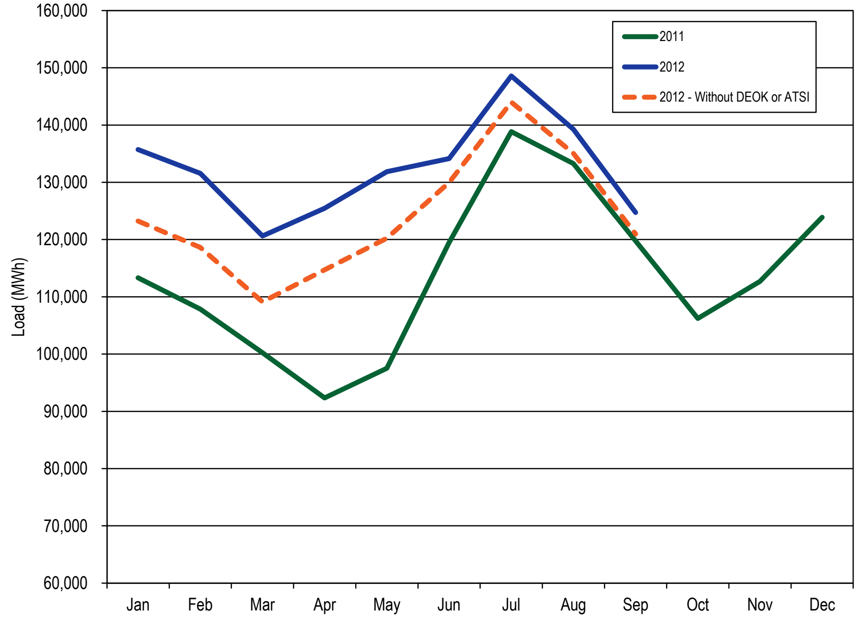
Table 2-32 PJM day-ahead average load: January through September for years 2001 through 2012[36] (See 2011 SOM, Table 2-31)

	PJM Day-Ahead Load (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
(Jan-Sep)	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load
2001	33,878	66	33,944	6,978	199	7,016	NA	NA	NA
2002	41,547	87	41,634	11,053	202	11,073	22.6%	32.2%	22.7%
2003	45,083	288	45,371	8,409	287	8,377	8.5%	230.4%	9.0%
2004	54,997	833	55,830	13,103	584	13,319	22.0%	189.4%	23.1%
2005	92,162	1,363	93,525	18,867	851	19,126	67.6%	63.6%	67.5%
2006	95,572	3,831	99,403	17,415	1,657	18,165	3.7%	181.1%	6.3%
2007	102,742	4,553	107,295	17,075	1,535	17,580	7.5%	18.8%	7.9%
2008	97,506	6,080	103,586	16,051	1,830	16,618	(5.1%)	33.6%	(3.5%)
2009	89,680	6,340	96,020	15,756	2,018	16,995	(8.0%)	4.3%	(7.3%)
2010	92,683	12,335	105,018	17,769	8,637	22,972	3.3%	94.6%	9.4%
2011	92,828	20,896	113,724	19,456	5,481	22,444	0.2%	69.4%	8.3%
2012	94,857	37,637	132,494	18,419	5,706	18,115	2.2%	80.1%	16.5%

PJM Day-Ahead, Monthly Average Load

Figure 2-11 compares the day-ahead, monthly average hourly loads of the first nine months of 2012 with those of 2011.

Figure 2-11 PJM day-ahead monthly average hourly load: 2011 through September of 2012 (See 2011 SOM, Figure 2-10)



Real-Time and Day-Ahead Load

Table 2-33 presents summary statistics for the first nine months of 2011 and 2012 day-ahead and real-time loads.

36 The version of this table in the *2012 State of the Market Report for PJM: January through March* incorrectly reported the standard deviation.

Table 2-33 Cleared day-ahead and real-time load (MWh): January through September for years 2011 and 2012 (See 2011 SOM, Table 2-32)

		Day Ahead					Real Time	Average Difference	
	(Jan-Sep)	Cleared Fixed Demand	Cleared Price Sensitive	Cleared DEC Bids	Cleared Up-to Congestion	Total Load	Total Load	Total Load	Total Load Minus Cleared DEC Bids Minus Up-to Congestion
Average	2011	80,729	864	11,235	20,896	113,724	83,762	29,962	(2,169)
	2012	85,748	756	8,354	37,637	132,494	88,680	43,815	(2,176)
Median	2011	77,364	859	10,959	19,698	109,755	81,027	28,728	(1,929)
	2012	83,361	725	8,019	36,844	130,970	86,116	44,854	(9)
Standard Deviation	2011	17,424	192	2,578	5,481	22,444	17,604	4,840	(3,219)
	2012	17,044	142	1,856	5,706	18,115	17,432	682	(6,880)
Peak Average	2011	89,882	941	13,011	21,788	125,621	93,020	32,601	(2,198)
	2012	95,511	810	9,347	37,608	143,276	98,393	44,883	(2,072)
Peak Median	2011	86,816	945	12,752	20,492	121,966	89,953	32,013	(1,230)
	2012	91,277	781	9,084	36,899	139,945	93,920	46,026	42
Peak Standard Deviation	2011	16,471	189	2,135	5,687	21,056	16,475	4,581	(3,240)
	2012	15,176	143	1,750	5,551	15,563	15,605	(42)	(7,343)
Off-Peak Average	2011	72,646	795	9,668	20,109	103,219	75,586	27,632	(2,145)
	2012	77,186	708	7,483	37,663	123,039	80,161	42,878	(2,268)
Off-Peak Median	2011	70,493	793	9,418	18,907	101,198	72,998	28,200	(125)
	2012	74,624	684	7,138	36,794	121,287	77,549	43,738	(194)
Off-Peak Standard Deviation	2011	13,887	168	1,803	5,168	17,938	14,191	3,747	(3,224)
	2012	13,653	123	1,469	5,840	14,567	14,198	369	(6,940)

Figure 2-12 shows the first nine months average 2012 hourly cleared volume of fixed-demand bids, the sum of cleared fixed-demand and cleared price-sensitive bids, total day-ahead load and real-time load. The difference between the cleared fixed-demand and cleared price-sensitive bids and the total day-ahead load is cleared decrement bids and up-to congestion transactions.

Figure 2-12 Day-ahead and real-time loads (Average hourly volumes): January through September of 2012 (See 2011 SOM, Figure 2-10)

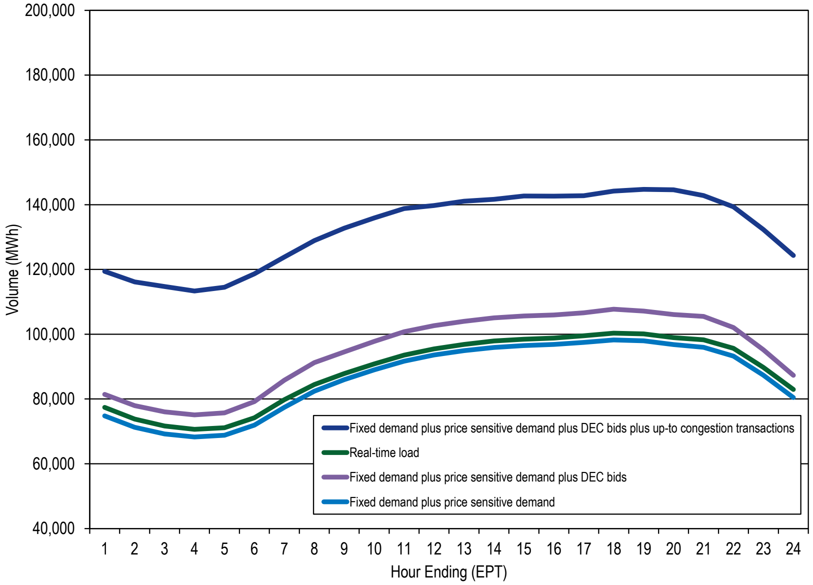
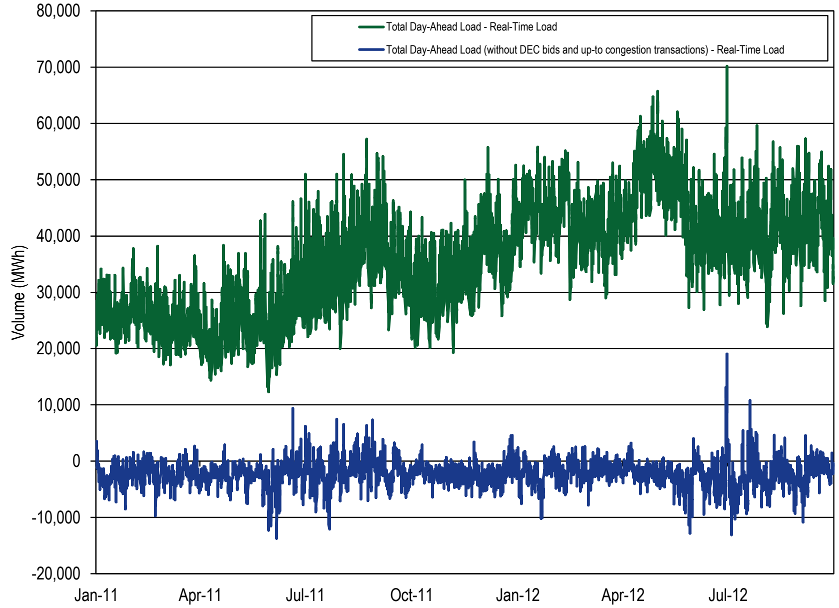


Figure 2-13 shows the difference between the day-ahead and real-time average daily loads in the first nine months of 2012 and the first nine months of 2011.

Figure 2-13 Difference between day-ahead and real-time loads (Average daily volumes): January 2011 through September 2012 (See 2011 SOM, Figure 2-12)



Real-Time and Day-Ahead Generation

PJM average real-time generation in the first nine months of 2012 increased by 3.9 percent from the first nine months of 2011, from 86,966 MW to 90,367 MW. PJM average real-time generation in the first nine months of 2012 would have decreased 1.6 percent from the first nine months of 2011, from 86,966 MW to 85,532 MW if the DEOK and ATSI Transmission Zones were excluded from the comparison for the months in 2011 when they were not part of PJM.[37]

PJM average day-ahead generation in the first nine months of 2012, including INCs and up-to congestion transactions, increased by 15.6 percent from the

37 The ATSI Transmission Zone was excluded from this comparison for the first 5 months of 2012 because it did not join PJM until June 1, 2011. The DEOK Transmission Zone was excluded from this comparison for all of the months of 2012 because it did not join PJM until January 1, 2012.

first nine months of 2011, from 116,988 MW to 135,213 MW. PJM average day-ahead generation in the first nine months of 2012, including INCs and up-to congestion transactions, would have increased 11.5 percent from the first nine months of 2011, from 116,988 MW to 135,213 MW if the DEOK and ATSI transmission zones were excluded from the comparison for the months in 2011 when they were not part of PJM.

The day-ahead generation growth was 300.0 percent higher than the real-time generation growth because of the continued growth of up-to congestion transactions. If up-to congestion transactions had not grown in the first nine months of 2012 compared to the first nine months of 2011, the day-ahead generation, including INCs and up-to congestion transactions, would have increased 1.3 percent instead of 15.6 percent. The day-ahead generation growth would have been 66.7 percent lower than the real-time generation growth.

Real-time generation is the actual production of electricity during the operating day. Real-time generation will always be greater than real-time load because of system losses.

In the Day-Ahead Energy Market, four types of financially binding generation offers are made and cleared: [38]

- **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 from a specific unit that also has a dispatchable component above the minimum.[39]
- **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 corresponding offer prices. An increment offer is a financial offer that can be submitted by any market participant.
- **Up-to Congestion Transactions.** An up-to congestion transaction is a conditional transaction that permits a market participant to specify a maximum price spread between the transaction source and sink.[40] In the PJM Day-Ahead Market, an up-to congestion transaction is evaluated and clears as a matched pair of injections and withdrawals analogous to a matched pair of INC offers and DEC bids. The DEC (sink) portion of each up-to congestion transaction is load in the Day-Ahead Energy Market. The INC (source) of each up-to congestion transaction is generation in the Day-Ahead Energy Market.

Table 2-34 presents summary real-time generation statistics for the first nine months of each year from 2003 through 2012.

Table 2-34 PJM real-time average hourly generation[41]: January through September for years 2003 through 2012 (See 2011 SOM, Table 2-33)

	PJM Real-Time Generation (MWh)		Year-to-Year Change	
(Jan-Sep)	Average Generation	Generation Standard Deviation	Average Generation	Generation Standard Deviation
2003	37,211	6,556	NA	NA
2004	45,888	11,035	23.3%	68.3%
2005	81,095	16,710	76.7%	51.4%
2006	84,260	14,696	3.9%	(12.1%)
2007	87,297	14,853	3.6%	1.1%
2008	85,241	14,203	(2.4%)	(4.4%)
2009	78,850	14,242	(7.5%)	0.3%
2010	84,086	16,346	6.6%	14.8%
2011	86,966	17,369	3.4%	6.3%
2012	90,367	16,893	3.9%	(2.7%)

Table 2-35 presents summary day-ahead generation statistics for the first nine months of each year from 2003 through 2012.

38 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 *2011 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market."

39 The definition of self-scheduled is based on the PJM. "eMKT User Guide" (December 1, 2011), pp. 38-40.

40 Up-to congestion transactions are cleared based on the entire price difference between source and sink including the congestion and loss components of LMP.

41 The version of this table in the *2012 State of the Market Report for PJM*: January through March incorrectly reported the standard deviation.

Table 2-35 PJM day-ahead average hourly generation[42]: January through September for years 2003 through 2012 (See 2011 SOM, Table 2-34)

	PJM Day-Ahead Generation (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
(Jan-Sep)	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation	Generation (Cleared Gen. and INC Offers)	Up-to Congestion	Total Generation
2003	39,736	288	40,024	9,113	287	9,079	NA	NA	NA
2004	55,270	833	56,103	13,158	584	13,380	39.1%	189.4%	40.2%
2005	93,074	1,363	94,437	18,401	851	18,671	68.4%	63.6%	68.3%
2006	97,056	3,831	100,888	17,304	1,657	18,061	4.3%	181.1%	6.8%
2007	105,748	4,553	110,300	17,092	1,535	17,561	9.0%	18.8%	9.3%
2008	101,287	6,080	107,367	16,015	1,830	16,601	(4.2%)	33.6%	(2.7%)
2009	92,187	6,340	98,527	16,220	2,018	17,462	(9.0%)	4.3%	(8.2%)
2010	95,974	12,335	108,309	18,086	8,637	23,294	4.1%	94.6%	9.9%
2011	96,092	20,896	116,988	19,705	5,481	22,722	0.1%	69.4%	8.0%
2012	97,576	37,637	135,213	18,929	5,706	18,553	1.5%	80.1%	15.6%

Table 2-36 presents summary statistics for first nine months of 2011 and 2012 for day-ahead and real-time generation.

Table 2-36 Day-ahead and real-time generation (MWh): January through September for years 2011 and 2012 (See 2011 SOM, Table 2-35)

		Day Ahead				Real Time	Average Difference	
	(Jan-Sep)	Cleared Generation	Cleared INC Offers	Cleared Up-to Congestion	Cleared Generation Plus INC Offers Plus Up-to Congestion	Generation	Cleared Generation	Cleared Generation Plus INC Offers Plus Up-to Congestion
Average	2011	88,220	7,872	20,896	116,988	86,966	1,255	30,023
	2012	91,382	6,194	37,637	135,213	90,367	1,015	44,846
Median	2011	85,314	7,800	19,698	113,095	84,276	1,038	28,819
	2012	88,873	6,191	36,844	133,659	87,665	1,207	45,993
Standard Deviation	2011	18,881	1,388	5,481	22,722	17,369	1,512	5,353
	2012	18,736	906	5,706	18,553	16,893	1,843	1,659
Peak Average	2011	98,419	8,823	21,788	129,030	95,885	2,534	33,145
	2012	102,016	6,547	37,608	146,171	99,382	2,635	46,789
Peak Median	2011	95,643	8,690	20,492	125,500	92,952	2,691	32,548
	2012	97,816	6,477	36,899	142,800	95,406	2,410	47,393
Peak Standard Deviation	2011	17,199	1,133	5,687	21,229	16,250	949	4,979
	2012	16,523	721	5,551	15,938	15,366	1,157	572
Off-Peak Average	2011	79,214	7,031	20,109	106,355	79,090	125	27,265
	2012	82,057	5,884	37,663	125,604	82,461	(405)	43,142
Off-Peak Median	2011	76,818	6,864	18,907	104,245	76,703	115	27,542
	2012	79,731	5,810	36,794	123,948	80,263	(532)	43,685
Off-Peak Standard Deviation	2011	15,400	994	5,168	18,252	14,235	1,164	4,017
	2012	15,277	939	5,840	15,023	13,960	1,318	1,064

42 The version of this table in the *2012 Q1 State of the Market Report for PJM* incorrectly reported the standard deviation.

Figure 2-14 shows the first nine months average 2012 hourly cleared volumes of day-ahead generation without increment offers or up-to congestion transactions, the day-ahead generation including cleared increment bids and up-to congestion transactions and the real-time generation.[43]

Figure 2-14 Day-ahead and real-time generation (Average hourly volumes): January through September of 2012 (See 2011 SOM, Figure 2-13)

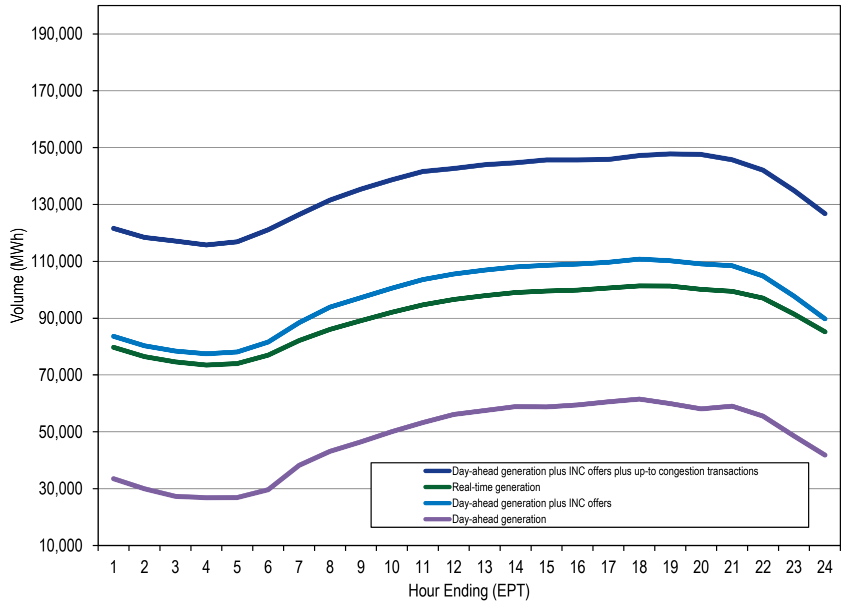
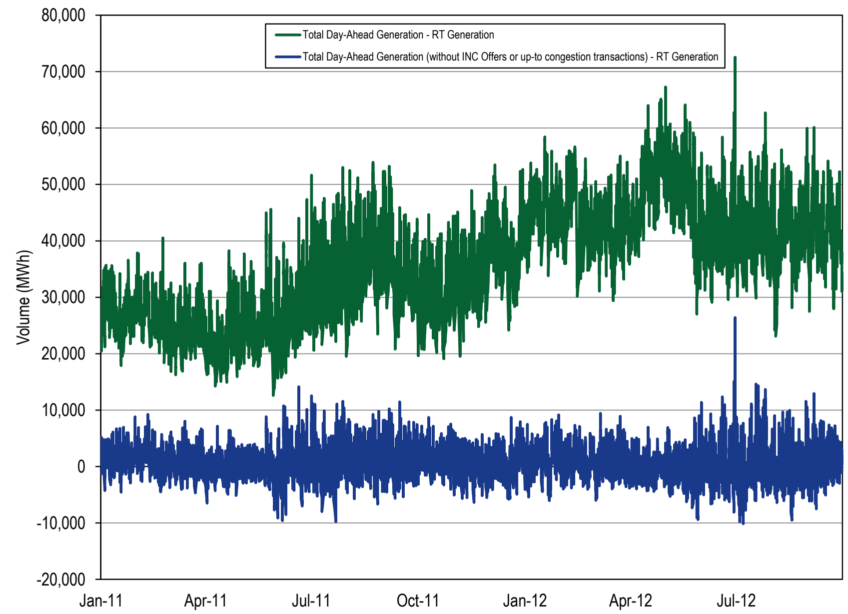


Figure 2-15 shows the difference between the day-ahead and real-time average daily generation in the first nine months of 2012 and the first nine months of 2011.

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

Figure 2-15 Difference between day-ahead and real-time generation (Average daily volumes): January 2011 through September 2012 (See 2011 SOM, Figure 2-14)



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.[44]

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 changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses

44 See the *2011 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market," for methodological background, detailed price data and the *Technical Reference for PJM Markets*, Section 4, "Calculating Locational Marginal Price" for more information on how bus LMPs are aggregated to system LMPs.

and local price differences caused by congestion. Real-Time and Day-Ahead Energy Market load-weighted prices were 29.2 percent and 29.1 percent lower than in the first nine months of 2011 as a result of lower fuel costs and relatively low demand.[45]

PJM Real-Time Energy Market prices decreased in the first nine months of 2012 compared to the first nine months of 2011. The system average LMP was 29.1 percent lower in the first nine months of 2012 than in the first nine months of 2011, $32.45 per MWh versus $45.79 per MWh. The load-weighted average LMP was 29.2 percent lower in the first nine months of 2012 than in the first nine months of 2011, $35.02 per MWh versus $49.48 per MWh.

PJM Day-Ahead Energy Market prices decreased in the first nine months of 2012 compared to the first nine months of 2011. The system average LMP was 28.8 percent lower in the first nine months of 2012 than in the first nine months of 2011, $32.16 per MWh versus $45.14 per MWh. The load-weighted average LMP was 29.1 percent lower in the first nine months of 2012 than in the first nine months of 2011, $34.29 per MWh versus $48.34 per MWh.[46]

Real-Time LMP

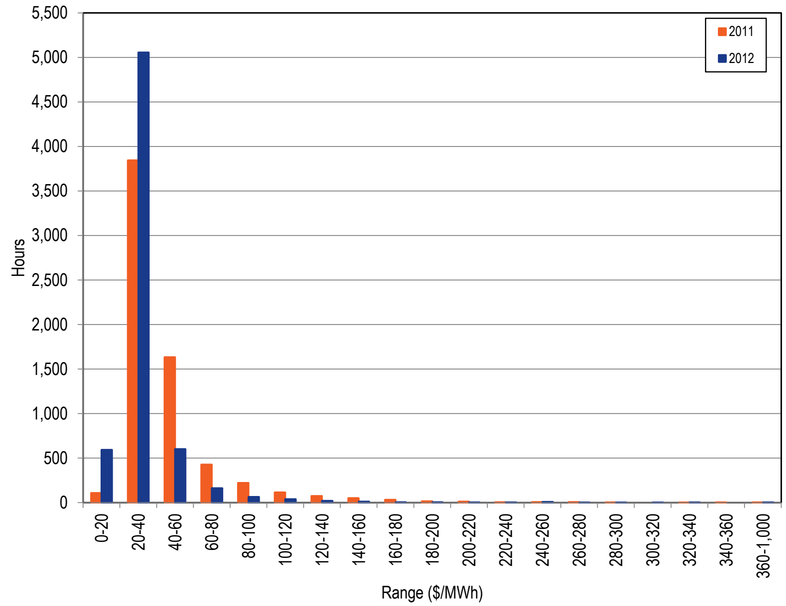
Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[47] This section discusses the real-time average LMP and the real-time load weighted average LMP. Average LMP is the unweighted average LMP.

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 2-16 shows the number of hours that PJM real-time average LMP for the first nine months of 2011 and 2012 were within a defined range.

Figure 2-16 Average LMP for the PJM Real-Time Energy Market: January through September, 2011 and 2012 (See 2011 SOM, Figure 2-15)



PJM Real-Time, Average LMP

Table 2-37 shows the PJM real-time, annual, average LMP for the first nine months of the 15-year period 1998 to 2012.[48]

45 There was an average reduction of 3.9 heating degree days and an average increase of 1.5 cooling degree days in the first nine months of 2012 which meant overall reduced demand.

46 Tables reporting zonal and jurisdictional load and prices are in Appendix C. See the *2011 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market".

47 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for detailed definition of Real-Time LMP.

48 The system annual, 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 2-37 PJM real-time, average LMP (Dollars per MWh): January through September, 1998 through 2012 (See 2011 SOM, Table 2-36)

	Real-Time LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$23.18	$16.86	$36.00	NA	NA	NA
1999	$31.65	$18.77	$83.28	36.6%	11.3%	131.3%
2000	$25.88	$18.22	$23.70	(18.2%)	(2.9%)	(71.5%)
2001	$36.00	$25.48	$51.30	39.1%	39.9%	116.4%
2002	$28.13	$20.70	$23.92	(21.9%)	(18.8%)	(53.4%)
2003	$40.42	$33.68	$26.00	43.7%	62.7%	8.7%
2004	$43.85	$39.99	$21.82	8.5%	18.7%	(16.1%)
2005	$54.69	$44.53	$33.67	24.7%	11.4%	54.3%
2006	$51.79	$43.50	$34.93	(5.3%)	(2.3%)	3.7%
2007	$57.34	$49.40	$35.52	10.7%	13.6%	1.7%
2008	$71.94	$61.33	$41.64	25.4%	24.2%	17.2%
2009	$37.42	$33.00	$17.92	(48.0%)	(46.2%)	(57.0%)
2010	$46.13	$37.89	$26.99	23.3%	14.8%	50.6%
2011	$45.79	$37.05	$32.25	(0.7%)	(2.2%)	19.5%
2012	$32.45	$28.78	$21.94	(29.1%)	(22.3%)	(32.0%)

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 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 LMP, each weighted by the PJM total hourly load.

PJM Real-Time, Load-Weighted, Average LMP

Table 2-38 shows the PJM real-time, load-weighted, average LMP for the first nine months of each year of the 15-year period 1998 to 2012.

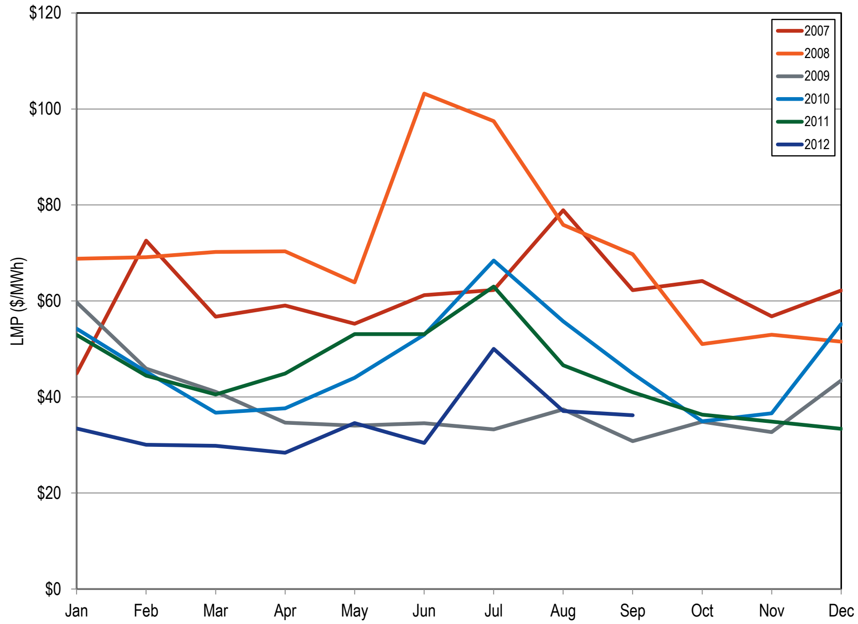
Table 2-38 PJM real-time, load-weighted, average LMP (Dollars per MWh): January through September, 1998 through 2012 (See 2011 SOM, Table 2-37)

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$26.06	$18.20	$44.65	NA	NA	NA
1999	$38.65	$20.02	$104.17	48.3%	10.0%	133.3%
2000	$28.49	$19.30	$26.89	(26.3%)	(3.6%)	(74.2%)
2001	$40.96	$28.18	$64.57	43.8%	46.0%	140.1%
2002	$31.95	$23.09	$29.14	(22.0%)	(18.1%)	(54.9%)
2003	$43.57	$38.17	$26.53	36.3%	65.3%	(9.0%)
2004	$46.44	$43.03	$21.89	6.6%	12.7%	(17.5%)
2005	$60.44	$50.10	$36.52	30.2%	16.4%	66.9%
2006	$56.39	$46.82	$40.70	(6.7%)	(6.5%)	11.4%
2007	$61.83	$55.12	$37.98	9.7%	17.7%	(6.7%)
2008	$77.27	$66.73	$43.80	25.0%	21.1%	15.3%
2009	$39.57	$34.57	$19.04	(48.8%)	(48.2%)	(56.5%)
2010	$49.91	$40.33	$29.65	26.2%	16.7%	55.7%
2011	$49.48	$38.72	$37.02	(0.9%)	(4.0%)	24.8%
2012	$35.02	$29.84	$25.44	(29.2%)	(22.9%)	(31.3%)

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

Figure 2-17 shows the PJM real-time, monthly, load-weighted LMP from 2007 through the first nine months of 2012.

Figure 2-17 PJM real-time, monthly, load-weighted, average LMP: 2007 through September of 2012 (See 2011 SOM, Figure 2-16)



Fuel Price Trends and LMP

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. Changes in emission allowance costs are another contributor to changes in the marginal cost of marginal units. Both coal and natural gas decreased in price in the first nine months of 2012. Comparing prices in the first nine months of 2012 to prices in the first nine months of 2011, the price of Northern Appalachian coal was 15.5 percent lower; the price of Central Appalachian coal was 19.4 percent lower; the price of Powder River Basin coal was 34.1 percent lower; the price of eastern natural gas was 40.5 percent lower; and the price of western natural gas was 37.1 percent lower. Figure 2-18 shows monthly average spot fuel prices for 2011 and 2012.[49]

Figure 2-18 Spot average fuel price comparison: 2011 and January through September 2012 ($/MMBtu) (See 2011 SOM, Figure 2-17)

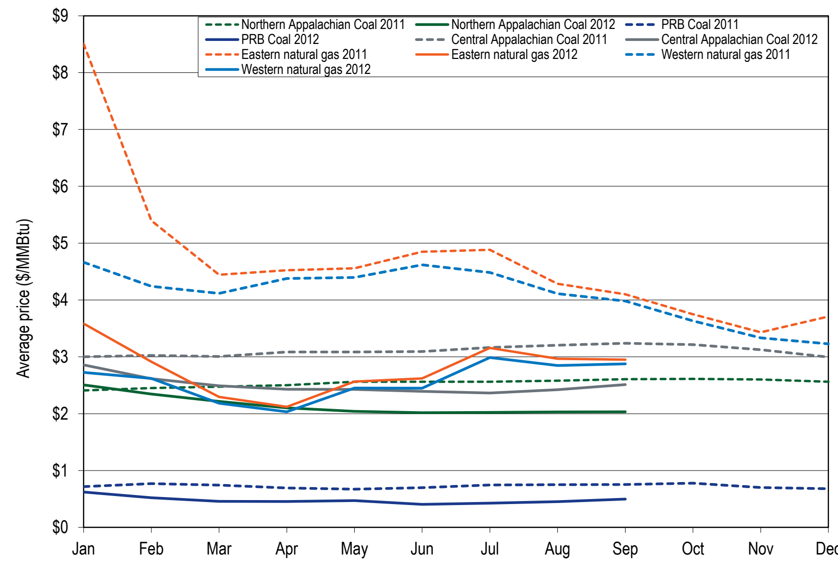


Figure 2-19 shows the average spot cost of generation, comparing the fuel cost of a coal plant, combined cycle, and combustion turbine in dollars per MWh. On average, the fuel cost of a new entrant combined cycle unit ($19.54/MWh) was lower than the fuel cost of a new entrant coal plant ($19.83/MWh) in the first nine months of 2012. On a $/MWh basis, a new entrant combined cycle was lower cost than a new entrant coal plant from February through June, but higher cost in the months of July through September.

49 Eastern natural gas and Western natural gas prices are the average of daily fuel price indices in the PJM footprint. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

Figure 2-19 Average spot fuel cost of generation of CP, CT, and CC: 2011 and January through September 2012 ($/MWh) (New Figure)

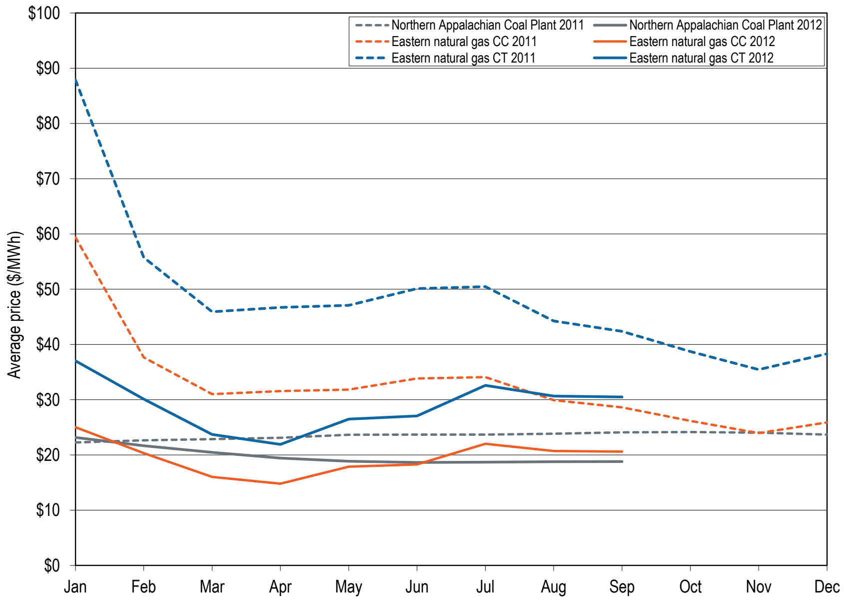


Table 2-39 compares the first nine months of 2012 PJM real-time fuel-cost-adjusted, load-weighted, average LMP to the first nine months of 2011 load-weighted, average LMP. The fuel-cost adjusted load-weighted, average LMP for the first nine month of 2012 was 20.3 percent higher than the load-weighted, average LMP for the first nine months of 2012. The real-time, fuel-cost-adjusted, load-weighted, average LMP for the first nine months of 2012 was 14.8 percent lower than the load-weighted LMP for the first nine months of 2011. If fuel costs in the first nine months of 2012 had been the same as in the first nine months of 2011, the 2012 load-weighted LMP would have been higher, $42.15 per MWh instead of the observed $35.02 per MWh. The mix of fuel types and fuel costs in 2012 resulted in lower prices in 2012 than would have occurred if fuel prices had remained at their 2011 levels.

Table 2-39 PJM real-time annual, fuel-cost-adjusted, load-weighted average LMP (Dollars per MWh): Year-over-year method (See 2011 SOM, Table 2-11)

	Jan-Sep, 2012 Load-Weighted LMP	Jan-Sep, 2012 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$35.02	$42.15	20.3%
	Jan-Sep, 2011 Load-Weighted LMP	Jan-Sep, 2012 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$49.48	$42.15	(14.8%)
	Jan-Sep, 2011 Load-Weighted LMP	Jan-Sep, 2012 Load-Weighted LMP	Change
Average	$49.48	$35.02	(29.2%)

Components of Real-Time, Load-Weighted LMP

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 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 and emission allowance costs and unit-specific emission rates, when applicable.

Table 2-40 shows that 53.8 percent of the annual, load-weighted LMP was the result of coal costs, 21.7 percent was the result of gas costs and 0.6 percent was the result of the cost of emission allowances. Markup was -$ 0.47. 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. (Numbers in parentheses in the table are negative.) The components of this difference are listed in Table 2-40.[50]

50 These components are explained in the *Technical Reference for PJM Markets*, Section 7 "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

Table 2-40 Components of PJM real-time, annual, load-weighted, average LMP: January through September 2012

Element	Contribution to LMP	Percent
Coal	$18.86	53.8%
Gas	$7.61	21.7%
Ten Percent Adder	$3.41	9.7%
VOM	$2.49	7.1%
Oil	$2.00	5.7%
NA	$0.73	2.1%
LPA-SCED Differential	$0.13	0.4%
LPA Rounding Difference	$0.12	0.4%
FMU Adder	$0.11	0.3%
CO2 Cost	$0.10	0.3%
NOx Cost	$0.09	0.3%
Increase Generation Adder	$0.07	0.2%
Market-to-Market Adder	$0.03	0.1%
Constraint Violation Adder	$0.02	0.1%
SO2 Cost	$0.02	0.1%
Municipal Waste	$0.01	0.0%
Uranium	$0.00	0.0%
Other	($0.00)	(0.0%)
Wind	($0.06)	(0.2%)
Decrease Generation Adder	($0.26)	(0.7%)
Markup	($0.47)	(1.3%)
Total	$35.02	100.0%

Day-Ahead LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[51] This section discusses the day-ahead average LMP and the day-ahead load weighted average LMP. Average LMP is the unweighted average LMP.

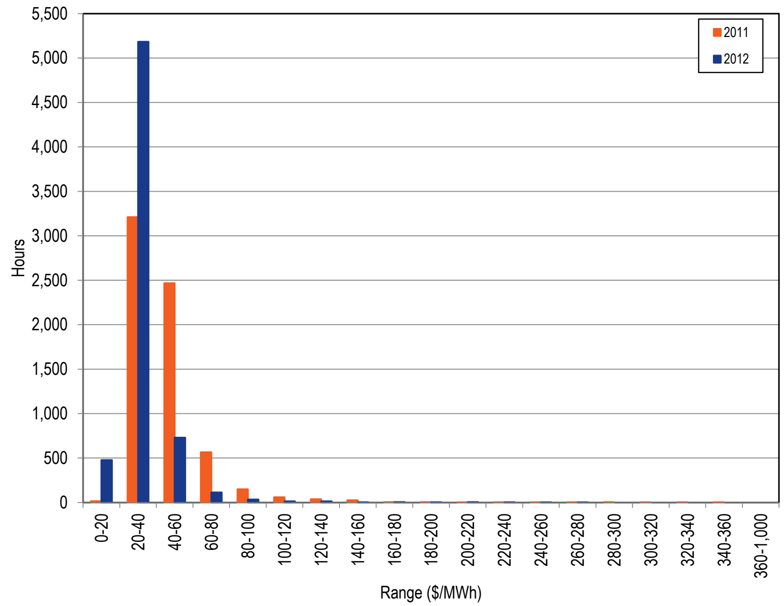
Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 2-20 shows the hourly distribution of PJM day-ahead average LMP for the first nine months of 2011 and 2012.

51 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for detailed definition of Day-Ahead LMP.

Figure 2-20 Price for the PJM Day-Ahead Energy Market: January through September, 2011 and 2012 (See 2011 SOM, Figure 2-18)



PJM Day-Ahead, Average LMP

Table 2-41 shows the PJM day-ahead, average LMP for the first nine months of each year for the 12 year period from 2001 to 2012.

Table 2-41 PJM day-ahead, average LMP (Dollars per MWh): January through September, 2001 through 2012 (See 2011 SOM, Table 2-40)

	Day-Ahead LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.07	$30.02	$34.25	NA	NA	NA
2002	$28.29	$22.54	$19.09	(21.6%)	(24.9%)	(44.3%)
2003	$41.20	$38.24	$22.02	45.6%	69.7%	15.4%
2004	$42.64	$42.07	$17.47	3.5%	10.0%	(20.7%)
2005	$54.48	$46.67	$28.83	27.8%	10.9%	65.1%
2006	$50.45	$46.32	$24.93	(7.4%)	(0.8%)	(13.5%)
2007	$54.24	$51.40	$24.95	7.5%	11.0%	0.1%
2008	$71.43	$66.38	$33.11	31.7%	29.2%	32.7%
2009	$37.35	$35.29	$14.32	(47.7%)	(46.8%)	(56.8%)
2010	$45.81	$41.03	$19.59	22.7%	16.3%	36.8%
2011	$45.14	$40.20	$22.68	(1.5%)	(2.0%)	15.7%
2012	$32.16	$30.10	$14.54	(28.8%)	(25.1%)	(35.9%)

Day-Ahead, Load-Weighted, Average LMP

Day-ahead, load-weighted LMP reflects the average LMP paid for day-ahead MWh. Day-ahead, load-weighted LMP is the average of PJM day-ahead hourly LMP, each weighted by the PJM total cleared day-ahead hourly load, including day-ahead fixed load, price-sensitive load, decrement bids and up-to congestion.

PJM Day-Ahead, Load-Weighted, Average LMP

Table 2-42 shows the PJM day-ahead, load-weighted, average LMP for the first nine months of each year of the 12-year period from 2001 to 2012.

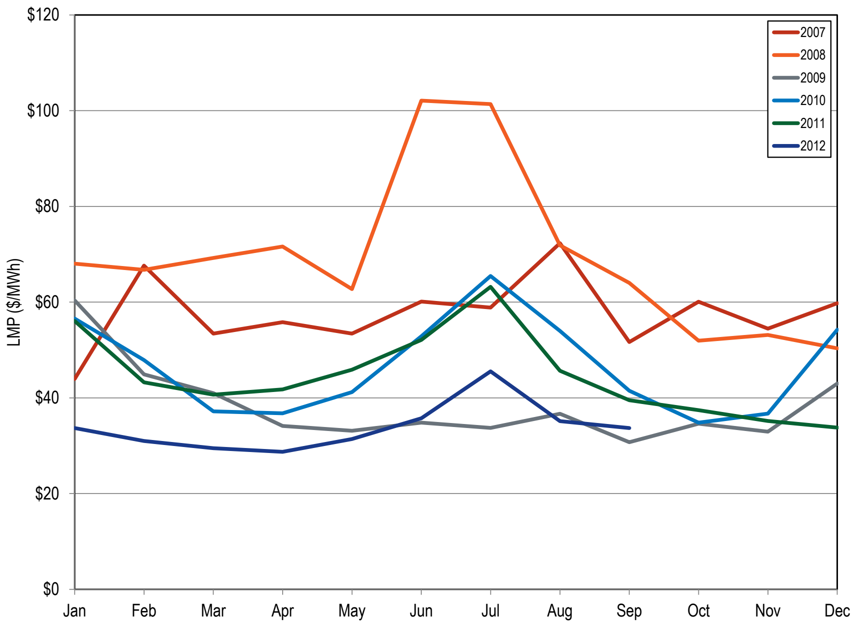
Table 2-42 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through September, 2001 through 2012 (See 2011 SOM, Table 2-41)

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$39.88	$32.68	$42.01	NA	NA	NA
2002	$32.29	$25.22	$22.81	(19.0%)	(22.8%)	(45.7%)
2003	$44.11	$41.51	$22.34	36.6%	64.6%	(2.1%)
2004	$44.59	$44.47	$17.40	1.1%	7.1%	(22.1%)
2005	$59.51	$51.33	$31.13	33.5%	15.4%	78.9%
2006	$54.19	$48.87	$28.35	(8.9%)	(4.8%)	(8.9%)
2007	$57.79	$55.62	$26.07	6.6%	13.8%	(8.0%)
2008	$75.96	$70.35	$35.19	31.5%	26.5%	35.0%
2009	$39.35	$36.92	$14.98	(48.2%)	(47.5%)	(57.4%)
2010	$49.12	$43.33	$21.35	24.8%	17.4%	42.6%
2011	$48.34	$42.35	$26.54	(1.6%)	(2.3%)	24.3%
2012	$34.29	$31.17	$17.12	(29.1%)	(26.4%)	(35.5%)

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

Figure 2-21 shows the PJM day-ahead, monthly, load-weighted LMP from 2007 through the first nine months of 2012.

Figure 2-21 Day-ahead, monthly, load-weighted, average LMP: 2007 through September of 2012 (See 2011 SOM, Figure 2-19)



Components of Day-Ahead, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources generally determine system LMPs, based on their offers. For physical units, those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder, Day-Ahead Scheduling Reserve (DASR) adder and the 10 percent cost offer adder. INC offers, DEC bids and price sensitive transactions are dispatchable injections and withdrawals in the Day Ahead market. To the extent that INCs, DECs or transactions are the marginal resource, they either directly or indirectly set price via their offers and bids. Using identified marginal resource offers and the components of the offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors. Table 2-43 shows the components of the PJM day ahead, annual, load-weighted average LMP.

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. Day Ahead Scheduling Reserve (DASR) lost opportunity cost (LOC) and DASR offer adders are the calculated contribution to LMP when redispatch of resources is needed in order to satisfy DASR requirements. Cost offers of marginal units are broken into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs were calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, fuel-specific emission rates for NO_x and unit-specific emission rates for SO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland and New Jersey.[52]

Table 2-43 Components of PJM day-ahead, annual, load-weighted, average LMP (Dollars per MWh): January through September, 2012 (See 2011 SOM, Table 2-42)

Element	Contribution to LMP	Percent
Coal	$13.49	39.3%
DEC	$8.40	24.5%
Gas	$4.29	12.5%
INC	$3.41	10.0%
10% Cost Adder	$1.98	5.8%
Up-to Congestion Transaction	$1.66	4.8%
VOM	$1.52	4.4%
Price Sensitive Demand	$0.58	1.7%
Dispatchable Transaction	$0.51	1.5%
Oil	$0.39	1.1%
DASR Offer Adder	$0.19	0.6%
CO_2	$0.06	0.2%
NO_x	$0.06	0.2%
SO_2	$0.01	0.0%
Constrained Off	$0.00	0.0%
Diesel	$0.00	0.0%
Wind	($0.00)	(0.0%)
DASR LOC Adder	($0.41)	(1.2%)
Markup	($1.87)	(5.4%)
NA	$0.01	0.0%
Total	$34.29	100.0%

52 New Jersey withdrew from RGGI, effective January 1, 2012.

Virtual Offers and Bids

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 PJM optimization algorithm works.

Table 2-44 shows the average volume of trading in increment offers and decrement bids per hour and the average total MW values of all bids per hour. Table 2-45 shows the average volume of up-to congestion transactions per hour and the average total MW values of all bids per hour.

Table 2-44 Hourly average volume of cleared and submitted INCs, DECs by month: January, 2011 through September, 2012 (See 2011 SOM, Table 2-43)

		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2011	Jan	8,137	14,299	218	1077	11,135	17,917	224	963
2011	Feb	8,530	16,263	215	1672	11,071	17,355	230	1034
2011	Mar	7,230	13,164	201	1059	10,435	16,343	219	982
2011	Apr	7,222	12,516	185	984	10,211	16,199	202	846
2011	May	7,443	12,161	220	835	10,250	15,956	243	800
2011	Jun	8,405	14,171	238	1084	11,648	17,542	279	1015
2011	Jul	8,595	14,006	185	1234	12,196	17,567	213	1140
2011	Aug	7,540	12,349	120	1034	10,992	15,368	161	847
2011	Sep	7,092	10,071	114	591	12,171	16,268	147	648
2011	Oct	7,726	10,242	104	351	10,983	14,550	116	396
2011	Nov	8,290	11,545	105	382	10,936	15,204	118	416
2011	Dec	8,914	12,159	107	409	11,964	15,515	114	404
2011	Annual	7,792	12,924	180	992	11,109	16,507	203	867
2012	Jan	6,781	10,341	91	455	9,031	12,562	111	428
2012	Feb	6,428	10,930	96	591	7,641	11,043	108	511
2012	Mar	5,969	9,051	90	347	7,193	10,654	112	362
2012	Apr	6,355	9,368	87	298	7,812	10,811	105	329
2012	May	6,224	8,447	80	271	8,785	11,141	109	316
2012	Jun	6,415	8,360	79	234	9,030	11,124	97	270
2012	Jul	6,485	8,270	81	285	8,981	11,121	112	349
2012	Aug	5,809	7,873	74	291	8,471	10,507	100	320
2012	Sep	5,274	7,509	78	313	8,192	10,814	109	381
2012	Annual	6,193	8,905	84	343	8,348	11,086	107	363

Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids and up-to congestion transactions as financial instruments that do not require physical generation or load. Increment offers, decrement bids and up-to congestion transactions may be submitted at any hub, transmission zone, aggregate, or single bus for which LMP is calculated.[53]

53 An import up-to congestion transaction must source at an interface, but may sink at any hub, transmission zone, aggregate, or single bus for which LMP is calculated. An export up-to congestion transaction may source at any hub, transmission zone, aggregate, or single bus for which LMP is calculated, but must sink at an interface. Wheeling up-to congestion transactions must both source and sink at an interface.

Table 2-45 Hourly average of cleared and submitted up-to congestion bids by month: January, 2011 through September, 2012 (See 2011 SOM, Table 2-44)

		Up-to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2011	Jan	17,687	44,361	338	779
2011	Feb	17,759	48,052	386	877
2011	Mar	17,451	41,666	419	940
2011	Apr	16,114	38,182	488	1,106
2011	May	18,854	47,312	560	1,199
2011	Jun	18,323	45,802	508	1,141
2011	Jul	24,742	55,809	641	1,285
2011	Aug	28,996	60,531	654	1,348
2011	Sep	27,184	55,706	638	1,267
2011	Oct	21,985	53,830	616	1,345
2011	Nov	26,234	78,486	718	1,682
2011	Dec	29,471	94,316	720	1,837
2011	Annual	22,067	55,338	557	1,234
2012	Jan	37,469	102,762	805	1,950
2012	Feb	37,132	106,741	830	2,115
2012	Mar	35,921	105,222	865	2,224
2012	Apr	43,777	120,955	1013	2,519
2012	May	43,468	119,374	1052	2,541
2012	Jun	35,052	101,065	915	2,193
2012	Jul	35,179	118,294	981	2,710
2012	Aug	35,515	122,458	986	2,787
2012	Sep	35,199	112,731	946	2,801
2012	Annual	37,635	112,178	933	2,427

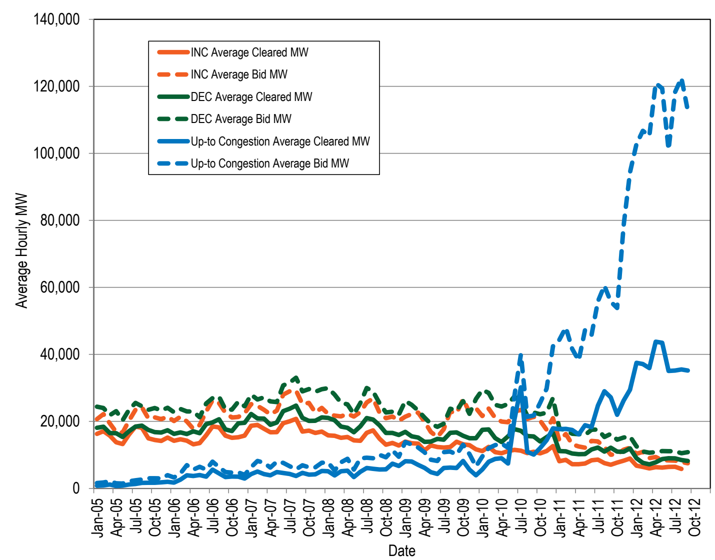
Table 2-46 shows the frequency with which generation offers, import or export transactions, up-to congestion transactions, decrement bids, increment offers and price-sensitive demand are marginal for each month.[54]

Table 2-46 Type of day-ahead marginal units: January through September, 2012 (See 2011 SOM, Table 2-45)

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	3.8%	0.1%	87.3%	5.7%	3.1%	0.1%
Feb	3.7%	0.1%	83.8%	5.4%	6.9%	0.1%
Mar	3.5%	0.1%	83.2%	6.2%	6.9%	0.1%
Apr	3.5%	0.1%	85.3%	5.2%	5.9%	0.0%
May	3.1%	0.1%	87.9%	4.6%	4.4%	0.0%
Jun	4.3%	0.0%	88.7%	4.3%	2.6%	0.0%
Jul	3.3%	0.1%	88.0%	6.1%	2.5%	0.1%
Aug	4.0%	0.1%	89.4%	4.1%	2.3%	0.0%
Sep	3.7%	0.1%	86.8%	4.5%	5.0%	0.0%
Annual	3.6%	0.1%	86.7%	5.1%	4.4%	0.1%

Figure 2-22 shows the hourly volume of bid and cleared INC, DEC and up-to congestion bids by month.

Figure 2-22 Hourly volume of bid and cleared INC, DEC and Up-to Congestion bids (MW) by month: January, 2005 through September, 2012 (See 2011 SOM, Figure 2-20)



54 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 making 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 2-47 shows, for the January through September period of 2011 and 2012, the total increment offers and decrement bids by the type of parent organization: financial or physical. Table 2-48 shows, for the January through September period of 2011 and 2012, the total up-to congestion transactions by the type of parent organization: financial or physical.

Table 2-47 PJM INC and DEC bids by type of parent organization (MW): January through September, 2011 and 2012 (See 2011 SOM, Table 2-46)

	2011 (Jan - Sep)		2012 (Jan - Sep)	
Category	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	89,824,892	45.8%	47,082,084	35.8%
Physical	106,162,195	54.2%	84,316,277	64.2%
Total	195,987,087	100.0%	131,398,361	100.0%

Table 2-48 PJM up-to congestion transactions by type of parent organization (MW): January through September, 2011 and 2012 (See 2011 SOM, Table 2-47)

	2011 (Jan - Sep)		2012 (Jan - Sep)	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	132,143,539	96.8%	235,531,919	95.2%
Physical	4,308,481	3.2%	11,950,279	4.8%
Total	136,452,020	100.0%	247,482,198	100.0%

Table 2-49 shows increment offers and decrement bids bid by top ten locations for the January through September period of 2011 and 2012.

Table 2-49 PJM virtual offers and bids by top ten locations (MW): January through September, 2011 and 2012 (See 2011 SOM, Table 2-48)

2011 (Jan - Sep)					2012 (Jan - Sep)				
Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	21,803,278	25,055,528	46,858,806	WESTERN HUB	HUB	22,645,383	25,448,690	48,094,072
N ILLINOIS HUB	HUB	7,548,766	11,359,168	18,907,933	AEP-DAYTON HUB	HUB	3,906,488	4,420,709	8,327,197
AEP-DAYTON HUB	HUB	4,595,058	6,186,285	10,781,343	SOUTHIMP	INTERFACE	7,038,188	0	7,038,188
MISO	INTERFACE	189,307	5,304,896	5,494,202	N ILLINOIS HUB	HUB	2,059,281	4,605,627	6,664,908
PECO	ZONE	1,322,244	3,821,502	5,143,746	MISO	INTERFACE	248,793	5,303,608	5,552,401
SOUTHIMP	INTERFACE	4,480,640	0	4,480,640	PPL	ZONE	286,342	4,331,684	4,618,026
PPL	ZONE	201,981	3,028,982	3,230,963	PECO	ZONE	858,512	3,219,905	4,078,417
COMED	ZONE	1,965,887	216,118	2,182,004	IMO	INTERFACE	2,591,173	45,924	2,637,097
JCPL BUS	GEN	1,037,760	1,037,827	2,075,587	BGE	ZONE	167,525	1,542,604	1,710,129
BGE	ZONE	89,509	1,680,790	1,770,299	METED	ZONE	133,855	1,063,889	1,197,744
Top Ten Total		43,234,428	57,691,095	100,925,523			39,935,538	49,982,640	89,918,178
PJM total		86,469,663	109,517,424	195,987,087			58,491,377	72,906,984	131,398,361
Top ten total as percent of PJM total		50.0%	52.7%	51.5%			68.3%	68.6%	68.4%

Table 2-50 shows up-to congestion transactions by import bids for the top ten locations for the January through September period of 2011 and 2012.[55]

55 The source and sink aggregates in these tables refer to the name and location of a bus and do not include information about the behavior of any individual market participant.

Table 2-50 PJM cleared up-to congestion import bids by top ten source and sink pairs (MW): January through September, 2011 and 2012 (See 2011 SOM, Table 2-49)

2011 (Jan - Sep)				
Imports				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	N ILLINOIS HUB	HUB	2,697,394
NORTHWEST	INTERFACE	ZION 1	AGGREGATE	1,950,476
OVEC	INTERFACE	CONESVILLE 6	AGGREGATE	1,686,827
MISO	INTERFACE	112 WILTON	EHVAGG	1,584,297
NYIS	INTERFACE	MARION	AGGREGATE	1,137,814
NYIS	INTERFACE	PSEG	ZONE	966,283
SOUTHEAST	AGGREGATE	CRVWOOD	AGGREGATE	855,719
OVEC	INTERFACE	MARYSVILLE	EHVAGG	813,663
OVEC	INTERFACE	JEFFERSON	EHVAGG	800,642
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	798,145
Top ten total				13,291,259
PJM total				75,607,294
Top ten total as percent of PJM total				17.6%
2012 (Jan - Sep)				
Imports				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	112 WILTON	EHVAGG	8,832,551
MISO	INTERFACE	N ILLINOIS HUB	HUB	2,265,566
OVEC	INTERFACE	JEFFERSON	EHVAGG	1,958,932
OVEC	INTERFACE	DEOK	ZONE	1,795,528
OVEC	INTERFACE	COOK	EHVAGG	1,664,824
OVEC	INTERFACE	MARYSVILLE	EHVAGG	1,658,701
OVEC	INTERFACE	CONESVILLE 4	AGGREGATE	1,598,854
NYIS	INTERFACE	HUDSON BC	AGGREGATE	1,477,807
OVEC	INTERFACE	STUART 1	AGGREGATE	1,456,182
MISO	INTERFACE	COOK	EHVAGG	1,386,981
Top ten total				24,095,925
PJM total				122,824,468
Top ten total as percent of PJM total				19.6%

Table 2-51 shows up-to congestion transactions by export bids for the top ten locations for the January through September period of 2011 and 2012.

Table 2-51 PJM cleared up-to congestion export bids by top ten source and sink pairs (MW): January through September, 2011 and 2012 (See 2011 SOM, Table 2-49)

2011 (Jan - Sep)				
Exports				
Source	Source Type	Sink	Sink Type	MW
LUMBERTON	AGGREGATE	SOUTHEAST	AGGREGATE	5,458,432
WESTERN HUB	HUB	MISO	INTERFACE	2,629,676
FE GEN	AGGREGATE	SOUTHWEST	AGGREGATE	1,286,402
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	1,269,001
23 COLLINS	EHVAGG	MISO	INTERFACE	1,149,885
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	AGGREGATE	1,074,975
BELMONT	EHVAGG	OVEC	INTERFACE	934,962
FOWLER 34.5 KV FWLR1AWF	AGGREGATE	OVEC	INTERFACE	783,782
RECO	ZONE	IMO	INTERFACE	776,982
BEAV DUQ UNIT1	AGGREGATE	MICHFE	INTERFACE	742,722
Top ten total				16,106,818
PJM total				58,031,610
Top ten total as percent of PJM total				27.8%
2012 (Jan - Sep)				
Exports				
Source	Source Type	Sink	Sink Type	MW
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	3,403,395
ROCKPORT	EHVAGG	OVEC	INTERFACE	3,140,361
23 COLLINS	EHVAGG	MISO	INTERFACE	3,055,342
STUART 1	AGGREGATE	OVEC	INTERFACE	2,144,288
WESTERN HUB	HUB	MISO	INTERFACE	1,643,318
ROCKPORT	EHVAGG	MISO	INTERFACE	1,572,838
QUAD CITIES 1	AGGREGATE	NORTHWEST	INTERFACE	1,554,154
SPORN 3	AGGREGATE	OVEC	INTERFACE	1,472,620
STUART 4	AGGREGATE	OVEC	INTERFACE	1,292,612
SPORN 5	AGGREGATE	OVEC	INTERFACE	1,184,697
Top ten total				20,463,626
PJM total				122,815,948
Top ten total as percent of PJM total				16.7%

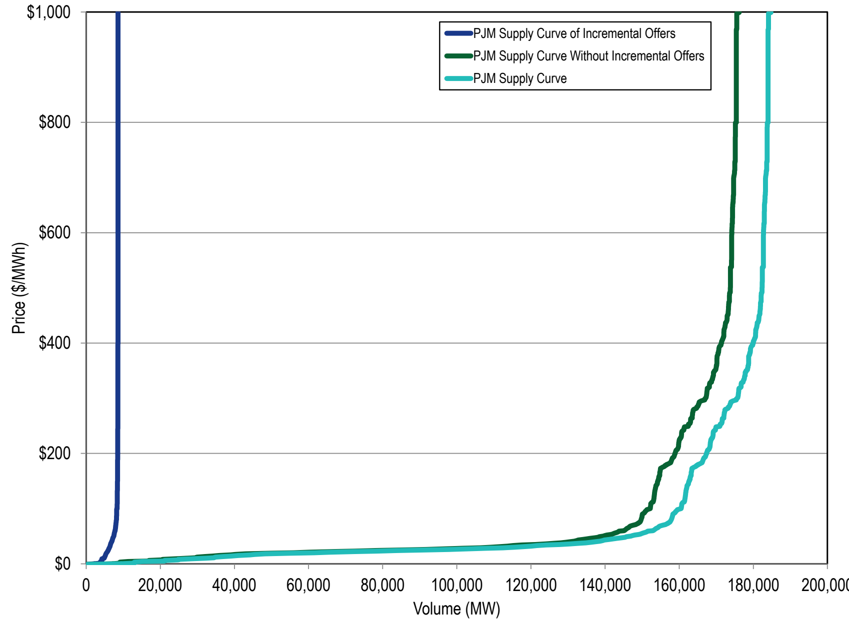
Table 2-52 shows up-to congestion transactions by wheel bids for the top ten locations for the January through September period of 2011 and 2012.

Table 2-52 PJM cleared up-to congestion wheel bids by top ten source and sink pairs (MW): January through September, 2011 and 2012 (See 2011 SOM, Table 2-49)

Source	Source Type	Sink	Sink Type	MW
2011 (Jan - Sep)				
Wheels				
CPLEIMP	INTERFACE	NCMPAEXP	INTERFACE	397,775
CPLEIMP	INTERFACE	DUKEXP	INTERFACE	287,643
NORTHWEST	INTERFACE	SOUTHWEST	AGGREGATE	204,835
NORTHWEST	INTERFACE	MISO	INTERFACE	188,239
NYIS	INTERFACE	MICHFE	INTERFACE	115,574
SOUTHWEST	AGGREGATE	OVEC	INTERFACE	111,932
MISO	INTERFACE	NIPSCO	INTERFACE	93,485
NIPSCO	INTERFACE	OVEC	INTERFACE	71,840
NIPSCO	INTERFACE	MISO	INTERFACE	63,809
NCMPAIMP	INTERFACE	OVEC	INTERFACE	62,459
Top ten total				1,597,590
PJM total				2,813,116
Top ten total as percent of PJM total				56.8%
2012 (Jan - Sep)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	252,804
NYIS	INTERFACE	IMO	INTERFACE	162,091
SOUTHIMP	INTERFACE	MISO	INTERFACE	147,801
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	120,035
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	112,478
MISO	INTERFACE	NIPSCO	INTERFACE	102,657
NORTHWEST	INTERFACE	MISO	INTERFACE	99,449
OVEC	INTERFACE	IMO	INTERFACE	72,960
MISO	INTERFACE	OVEC	INTERFACE	66,900
SOUTHWEST	INTERFACE	OVEC	INTERFACE	61,943
Top ten total				1,199,119
PJM total				1,841,782
Top ten total as percent of PJM total				65.1%

Figure 2-23 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 March 2012.

Figure 2-23 PJM day-ahead aggregate supply curves: 2012 example day (See 2011 SOM, Figure 2-21)



Price Convergence

The introduction of the PJM Day-Ahead Energy Market created the possibility that competition, exercised through the use of virtual offers and bids, would tend to cause prices in the Day-Ahead and Real-Time Energy Markets to converge. Convergence is not the goal of virtual trading but it is a possible outcome. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Market. 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 differences in 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 (Figure 2-24). There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis (Figure 2-25).

As Table 2-53 shows, day-ahead and real-time prices were relatively close, on average, in the first nine months of 2011 and 2012.

Table 2-53 Day-ahead and real-time average LMP (Dollars per MWh): January through September, 2011 and 2012[56] (See 2011 SOM, Table 2-50)

	2011 (Jan - Sep)				2012 (Jan - Sep)			
	Day Ahead	Real Time	Difference	Difference as Percent of Real Time	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$45.14	$45.79	$0.65	1.4%	$32.16	$32.45	$0.29	0.9%
Median	$40.20	$37.05	($3.14)	(8.5%)	$30.10	$28.78	($1.32)	(4.6%)
Standard deviation	$22.68	$32.25	$9.57	29.7%	$14.54	$21.94	$7.40	33.7%
Peak average	$54.11	$55.31	$1.19	2.2%	$38.16	$39.50	$1.34	3.4%
Peak median	$47.56	$42.89	($4.67)	(10.9%)	$33.74	$32.19	($1.55)	(4.8%)
Peak standard deviation	$27.09	$40.01	$12.92	32.3%	$17.76	$27.37	$9.60	35.1%
Off peak average	$37.22	$37.40	$0.18	0.5%	$26.95	$26.33	($0.62)	(2.4%)
Off peak median	$33.74	$32.90	($0.84)	(2.6%)	$25.95	$25.20	($0.74)	(2.9%)
Off peak standard deviation	$13.67	$19.86	$6.19	31.2%	$7.92	$12.98	$5.06	39.0%

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.

Table 2-54 shows the difference between the Real-Time and the Day-Ahead Energy Market Prices for the first nine months of 2001 to 2012.

Table 2-54 Day-ahead and real-time average LMP (Dollars per MWh): January through September, 2001 through 2012 (See 2011 SOM, Table 2-51)

(Jan - Sep)	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2001	$36.07	$36.00	($0.07)	(0.2%)
2002	$28.29	$28.13	($0.16)	(0.6%)
2003	$41.20	$40.42	($0.77)	(1.9%)
2004	$42.64	$43.85	$1.22	2.9%
2005	$54.48	$54.69	$0.21	0.4%
2006	$50.45	$51.79	$1.34	2.7%
2007	$54.24	$57.34	$3.10	5.7%
2008	$71.43	$71.94	$0.51	0.7%
2009	$37.35	$37.42	$0.08	0.2%
2010	$45.81	$46.13	$0.32	0.7%
2011	$45.14	$45.79	$0.65	1.4%
2012	$32.16	$32.45	$0.29	0.9%

56 The averages used are the annual average of the hourly average PJM prices for day-ahead and real-time.

Table 2-55 provides frequency distributions of the differences between PJM real-time load-weighted hourly LMP and PJM day-ahead load-weighted hourly LMP for the first nine months of years 2007 through 2012.

Table 2-55 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): January through September, 2007 through 2012 (See 2011 SOM, Table 2-52)

	2007		2008		2009		2010		2011		2012	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%	5	0.08%
($150) to ($100)	0	0.00%	1	0.02%	0	0.00%	0	0.00%	2	0.05%	6	0.17%
($100) to ($50)	26	0.40%	88	1.35%	3	0.05%	13	0.20%	49	0.79%	17	0.43%
($50) to $0	3,385	52.07%	3,730	58.08%	3,776	57.69%	4,091	62.65%	4,011	62.02%	4,112	62.97%
$0 to $50	2,914	96.55%	2,448	95.32%	2,736	99.45%	2,288	97.57%	2,290	96.98%	2,343	98.60%
$50 to $100	193	99.50%	264	99.33%	34	99.97%	130	99.56%	169	99.56%	61	99.53%
$100 to $150	21	99.82%	37	99.89%	2	100.00%	20	99.86%	21	99.88%	14	99.74%
$150 to $200	4	99.88%	4	99.95%	0	100.00%	8	99.98%	2	99.91%	10	99.89%
$200 to $250	1	99.89%	2	99.98%	0	100.00%	1	100.00%	3	99.95%	4	99.95%
$250 to $300	3	99.94%	0	99.98%	0	100.00%	0	100.00%	0	99.95%	1	99.97%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.95%	2	100.00%
$350 to $400	0	99.97%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%
$400 to $450	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%

Figure 2-24 shows the hourly differences between day-ahead and real-time load-weighted hourly LMP in the first nine months of 2012.

Figure 2-24 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: January through September, 2012 (See 2011 SOM, Figure 2-22)

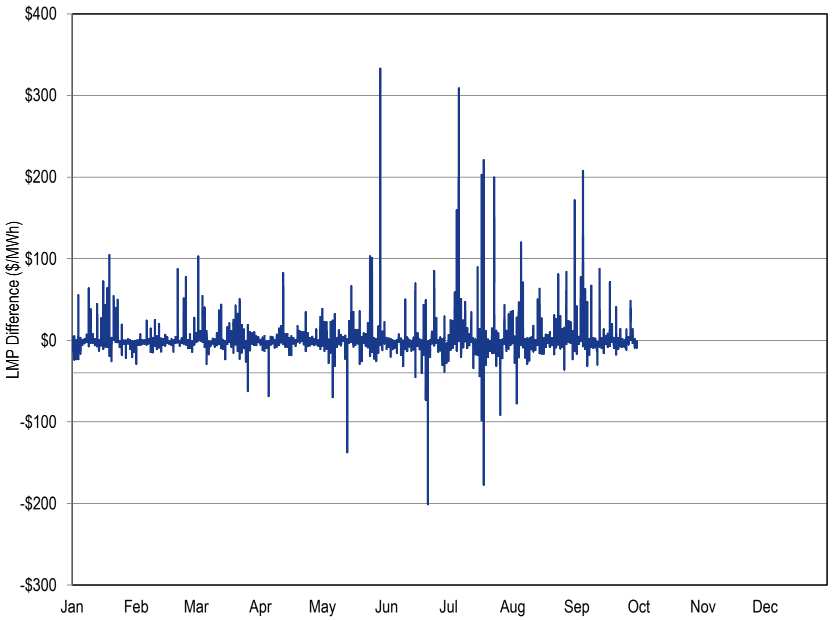
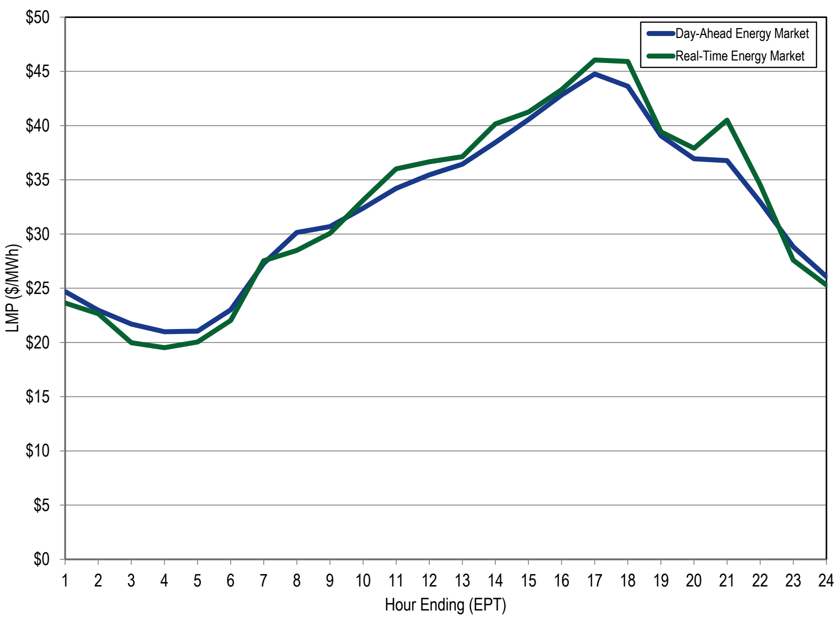


Figure 2-25 shows the monthly average differences between the day-ahead and real-time LMP in the first nine months of 2012.

Figure 2-25 Monthly average of real-time minus day-ahead LMP: January through September, 2012 (See 2011 SOM, Figure 2-23)

Figure 2-26 shows day-ahead and real-time LMP on an average hourly basis.

Figure 2-26 PJM system hourly average LMP: January through September, 2012 (See 2011 SOM, Figure 2-24)



Load and Spot Market

Real-Time Load and Spot Market

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).

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 from a non-affiliated company 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 the parent companies of PJM billing organizations that serve load in the Real-Time Energy Market for each hour. Table 2-56 shows the monthly average share of real-time load served by self-supply, bilateral contract and spot purchase in 2011 and 2012 based on parent company. For 2012, 9.4 percent of real-time load was supplied by bilateral contracts, 23.3 percent by spot market purchase and 67.3 percent by self-supply. Compared with 2011, reliance on bilateral contracts decreased 1.1 percentage points, reliance on spot supply decreased by 3.3 percentage points and reliance on self-supply increased by 4.4 percentage points.

Table 2-56 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2011 through 2012 (See 2011 SOM, Table 2-53)

	2011			2012			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	9.3%	28.8%	61.9%	10.0%	23.2%	66.9%	0.7%	(5.6%)	5.0%
Feb	10.9%	27.9%	61.2%	10.2%	22.3%	67.5%	(0.7%)	(5.6%)	6.3%
Mar	10.4%	29.3%	60.3%	10.6%	24.5%	64.8%	0.3%	(4.8%)	4.5%
Apr	10.7%	25.3%	64.1%	9.8%	23.8%	66.3%	(0.9%)	(1.4%)	2.3%
May	11.1%	25.7%	63.3%	8.9%	23.6%	67.5%	(2.3%)	(2.1%)	4.2%
Jun	10.5%	25.4%	64.1%	9.1%	23.0%	67.9%	(1.5%)	(2.4%)	3.9%
Jul	9.5%	24.7%	65.8%	8.6%	22.6%	68.8%	(0.9%)	(2.1%)	3.0%
Aug	10.3%	24.6%	65.1%	9.1%	23.2%	67.7%	(1.1%)	(1.4%)	2.6%
Sep	10.9%	26.7%	62.4%	9.6%	24.3%	66.1%	(1.3%)	(2.4%)	3.7%
Oct	12.2%	29.8%	58.0%						
Nov	10.7%	28.3%	61.1%						
Dec	10.1%	24.3%	65.5%						
Annual	10.5%	26.6%	62.9%	9.4%	23.3%	67.3%	(1.1%)	(3.3%)	4.4%

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 2-57 shows the monthly average share of day-ahead load served by self-supply, bilateral contracts and spot purchases in 2011 and 2012, based on parent companies. For 2012, 6.6 percent of day-ahead load was supplied by bilateral contracts, 22.2 percent by spot market purchases, and 71.1 percent by self-supply. Compared with 2011, reliance on bilateral contracts increased by 0.9 percentage points, reliance on spot supply decreased by 2.2 percentage points, and reliance on self-supply increased by 1.3 percentage points.

Table 2-57 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: 2011 through 2012 (See 2011 SOM, Table 2-54)

	2011			2012			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	4.7%	23.7%	71.6%	6.6%	21.4%	72.0%	1.9%	(2.3%)	0.4%
Feb	5.4%	23.7%	70.9%	6.7%	20.0%	73.3%	1.3%	(3.6%)	2.4%
Mar	5.8%	24.3%	70.0%	6.7%	22.9%	70.5%	0.9%	(1.4%)	0.5%
Apr	6.1%	23.8%	70.1%	6.7%	22.9%	70.4%	0.6%	(0.8%)	0.3%
May	6.0%	24.0%	70.0%	6.6%	22.8%	70.6%	0.6%	(1.2%)	0.6%
Jun	6.0%	25.3%	68.8%	7.9%	21.4%	70.7%	2.0%	(3.9%)	1.9%
Jul	5.5%	23.4%	71.2%	5.9%	22.2%	71.9%	0.5%	(1.2%)	0.7%
Aug	5.7%	24.1%	70.1%	6.4%	22.8%	70.8%	0.7%	(1.3%)	0.6%
Sep	5.8%	25.2%	69.0%	6.5%	24.4%	69.1%	0.7%	(0.8%)	0.1%
Oct	5.7%	25.7%	68.5%						
Nov	6.4%	25.3%	68.3%						
Dec	6.6%	25.3%	68.1%						
Annual	5.8%	24.4%	69.8%	6.6%	22.2%	71.1%	0.9%	(2.2%)	1.3%

Operating Reserve

Day-ahead and real-time operating reserve credits are paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss.[1] Sometimes referred to as uplift or 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.

Highlights

- Operating reserve charges decreased $42.8 million, or 8.9 percent, from $479.8 million in the first nine months of 2011, to $437.0 million in the first nine months of 2012. Day-ahead operating reserve charges increased $17.8 million, or 26.3 percent to $85.3 million and balancing operating reserve charges decreased $59.9 million, or 14.5 percent to $351.7 million.
- Balancing operating reserve charges for reliability decreased by $5.3 million, or 7.1 percent compared to the first nine months of 2011. Balancing operating reserve charges for deviations decreased by $47.4 million, or 27.6 percent.
- The reduction in balancing operating reserve charges was comprised of a decrease of $52.7 million in generator and real-time import transactions balancing operating reserve charges, a decrease of $9.8 million in lost opportunity costs, a decrease of $2.6 million in canceled resources and an increase of $5.2 million in charges to participants requesting resources to control local constraints.
- Generators and real-time transactions balancing operating reserve charges were $194.2 million, 55.2 percent of all balancing operating reserve charges. Balancing operating reserve charges were allocated 35.8 percent as reliability charges and 64.2 percent as deviation charges. Lost opportunity cost charges were $146.5 million or 41.7 percent of all balancing charges. The remaining 3.1 percent of balancing operating reserve charges were comprised of 0.9 percent canceled resources charges and 2.2 percent of local constraints control charges.
- The concentration of operating reserve credits among a small number of units remains high. The top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 21.1 percent of total operating reserve credits in the first nine months of 2012, compared to 29.7 percent in the first nine months of 2011. HHI for day-ahead operating reserve credits was 3868, for balancing operating reserve credits was 2847 and for lost opportunity cost credits was 3832.
- The regional concentration of operating reserves remained high in the first nine months of 2012. In the first nine months of 2012, 47.1 percent of all operating reserve credits were paid to resources in the top three zones, a decrease of 13.5 percentage points from the first nine months of 2011.

Conclusion

Day-ahead and real-time operating reserve credits are paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or 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 and variability of operating reserve charges is as low as possible consistent with the reliable operation of the system and that

1 See the *2011 State of the Market Report for PJM: Volume II*, Section 3, "Operating Reserve" at "Description of Operating Reserves" for a full description of how operating reserve credits and charges are calculated.

the allocation of operating reserve charges reflects the reasons that the costs are incurred.

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 and 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, no load and startup costs.

PJM has improved its oversight of operating reserves and continues 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. However, given the impact of operating reserve charges on market participants, particularly virtual market participants, PJM should take another step towards more precise definition of the reasons for incurring operating reserve charges and about the necessity of paying operating reserve charges in some cases. The goal should be to have dispatcher decisions reflected in transparent market outcomes to the maximum extent possible and to minimize the level and rate of operating reserve charges.

In addition, the allocation of operating reserve charges to participants should be carefully reexamined to ensure that such charges are paid by all whose market actions result in the incurrence of such charges. For example, there has not been an analysis of the impact of up-to congestion transactions and their impact on the payment of operating reserve credits. Up-to congestion transactions continue to pay no operating reserve charges, which means that all others who pay operating reserve charges are paying too much. In addition, the issue of netting using internal bilateral transactions should be addressed.

Overall the goal should be to minimize the total level of operating reserve credits paid and to ensure that the associated charges are paid by all those whose market actions result in the incurrence of such charges. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with operating reserve charges and to reduce the impact of operating reserve charges on decisions about how and when to participate in PJM markets.

Operating Reserve Credits and Charges

The level of operating reserve credits paid to specific units depends on the level of the unit's energy offer, the LMP, the unit's operating parameters and 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, no load and startup costs.

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 3-1 shows the categories of credits and charges and their relationship. This table shows how charges are allocated. Table 3-2 shows the different types of deviations.

Table 3-1 Operating reserve credits and charges (See 2011 SOM, Table 3-1)

Credits received for:		Charges paid by:
	Day-Ahead	
Day-Ahead Import Transactions Demand-Side Response Resources Generation Resources	→	Day-Ahead Demand Bid Day-Ahead Export Transactions Decrement Bids
Synchronous Condensing	→	Real-Time Export Transactions Real-Time Load
	Balancing	
Generation Resources — Deviations	→	Real-Time Deviations from Day-Ahead Schedule by RTO, East and West Region
Generation Resources — Reliability	→	Real-Time Load plus Export Transactions by RTO, East and West Region
Canceled Resources Demand-Side Response Resources Lost Opportunity Cost Performing Annual Scheduled Black Start Tests Providing Quick Start Reserve Real-Time Import Transactions	→	Real-Time Deviations from Day-Ahead Schedule in the entire RTO
Local Constraints Control	→	Applicable Requesting Party
Providing Reactive Service	→	Zonal Real-Time Load

Table 3-2 Operating reserve deviations (See 2011 SOM, Table 3-2)

Day-Ahead	Deviations	Real-Time
Day-Ahead Demand Bid Day-Ahead Sales Day-Ahead Export Transactions Decrement Bids	Demand (Withdrawal) (RTO, East, West)	Real-Time Load Real-Time Sales Real-Time Export Transactions
Day-Ahead Purchases Day-Ahead Import Transactions Increment Offers	Supply (Injection) (RTO, East, West)	Real-Time Purchases Real-Time Import Transactions
Day-Ahead Scheduled Generation	Generator (Unit)	Real-Time Generation

Operating Reserve Results

Operating Reserve Charges

Table 3-3 shows total operating reserve charges for the first nine months of 2011 and 2012.[2] Total operating reserve charges decreased by 8.9 percent in the first nine months of 2012 compared to the first nine months of 2011, to a total of $437.0 million.

Table 3-3 Total operating reserve charges: January through September 2011 and 2012 (See 2011 SOM, Table 3-6)[3]

	Jan-Sep 2011	Jan-Sep 2012	Change	Percentage Change
Total Operating Reserve Charges	$479,805,042	$436,984,853	($42,820,190)	(8.9%)
Operating Reserve as a Percent of Total PJM Billing	1.7%	2.0%	0.3%	18.7%
Day-Ahead Rate ($/MWh)	0.1092	0.1350	0.0258	23.6%
Balancing RTO Deviation Rate ($/MWh)	1.0510	0.9398	(0.1113)	(10.6%)
Balancing RTO Reliability Rate ($/MWh)	0.0832	0.0230	(0.0603)	(72.4%)

Total operating reserve charges in the first nine months of 2012 were $437.0 million, down from the total of $479.8 million in the first nine months of 2011. Table 3-4 compares monthly operating reserve charges by category for calendar years 2011 and 2012. The decrease of 8.9 percent in the first nine months of 2012 is comprised of a 26.3 percent increase in day-ahead operating reserve charges, a 93.0 percent decrease in synchronous condensing charges and a 14.5 percent decrease in balancing operating reserve charges.

The increase in day-ahead operating reserve charges was primarily a result of PJM scheduling units for reliability purposes in the Day-Ahead Energy Market in order to reduce divergence between the Day-Ahead and the Real-Time Energy Markets.

2 Table 3-3 includes all categories of charges as defined in Table 3-1 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 current on October 11, 2012.

3 The total operating reserve charges in Table 3-3 are $0.6 million higher than the total charges published in the *2011 State of the Market Report for PJM*. PJM may recalculate new settlements after the State of the Market Report is published.

Table 3-4 Monthly operating reserve charges: Calendar years 2011 and 2012 (See 2011 SOM, Table 3-7)

	2011				2012			
	Day-Ahead	Synchronous Condensing	Balancing	Total	Day-Ahead	Synchronous Condensing	Balancing	Total
Jan	$12,373,099	$110,095	$47,090,369	$59,573,563	$8,311,574	$15,362	$27,322,330	$35,649,266
Feb	$8,940,203	$139,287	$26,607,792	$35,687,282	$5,858,308	$18,592	$24,869,649	$30,746,549
Mar	$6,837,719	$66,032	$23,238,170	$30,141,921	$3,852,873	$1,648	$29,702,257	$33,556,779
Apr	$4,405,102	$13,011	$18,764,254	$23,182,366	$2,967,302	$0	$34,168,700	$37,136,002
May	$7,064,934	$39,417	$43,540,784	$50,645,135	$7,956,965	$0	$43,695,141	$51,652,106
Jun	$8,303,391	$9,056	$59,886,618	$68,199,066	$6,988,065	$0	$45,664,065	$52,652,130
Jul	$4,993,311	$238,127	$103,271,440	$108,502,878	$11,773,101	$0	$66,408,580	$78,181,681
Aug	$8,360,392	$104,982	$53,819,941	$62,285,315	$8,695,770	$0	$47,310,263	$56,006,033
Sep	$6,249,240	$40,878	$35,297,398	$41,587,517	$28,877,736	$17,512	$32,509,059	$61,404,307
Oct	$5,133,837	$0	$20,415,483	$25,549,319				
Nov	$7,063,847	$0	$19,528,707	$26,592,554				
Dec	$7,593,046	$0	$24,716,729	$32,309,775				
Total	$67,527,391	$760,886	$411,516,766	$479,805,042	$85,281,694	$53,115	$351,650,044	$436,984,853
Share of Charges	14.1%	0.2%	85.8%	100.0%	19.5%	0.0%	80.5%	100.0%

Table 3-5 shows the monthly composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing generation, real-time import transaction, lost opportunity cost charges, canceled pool-scheduled resources, and charges paid to resources controlling local constraints. In the first nine months of 2012, generation and transactions charges decreased by $52.7 million or 21.3 percent, lost opportunity cost charges decreased by $9.8 million or 6.2 percent, canceled resources charges decreased by $2.6 million or 43.9 percent and charges for local constraints control increased by $5.2 million or 214.1 percent.

Table 3-5 Monthly balancing operating reserve charges by category: Calendar years 2011 and 2012 (See 2011 SOM, Table 3-8)

	2011				2012			
	Generation and Transactions	Lost Opportunity Cost	Canceled Resources	Local Constraints Control	Generation and Transactions	Lost Opportunity Cost	Canceled Resources	Local Constraints Control
Jan	$43,170,696	$2,946,513	$639,107	$334,052	$20,440,833	$5,449,229	$777,386	$654,882
Feb	$22,698,872	$3,205,948	$208,046	$494,927	$18,907,159	$4,644,133	$517,613	$800,744
Mar	$15,456,921	$7,094,881	$358,223	$328,146	$16,982,255	$10,777,661	$1,120,962	$821,380
Apr	$11,096,912	$7,222,704	$303,514	$141,123	$20,252,666	$12,507,091	$409,047	$999,896
May	$20,331,609	$20,364,971	$2,742,644	$101,559	$23,216,158	$19,242,410	$452,294	$784,279
Jun	$30,610,434	$27,996,648	$901,825	$377,711	$29,111,054	$15,179,311	$13,031	$1,360,668
Jul	$56,569,143	$46,339,477	$299,607	$63,213	$34,779,195	$30,943,088	$21,256	$665,042
Aug	$29,236,518	$24,156,594	$311,184	$115,645	$19,632,482	$26,491,201	$0	$1,186,580
Sep	$17,735,689	$16,948,364	$151,195	$462,150	$10,902,289	$21,279,381	$4,624	$322,765
Oct	$10,460,806	$6,327,845	$1,250,928	$2,375,903				
Nov	$11,415,410	$6,181,160	$1,663,154	$268,983				
Dec	$20,477,899	$3,574,430	$306,260	$358,140				
Total	$246,906,793	$156,276,100	$5,915,345	$2,418,527	$194,224,092	$146,513,504	$3,316,212	$7,596,235
Share of Charges	60.0%	38.0%	1.4%	0.6%	55.2%	41.7%	0.9%	2.2%

Table 3-6 and Table 3-7 show the amount and percentages of regional balancing charge allocations for the first nine months of 2011 and 2012. The largest share of charges was paid by RTO demand deviations. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints, resources providing quick start reserve and resources performing annual, scheduled black start tests.

In the first nine months of 2012, balancing operating reserve charges, excluding lost opportunity costs, canceled resources and local constraints control categories, decreased by $52.7 million compared to the first nine months of 2011. Balancing operating reserve charges for reliability decreased by $5.3 million or 7.1 percent and balancing reserve charges for deviations decreased by $47.4 million or 27.6 percent. Reliability charges in the Western Region increased by $30.9 million compared to the first nine months of 2011, as a result of payments to units providing black start and voltage support. The remaining two reliability categories decreased by $36.2 million.

Table 3-6 Regional balancing charges allocation: January through September 2011[4] (See 2011 SOM, Table 3-9)

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$45,781,885	11.2%	$9,760,186	2.4%	$16,011,131	3.9%	$71,553,202	17.5%
	Real-Time Exports	$1,850,168	0.5%	$583,295	0.1%	$874,280	0.2%	$3,307,743	0.8%
	Total	$47,632,053	11.6%	$10,343,482	2.5%	$16,885,410	4.1%	$74,860,945	18.3%
Deviation Charges	Demand	$79,655,606	19.5%	$23,547,417	5.8%	$3,510,103	0.9%	$106,713,126	26.1%
	Supply	$23,726,418	5.8%	$6,097,061	1.5%	$1,248,814	0.3%	$31,072,294	7.6%
	Generator	$26,914,956	6.6%	$5,870,431	1.4%	$1,475,040	0.4%	$34,260,428	8.4%
	Total	$130,296,980	31.8%	$35,514,910	8.7%	$6,233,958	1.5%	$172,045,848	42.1%
Lost Opportunity Cost and Canceled Resources Charges	Demand	$101,180,178	24.7%	$0	0.0%	$0	0.0%	$101,180,178	24.7%
	Supply	$27,636,347	6.8%	$0	0.0%	$0	0.0%	$27,636,347	6.8%
	Generator	$33,374,919	8.2%	$0	0.0%	$0	0.0%	$33,374,919	8.2%
	Total	$162,191,445	39.6%	$0	0.0%	$0	0.0%	$162,191,445	39.6%
Total Balancing Charges		$340,120,479	83.1%	$45,858,392	11.2%	$23,119,368	5.7%	$409,098,238	100%

Table 3-7 Regional balancing charges allocation: January through September 2012[5] (See 2011 SOM, Table 3-9)

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$13,447,588	3.9%	$7,743,241	2.3%	$45,958,032	13.4%	$67,148,860	19.5%
	Real-Time Exports	$389,645	0.1%	$163,838	0.0%	$1,875,423	0.5%	$2,428,906	0.7%
	Total	$13,837,233	4.0%	$7,907,079	2.3%	$47,833,455	13.9%	$69,577,767	20.2%
Deviation Charges	Demand	$62,737,232	18.2%	$9,169,890	2.7%	$3,799,573	1.1%	$75,706,696	22.0%
	Supply	$18,211,804	5.3%	$2,962,176	0.9%	$898,364	0.3%	$22,072,344	6.4%
	Generator	$22,649,202	6.6%	$2,549,641	0.7%	$1,668,443	0.5%	$26,867,286	7.8%
	Total	$103,598,238	30.1%	$14,681,707	4.3%	$6,366,381	1.9%	$124,646,325	36.2%
Lost Opportunity Cost and Canceled Resources Charges	Demand	$89,482,171	26.0%	$0	0.0%	$0	0.0%	$89,482,171	26.0%
	Supply	$26,555,929	7.7%	$0	0.0%	$0	0.0%	$26,555,929	7.7%
	Generator	$33,791,618	9.8%	$0	0.0%	$0	0.0%	$33,791,618	9.8%
	Total	$149,829,717	43.5%	$0	0.0%	$0	0.0%	$149,829,717	43.5%
Total Balancing Charges		$267,265,187	77.7%	$22,588,786	6.6%	$54,199,836	15.8%	$344,053,809	100%

Operating Reserve Rates

Under the operating reserves cost allocation rules, PJM calculates nine separate rates, a day-ahead operating reserve rate, a reliability rate for each region, a deviation rate for each region, a lost opportunity cost rate and a canceled resources rate for the entire RTO. See Table 3-1 for how these charges are allocated.

Figure 3-1 shows the weekly weighted average day-ahead operating reserve rate for the first nine months of 2011 and 2012. The average rate in the first nine months of 2012 was $0.1350 per MWh, $0.0258 per MWh higher than the average of the first nine months of 2011. The highest rate occurred on September 20, when the rate reached $0.8714 per MWh, 90.5 percent higher than the $0.4574 reached during the first nine months of 2011, on August 27. On September 13, 2012, PJM increased the amount of generation scheduled in the Day-Ahead Energy Market for reliability purposes. This change shifted the allocation operating reserve charges from the Real-Time Energy Market to the Day-Ahead Energy Market.

4 The total charges shown in Table 3-6 do not equal the total balancing charges shown in Table 3-5 because the totals in Table 3-5 include charges to resources controlling local constraints while the totals in Table 3-6 do not.

5 The total charges shown in Table 3-7 do not equal the total balancing charges shown in Table 3-5 because the totals in Table 3-5 include charges to resources controlling local constraints while the totals in Table 3-7 do not.

Figure 3-1 Weekly weighted average day-ahead operating reserve rate ($/MWh): Calendar years 2011 and 2012 (See 2011 SOM, Figure 3-1)

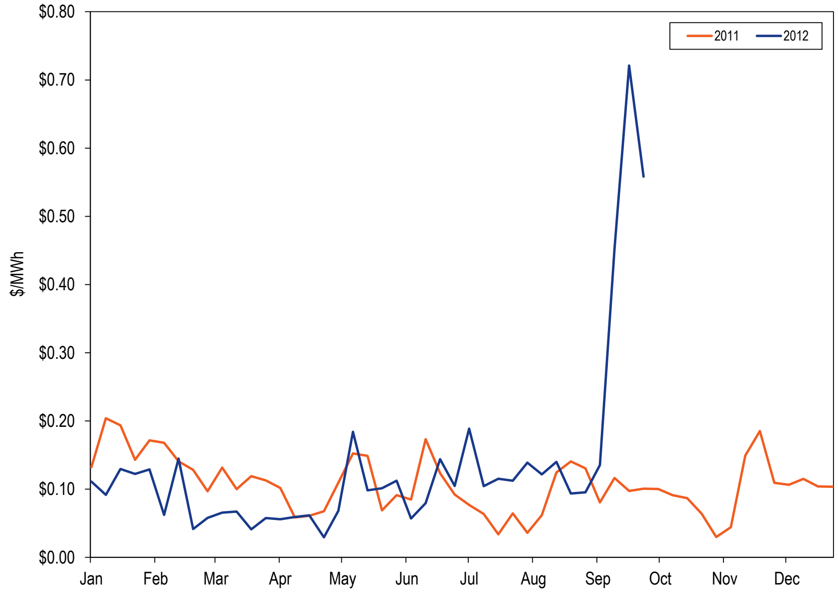


Figure 3-2 Daily balancing operating reserve reliability rates ($/MWh): Calendar years 2011 and 2012 (See 2011 SOM, Figure 3-2)

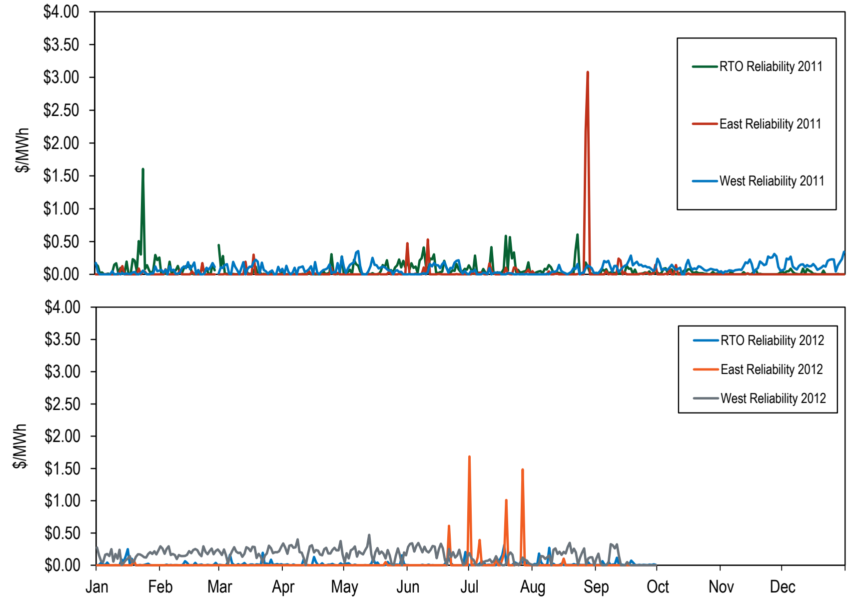


Figure 3-2 shows the RTO and the regional reliability rates for the first nine months of 2011 and 2012. The average daily RTO reliability rate was $0.0230 per MWh. The highest RTO reliability rate of 2012 occurred on July 18, when the rate reached $0.3160 per MWh. In the first nine months of 2012, reliability rates in the Eastern Region were positive for only 14 days. Hot weather related demand in the entire RTO and specifically in the Dominion control zone led to the top three Eastern Region reliability rates in 2012, on July 1, 19 and 27, the Eastern Region reliability rate reached $1.6869, $1.0099 and $1.4847 per MWh.[6] Reliability rates in the Western Region have been high primarily because of the use of certain units to provide black start and voltage support.

Figure 3-3 shows the RTO and the regional deviation rates for the first nine months of 2011 and 2012. The average daily RTO deviation rate was $0.9398 per MWh. The highest daily rate in the first nine months occurred on July 26, when the RTO deviation rate reached $3.7260 per MWh.[7] The highest Eastern Region rate occurred on July 7. The Western Region deviation rate increase on April 12 was due to the loss of a 345 kV transmission line in the Pittsburgh area.

6 PJM issued consecutive Hot Weather Alerts for the entire RTO region for June 20 and June 21, and for June 28 through July 7, for the Dominion and Mid-Atlantic zones for June 22 and July 27 and for the Dominion zone only on July 19.

7 The June 29, 2012, RTO deviation rate ($3.9347 per MWh) published in the *2012 Quarterly State of the Market Report for PJM: January through June* was higher than the July 26 rate, but the former was recalculated by PJM and resulted in a lower rate ($3.6802 per MWh).

Figure 3-3 Daily balancing operating reserve deviation rates ($/MWh): Calendar years 2011 and 2012 (See 2011 SOM, Figure 3-2)

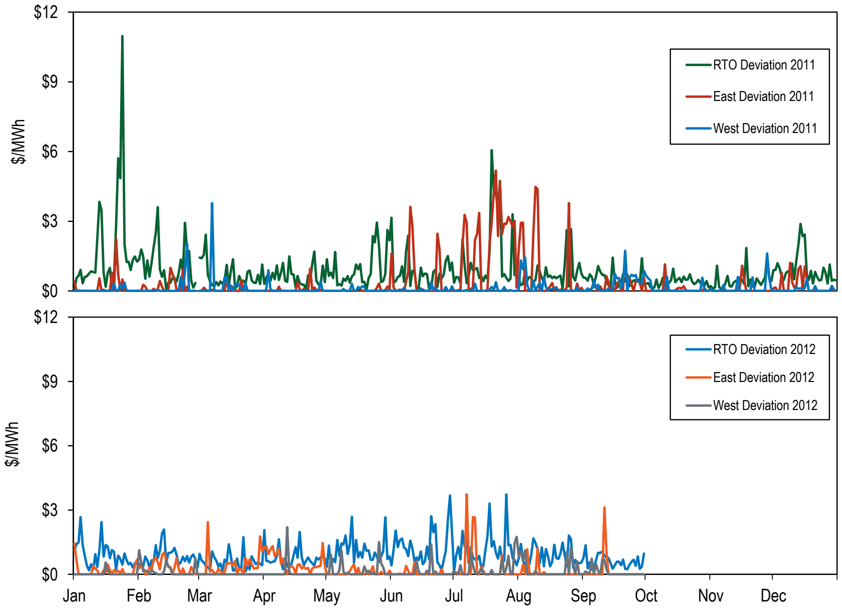


Figure 3-4 Daily lost opportunity cost and canceled resources rates ($/MWh): Calendar years 2011 and 2012 (See 2011 SOM, Figure 3-2)

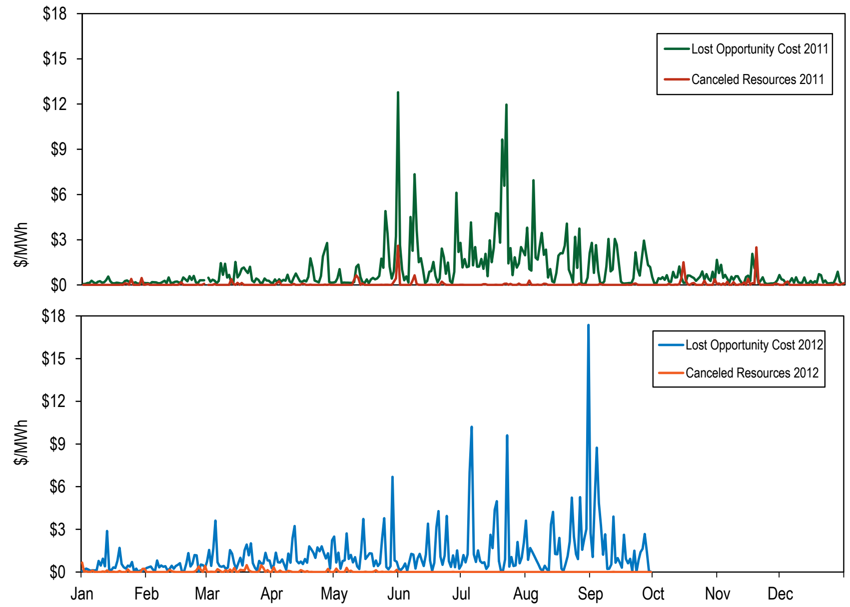


Figure 3-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for the first nine months of 2011 and 2012. The lost opportunity rate averaged $1.3291 per MWh. The highest lost opportunity cost rate occurred on August 31, when it reached $17.3678 per MWh. Increases in the lost opportunity rate are often caused by high real-time prices which increases the total lost opportunity cost credits paid to combustion turbines scheduled to run but not called in real time. The canceled resources rate averaged $0.0301 per MWh and credits were paid during 35.3 percent of all the days in the first nine months of 2012.

Table 3-8 shows the rates for each region in each category. RTO deviation charges and lost opportunity cost charges accounted for 71.1 percent of all balancing operating reserve charges in the first nine months of 2012.

Table 3-8 Balancing operating reserve rates ($/MWh): January through September 2011 and 2012 (See 2011 SOM, Table 3-10)

	2011				2012			
	Reliability ($/MWh)	Deviations ($/MWh)	Lost Opportunity Cost ($/MWh)	Canceled Resources ($/MWh)	Reliability ($/MWh)	Deviations ($/MWh)	Lost Opportunity Cost ($/MWh)	Canceled Resources ($/MWh)
RTO	0.0832	1.0510	1.2606	0.0477	0.0230	0.9398	1.3291	0.0301
East	0.0347	0.5087	NA	NA	0.0277	0.2424	NA	NA
West	0.0616	0.1160	NA	NA	0.1505	0.1289	NA	NA

Table 3-9 shows the operating reserve cost of a 1 MW transaction during the first nine months of 2012. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $2.5612 per MWh with a maximum rate of $17.9612 per MWh, a minimum rate of $0.4698 per MWh and a standard deviation of $1.8549 per MWh. The rates in the table include all operating reserve charges including RTO deviation charges. Table 3-9 illustrates both the average level of operating reserve charges to transaction types but also the uncertainty reflected in the maximum, minimum and standard deviation levels.

Table 3-9 Operating reserve rates statistics ($/MWh): January through September 2012 (See 2011 SOM, Table 3-11)

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	17.9166	2.4227	0.3299	1.8717
	DEC	17.9612	2.5612	0.4698	1.8549
	DA Load	0.8714	0.1385	0.0000	0.1572
	RT Load	1.6900	0.0428	0.0000	0.1637
	Deviation	17.9166	2.4227	0.3299	1.8717
West	INC	17.9166	2.3008	0.3299	1.9071
	DEC	17.9612	2.4393	0.4092	1.8964
	DA Load	0.8714	0.1385	0.0000	0.1572
	RT Load	0.4726	0.1788	0.0016	0.0990
	Deviation	17.9166	2.3008	0.3299	1.9071

Deviations

Under PJM's operating reserve rules, credits allocated to generators defined to be operating to control deviations on the system, lost opportunity credits and credits to canceled resources are charged to deviations. Deviations fall into three categories; demand, supply and generator deviations, and are calculated on an hourly basis. Supply and demand deviations are netted separately for each participant by zone, hub, or interface, and totaled for the day. Each category of deviation is calculated separately and a PJM member may have deviations in all three categories.

Table 3-10 shows monthly real-time deviations for demand, supply and generator categories for 2011 and the first nine months of 2012. These deviations are the sum of the regional deviations. Total deviations summed across the demand, supply, and generator categories were lower in the first nine months of 2012 compared to the first nine months of 2011 by 13,744,693 MWh or 11.1 percent. Demand deviations decreased by 13.4 percent, supply deviations decreased by 10.7 percent, and generator deviations decreased by 4.6 percent. In the first nine months of 2012 compared to the first nine months of 2011, the share of total deviations in the demand category decreased by 1.6 percentage points, the share of supply deviations increased by 0.1 percentage points, and the share of generator deviations increased by 1.5 percentage points.

Table 3-10 Monthly balancing operating reserve deviations (MWh): Calendar years 2011 and 2012 (See 2011 SOM, Table 3-3)

	2011 Deviations				2012 Deviations			
	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)	Demand (MWh)	Supply (MWh)	Generator (MWh)	Total (MWh)
Jan	9,798,230	3,261,409	3,107,683	16,167,323	7,340,668	2,496,321	2,779,139	12,616,128
Feb	7,196,554	2,809,384	2,680,742	12,686,680	5,894,708	2,380,558	2,303,940	10,579,207
Mar	7,510,358	2,467,175	2,730,454	12,707,988	6,041,789	2,776,439	2,608,928	11,427,156
Apr	6,623,238	2,027,200	2,662,761	11,313,199	6,295,762	2,288,554	2,504,541	11,088,857
May	7,144,854	2,381,825	2,902,093	12,428,772	7,738,120	2,565,938	2,915,540	13,219,598
Jun	9,845,466	2,558,697	2,996,041	15,400,204	8,400,299	2,020,919	3,092,756	13,513,974
Jul	10,160,922	2,690,836	3,306,340	16,158,098	9,237,687	2,188,799	3,498,150	14,924,636
Aug	8,566,032	2,057,281	2,907,427	13,530,739	7,676,248	1,640,431	2,635,129	11,951,808
Sep	8,829,765	2,198,858	2,561,534	13,590,157	6,908,675	1,687,460	2,320,968	10,917,102
Oct	7,140,856	2,514,963	2,388,186	12,044,005				
Nov	6,739,882	2,704,677	2,949,889	12,394,448				
Dec	7,646,566	2,606,633	2,629,846	12,883,045				
Total	75,675,421	22,452,664	25,855,076	123,983,161	65,533,957	20,045,419	24,659,091	110,238,467
Share of Deviations	61.0%	18.1%	20.9%	100.0%	59.4%	18.2%	22.4%	100.0%

Real-time load, real-time exports, and deviations in each region are shown in Table 3-11. RTO deviations are defined as the sum of eastern and western deviations, plus deviations from hubs that span multiple regions.

Table 3-11 Regional charges determinants (MWh): January through September 2012 (See 2011 SOM, Table 3-4)

	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
RTO	583,065,065	19,828,074	602,893,139	65,533,957	20,045,419	24,659,091	110,238,467
East	277,605,000	7,555,552	285,160,552	37,727,176	11,735,893	11,106,979	60,570,049
West	305,460,065	12,272,522	317,732,587	27,568,221	8,261,711	13,552,112	49,382,044

Operating Reserve Credits by Category

Table 3-12 shows the totals for each credit category for the first nine months of 2011 and 2012. During the first nine months of 2012, 80.5 percent of total operating reserve credits were in the balancing energy market category, which includes the balancing generator, real-time transactions, and lost opportunity cost credits. This percentage decreased 5.3 percentage points from the 85.8 percent for the first nine months of 2011.

Table 3-12 Credits by operating reserve category: January through September 2011 and 2012 (See 2011 SOM, Table 3-12)

Category	Jan-Sep 2011	Jan-Sep 2012	Change	Percentage Change	Jan-Sep 2011 Share of Credits	Jan-Sep 2012 Share of Credits
Day-Ahead Generator	$67,216,527	$85,281,139	$18,064,612	26.9%	14.0%	19.5%
Day-Ahead Transactions	$310,864	$554	($310,310)	(99.8%)	0.1%	0.0%
Synchronous Condensing	$760,885	$53,115	($707,771)	(93.0%)	0.2%	0.0%
Balancing Generator	$245,338,532	$194,175,120	($51,163,412)	(20.9%)	51.1%	44.4%
Balancing Transactions	$1,568,263	$48,972	($1,519,291)	(96.9%)	0.3%	0.0%
Lost Opportunity Cost	$156,276,098	$146,513,503	($9,762,596)	(6.2%)	32.6%	33.5%
Canceled Resources	$5,915,347	$3,316,214	($2,599,133)	(43.9%)	1.2%	0.8%
Local Constraints Control	$2,418,527	$7,596,235	$5,177,707	214.1%	0.5%	1.7%
Total	$479,805,044	$436,984,851	($42,820,193)	(8.9%)	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 3-13 shows the distribution of credits by unit type and type of operating reserve (each row sums to 100 percent). Credits to demand resources are not included.

Table 3-13 Credits by unit types (By operating reserve category): January through September 2012 (See 2011 SOM, Table 3-13)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Canceled Resources	Local Constraints Control	Total
Battery	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	$1,938
Combined Cycle	34.4%	0.0%	53.1%	12.4%	0.0%	0.0%	$40,817,603
Combustion Turbine	3.7%	0.0%	22.5%	73.6%	0.0%	0.2%	$181,560,737
Diesel	1.0%	0.0%	50.8%	48.1%	0.0%	0.0%	$2,405,958
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	$0
Hydro	0.0%	0.0%	89.9%	0.0%	10.1%	0.0%	$270,027
Nuclear	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	$337,984
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	$0
Steam - Coal	33.8%	0.0%	59.3%	2.8%	0.0%	4.1%	$175,368,663
Steam - Others	16.9%	0.0%	82.0%	1.1%	0.0%	0.0%	$31,826,060
Wind	0.0%	0.0%	1.1%	25.0%	74.0%	0.0%	$4,346,356

Table 3-14 shows the distribution of credits for each operating reserve category received by each unit type (each column sums to 100 percent). Combined cycle units and conventional steam units fueled by coal received 85.9 percent of the day-ahead generator credits. Combustion turbines received 100.0 percent of the synchronous condensing credits. Combustion turbines and diesels received 92.0 percent of the lost opportunity cost credits. Wind units received 97.0 percent of the canceled resources credits.

Table 3-14 Credits by operating reserve category (By unit type): January through September 2012 (See 2011 SOM, Table 3-14)

Unit Type	Day-Ahead Generator	Synchronous Condensing	Balancing Generator	Lost Opportunity Cost	Canceled Resources	Local Constraints Control
Battery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Combined Cycle	16.5%	0.0%	11.2%	3.5%	0.2%	0.1%
Combustion Turbine	7.8%	100.0%	21.0%	91.2%	2.0%	4.9%
Diesel	0.0%	0.0%	0.6%	0.8%	0.0%	0.0%
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Hydro	0.0%	0.0%	0.1%	0.0%	0.8%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	69.4%	0.0%	53.6%	3.4%	0.0%	94.9%
Steam - Others	6.3%	0.0%	13.4%	0.2%	0.0%	0.1%
Wind	0.0%	0.0%	0.0%	0.7%	97.0%	0.0%
Total	$85,281,139	$53,115	$194,175,120	$146,513,503	$3,316,214	$7,596,235

Table 3-15 shows the total credits by unit type for the first nine months of 2011 and 2012. The reduction of the price spread between natural gas and coal prices resulted in an increase in operating reserve credits paid to steam turbines fueled by coal. In the first nine months of 2012, 40.1 percent of all credits were paid to coal units, 19.4 percentage points more than the share in the first nine months of 2011. In contrast, the share of total credits paid to gas fired combined cycles declined from 20.0 percent in the first nine months of 2011 to 9.3 percent in the first nine months of 2012.

Table 3-15 Credits by unit type: January through September 2011 and 2012 (New Table)

Unit Type	Jan-Sep 2011	Jan-Sep 2012	Change	Percentage Change	Jan-Sep 2011 Share of Credits	Jan-Sep 2012 Share of Credits
Battery	$12,488	$1,938	($10,550)	(84.5%)	0.0%	0.0%
Combined Cycle	$95,458,909	$40,817,603	($54,641,306)	(57.2%)	20.0%	9.3%
Combustion Turbine	$193,268,239	$181,560,737	($11,707,502)	(6.1%)	40.4%	41.6%
Diesel	$14,691,893	$2,405,958	($12,285,935)	(83.6%)	3.1%	0.6%
Fuel Cell	$0	$0	$0	0.0%	0.0%	0.0%
Hydro	$285,577	$270,027	($15,550)	(5.4%)	0.1%	0.1%
Nuclear	$291,748	$337,984	$46,235	15.8%	0.1%	0.1%
Solar	$0	$0	$0	0.0%	0.0%	0.0%
Steam - Coal	$99,156,003	$175,368,663	$76,212,659	76.9%	20.7%	40.1%
Steam - Others	$69,645,774	$31,826,060	($37,819,714)	(54.3%)	14.6%	7.3%
Wind	$5,115,285	$4,346,356	($768,929)	(15.0%)	1.1%	1.0%
Total	$477,925,917	$436,935,325	($40,990,592)	(8.6%)	100.0%	100.0%

Wind Unit Credits

On June 1, 2012, PJM began to correctly categorize credits paid to wind units for lost opportunity cost and not as canceled resources credits. Also on June 1, 2012, PJM implemented new lost opportunity cost credit rules for wind units. Under the new rules, lost opportunity cost credits paid to wind units will be based on the lesser of the LMP desired output and the forecasted output of the unit.[8]

Credits paid to wind units decreased in the first nine months of 2012. In the first nine months of 2012 the total was $4.3 million, lower than the $5.1 million paid in the first nine months of 2011. Table 3-16 shows the monthly credits paid to wind units.

8 See "PJM Manual 28: Operating Agreement Accounting" Revision 52 (June 1, 2012), Credits for Resources Reduced or Suspended due to a Transmission Constraint or for Other Reliability Reasons.

Table 3-16 Credits paid to wind units: Calendar years 2011 and 2012 (See 2011 SOM, Table 3-15)

	2011				2012			
	Balancing Generator	Lost Opportunity Cost	Canceled Resources	Total	Balancing Generator	Lost Opportunity Cost	Canceled Resources	Total
Jan	$0	$0	$468,059	$468,059	$0	$0	$741,979	$741,979
Feb	$0	$0	$182,151	$182,151	$0	$0	$517,612	$517,612
Mar	$0	$0	$344,622	$344,622	$0	$72	$1,098,130	$1,098,202
Apr	$0	$0	$271,810	$271,810	$20,990	$0	$409,047	$430,038
May	$0	$0	$2,446,129	$2,446,129	$23,212	$0	$448,836	$472,048
Jun	$0	$0	$839,074	$839,074	$817	$119,002	$0	$119,819
Jul	$0	$0	$167,310	$167,310	$129	$63,805	$0	$63,934
Aug	$0	$0	$244,935	$244,935	$0	$156,792	$0	$156,792
Sep	$0	$0	$151,194	$151,194	$683	$745,249	$0	$745,931
Oct	$0	$0	$1,325,128	$1,325,128				
Nov	$0	$0	$2,336,582	$2,336,582				
Dec	$0	$0	$420,210	$420,210				
Total	$0	$0	$5,115,285	$5,115,285	$45,831	$1,084,920	$3,215,605	$4,346,356

The AEP and ComEd Control Zones are the only zones with wind units receiving operating reserve credits.

Economic and Noneconomic Generation[9]

Economic dispatch generation includes units scheduled day ahead or producing energy in real time at an incremental offer less than or equal to the LMP at the unit's bus. Noneconomic generation includes units that are scheduled or producing energy at an incremental offer higher than the LMP at the unit's bus. Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing generator operating reserve credits are paid on a segmented basis for each period defined by the greater of the day-ahead schedule and minimum run time. Table 3-17 shows PJM's day-ahead and real-time total generation and the amount of generation eligible for operating reserve credits. In the Day-Ahead Energy Market only pool-scheduled resources are eligible for day-ahead operating reserve credits. In the Real-Time Energy Market only pool-scheduled resources that follow PJM's dispatch instructions are eligible for balancing operating reserve credits.

9 The analysis of economic and noneconomic generation in previous *State of the Market Reports for PJM* was based on the relationship between the units' hourly average incremental offer and the LMP at the units' bus. The new analysis is based on the units' incremental offer, the value used by PJM to calculate the LMPs. Both analysis do not include no load and startup cost.

The MMU analyzed PJM's day-ahead and real-time generation eligible for operating reserve credits to determine the economic and noneconomic generation. Each unit's hourly generation was determined to be economic or noneconomic based solely on the unit's hourly incremental offer, excluding the hourly no load cost and any applicable startup cost. A unit could be economic for every hour during a day or segment, but still receive operating reserve credits because the energy revenues did not cover the additional hourly no load and startup costs. A unit could be noneconomic for an hour or multiple hours and not receive operating reserve credits because total energy revenues covered total hourly costs. In the first nine months of 2012, 35.0 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 32.8 percent of the real-time generation was eligible for balancing operating reserve credits.

Table 3-17 Day-ahead and real-time generation (GWh): January through September 2012 (New Table)

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percentage
Day-Ahead	606,162	211,986	35.0%
Real-Time	602,561	197,561	32.8%

Table 3-18 shows PJM's economic and noneconomic generation eligible for operating reserve credits. In the first nine months of 2012, 84.9 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.7 percent of the real-time generation eligible for operating reserve credits was economic.

Table 3-18 Day-ahead and real-time economic and noneconomic generation (GWh): January through September 2012 (New Table)

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percentage	Noneconomic Generation Percentage
Day-Ahead	179,884	32,102	84.9%	15.1%
Real-Time	131,678	65,882	66.7%	33.3%

Table 3-19 shows the generation receiving day-ahead and balancing operating reserve credits. In the first nine months of 2012, 7.4 percent of the day-ahead generation eligible for operating reserve credits was made whole and 8.9 percent of the real-time generation eligible for operating reserve credits was made whole.

Table 3-19 Day-ahead and real-time generation receiving operating reserve credits (GWh): January through September 2012 (New Table)

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percentage
Day-Ahead	211,986	15,610	7.4%
Real-Time	197,561	17,632	8.9%

Geography of Charges and Credits

Table 3-20 shows the geography of charges and credits in the first nine months of 2012. Charges are categorized by the location (zone, hub or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, the transactions and resources in the AEP Control Zone paid 13.1 percent of all operating reserve charges, and resources were paid 19.8 percent of all operating reserve credits. The AEP Control Zone received more operating reserve credits than operating reserve charges paid. The JCPL Control Zone received fewer operating reserve credits than operating reserve charges paid. Table 3-20 also shows that 82.8 percent of all charges were allocated in control zones, 5.7 percent in hubs and 11.5 percent in interfaces.

Table 3-20 Geography of charges and credits: January through September 2012[10] (New Table)

					Shares			
Location		Charges	Credits	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$4,980,372	$4,807,161	($173,211)	1.2%	1.1%	0.1%	0.0%
	AEP	$56,205,789	$84,919,362	$28,713,573	13.1%	19.8%	0.0%	18.9%
	AP - DLCO	$34,420,143	$30,663,883	($3,756,261)	8.0%	7.1%	2.5%	0.0%
	ATSI	$27,090,348	$36,374,286	$9,283,938	6.3%	8.5%	0.0%	6.1%
	BGE - Pepco	$33,435,320	$67,747,847	$34,312,528	7.8%	15.8%	0.0%	22.6%
	ComEd - External	$55,921,538	$36,776,061	($19,145,477)	13.0%	8.6%	12.6%	0.0%
	DAY - DEOK	$20,664,284	$3,633,613	($17,030,671)	4.8%	0.8%	11.2%	0.0%
	Dominion	$27,731,198	$67,256,877	$39,525,679	6.5%	15.7%	0.0%	26.1%
	DPL	$9,992,736	$20,457,633	$10,464,897	2.3%	4.8%	0.0%	6.9%
	JCPL	$10,225,784	$2,697,493	($7,528,291)	2.4%	0.6%	5.0%	0.0%
	Met-Ed	$7,417,545	$3,138,809	($4,278,736)	1.7%	0.7%	2.8%	0.0%
	PECO	$19,035,847	$6,718,471	($12,317,375)	4.4%	1.6%	8.1%	0.0%
	PENELEC	$9,511,188	$12,788,061	$3,276,873	2.2%	3.0%	0.0%	2.2%
	PPL	$17,614,334	$4,841,166	($12,773,169)	4.1%	1.1%	8.4%	0.0%
	PSEG	$20,463,106	$46,465,254	$26,002,148	4.8%	10.8%	0.0%	17.2%
	RECO	$621,692	$0	($621,692)	0.1%	0.0%	0.4%	0.0%
	All Zones	$355,331,223	$429,285,976	$73,954,753	82.8%	100.0%	51.2%	100.0%
Hubs	AEP - Dayton	$4,218,549	$0	($4,218,549)	1.0%	0.0%	2.8%	0.0%
	Dominion	$599,894	$0	($599,894)	0.1%	0.0%	0.4%	0.0%
	Eastern	$874,983	$0	($874,983)	0.2%	0.0%	0.6%	0.0%
	New Jersey	$404,860	$0	($404,860)	0.1%	0.0%	0.3%	0.0%
	Ohio	$135,530	$0	($135,530)	0.0%	0.0%	0.1%	0.0%
	Western Interface	$74,224	$0	($74,224)	0.0%	0.0%	0.0%	0.0%
	Western	$18,260,962	$0	($18,260,962)	4.3%	0.0%	12.0%	0.0%
	All Hubs	$24,569,003	$0	($24,569,003)	5.7%	0.0%	16.2%	0.0%
Interfaces	IMO	$6,931,826	$0	($6,931,826)	1.6%	0.0%	4.6%	0.0%
	Linden	$1,631,401	$0	($1,631,401)	0.4%	0.0%	1.1%	0.0%
	MISO	$12,185,684	$0	($12,185,684)	2.8%	0.0%	8.0%	0.0%
	Neptune	$641,499	$0	($641,499)	0.1%	0.0%	0.4%	0.0%
	NIPSCO	$72,229	$0	($72,229)	0.0%	0.0%	0.0%	0.0%
	Northwest	$363,712	$0	($363,712)	0.1%	0.0%	0.2%	0.0%
	NYIS	$4,138,173	$0	($4,138,173)	1.0%	0.0%	2.7%	0.0%
	OVEC	$1,254,914	$0	($1,254,914)	0.3%	0.0%	0.8%	0.0%
	South Exp	$6,362,522	$0	($6,362,522)	1.5%	0.0%	4.2%	0.0%
	South Imp	$15,853,317	$0	($15,853,317)	3.7%	0.0%	10.5%	0.0%
	All Interfaces	$49,435,277	$49,526	($49,385,751)	11.5%	0.0%	32.6%	0.0%
	Total	$429,335,502	$429,335,502	$0	100.0%	100.0%	100.0%	100.0%

Table 3-21 and Table 3-22 compare 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. Generator charges are defined in these tables as the allocation of charges paid by generators due to generator deviations from day-ahead schedules or not following PJM dispatch.

Table 3-21 shows that on average, 10.7 percent of balancing generator charges, including lost opportunity cost and canceled resources charges were paid by generators deviating in the Eastern Region while these generators received 48.6 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 3-22 also shows that generators in the Western Region paid 12.3 percent of balancing generator charges including lost opportunity cost and canceled resources charges while these generators received 51.4 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

10 Zonal information in each zonal table has been aggregated to ensure that market sensitive data is not revealed. Table 3-20 does not include synchronous condensing and local constraint control charges and credits since these are allocated zonally.

Table 3-21 Monthly balancing operating reserve charges and credits to generators (Eastern Region): January through September 2012 (See 2011 SOM, Table 3-17)

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$1,173,478	$234,258	$562,031	$1,969,766	$14,130,635
Feb	$733,719	$281,274	$433,268	$1,448,262	$9,874,828
Mar	$620,144	$477,947	$1,177,834	$2,275,925	$11,741,895
Apr	$803,236	$546,718	$1,263,975	$2,613,929	$17,370,555
May	$1,363,506	$73,346	$2,010,502	$3,447,354	$20,570,538
Jun	$1,917,827	$65,193	$1,644,838	$3,627,858	$22,401,191
Jul	$1,956,790	$619,582	$3,573,015	$6,149,388	$33,543,351
Aug	$1,195,834	$148,582	$2,939,872	$4,284,288	$23,678,824
Sep	$683,003	$102,742	$2,193,770	$2,979,514	$13,760,926
Oct					
Nov					
Dec					
East Generators Total	$10,447,537	$2,549,641	$15,799,105	$28,796,284	$167,072,744
PJM Total Charges	$103,598,238	$14,681,707	$149,829,717	$268,109,662	$344,004,837
Share	10.1%	17.4%	10.5%	10.7%	48.6%

Table 3-22 Monthly balancing operating reserve charges and credits to generators (Western Region): January through September 2012 (See 2011 SOM, Table 3-18)

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$1,309,915	$32,410	$787,486	$2,129,811	$12,526,783
Feb	$1,109,193	$282,686	$706,304	$2,098,184	$14,189,145
Mar	$827,049	$0	$1,515,079	$2,342,127	$17,113,158
Apr	$1,072,628	$139,080	$1,712,412	$2,924,120	$15,790,612
May	$1,775,248	$232,625	$2,441,180	$4,449,052	$22,297,577
Jun	$2,124,027	$128,649	$1,782,091	$4,034,767	$21,871,633
Jul	$2,165,402	$393,318	$3,850,561	$6,409,281	$32,184,308
Aug	$1,084,609	$316,755	$2,926,965	$4,328,329	$22,404,686
Sep	$733,593	$142,920	$2,270,434	$3,146,947	$18,398,444
Oct					
Nov					
Dec					
West Generators Total	$12,201,664	$1,668,443	$17,992,512	$31,862,620	$176,776,346
PJM Total	$103,598,238	$6,366,381	$149,829,717	$259,794,335	$344,004,837
Share	11.8%	26.2%	12.0%	12.3%	51.4%

Table 3-23 shows that on average in the first nine months of 2012, generator charges were 14.1 percent of all operating reserve charges, excluding local constraints control charges which are allocated to the requesting transmission owner, 0.04 percentage points lower than the average of the first nine months of 2011. Generators received 99.99 percent of all operating reserve credits, while the remaining 0.01 percent were credits paid to import transactions.

Table 3-23 Percentage of unit credits and charges of total credits and charges: Calendar years 2011 and 2012 (See 2011 SOM, Table 3-19)

	2011		2012	
	Generators Share of Total Operating Reserve Charges	Generators Share of Total Operating Reserve Credits	Generators Share of Total Operating Reserve Charges	Generators Share of Total Operating Reserve Credits
Jan	11.2%	99.2%	11.7%	100.0%
Feb	11.8%	98.7%	11.8%	100.0%
Mar	12.9%	98.6%	14.1%	99.9%
Apr	15.5%	99.0%	15.3%	100.0%
May	16.0%	100.0%	15.5%	100.0%
Jun	13.4%	99.8%	14.9%	100.0%
Jul	16.6%	100.0%	16.2%	100.0%
Aug	14.2%	100.0%	15.7%	100.0%
Sep	13.1%	99.9%	10.0%	100.0%
Oct	11.3%	99.8%		
Nov	12.8%	99.6%		
Dec	11.4%	99.9%		
Average	14.2%	99.6%	14.1%	100.0%

Load Response Resource Operating Reserve Credits

End-use customers or their representative may make demand reduction offers which include the day-ahead LMP above which the end-use customer would not consume, and which may also include shut-down costs. Payment for reducing load is based on the MWh reductions committed in the Day-Ahead market.

Total payments to end-use customers or their representative for accepted day-ahead Economic Load Response offers will not be less than the total load response offer, included any submitted shut-down costs. If total payments are less than the total value of the load response offer, PJM will made the resource whole through day-ahead operating reserve credits.

In real-time, reimbursement for reducing load is based on the actual MWh reduction in excess of committed day-ahead load reductions plus an adjustment for losses. In cases where load response is dispatched by PJM, the total payment to end-use customers or their representative will not be less than the total value of the load response offer, including any submitted shut-down costs. If total payments are less than the total value of the load response offer, PJM will make the resource whole through balancing operating reserve credits.

In the first nine months of 2012, 4.7 percent of payments for demand reduction offers were covered by operating reserve credits while the remaining 95.3 percent were paid through the economic load response program as shown in Table 3-24.

Table 3-24 Day-ahead and balancing operating reserve for load response credits: Calendar year 2011 through September 2012 (See 2011 SOM, Table 3-20)

	2011				2012			
	Economic Program Credits	Operating Reserve Credits	Proportion Covered by the Economic Load Program	Proportion Covered by Operating Reserve	Economic Program Credits	Operating Reserve Credits	Proportion Covered by the Economic Load Program	Proportion Covered by Operating Reserve
Jan	$140,236	$1,111	99.2%	0.8%	$8,664	$19,002	31.3%	68.7%
Feb	$88,599	$0	100.0%	0.0%	$14,994	$7,878	65.6%	34.4%
Mar	$11,469	$0	100.0%	0.0%	$6,749	$56,130	10.7%	89.3%
Apr	$37,533	$17,796	67.8%	32.2%	$195,706	$3,807	98.1%	1.9%
May	$271,955	$130,162	67.6%	32.4%	$484,756	$24,995	95.1%	4.9%
Jun	$906,532	$3,932	99.6%	0.4%	$1,389,134	$34,125	97.6%	2.4%
Jul	$379,570	$539	99.9%	0.1%	$3,395,517	$173,846	95.1%	4.9%
Aug	$87,943	$191	99.8%	0.2%	$1,156,156	$20,741	98.2%	1.8%
Sep	$19,670	$0	100.0%	0.0%	$188,429	$0	100.0%	0.0%
Oct	$48,863	$857	98.3%	1.7%				
Nov	$15,524	$0	100.0%	0.0%				
Dec	$45,102	$8,898	83.5%	16.5%				
Total	$1,943,507	$153,732	92.7%	7.3%	$6,840,104	$340,523	95.3%	4.7%

Reactive Service

Credits to resources providing reactive services are separate from operating reserve credits. These credits are divided into three categories. Reactive Service Credits are paid to units providing reactive services with an offer price higher than the LMP at the unit's bus. Reactive Service Lost Opportunity Cost Credits are paid to units reduced or suspended by PJM for reactive reliability purposes when their offer price is lower than the LMP at the unit's bus. Reactive Service Synchronous Condensing Credits are paid to units providing synchronous condensing for the purpose of maintaining the reactive reliability of the system. Reactive service charges are allocated daily to real-time load in the transmission zone where the reactive service was provided.

Total reactive service credits in the first nine months of 2012 were $49.3 million, 192.4 percent higher than the $16.9 million in the first nine months of 2011. Table 3-25 shows the monthly distribution of reactive service credits. This increase was in part a result of the need for reactive support in the ATSI Control Zone in the first quarter of 2012. The top three zones accounted for 62.8 percent of the total reactive costs, a decrease of 16.1 percentage points from the first nine months of 2011 share. The top three control zones were DPL, PENELEC and ATSI.

Table 3-25 Monthly reactive service credits: Calendar years 2011 and 2012 (See 2011 SOM, Table 3-21)

	2011	2012	Change	Percentage Change
Jan	$1,546,278	$2,920,441	$1,374,163	88.9%
Feb	$1,912,027	$13,108,018	$11,195,991	585.6%
Mar	$1,438,306	$6,731,994	$5,293,688	368.1%
Apr	$2,077,101	$4,518,321	$2,441,220	117.5%
May	$2,712,293	$5,392,085	$2,679,792	98.8%
Jun	$1,868,004	$5,132,979	$3,264,975	174.8%
Jul	$929,807	$2,955,586	$2,025,779	217.9%
Aug	$1,696,735	$4,112,186	$2,415,451	142.4%
Sep	$2,688,094	$4,458,794	$1,770,700	65.9%
Oct	$15,523,789			
Nov	$7,105,062			
Dec	$1,790,778			
Total	$16,868,645	$49,330,404	$32,461,759	192.4%

Table 3-26 shows the distribution of credits for each category of reactive service credit received by each unit type (each column sums to 100 percent). In the first nine months of 2012 combined cycles and coal steam turbines received 82.1 percent of all credits, 8.5 percentage points higher than the share received in the first nine months of 2011, combustion turbines received 14.4 percent, 8.2 percentage points lower than the share received in the first nine months of 2011.

Table 3-26 Reactive service credits by unit type: January through September 2012 (See 2011 SOM, Table 3-22)

Unit Type	Reactive Service Credits	Reactive Service Lost Opportunity Cost Credits	Reactive Service Synchronous Condensing Credits	Locally Requested Reactive Service	Total Reactive Credits
Battery	0.0%	0.0%	0.0%	0.0%	0.0%
Combined Cycle	16.6%	6.4%	0.0%	0.0%	16.1%
Combustion Turbine	14.7%	4.3%	100.0%	0.0%	14.4%
Diesel	2.0%	0.0%	0.0%	100.0%	1.9%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	65.2%	86.0%	0.0%	0.0%	66.0%
Steam - Others	1.5%	3.3%	0.0%	0.0%	1.6%
Wind	0.0%	0.0%	0.0%	0.0%	0.0%
Total	$46,880,384	$2,291,235	$121,519	$37,266	$49,330,404

Operating Reserve Issues

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.

The concentration of operating reserve credits remains high, but decreased in the first nine months of 2012 compared to the first nine months of 2011. Table 3-27 shows the top 10 units receiving total operating reserve credits, which make up less than one percent of all units in PJM's footprint, received 21.1 percent of total operating reserve credits in the first nine months of 2012, compared to 29.7 percent in the first nine months of 2011. The top 20 units received 33.7 percent of total operating reserve credits in the first nine months of 2012.

Table 3-27 Top 10 operating reserve credits units (By percent of total system): Calendar years 2001 through September 2012 (See 2011 SOM, Table 3-23)

	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%
2010	33.2%	0.8%
2011	28.1%	0.8%
2012	21.1%	0.7%

Table 3-20 shows the distribution of operating reserve credits to units by zone. The AEP Control Zone had the largest share of credits with 19.8 percent, the BGE and Pepco Control Zones combined had the second highest with 15.8 percent, and the Dominion Control Zone had the third highest with a 15.7 percent share.

Table 3-28 shows the credits received by the top 10 units and top 10 organizations in each of the operating reserve categories. The shares of the top 10 organizations in all categories separately were above 80.0 percent.

Table 3-28 Top 10 units and organizations operating reserve credits: January through September 2012 (New Table)

	Top 10 units		Top 10 organizations	
Category	Credits	Credits Share	Credits	Credits Share
Day-Ahead	$43,922,337	51.5%	$80,804,042	94.7%
Balancing	$64,867,193	33.4%	$171,340,678	88.2%
Canceled Resources	$2,572,219	77.6%	$3,244,269	97.8%
Local Constraints Control	$7,543,458	99.3%	$7,564,851	99.6%
Lost Opportunity Cost	$41,504,224	28.3%	$128,026,650	87.4%
Synchronous Condensing	$45,095	84.9%	$53,115	100.0%
Reactive Services	$33,769,238	68.5%	$45,326,877	91.9%
Total Operating Reserve Credits	$92,274,586	21.1%	$364,949,777	83.5%

HHI for day-ahead operating reserve credits was 3868, for balancing operating reserve credits was 2847 and for lost opportunity cost credits was 3832.

Table 3-29 Daily operating reserve credits HHI: January through September 2012 (See 2011 SOM, Table 3-34)

	Daily Operating Reserve Credits HHI							
	Day-Ahead Generators	Day-Ahead Transactions	Synchronous Condensing	Balancing Generators	Balancing Transactions	Lost Opportunity Cost	Canceled Resources	Total Credits
Average	3868	10000	10000	2847	10000	3832	5819	1676
Minimum	1044	10000	10000	996	10000	614	1009	521
Maximum	10000	10000	10000	7826	10000	10000	10000	5149
Highest market share (One day)	0.0%	100.0%	100.0%	88.2%	100.0%	100.0%	100.0%	70.7%
Highest market share (All days)	31.1%	60.3%	99.2%	27.5%	99.7%	25.3%	37.1%	16.8%
Numbers of Days	273	3	6	274	52	273	97	274
Days with HHI > 1800	249	3	6	246	52	228	84	94
% of Days with HHI > 1800	91.2%	100.0%	100.0%	89.8%	100.0%	83.5%	86.6%	34.3%
Days with HHI = 10000	4	3	6	0	52	5	36	0
% of Days with HHI = 10000	1.5%	100.0%	100.0%	0.0%	100.0%	1.8%	37.1%	0.0%

Table 3-30 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In the first nine months of 2012, 45.0 percent of all credits paid to these units were allocated to deviations while the remaining 55.0 percent were paid for reliability reasons.

Table 3-30 Identification of balancing operating reserve credits received by the top 10 units by category and region: January through September 2012 (See 2011 SOM, Table 3-35)

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits	$404,209	$6,677,489	$28,610,093	$26,064,727	$3,110,674	$0	$64,867,193
Share	0.6%	10.3%	44.1%	40.2%	4.8%	0.0%	100.0%

Day-Ahead Unit Commitment for Reliability

The Day-Ahead Energy Market is solved with the objective function of minimizing total production cost of meeting day-ahead load plus reserves subject to security constraints.[11] Under some circumstances PJM deviates from the optimal day-ahead solution when PJM is reasonably certain that specific units will be needed for reliability reasons in real time. In that case, PJM schedules the units as must run in the day ahead also. Participants can submit units as self-scheduled (must run), meaning that the unit must be committed.[12] A unit submitted as must run by a participant cannot set LMP and is not eligible for operating reserve credits.

On September 13, PJM increased the number and MWh of units scheduled as must run in the Day-Ahead Energy Market because the units were needed for reliability in real time. PJM identified the need to schedule these units in the Day-Ahead Energy Market after determining that these units were affecting the commitment process of combustion turbines in real time. The increase in such scheduling was intended to reduce the divergence between the scheduled resources in the Day-Ahead Market and the actual resources operating in the Real-Time Energy Markets.

PJM may schedule units as must run in the Day-Ahead Energy Market when needed in real time to address reliability issues of various types. PJM put such reliability issues in four categories:[13]

- Voltage issues (high and low).
- Black start requirement (from automatic load rejection units).
- Local contingencies not seen in the Day-Ahead Energy Market.
- Long lead time units not able to be scheduled in the Day-Ahead Energy Market.

The addition of units scheduled as must run in the Day-Ahead Energy Market shifted substantial operating reserve credits from the Balancing Energy Market to the Day-Ahead Energy Market. This is significant because day-ahead operating reserve charges and balancing operating reserve charges are allocated differently. Day-ahead operating reserve charges are paid by day-ahead load, day-ahead exports and decrement bids across the entire RTO region. Balancing operating reserve charges are paid by real-time load and real-time exports or by deviations from the day ahead depending on the allocation process. Balancing operating reserve charges are allocated across three different regions, while day-ahead operating reserve charges are not. In addition, reactive services charges (attributable to units providing voltage support) are paid by real-time load on a zonal level.

The effects of this decision on the operating reserve rates can be seen in Figure 3-1, Figure 3-2 and Figure 3-3. Figure 3-1 shows an increase in the day-ahead operating reserve rates in September 2012, and Figure 3-2 and Figure 3-3 show a decrease in the balancing operating reserve rates. Table 3-31 shows the average operating reserve rates from January 1 through September 12, 2012 and from September 13 through September 30, 2012. The average day-ahead operating reserve rate after September 13 increased by 501.4 percent compared to the average before September 13, while the average Western Region balancing operating reserve rate decreased by 97.8 percent after September 13.

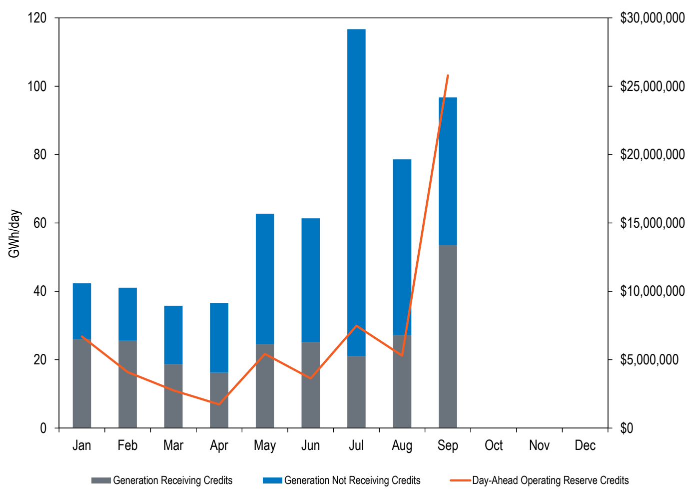
Table 3-31 Average operating reserve rates before and after September 13, 2012 (New Table)

	Rate before September 13 ($/MWh)	Rate after September 13 ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.1043	0.6275	0.5231	501.4%
RTO Reliability	0.0237	0.0115	(0.0121)	(51.2%)
East Reliability	0.0294	0.0000	(0.0294)	(100.0%)
West Reliability	0.1596	0.0035	(0.1560)	(97.8%)
RTO Deviations	0.9638	0.5164	(0.4474)	(46.4%)
East Deviations	0.2554	0.0000	(0.2554)	(100.0%)
West Deviations	0.1367	0.0000	(0.1367)	(100.0%)
Lost Opportunity Cost	1.3482	0.9918	(0.3564)	(26.4%)
Canceled Resources	0.0318	0.0003	(0.0315)	(99.2%)

11 OATT Attachment K - Appendix § 1.10.8 (a)
12 See "PJM eMkt Users Guide" Section Managing Unit Data (version June, 2012) p. 40.
13 See "Item 12 - October 2012 MIC DAM Cost Allocation" from PJM's MIC meeting <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-12-october-2012-mic-dam-cost-allocation.ashx>. (Accessed October 25, 2012)

Figure 3-5 shows the total day-ahead generation of units scheduled as must run by PJM and the subset of generation from units scheduled as must run by PJM that received day-ahead operating reserve credits. Figure 3-5 also shows the day-ahead operating reserve credits paid to these units. September had the second highest day-ahead generation from units scheduled as must run by PJM in the first nine months of 2012, surpassed only by July.[14] Before September 13, the average daily day-ahead generation from units scheduled as must run by PJM receiving day-ahead operating reserve credits was 23.6 GWh per day. After September 13, the daily average increased to 67.1 GWh per day. Before September 13, day-ahead operating reserve credits averaged $0.2 million per day and balancing operating reserve credits (including lost opportunity costs and canceled resources credits) averaged $1.3 million per day. After September 13 the day-ahead operating reserve credits averaged $1.2 million per day and the balancing operating reserve credits averaged $0.1 million per day. Although these results show a distinct pattern, the time periods are not strictly comparable since operating reserve credits are historically low during shoulder months.

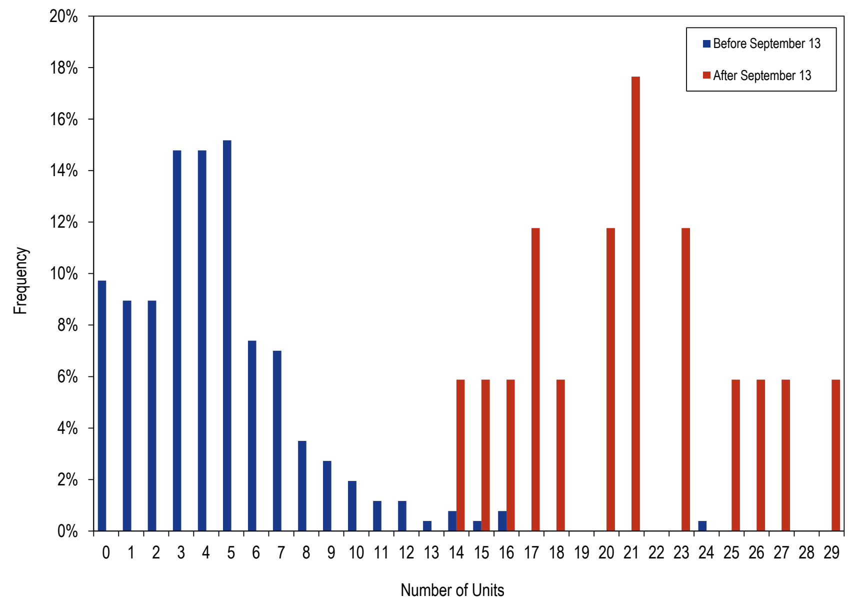
Figure 3-5 Daily average day-ahead generation from units scheduled as must run by PJM: January through September 2012 (New Figure)



14 PJM issued 12 hot weather alerts for the RTO region or the Mid-Atlantic region in July out of a total of 20 in the first nine months for those regions.

PJM scheduled an average of 9.4 units per day as must run before September 13 and on average 4.4 units received day-ahead operating reserve credits. After September 13, PJM scheduled as must run an average of 23.9 units per day and on average 20.8 units received day-ahead operating reserve credits. Figure 3-6 shows the frequency of the number of units scheduled as must run by PJM receiving day-ahead operating reserve credits before and after September 13 in the first nine months 2012. For example, before September 13, 5 units scheduled as must run by PJM received day-ahead operating reserve credits on 15.2 percent of the days. After September 13, 21 units scheduled as must run by PJM received day-ahead operating reserve credits on 17.6 percent of the days.

Figure 3-6 Units scheduled as must run by PJM receiving day-ahead operating reserve credits: January through September 2012 (New Figure)



On October 10, 2012, PJM presented a problem statement at PJM's Market Implementation Committee (MIC) indicating the need to modify the allocation rules of day-ahead operating reserve charges as a result of the shift of balancing operating reserve charges to the Day-Ahead Energy Market. [15]

The MMU supports the concept of PJM's change in unit commitment since it improves the market's efficiency. The MMU also supports the position that the allocation of operating reserve charges en the Day-Ahead Energy Market must be made consistent with cost causation.

The MMU recommends that PJM should, on an expedited basis, request that the tariff be modified to permit allocation of day-ahead operating reserve charges consistent with the prior allocation of these charges in real time. This would be a short term solution to the issue created by shifting operating reserve charges to the Day-Ahead Energy Market and therefore changing the allocation of those charges. In addition, PJM should start a stakeholder process to consider the market design and cost allocation issues in detail and propose a permanent tariff change that results from the process.

The MMU recommends that this stakeholder process address three areas of incorrect allocation that are directly related to and part of the current issue. These areas are related to reactive service costs, black start service costs and the inclusion of no load costs in the lost opportunity cost calculation.[16,17,18] As part of the stakeholder process, the MMU recommends that PJM clearly identify and classify the reasons for operating reserve credits in the Day-Ahead and the Real-Time Energy Markets in order to ensure the correct allocation of the corresponding charges.

Lost Opportunity Cost Credits

In the first nine months of 2012, lost opportunity cost credits decreased by 6.2 percent, after increasing by 57.5 percent in the first quarter of 2012. In the first nine months of 2012 lost opportunity cost credits decreased by $9.8 million compared to the first nine months of 2011.

Balancing operating reserve lost opportunity cost credits are paid to units under two scenarios. If a combustion turbine or an engine is scheduled to operate in the Day-Ahead Energy Market but is not dispatched by PJM in real time, the unit will receive a credit which covers the day-ahead financial position of the unit plus any balancing spot energy market charge that the unit will have to pay. If a unit generating in real time with an offer price lower than the LMP at the unit's bus is reduced or suspended by PJM, the unit will receive a credit for lost opportunity cost based on the desired output.

On April, 2012 PJM implemented a new rule to reduce the unnecessary payment of operating reserve credits to combustion turbines and engines that are committed day ahead but not dispatched in real time. Under the new rule, such units are eligible for lost opportunity cost credits only if their lead times (notification plus start time) are less than or equal to two hours.[19]

Table 3-32 shows, for combustion turbines and engines scheduled day ahead, the total day-ahead generation, the day-ahead generation from units that were not requested by PJM in real time and the subset of that generation that received lost opportunity costs credits. In the first nine months of 2012, PJM scheduled 17,005 GWh from combustion turbines and engines, of which 61.1 percent was not requested by PJM in real time and of which 50.1 percent received lost opportunity cost credits. In the first nine months of 2011, PJM scheduled 7,102 GWh from combustion turbines and engines.

15 See "Item 12 - October 2012 MIC DAM Cost Allocation" from PJM's MIC meeting <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-12-october-2012-mic-dam-cost-allocation.ashx>. (Accessed October 25, 2012)
16 See the *2012 Quarterly State of the Market Report for PJM: January through September*, Section 3, "Operating Reserve" at "Black Start and Voltage Support Units".
17 See the *2012 Quarterly State of the Market Report for PJM: January through September*, Section 3, "Operating Reserve" at "Reactive Service Credits and Operating Reserve Credits".
18 See the *2012 Quarterly State of the Market Report for PJM: January through September*, Section 3, "Operating Reserve" at "Lost Opportunity Cost Calculation".
19 See "PJM Manual 28: Operational Agreement Accounting," Revision 53 (Effective July 26, 2012), p. 22.

Table 3-32 Day-ahead generation from pool-scheduled combustion turbines and engines (GWh): Calendar years 2011 and 2012 (New Table)

	2011			2012		
	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time receiving LOC Credits	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time receiving LOC Credits
Jan	93	71	51	572	435	373
Feb	92	79	73	753	590	546
Mar	259	237	210	1,408	1,076	921
Apr	175	126	100	1,870	1,431	1,249
May	578	366	276	1,926	1,250	1,047
Jun	1,217	692	492	2,586	1,624	1,235
Jul	2,810	1,275	883	3,898	1,424	990
Aug	1,198	692	524	2,356	1,383	1,122
Sep	680	431	347	1,635	1,169	1,032
Oct	282	266	233			
Nov	351	324	254			
Dec	234	214	156			
Total	7,102	3,970	2,957	17,005	10,382	8,515
Share	100.0%	55.9%	41.6%	100.0%	61.1%	50.1%

In the first nine months of 2012, the top three control zones, AP, ATSI and Dominion combined for 60.3 percent of all the day-ahead generation from pool-scheduled combustion turbines and engines, 64.8 percent of all day-ahead generation not called in real time by PJM from those unit types and 68.1 percent of all day-ahead generation not called in real time by PJM and receiving lost opportunity cost credits from those unit types.

Combustion turbines and engines receive lost opportunity cost credits when scheduled in the Day-Ahead Energy Market and not called in real time on an hourly basis. For example, if a combustion turbine is scheduled to run from hour 10 to hour 18 and the unit only runs from hour 12 to hour 16, the unit is eligible for lost opportunity cost credits for hours 10, 11, 17 and 18. Table 3-33 shows the lost opportunity costs credits paid to combustion turbines and engines scheduled in the Day-Ahead Energy Market for units that did not run in real time and units that ran in real time for at least one hour of their day-ahead schedule. Table 3-33 shows that $109.1 million or 74.5 percent of all lost opportunity cost credits were paid to combustion turbines and engines that did not run for any hour in real time.

Table 3-33 Lost opportunity cost credits paid to pool-scheduled combustion turbines and engines by scenario (New Table)

	Lost Opportunity Cost Credits	
	From Units That Did Not Run in Real Time	From Units That Ran in Real Time for at least One Hour of Their Day-Ahead Schedule
Jan	$4,857,442	$355,007
Feb	$4,382,996	$154,019
Mar	$9,661,923	$894,042
Apr	$10,846,998	$1,028,201
May	$12,925,885	$2,775,886
Jun	$12,550,655	$2,163,079
Jul	$13,913,026	$13,967,989
Aug	$22,219,006	$3,408,932
Sep	$17,783,763	$2,196,639
Oct		
Nov		
Dec		
Total	$109,141,694	$26,943,793

PJM may not run units in real time if the real-time value of that energy (defined as generation multiplied by the real-time LMP) is lower than the units' total offer (including no load and startup costs).

Table 3-34 shows the total day-ahead generation from combustion turbines and engines that were not called in real time by PJM and received lost opportunity cost credit. Table 3-34 shows the scheduled generation that had a total offer (including no load and startup costs) lower than its real-time value (generation multiplied by the real-time LMP) or economic scheduled generation, and the scheduled generation that had a total offer greater than its real-time value or noneconomic scheduled generation. In the first nine months of 2012, 30.8 percent of the scheduled generation not called by PJM from units receiving lost opportunity cost credits was economic and the remainder 69.2 percent was noneconomic.[20]

Table 3-34 Day-ahead generation (GWh) from pool-scheduled turbines and engines receiving lost opportunity cost credits by value (New Table)

	Day-Ahead Generation Not Requested in Real Time		
	Economic Scheduled Generation	Noneconomic Scheduled Generation	Total
Jan	136	309	445
Feb	248	422	670
Mar	287	805	1,092
Apr	329	1,126	1,455
May	363	875	1,237
Jun	663	838	1,501
Jul	402	826	1,228
Aug	397	945	1,342
Sep	305	880	1,185
Oct			
Nov			
Dec			
Total	3,130	7,027	10,156
Share	30.8%	69.2%	100.0%

20 The total generation in Table 3-34 is lower than the Day-Ahead Generation not requested in Real Time in Table 3-32 because the former only includes generation from units that received lost opportunity costs during at least one hour of the day. Table 3-34 includes all generation, including generation from units that were not called in real time and did not receive lost opportunity cost credits.

Lost Opportunity Cost Calculation

On February 17, 2012, the PJM Market Implementation Committee (MIC) endorsed the charge to prepare a proposal to make all energy related lost opportunity costs calculations consistent throughout the PJM rules.[21] PJM and the MMU jointly proposed two specific modifications. The MMU also believes that two additional modifications would be appropriate but the MMU has not recommended these to the MIC for consideration.

- Unit Schedule Used: Current rules require the use of the higher of a unit's price-based and cost-based schedules to calculate the lost opportunity cost in the energy market. The MMU recommends that the lost opportunity cost in the energy and ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market.
- No load and startup costs: Current rules do not include in the calculation of lost opportunity cost credits all of the costs not incurred by a scheduled unit not running in real-time. Generating units do not incur no load or startup costs if they are not dispatched in real time. As a result, no load and startup costs should be subtracted from the real time LMP in the same way that the energy offer is subtracted to calculate the actual value of the opportunity lost by the unit.
- Day-Ahead LMP: Current rules require the use of the day-ahead LMP as part of the lost opportunity cost calculation logic when a unit is scheduled on a noneconomic basis day ahead, meaning that the unit's offer is greater than the day-ahead LMP. In the day-ahead market, such units receive operating reserve credits equal to the difference between the unit's offer (including no load and startup costs) and the day-ahead LMP. If such a unit is not dispatched in real time, under the current rules the unit receives lost opportunity cost credits equal to the difference between the real-time LMP and the day-ahead LMP. This calculation results in double counting because the unit has already been made whole to its day-ahead offer in the day-ahead market through day-ahead operating reserve credits if necessary. If the unit is not dispatched in real time, it

21 See "Meeting Minutes" from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20120217/20120217-minutes.ashx>. (April 4, 2012)

should receive only the difference between real-time LMP and the unit's offer, which is the actual lost opportunity cost.

- Offer Curve: Current rules require the use of the difference between the real-time LMP and the incremental offer at a single point on the offer curve (at the desired or scheduled output), instead of using the difference between the real-time LMP and the entire offer curve (area between LMP and the offer curve) when calculating the lost opportunity cost in the energy market for units scheduled in day ahead but which are backed down or not dispatched in real time. Units with an offer lower than the real-time LMP at the units' bus that are reduced in real-time by PJM should be paid lost opportunity cost based on the area between the real-time LMP and their offer curve between the actual and desired output points. Units scheduled in day-ahead and not dispatched in real-time should be paid lost opportunity cost based on the area between the real-time LMP and their offer curve between zero output and scheduled output points.

These four modifications are consistent with the inputs used by PJM's software to commit combustion turbines in real time. PJM's commitment process is based on the forecasted LMPs, the reliability requirements, reserve requirement and the total cost of the units. The total cost of the units includes no load costs and startup costs and is based on the units' price schedule if available and the unit does not fail the TPS test.

Table 3-35 shows the impact that each of these changes would have had on the lost opportunity cost credits in the energy market for the first nine months of 2012, for the two categories of lost opportunity cost credits. Energy market lost opportunity cost credits would have been reduced by $46.6 million, or 31.8 percent, if all these changes had been implemented.[22]

22 The impacts on the lost opportunity cost credits were calculated following the order presented. Eliminating one of the changes has an effect on the remaining impacts.

Table 3-35 Impact on energy market lost opportunity cost credits of rule changes: January through September 2012 (New Table)

	LOC when output reduced in RT	LOC when scheduled DA not called RT	Total
Current Credits	$10,428,015	$136,085,488	$146,513,503
Impact 1: Committed Schedule	$689,492	$21,523,234	$22,212,726
Impact 2: Eliminating DA LMP	NA	($3,000,395)	($3,000,395)
Impact 3: Using Offer Curve	($516,221)	$18,731,749	$18,215,528
Impact 4: Including No Load Cost	NA	($63,548,330)	($63,548,330)
Impact 5: Including Startup Cost	NA	($20,448,955)	($20,448,955)
Net Impact	$173,271	($46,742,697)	($46,569,426)
Credits After Changes	$10,601,286	$89,342,791	$99,944,077

Table 3-36 shows the impact of each of the proposed modifications made jointly by PJM and the MMU. Energy market lost opportunity cost credits would have been reduced by $55.0 million, or 37.5 percent, if the two proposed modifications had been implemented.

Table 3-36 Impact on energy market lost opportunity cost credits of proposed rule changes: January through September 2012 (New Table)

	LOC when output reduced in RT	LOC when scheduled DA not called RT	Total
Current Credits	$10,428,015	$136,085,488	$146,513,503
Impact 1: Committed Schedule	$689,492	$21,523,234	$22,212,726
Impact 2: Including No Load Cost	NA	($58,674,824)	($58,674,824)
Impact 3: Including Startup Cost	NA	($18,501,959)	($18,501,959)
Net Impact	$689,492	($55,653,549)	($54,964,057)
Credits After Changes	$11,117,507	$80,431,939	$91,549,446

Black Start and Voltage Support Units

Certain units located in the Western Region zone are relied on for their black start capability and for voltage support on a regular basis even during periods when the units are not economic. The relevant black start units provide black start service under the Automatic Load Rejection (ALR) option, which means that the units must be running even if not economic. Units providing black start service under the ALR option could remain running at a minimum level, disconnected from the grid. The MMU recommends that PJM dispatchers explicitly log the reasons that these units are run out-of-merit to comply with black start requirements or voltage support in order to correctly assign the associated charges.

On August 8, 2012, the PJM Market Implementation Committee (MIC) endorsed a charge presented by the MMU to prepare a proposal to correct the allocation of make whole payments (in the form of operating reserve charges) attributable to the operation of units for black start requirement and black start testing.[23]

Credits categorized as reliability paid to units in the Western Region increased considerably in the first nine months of 2012 compared to the first nine months of 2011 because of these units used for black start and voltage support.

Up-to Congestion Transactions

Up-to congestion transactions do not pay balancing operating reserve charges. The MMU calculated the impact on balancing operating reserve rates if up-to congestion transactions had paid operating reserve charges based on deviations in the same way that increment offers and decrement bids do, while accounting for the impact of such payments on the profitability of the transactions.

In the first nine months of 2012, 51.5 percent of all up-to congestion transactions were profitable.[24]

The MMU calculated the up-to congestion transactions that would have remained if operating reserve charges had been applied. It was assumed that up-to congestion transactions would have had the same proportional distribution of profitable and unprofitable transactions after paying operating reserve charges as actually occurred when no operating reserve charges were paid. If up-to congestion transactions were allocated operating reserve charges, only 28.5 percent of all up-to congestion transactions would have been made if such transactions had to pay operating reserve charges and the proportional distribution of profitable and unprofitable transactions remained the same.

23 See "Meeting Minutes" from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20120808/20120808-minutes.ashx>. (Accessed October 16, 2012)

24 An up-to congestion transaction profitability is based on its market value (difference between the day-ahead and real-time value) net of PJM and MMU administrative charges.

Even with this reduction in the level of up-to congestion transactions, the contribution to total operating reserve charges and the impact on other participants who pay those charges would have been significant.

Table 3-37 shows the impact that including the identified 28.5 percent of up-to congestion transactions in the allocation of balancing operating reserve charges would have had on the operating reserve charge rates in the first nine months of 2012. For example, the RTO deviations rate would have been reduced by 54.8 percent.

Table 3-37 Up-to Congestion Transactions Impact on the Operating Reserve Rates: January through September 2012 (See 2011 SOM, Table 3-44)

	Current Rates ($/MWh)	Rates Including Up-To Congestion Transactions ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.1350	0.1220	(0.0130)	(9.6%)
RTO Deviations	0.9398	0.4250	(0.5147)	(54.8%)
East Deviations	0.2424	0.1478	(0.0946)	(39.0%)
West Deviations	0.1289	0.0442	(0.0847)	(65.7%)
Lost Opportunity Cost	1.3291	0.6011	(0.7279)	(54.8%)
Canceled Resources	0.0301	0.0136	(0.0165)	(54.8%)

Reactive Service Credits and Operating Reserve Credits

Credits to resources providing reactive services are separate from operating reserve credits.[25] Under the rules providing for credits for reactive service, units are not assured recovery of the entire offer including no load and startup costs as they are under the operating reserve credits rules. Units providing reactive services at the request of PJM are made whole through reactive service credits. But when the reactive service credits do not cover a unit's entire offer, the unit is paid through balancing operating reserves. The result is a misallocation of the costs of providing reactive service. Reactive service credits are paid by real-time load in the control zone where the service is provided while balancing operating reserve are paid by deviations from day-

25 OA Schedule 1 § 3.2.3B(f).

ahead or real-time load plus exports depending on the allocation process rather than by zone.[26]

In the first nine months of 2012, units providing reactive services were paid $19.4 million in balancing operating reserve credits in order to cover their total energy offer. Of these credits, 94.6 percent were paid by deviations in the RTO Region, 5.1 percent by real-time load and real-time exports in the RTO Region and the remaining 0.3 percent by real-time load and real-time exports in the Western Region.

Table 3-38 shows the impact of these credits in each of the balancing operating reserve categories.

Table 3-38 Impact of credits paid to units providing reactive services on the balancing operating reserve rates ($/MWh): January through September 2012 (New Table)

		Balancing Operating Reserve Rates ($/MWh)		Impact	
Category	Region	Without Credits to Units Providing Reactive Services	Current	($/MWh)	Percentage
Reliability	RTO	0.0213	0.0230	0.0016	7.7%
	East	0.0277	0.0277	0.0000	0.0%
	West	0.1504	0.1505	0.0002	0.1%
Deviation	RTO	0.7736	0.9398	0.1662	21.5%
	East	0.2424	0.2424	0.0000	0.0%
	West	0.1289	0.1289	0.0000	0.0%

26 The MMU presented this issue at the PJM Market Implementation Committee on October 10, 2012. See "Item 7: Reactive Service and Operating Reserve Credits Problem Statement and Issue Charge" from the PJM's MIC meeting. <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-07-reactive-service-and-operating-reserve-credits-problem-statement-and-issue-charge.ashx>. (Accessed October 16, 2012)

Capacity Market

Each organization serving PJM load must meet its capacity obligations through the PJM Capacity Market, where load serving entities (LSEs) must pay the locational capacity price for their zone. LSEs can also construct generation and offer it into the capacity market, enter into bilateral contracts, develop demand-side resources and Energy Efficiency (EE) resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for the first nine months of calendar year 2012, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1]

Table 4-1 The Capacity Market results were competitive (See the 2011 SOM, Table 4-1)

Market Element	Evaluation	Market Design
Market Structure: Aggregate Market	Not Competitive	
Market Structure: Local Market	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Mixed

- The aggregate market structure was evaluated as not competitive. The entire PJM region failed the preliminary market structure screen (PMSS), which is conducted by the MMU prior to each Base Residual Auction (BRA), for every planning year for which a BRA has been run to date. For almost all auctions held from 2007 to the present, the PJM region failed the Three Pivotal Supplier Test (TPS), which is conducted at the time of the auction.[2]
- The local market structure was evaluated as not competitive. All modeled Locational Deliverability Areas (LDAs) failed the PMSS, which is conducted by the MMU prior to each Base Residual Auction, for every planning year for which a BRA has been run to date. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[3]
- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a new resource or uprate that was below the Minimum Offer Price Rule (MOPR) threshold.
- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.
- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design, there are several features of the RPM design which threaten competitive outcomes. These include the 2.5 percent reduction in demand in Base Residual Auctions and the definition of DR which permits inferior products to substitute for capacity.

Highlights

- During the period January 1, through September 30, 2012, PJM installed capacity increased 4,019.4 MW or 2.2 percent from 178,854.1 MW on January 1 to 182,873.5 MW on September 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- The 2013/2014 RPM Second Incremental Auction and the 2014/2015 RPM First Incremental Auction were conducted in the third quarter of 2012. In the 2013/2014 RPM Second Incremental Auction, the rest of RTO clearing price was $7.01 per MW-day. In the 2014/2015 RPM First Incremental Auction, the rest of RTO clearing price for Annual and Extended Summer Resources was $5.54 per MW-day.

1 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.

2 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.

3 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test.

- Capacity in the RPM load management programs was 7,118.5 MW for June 1, 2012 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2012/2013 Delivery Year (9,407.0 MW) less replacement capacity (2,288.5 MW).
- Annual weighted average capacity prices increased from a Capacity Credit Market (CCM) weighted average price of $5.73 per MW-day in 2006 to an RPM weighted-average price of $164.71 per MW-day in 2010 and then declined to $148.33 per MW-day in 2015.
- Combined cycle units ran more often in January through September 2012, than in the same period in 2011, increasing from a 47.1 percent capacity factor in 2011 to a 63.8 percent capacity factor in 2012. Combined cycle units had a higher capacity factor than steam units, for which the capacity factor decreased from 54.0 percent in 2011 to 45.5 percent in January through September 2012.
- The average PJM equivalent demand forced outage rate (EFORd) decreased from 7.6 percent in the first nine months of 2011 to 6.8 percent in the first nine months of 2012.
- The PJM aggregate equivalent availability factor (EAF) increased from 84.9 percent in January through September 2011 to 85.5 percent for the same period in 2012. The equivalent maintenance outage factor (EMOF) increased from 2.8 percent to 3.5 percent, the equivalent planned outage factor (EPOF) decreased from 7.1 percent to 6.3 percent, and the equivalent forced outage factor (EFOF) decreased from 5.3 percent to 4.7 percent (Figure 4-4).

Conclusion

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 PJM 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 PJM Capacity Market is unlikely ever to approach a competitive market structure in the absence of a substantial and unlikely structural change that results in much more diversity of ownership.

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 the Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity Market in the first nine months of 2012. 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 in the first nine months of 2012.

The MMU has also identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[4,5,6,7] In 2011 and 2012, the MMU prepared a number of RPM-related reports and testimony, shown in Table 4-2.

4 See "Analysis of the 2011/2012 RPM Auction Revised" <http://www.monitoringanalytics.com/reports/Reports/2008/20081002-review-of-2011-2012-rpm-auction-revised.pdf> (October 1, 2008).
5 See "Analysis of the 2012/2013 RPM Base Residual Auction" <http://www.monitoringanalytics.com/reports/Reports/2009/Analysis_of_2012_2013_RPM_Base_Residual_Auction_20090806.pdf> (August 6, 2009)
6 See "Analysis of the 2013/2014 RPM Base Residual Auction Revised and Updated" <http://www.monitoringanalytics.com/reports/Reports/2010/Analysis_of_2013_2014_RPM_Base_Residual_Auction_20090920.pdf> (September 20, 2010).
7 See "IMM Response to Maryland PSC re: Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results" <http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Response_to_MDPSC_RPM_and_2013-2014_BRA_Results.pdf> (October 4, 2010).

Table 4-2 RPM Related MMU Reports

Date	Name
January 6, 2011	Analysis of the 2011/2012 RPM First Incremental Auction http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_RPM_First_Incremental_Auction_20110106.pdf
January 6, 2011	Impact of New Jersey Assembly Bill 3442 on the PJM Capacity Market http://www.monitoringanalytics.com/reports/Reports/2011/NJ_Assembly_3442_Impact_on_PJM_Capacity_Market.pdf
January 14, 2011	Analysis of the 2011/2012 and 2012/2013 ATSI Integration Auctions http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_and_2012_2013_ATSI_Integration_Auctions_20110114.pdf
January 28, 2011	Impact of Maryland PSC's Proposed RFP on the PJM Capacity Market http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_to_MDPSC_Case_No_9214_20110128.pdf
February 1, 2011	Preliminary Market Structure Screen results for the 2014/2015 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2011/PMSS_Results_20142015_20110201.pdf
March 4, 2011	IMM Comments re MOPR Filing Nos. EL11-20, ER11-2875 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_EL11-20-000_ER11-2875-000_20110304.pdf
March 21, 2011	IMM Answer and Motion for Leave to Answer re: MOPR Filing Nos. EL11-20, ER11-2875 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Answer_and_Motion_for_Leave_to_Answer_EL11-20-000_ER11-2875-000_20110321.pdf
June 2, 2011	IMM Protest re: PJM Filing in Response to FERC Order Regarding MOPR No. ER11-2875-002 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Protest_ER11-2875-002.pdf
June 17, 2011	IMM Comments re: In the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning No. EO11050309 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_NJ_EO_11050309_20110617.pdf
June 27, 2011	Units Subject to RPM Must Offer Obligation http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Units_Subject_to_RPM_Must_Offer_Obligation_20110627.pdf
August 29, 2011	Post Technical Conference Comments re: PJM's Minimum Offer Price Rule Nos. ER11-2875-001, 002, and EL11-20-001 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Post_Technical_Conference_Comments_ER11-2875_20110829.pdf
September 15, 2011	IMM Motion for Leave to Answer and Answer re: MMU Role in MOPR Review No. ER11-2875-002 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Motion_for_Leave_to_Answer_and_Answer_ER11-2875-002_20110915.pdf
November 22, 2011	Generator Capacity Resources in PJM Region Subject to "Must Offer" Obligatrion for the 2012/2013, 2013/2014 and 2014/2015 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20111123.pdf
January 9, 2012	IMM Comments re:MOPR Compliance No. ER11-2875-003 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER11-2875-003_20120109.pdf
January 20, 2012	IMM Testimony re: Review of the Potential Impact of the Proposed Capacity Additions in the State of Maryland's Joint Petition for Approval of Settlement MD PSC Case No. 9271 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Testimony_MD_PSC_9271.pdf
January 20, 2012	IMM Comments re: Capacity Procurement RFP MD PSC Case No. 9214 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_MD_PSC_9214.pdf
February 7, 2012	Preliminary Market Structure Screen results for the 2015/2016 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2012/PMSS_Results_20152016_20120207.pdf
February 15, 2012	RPM-ACR and RPM Must Offer Obligation FAQs http://www.monitoringanalytics.com/Tools/docs/RPM-ACR_FAQ_RPM_Must_Offer_Obligation_20120215.pdf
February 17, 2012	IMM Motion for Clarification re: Minimum Offer Price Rule Revision Nos.ER11-2871-000, -001 and -002, EL11-20-000 and -001 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Motion_for_Clarification_ER11-2875_EL-20_20120217.pdf
April 9, 2012	Analysis of the 2014/2015 RPM Base Residual Auction www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf
May 1, 2012	IMM Complaint and Request for Fast Track Treatment and Shortened Comment Period re Complaint v. Unnamed Participant No. EL12-63 www.monitoringanalytics.com/report/Report/2012/IMM_Complaint_and_Fast_Track_Treatment_and_Shortened_Comment_Period_EL12-63-000_20120501.pdf
May 17, 2012	IMM Notice of Withdrawal re Complaint v. Unnamed Participant No. EL12-63 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Notice_of_Withdrawal_EL12-63-000_20120517.pdf
July 3, 2012	Generator Capacity Resources in PJM Region Subject to "Must Offer" Obligatrion for the 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20120703.pdf
August 10, 2012	IMM Comments re Capacity Portability AD12-16 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_AD12-16_20120810.pdf
August 20, 2012	IMM and PJM Capacity White Papers on OPSI Issues http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf
August 29, 2012	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20120829.pdf

Recommendations

- The MMU recommends that the notification requirement for deactivations be extended from 90 days prior to the date of deactivation to 12 months prior to the date of deactivation and that PJM and the MMU be provided 60 days rather than 30 days to complete their reliability and market power analyses. The MMU also recommends that the notification requirement for deactivations be modified to include required notification of six to twelve months prior to an auction in which the unit will not be offered due to deactivation. The purpose of this deadline is to allow adequate time for potential Capacity Market Sellers to offer new capacity in the auction. The currently proposed related deadline of 120 days prior to an RPM Auction for requesting exemption to the RPM Must Offer Obligation is a step in the right direction.[8] All notification recommendations assume that the generation owner has the required knowledge in the defined time frame.
- The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened.[9]
- The MMU recommends that generation capacity resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. All revenues should be at risk under the peak hour availability charge.
- The MMU recommends that 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 MMU recommends that all generation types face the same performance incentives.
- The MMU recommends elimination of the exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.
- The MMU recommends elimination of the exception related to a unit that runs less than 50 hours during the RPM peak period.
- The MMU recommends that PJM eliminate all Out of Management Control (OMC) outages from use in planning or capacity markets.

Installed Capacity

On January 1, 2012, PJM installed capacity was 178,854.1 MW (Table 4-3).[10] Over the next five months, unit retirements, facility reratings plus import and export shifts resulted in PJM installed capacity of 185,243.3 MW on May 31, 2012, an increase of 6,389.2 MW or 3.6 percent over the January 1 level.[11,12] The 6,389.2 MW increase was the result of the integration of the DEOK Zone (3,560.4 MW), a decrease in exports (2,116.5 MW), new generation (1,392.2 MW), an increase in imports (203.0 MW), and capacity modifications (140.0 MW), offset by deactivations (971.0 MW) and derates (51.9 MW).

At the beginning of the new planning year on June 1, 2012, PJM installed capacity was 185,732.9 MW, an increase of 489.6 MW or 0.3 percent over the May 31 level. On September 30, 2012, PJM installed capacity was 182,873.5 MW.

8 In order to make an offer in a BRA, planned generation must be in a generation queue, have completed a Feasibility Study and have a signed Impact Study Agreement. Planned generation must be in the queue at least six months prior to the month of the BRA, or by October 31 of the calendar year preceding the auction, in order to ensure timely completion of the Feasibility Study and Impact Study Agreement. Given these requirements of the queue process, a notification period of nine months prior to the BRA would be required to allow planned generation time to enter the queue in response to a notice of deactivation.

9 For more details on the reasons for these recommendations, see the IMM's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, *"Capacity in the PJM Market,"* <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012).

10 Percent values shown in Table 4-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

11 The capacity described in this section is the summer installed capacity rating of all PJM generation capacity resources, as entered into the eRPM system, regardless of whether the capacity cleared in the RPM Auctions.

12 Wind resources accounted for 779.6 MW of installed capacity in PJM on June 30, 2012. 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. There are additional wind resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market.

Table 4-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and September 30, 2012 (See the 2011 SOM, Table 4-3)

	1-Jan-12		31-May-12		1-Jun-12		30-Sep-12	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	75,190.4	42.0%	79,311.0	42.8%	79,664.6	42.9%	76,739.2	42.0%
Gas	50,529.3	28.3%	51,940.1	28.0%	52,709.1	28.4%	51,995.2	28.4%
Hydroelectric	8,047.0	4.5%	8,047.0	4.3%	7,879.8	4.2%	7,879.8	4.3%
Nuclear	32,492.6	18.2%	33,085.0	17.9%	33,149.5	17.8%	33,164.9	18.1%
Oil	11,217.3	6.3%	11,494.7	6.2%	10,767.2	5.8%	11,531.7	6.3%
Solar	15.3	0.0%	16.3	0.0%	47.0	0.0%	47.0	0.0%
Solid waste	705.1	0.4%	689.1	0.4%	736.1	0.4%	736.1	0.4%
Wind	657.1	0.4%	660.1	0.4%	779.6	0.4%	779.6	0.4%
Total	178,854.1	100.0%	185,243.3	100.0%	185,732.9	100.0%	182,873.5	100.0%

RPM Capacity Market

The RPM Capacity Market, implemented June 1, 2007, is a forward-looking, annual, locational market, with a must-offer requirement for Existing Generation Capacity Resources and mandatory participation by load, with performance incentives, 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 31, 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.[13]

Market Structure

Supply

Table 4-4 shows generation capacity additions since the implementation of the Reliability Pricing Model. New generation capacity resources (13,809.3 MW), reactivated generation capacity resources (858.7 MW), uprates to existing generation capacity resources (5,957.0 MW), and the net increase in capacity imports (6,754.6 MW) totals 27,379.6 MW since the implementation of the Reliability Pricing Model.

13 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).

In the 2013/2014 RPM Second Incremental Auction, 1,996.7 MW cleared of the 6,072.9 MW of participant sell offers. In the 2014/2015 RPM First Incremental Auction, 79.4 MW cleared of the 1,508.2 MW cleared of participant sell offers for Limited Resources, 29.0 MW cleared of the 446.5 MW of participant sell offers for Extended Summer Resources, and 4,131.4 MW cleared of the 9,171.6 MW of participant sell offers for Annual Resources.

Table 4-4 RPM generation capacity additions: 2007/2008 through 2015/2016[14] (See 2011 SOM, Table 4-5)

	ICAP (MW)				
Delivery Year	New Generation Capacity Resources	Reactivated Generation Capacity Resources	Uprates to Existing Generation Capacity Resources	Net Increase in Capacity Imports	Total
2007/2008	19.0	47.0	536.0	1,576.6	2,178.6
2008/2009	145.1	131.0	438.1	107.7	821.9
2009/2010	476.3	0.0	793.3	105.0	1,374.6
2010/2011	1,031.5	170.7	876.3	24.1	2,102.6
2011/2012	2,332.5	501.0	896.8	672.6	4,402.9
2012/2013	901.5	0.0	946.6	676.8	2,524.9
2013/2014	1,080.2	0.0	418.2	963.3	2,461.7
2014/2015	1,102.8	9.0	482.5	818.9	2,413.2
2015/2016	6,720.4	0.0	569.2	1,809.6	9,099.2
Total	13,809.3	858.7	5,957.0	6,754.6	27,379.6

Demand

In the 2013/2014 RPM Second Incremental Auction, 5,598.8 MW cleared of the 16,385.8 MW of participant buy bids. In the 2014/2015 RPM First Incremental Auction, 2,781.8 MW cleared of the 4,437.2 MW of participant buy bids for Limited Resources, 116.6 MW cleared of the 943.0 MW of participant buy bids for Extended Summer Resources, and 3,951.4 MW cleared of the 7,850.9 MW of participant buy bids for Annual Resources. Participant buy bids are submitted to cover commitment and compliance shortfalls or because participants wanted to purchase additional capacity.

14 The value for the 2014/2015 net increase in capacity imports has been updated since the *2012 Quarterly State of the Market Report for PJM: January through June.*

Market Concentration

Auction Market Structure

As shown in Table 4-5, all participants in the total PJM market failed the three pivotal supplier (TPS) market structure test in the 2013/2014 RPM Second Incremental Auction and the 2014/2015 RPM First Incremental Auction.[15] The result was that offer caps were applied to all sell offers for resources which were subject to mitigation when the Capacity Market Seller did not pass the test, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[16,17,18]

Table 4-5 presents the results of the TPS test.

15 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 *MMU Technical Reference for PJM Markets*, at "Three Pivotal Supplier Test" for additional discussion.
16 See OATT Attachment DD § 6.5.
17 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.
18 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

Table 4-5 RSI results: 2012/2013 through 2015/2016 RPM Auctions[19] (See the 2011 SOM, Table 4-8)

RPM Markets	$RSI_{1\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2012/2013 BRA				
RTO	0.84	0.63	98	98
MAAC/SWMAAC	0.77	0.54	15	15
EMAAC/PSEG	0.00	7.03	6	0
PSEG North	0.00	0.00	2	2
DPL South	0.00	0.00	3	3
2012/2013 ATSI FRR Integration Auction				
RTO	0.34	0.10	16	16
2012/2013 First Incremental Auction				
RTO/MAAC/SWMAAC/PSEG/PSEG North/DPL South	0.40	0.60	25	25
EMAAC	0.40	0.00	2	2
2012/2013 Second Incremental Auction				
RTO/MAAC/SWMAAC/PSEG/PSEG North/DPL South	0.62	0.64	33	33
EMAAC	0.00	0.00	2	2
2012/2013 Third Incremental Auction				
RTO/MAAC/EMAAC/SWMAAC/PSEG/PSEG North/DPL South	0.39	0.28	53	53
2013/2014 BRA				
RTO	0.80	0.59	87	87
MAAC/SWMAAC	0.42	0.23	9	9
EMAAC/PSEG/PSEG North/DPL South	0.25	0.00	2	2
Pepco	0.00	0.00	1	1
2013/2014 First Incremental Auction				
RTO/MAAC	0.24	0.28	33	33
EMAAC/PSEG/PSEG North/DPL South	0.34	0.00	3	3
SWMAAC/Pepco	0.00	0.00	0	0
2013/2014 Second Incremental Auction				
RTO	0.44	0.27	32	32
MAAC/SWMAAC/Pepco	0.00	0.00	0	0
EMAAC/PSEG/PSEG North/DPL South	0.00	0.00	0	0
2014/2015 BRA				
RTO	0.76	0.58	93	93
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	1.40	1.03	7	0
PSEG North	0.00	0.00	1	1
2014/2015 First Incremental Auction				
RTO	0.45	0.14	36	36
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	0.00	0.00	1	1
PSEG North	0.00	0.00	1	1
2015/2016 BRA				
RTO	0.75	0.57	99	99
MAAC/EMAAC/SWMAAC/PSEG/PSEG North/DPL South/Pepco	0.49	0.63	12	12
ATSI	0.01	0.00	3	3

19 The RSI shown is the lowest RSI in the market.

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 delivery year, an LDA will be modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 delivery year, EMAAC, SWMAAC, and MAAC LDAs will be modeled as potentially constrained LDAs regardless of the results of the above three tests.[20] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[21] A reliability requirement, a Variable Resource Requirement (VRR) curve, a Minimum Annual Resource Requirement, and a Minimum Extended Summer Resource Requirement are established for each modeled LDA.

Locational Deliverability Areas are shown in Figure 4-1 and Figure 4-2.

Figure 4-1 PJM Locational Deliverability Areas (See the 2011 SOM, Figure A-3)

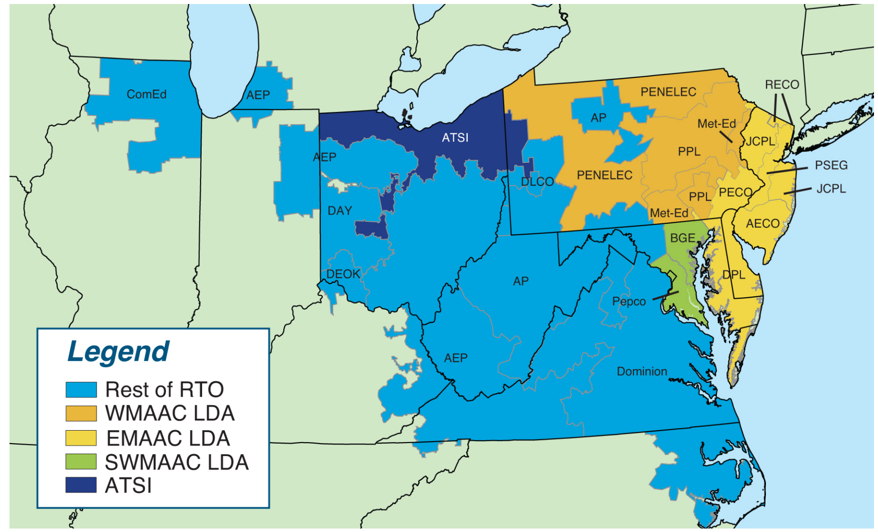
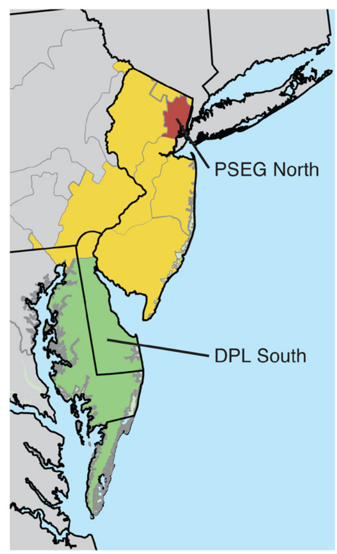


Figure 4-2 PJM RPM EMAAC subzonal LDAs (See the 2011 SOM, Figure A-4)



20 Prior to the 2012/2013 delivery year, an LDA with a CETL less than 1.05 times CETO was modeled as a constrained LDA in RPM. No additional criteria were used in determining modeled LDAs.

21 OATT Attachment DD § 5.10 (a) (ii).

Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources. Generators on the PJM system that do not have a commitment to serve PJM loads in the given delivery year as a result of RPM Auctions, FRR capacity plans, locational UCAP transactions, and/or are not designated as a replacement resource, are eligible to export their capacity outside PJM.[22]

The PJM market rules should not create inappropriate barriers to either the import or export of capacity. The market rules in other balancing authorities should also not create inappropriate barriers to the import or export of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market. Physical deliverability is assured by the requirements for firm transmission service. Selling capacity into the PJM capacity market but making energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the Day-Ahead Energy Market should be clarified for both internal and external resources.

Demand-Side Resources

As shown in Table 4-6 and Table 4-8, capacity in the RPM load management programs was 7,118.5 MW for June 1, 2012 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2012/2013 Delivery Year (9,407.0 MW) less replacement capacity (2,288.5 MW). Table 4-7 shows RPM commitments for DR and EE resources as the result of RPM Auctions prior to adjustments for replacement capacity transactions and certified ILR.

22 OATT Attachment DD § 5.6.6(b).

Table 4-6 RPM load management statistics by LDA: June 1, 2011 to June 1, 2015[23,24] (See the 2011 SOM, Table 4-10)

	UCAP (MW)								
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI
DR cleared	1,826.6								
EE cleared	76.4								
DR net replacements	(1,052.4)								
EE net replacements	0.2								
ILR	9,032.6								
RPM load management @ 01-Jun-11	9,883.4								
DR cleared	8,740.9	5,193.6	1,971.8	1,794.4	71.0	517.8	97.9		
EE cleared	666.1	253.6	48.1	160.1	0.0	15.9	7.8		
DR net replacements	(2,253.6)	(1,848.6)	(761.5)	(645.5)	(30.6)	(182.9)	10.1		
EE net replacements	(34.9)	(32.4)	(16.2)	(16.5)	0.0	(3.0)	(1.0)		
RPM load management @ 01-Jun-12	7,118.5	3,566.2	1,242.2	1,292.5	40.4	347.8	114.8		
DR cleared	10,458.8	6,297.6	2,702.1	1,788.6	155.4	1,185.0	534.8	661.7	
EE cleared	870.9	269.6	61.3	133.1	6.8	26.2	9.4	56.3	
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
RPM load management @ 01-Jun-13	11,329.7	6,567.2	2,763.4	1,921.7	162.2	1,211.2	544.2	718.0	
DR cleared	14,226.8	7,320.0	2,923.5	2,250.3	220.9	989.5	468.0	908.5	
EE cleared	956.4	276.9	35.2	169.8	8.1	14.9	7.6	51.4	
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
RPM load management @ 01-Jun-14	15,183.2	7,596.9	2,958.7	2,420.1	229.0	1,004.4	475.6	959.9	
DR cleared	14,832.8	6,648.7	2,610.4	2,009.1	86.3	796.1	263.3	867.4	1,763.7
EE cleared	922.5	222.6	42.2	159.4	0.0	10.7	3.1	55.8	44.9
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RPM load management @ 01-Jun-15	15,755.3	6,871.3	2,652.6	2,168.5	86.3	806.8	266.4	923.2	1,808.6

23 For delivery years through 2011/2012, certified ILR data were used in the calculation, because the certified ILR data are now available. Effective the 2012/2013 Delivery Year, ILR was eliminated. Starting with the 2012/2013 Delivery Year and also for incremental auctions in the 2011/2012 Delivery Year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM Auctions.

24 The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges. See OATT Attachment DD § 8.4. For the 2012/2013 Delivery Year, relief from charges was granted by PJM for 11.7 MW.

Table 4-7 RPM load management cleared capacity and ILR: 2007/2008 through 2015/2016[25,26,27] (See the 2011 SOM, Table 4-11)

	DR Cleared		EE Cleared		ILR	
Delivery Year	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
2007/2008	123.5	127.6	0.0	0.0	1,584.6	1,636.3
2008/2009	540.9	559.4	0.0	0.0	3,488.5	3,608.1
2009/2010	864.5	892.9	0.0	0.0	6,273.8	6,481.5
2010/2011	930.9	962.9	0.0	0.0	7,961.3	8,236.4
2011/2012	1,766.0	1,826.6	74.0	76.4	8,730.7	9,032.6
2012/2013	8,429.7	8,740.9	643.4	666.1	0.0	0.0
2013/2014	10,075.3	10,458.8	841.4	870.9	0.0	0.0
2014/2015	13,717.4	14,226.8	923.9	956.4	0.0	0.0
2015/2016	14,303.2	14,832.8	890.8	922.5	0.0	0.0

Table 4-8 RPM load management statistics: June 1, 2007 to June 1, 2015[28,29] (See the 2011 SOM, Table 4-12)

	DR and EE Cleared Plus ILR		DR Net Replacements		EE Net Replacements		Total RPM LM	
	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
01-Jun-07	1,708.1	1,763.9	0.0	0.0	0.0	0.0	1,708.1	1,763.9
01-Jun-08	4,029.4	4,167.5	(38.7)	(40.0)	0.0	0.0	3,990.7	4,127.5
01-Jun-09	7,138.3	7,374.4	(459.5)	(474.7)	0.0	0.0	6,678.8	6,899.7
01-Jun-10	8,892.2	9,199.3	(499.1)	(516.3)	0.0	0.0	8,393.1	8,683.0
01-Jun-11	10,570.7	10,935.6	(1,017.3)	(1,052.4)	0.2	0.2	9,553.6	9,883.4
01-Jun-12	9,073.1	9,407.0	(2,173.4)	(2,253.6)	(33.7)	(34.9)	6,866.0	7,118.5
01-Jun-13	10,916.7	11,329.7	0.0	0.0	0.0	0.0	10,916.7	11,329.7
01-Jun-14	14,641.3	15,183.2	0.0	0.0	0.0	0.0	14,641.3	15,183.2
01-Jun-15	15,194.0	15,755.3	0.0	0.0	0.0	0.0	15,194.0	15,755.3

Market Conduct

Offer Caps

Market power mitigation measures were applied to Capacity Resources such that the sell offer was set equal to the defined offer cap when the Capacity Market Seller failed the market structure test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, increased the market clearing price.[30,31,32]

25 For delivery years through 2011/2012, certified ILR data is shown, because the certified ILR data are now available. Effective the 2012/2013 Delivery Year, ILR was eliminated. Starting with the 2012/2013 Delivery Year and also for incremental auctions in the 2011/2012 Delivery Year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM Auctions.

26 FRR committed load management resources are not included in this table.

27 The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges. See OATT Attachment DD § 8.4. For the 2012/2013 Delivery Year, relief from charges was granted by PJM for 11.7 MW.

28 For delivery years through 2011/2012, certified ILR data were used in the calculation, because the certified ILR data are now available. Effective the 2012/2013 Delivery Year, ILR was eliminated. Starting with the 2012/2013 Delivery Year and also for incremental auctions in the 2011/2012 Delivery Year, the Energy Efficiency (EE) resource type is eligible to be offered in RPM Auctions.

29 FRR committed load management resources are not included in this table.

30 See OATT Attachment DD § 6.5.

31 Prior to November 1, 2009, existing DR and EE resources were subject to market power mitigation in RPM Auctions. See 129 FERC ¶ 61,081 (2009) at P 30.

32 Effective January 31, 2011, the RPM rules related to market power mitigation were changed, including revising the definition for Planned Generation Capacity Resource and creating a new definition for Existing Generation Capacity Resource for purposes of the must-offer requirement and market power mitigation, and treating a proposed increase in the capability of a Generation Capacity Resource the same in terms of mitigation as a Planned Generation Capacity Resource. See 134 FERC ¶ 61,065 (2011).

Table 4-9 ACR statistics: Auctions conducted in third quarter, 2012 (See the 2011 SOM, Table 4-14)

	2013/2014 Second Incremental Auction		2014/2015 First Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	55	33.7%	59	31.1%
ACR data input (APIR)	8	4.9%	21	11.1%
ACR data input (non-APIR)	0	0.0%	0	0.0%
Opportunity cost input	4	2.5%	4	2.1%
Default ACR and opportunity cost	0	0.0%	1	0.5%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned uprate and default ACR	10	6.1%	11	5.8%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and price taker	5	3.1%	4	2.1%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned generation resources	11	6.7%	5	2.6%
Price takers	70	42.9%	85	44.7%
Total Generation Capacity Resources offered	163	100.0%	190	100.0%

Market Performance[33]

As shown in Table 4-10, the rest of RTO clearing price in the 2013/2014 RPM Second Incremental Auction was $7.01 per MW-day, and the rest of RTO clearing price for Annual and Extended Summer Resources in the 2014/2015 RPM First Incremental Auction was $5.54 per MW-day. In the 2014/2015 RPM First Incremental Auction, the PSEG North resource clearing price for Annual and Extended Summer Resources was $410.95 per MW-day and the rest of RTO resource clearing price for Limited Resources was $0.03 per MW-day, the highest and lowest resource clearing prices in RPM history. In the 2014/2015 First Incremental Auction, PJM attempted to procure additional capacity in PSEG North, while PJM attempted to sell capacity in the rest of RTO.

Annual weighted average capacity prices increased from a CCM weighted average price of $5.73 per MW-day in 2006 to an RPM weighted-average price of $164.71 per MW-day in 2010 and then declined to $148.33 per MW-day in 2015. Figure 4-3 presents cleared MW weighted average capacity market prices on a calendar year basis for the entire history of the PJM capacity markets.

Cleared capacity resources across the entire RTO will receive a total of $8.7 million based on the unforced MW cleared and the prices in the 2013/2014 RPM Second Incremental Auction and a total of $35.6 million based on the unforced MW cleared and prices in the 2014/2015 RPM First Incremental Auction.

Table 4-11 shows RPM revenue by resource type for all RPM Auctions held to date with $1.5 billion for new/reactivated generation resources based on the unforced MW cleared and the resource clearing prices.

Table 4-12 shows RPM revenue by calendar year for all RPM Auctions held to date.

33 The MMU provides detailed analyses of market performance in reports for each RPM Auction. See <http://www.monitoringanalytics.com/reports/Reports/2012.shtml>.

Table 4-10 Capacity prices: 2007/2008 through 2015/2016 RPM Auctions (See the 2011 SOM, Table 4-21)

		RPM Clearing Price ($ per MW-day)								
	Product Type	RTO	MAAC	APS	EMAAC	SWMAAC	DPL South	PSEG North	Pepco	ATSI
2007/2008 BRA		$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$188.54	
2008/2009 BRA		$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$148.80	$210.11	
2008/2009 Third Incremental Auction		$10.00	$10.00	$10.00	$10.00	$223.85	$10.00	$10.00	$223.85	
2009/2010 BRA		$102.04	$191.32	$191.32	$191.32	$237.33	$191.32	$191.32	$237.33	
2009/2010 Third Incremental Auction		$40.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	$86.00	
2010/2011 BRA		$174.29	$174.29	$174.29	$174.29	$174.29	$186.12	$174.29	$174.29	
2010/2011 Third Incremental Auction		$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	
2011/2012 BRA		$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	$110.00	
2011/2012 First Incremental Auction		$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	$55.00	
2011/2012 ATSI FRR Integration Auction		$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89
2011/2012 Third Incremental Auction		$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
2012/2013 BRA		$16.46	$133.37	$16.46	$139.73	$133.37	$222.30	$185.00	$133.37	
2012/2013 ATSI FRR Integration Auction		$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46
2012/2013 First Incremental Auction		$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$16.46	$16.46
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$13.01	$13.01
2012/2013 Third Incremental Auction		$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51
2013/2014 BRA		$27.73	$226.15	$27.73	$245.00	$226.15	$245.00	$245.00	$247.14	$27.73
2013/2014 First Incremental Auction		$20.00	$20.00	$20.00	$178.85	$54.82	$178.85	$178.85	$54.82	$20.00
2013/2014 Second Incremental Auction		$7.01	$10.00	$7.01	$40.00	$10.00	$40.00	$40.00	$10.00	$7.01
2014/2015 BRA	Limited	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47	$125.47
2014/2015 BRA	Extended Summer	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99
2014/2015 First Incremental Auction	Limited	$0.03	$5.23	$0.03	$5.23	$5.23	$5.23	$399.62	$5.23	$0.03
2014/2015 First Incremental Auction	Extended Summer	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54
2014/2015 First Incremental Auction	Annual	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54
2015/2016 BRA	Limited	$118.54	$150.00	$118.54	$150.00	$150.00	$150.00	$150.00	$150.00	$304.62
2015/2016 BRA	Extended Summer	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$322.08
2015/2016 BRA	Annual	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$357.00

Table 4-11 RPM revenue by type: 2007/2008 through 2015/2016[34,35] (See the 2011 SOM, Table 4-22)

Type	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016	Total
Demand Resources	$5,537,085	$35,349,116	$65,762,003	$60,235,796	$55,795,785	$264,387,897	$554,697,058	$670,147,703	$880,020,384	$2,591,932,826
Energy Efficiency Resources	$0	$0	$0	$0	$139,812	$11,408,552	$21,131,133	$40,247,604	$52,113,238	$125,040,339
Imports	$22,225,980	$60,918,903	$56,517,793	$106,046,871	$185,421,273	$13,260,822	$31,738,568	$178,473,828	$186,311,568	$840,915,605
Coal existing	$1,022,372,301	$1,844,120,476	$2,417,576,805	$2,662,434,386	$1,595,707,479	$1,016,194,603	$1,738,281,395	$1,853,342,698	$2,656,149,396	$16,806,179,541
Coal new/reactivated	$0	$0	$1,854,781	$3,168,069	$28,330,047	$7,568,127	$12,946,883	$56,917,305	$62,882,021	$173,667,234
Gas existing	$1,460,544,471	$1,911,518,321	$2,276,961,764	$2,586,971,699	$1,607,317,731	$1,079,413,451	$1,830,451,475	$1,969,632,253	$2,473,484,871	$17,196,296,036
Gas new/reactivated	$3,472,667	$9,751,112	$30,168,831	$58,065,964	$98,448,693	$76,633,409	$167,340,901	$184,293,676	$527,114,537	$1,155,289,790
Hydroelectric existing	$209,490,444	$287,850,403	$364,742,517	$442,429,815	$278,529,660	$179,117,975	$308,773,557	$328,974,881	$384,329,997	$2,784,239,249
Hydroelectric new/reactivated	$0	$0	$0	$0	$0	$11,397	$25,708	$6,591,114	$14,880,302	$21,508,521
Nuclear existing	$996,085,233	$1,322,601,837	$1,517,723,628	$1,799,258,125	$1,079,386,338	$762,719,550	$1,346,210,480	$1,460,152,259	$1,846,030,461	$12,130,167,912
Nuclear new/reactivated	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Oil existing	$502,172,373	$572,259,505	$715,618,319	$668,505,533	$368,084,004	$423,957,756	$685,582,719	$469,738,966	$562,402,530	$4,968,321,705
Oil new/reactivated	$0	$4,837,523	$5,676,582	$4,339,539	$967,887	$2,772,987	$5,669,955	$3,896,120	$5,166,777	$33,327,370
Solid waste existing	$29,956,764	$33,843,188	$41,243,412	$40,731,606	$25,636,836	$26,840,670	$43,613,120	$34,529,651	$35,405,293	$311,800,540
Solid waste new/reactivated	$0	$0	$523,739	$413,503	$261,690	$316,420	$1,964,565	$1,190,758	$3,324,459	$7,995,134
Solar existing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Solar new/reactivated	$0	$0	$0	$0	$66,978	$1,246,337	$2,720,170	$3,152,447	$3,403,067	$10,588,999
Wind existing	$430,065	$1,180,153	$2,011,156	$1,819,413	$1,072,929	$812,644	$1,373,205	$1,493,377	$1,768,330	$11,961,271
Wind new/reactivated	$0	$2,917,048	$6,836,827	$15,232,177	$9,919,881	$5,052,036	$13,064,541	$31,173,865	$39,549,396	$123,745,769
Total	$4,252,287,381	$6,087,147,586	$7,503,218,157	$8,449,652,496	$5,335,087,023	$3,871,714,635	$6,765,585,432	$7,293,948,503	$9,734,336,627	$59,292,977,841

Table 4-12 RPM revenue by calendar year: 2007 through 2016[36] (New Table)

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	129,409.2	214	$2,486,310,108
2008	$111.93	130,223.2	366	$5,334,880,241
2009	$142.74	132,772.0	365	$6,917,391,702
2010	$164.71	134,033.9	365	$8,058,113,907
2011	$135.14	134,105.2	365	$6,615,032,130
2012	$89.01	137,684.7	366	$4,485,656,150
2013	$100.22	152,226.6	365	$5,568,395,048
2014	$124.72	155,428.1	365	$7,075,365,425
2015	$148.33	160,866.8	365	$8,709,157,810
2016	$161.62	164,563.9	152	$4,042,675,320

34 A resource classified as "new/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/reactivated" for its initial offer and all its subsequent offers in RPM Auctions.
35 The results for the ATSI Integration Auctions are not included in this table.
36 The results for the ATSI Integration Auctions are not included in this table.

Figure 4-3 History of capacity prices: Calendar year 1999 through 2015[37] (See the 2011 SOM, Figure 4-1)

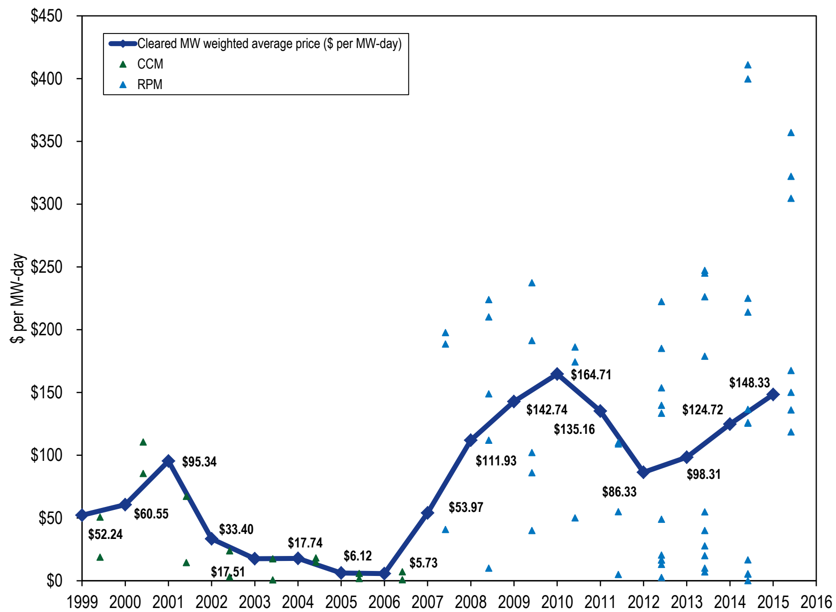


Table 4-13 shows the RPM annual charges to load. For the 2012/2013 planning year, RPM annual charges to load total approximately $3.9 billion.

37 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2015 capacity prices are RPM weighted average prices. The CCM data points plotted are cleared MW weighted average prices for the daily and monthly markets by delivery year. The RPM data points plotted are RPM resource clearing prices.

Table 4-13 RPM cost to load: 2011/2012 through 2015/2016 RPM Auctions[38,39,40] (See the 2011 SOM, Table 4-23)

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2011/2012			
RTO	$116.15	133,815.3	$5,688,608,837
2012/2013			
RTO	$16.74	65,495.4	$400,296,161
MAAC	$133.42	30,107.9	$1,466,181,230
EMAAC	$143.06	19,954.6	$1,041,932,095
DPL	$171.27	4,523.9	$282,806,394
PSEG	$157.73	11,645.3	$670,441,158
2013/2014			
RTO	$28.37	81,517.7	$844,133,053
MAAC	$232.07	14,930.2	$1,264,667,275
EMAAC	$250.12	36,738.0	$3,353,903,318
SWMAAC	$231.08	8,057.0	$679,559,435
Pepco	$244.74	7,653.2	$683,667,039
2014/2015			
RTO	$128.17	82,577.4	$3,863,199,144
MAAC	$137.60	30,833.8	$1,548,586,169
EMAAC	$137.61	20,460.8	$1,027,667,647
DPL	$145.32	4,625.7	$245,357,435
PSEG	$170.24	11,833.5	$735,288,837
2015/2016			
RTO	$134.62	84,948.0	$4,185,534,909
MAAC	$165.78	68,742.2	$4,170,968,816
ATSI	$294.03	14,940.4	$1,607,805,047

38 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM Base Residual Auction results.
39 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.
40 Prior to the 2009/2010 Delivery Year, the Final UCAP Obligation is determined after the clearing of the Second Incremental Auction. For the 2009/2010 through 2011/2012 Delivery Years, the Final UCAP Obligations are determined after the clearing of the Third Incremental Auction. 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 2013/2014, 2014/2015, and 2015/2016 Net Load Prices are not finalized. The 2013/2014, 2014/2015, and 2015/2016 Obligation MW are not finalized.

Generator Performance

Generator performance results from the interaction between the physical characteristics 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).[41]

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity during that period. Nuclear units typically run at a greater than 90 percent capacity factor. In January through September 2012, nuclear units had a capacity factor of 92.8 percent. Combined cycle units ran more often in January through September 2012 than in the same period in 2011, increasing from a 47.1 percent capacity factor in 2011 to a 63.8 percent capacity factor in 2012. In contrast, the capacity factor for steam units decreased from 54.0 percent in 2011 to 45.5 percent in January through September 2012.

Table 4-14 PJM capacity factor (By unit type (GWh)); January through September 2011 and 2012[42] (See the 2011 SOM, Table 4-24)

	Jan-Sep 2011		Jan-Sep 2012	
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
Battery	0.2	1.3%	5.9	3.0%
Combined Cycle	74,481.1	47.1%	108,088.4	63.8%
Combustion Turbine	5,510.2	3.0%	7,273.8	3.7%
Diesel	495.3	18.0%	456.7	15.9%
Diesel (Landfill gas)	629.1	34.9%	913.4	41.2%
Nuclear	195,196.7	91.7%	205,503.9	92.8%
Pumped Storage Hydro	5,460.1	15.2%	5,097.0	14.1%
Run of River Hydro	5,919.8	38.7%	4,671.2	29.5%
Solar	37.9	12.0%	192.7	17.2%
Steam	286,978.5	54.0%	261,413.2	45.5%
Wind	7,924.5	27.2%	8,944.7	25.2%
Total	582,633.3	49.6%	602,560.9	47.9%

Generator Performance Factors

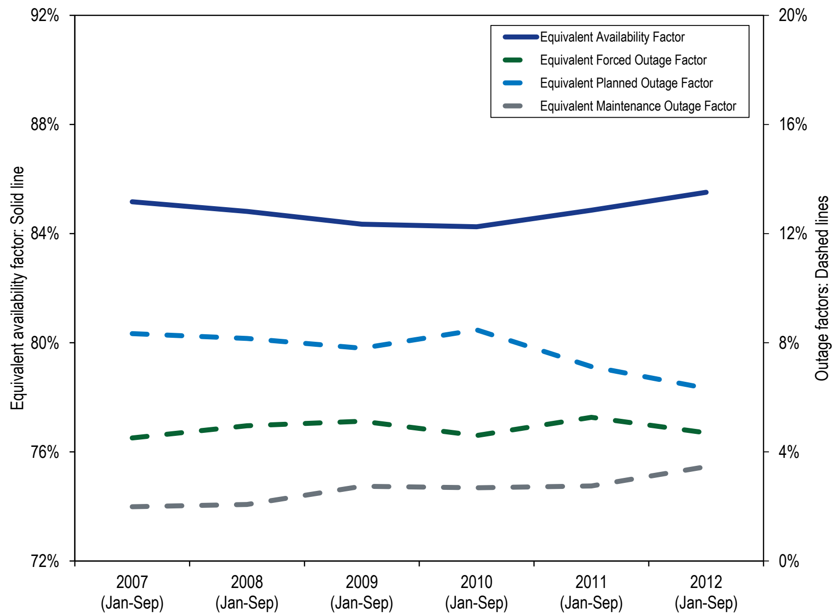
Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of hours in a year when a unit is available to generate at full capacity while the 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 increased from 84.9 percent in January through September 2011, to 85.5 percent for the same period in 2012. The EMOF increased from 2.8 percent to 3.5 percent, the EPOF decreased from 7.1 percent to 6.3 percent, and the EFOF decreased from 5.3 percent to 4.7 percent (Figure 4-4).

41 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.

42 The capacity factors for wind and solar unit types described in this table are based on nameplate capacity values, and are calculated based on when the units come online.

Figure 4-4 PJM equivalent outage and availability factors: Calendar years 2007 to 2012 (See the 2011 SOM, Table 4-1)



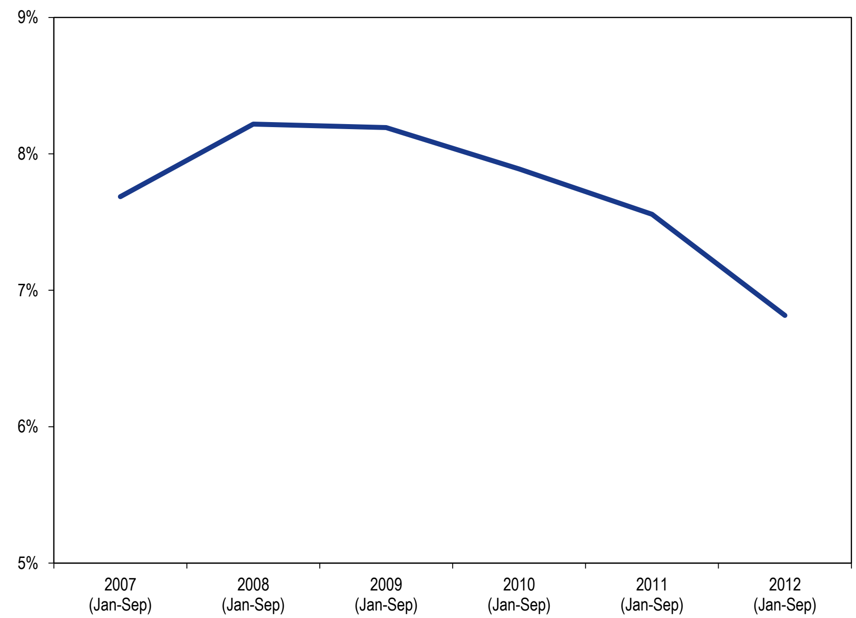
Generator Forced Outage Rates

There are three primary forced outage rate metrics. The most fundamental forced outage rate metric is EFORd. The other forced outage rate metrics either exclude some outages, XEFORd, or exclude some outages and exclude some time periods, EFORp.

The unadjusted forced outage rate of a generating unit is measured as the equivalent demand forced outage rate (EFORd). EFORd 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 measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours,[43] service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours. The EFORd metric includes all forced outages, regardless of the reason for those outages.

Figure 4-5 shows the average January through September EFORd since 2007 for all units in PJM.

Figure 4-5 Trends in the PJM equivalent demand forced outage rate (EFORd): January through September, 2007 to 2012 (See the 2011 SOM, Figure 4-3)



43 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.

Table 4-15 shows the class average EFORd by unit type.

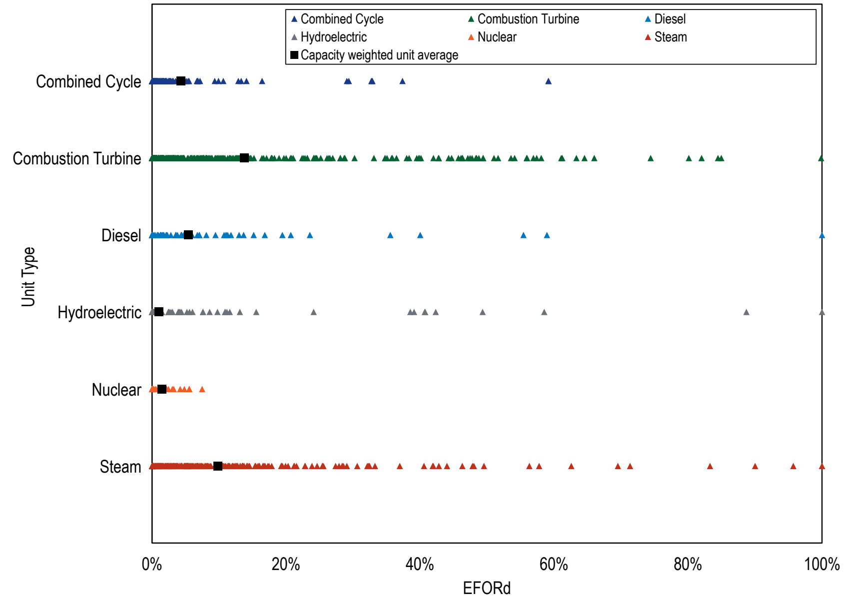
Table 4-15 PJM EFORd data for different unit types: 2007 to 2012 (See the 2011 SOM, Table 4-25)

	2007 (Jan-Sep)	2008 (Jan-Sep)	2009 (Jan-Sep)	2010 (Jan-Sep)	2011 (Jan-Sep)	2012 (Jan-Sep)
Combined Cycle	3.7%	3.4%	5.2%	4.3%	3.0%	3.1%
Combustion Turbine	17.0%	14.2%	10.3%	13.8%	7.1%	6.5%
Diesel	10.7%	10.1%	8.5%	5.5%	9.4%	5.3%
Hydroelectric	2.2%	2.1%	2.3%	1.1%	2.2%	4.0%
Nuclear	1.2%	1.1%	4.0%	1.5%	2.4%	1.5%
Steam	8.7%	10.7%	10.3%	9.8%	11.1%	10.2%
Total	7.7%	8.2%	8.2%	7.9%	7.6%	6.8%

Distribution of EFORd

The average EFORd results do not show the underlying pattern of EFORd rates by unit type. The distribution of EFORd by unit type is shown in Figure 4-6. Each generating unit is represented by a single point, and the capacity weighted unit average is represented by a solid square. Steam and combustion turbine units have the greatest variance of EFORd, while nuclear and combined cycle units have the lowest variance in EFORd values.

Figure 4-6 PJM January through September 2012 distribution of EFORd data by unit type (See the 2011 SOM, Figure 4-4)



Other Forced Outage Rate Metrics

There are two additional primary forced outage rate metrics that play a significant role in PJM markets, XEFORd and EFORp. The XEFORd metric is the EFORd metric adjusted to remove outages that have been defined to be outside management control (OMC). The EFORp metric is the EFORd metric adjusted to remove OMC outages and to reflect unit availability only during the approximately 500 hours defined in the PJM RPM tariff to be the critical load hours.

The PJM capacity market rules use XEFORd to determine the UCAP for generating units. Unforced capacity in the PJM Capacity Market for any individual generating unit is equal to one minus the XEFORd multiplied by the unit ICAP.

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 of XEFORd, which are used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market.

Thus the PJM Capacity Market creates an incentive to minimize the forced outage rate excluding OMC outages, but not an incentive to minimize the forced outage rate accounting for all forced outages. In fact, because PJM uses XEFORd as the outage metric to define capacity available for sale, the PJM Capacity Market includes an incentive to classify as many forced outages as possible as OMC.

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages to be deemed Outside Management Control (OMC).[44] An outage can be classified as an OMC outage only if the outage meets the requirements outlined in Appendix K of the "Generator Availability Data System Data Reporting Instructions." Appendix K of the "Generator Availability Data Systems Data Reporting Instructions" also lists specific cause codes (i.e., codes that are standardized for specific outage causes) that would be considered OMC outages.[45] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, according to the NERC specifications, fuel quality issues (codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered separately per the NERC directive.

Nothing in NERC's classification of outages requires that PJM exclude OMC outages from the forced outage rate metric used in the Capacity Market. That choice was made by PJM and can be modified without violating any NERC requirements.[46] It is possible to have an OMC outage under the NERC definition, which PJM does not define as OMC for purposes of calculating XEFORd. That is the current PJM practice. The actual implementation of the OMC outages and their impact on XEFORd is and has been within the control of PJM. PJM has chosen to exclude only some of the OMC outages from the XEFORd metric.

At present, PJM does not have a clear, documented, public set of criteria for designating outages as OMC.

All outages, including OMC outages, are included in the EFORd that is used for PJM 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 that must be offered in PJM's Capacity Market. This modified EFORd is termed the XEFORd. Table 4-16 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages account for 6.5 percent of all forced outages. The largest contributor to OMC outages, lack of fuel, is the cause of 69.4 percent of OMC outages and 4.5 percent of all forced outages. The NERC GADS guidelines in Appendix K describe OMC lack of fuel as "lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels."

44 Generator Availability Data System Data Reporting Instructions states, "The electric industry in Europe and other parts of the world has made a change to examine losses of generation caused by problems with and outside plant management control… There are a number of outage causes that may prevent the energy coming from a power generating plant from reaching the customer. Some causes are due to the plant operation and equipment while others are outside plant management control. The standard sets a boundary on the generator side of the power station for the determination of equipment outside management control." The Generator Availability Data System Data Reporting Instructions can be found on the NERC website: <http://www.nerc.com/files/GADS_DRI_Complete_Version_010111.pdf>.

45 For a list of these cause codes, see the *Technical Reference for PJM Markets*, at "Generator Performance: NERC OMC Outage Cause Codes" <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

46 It is unclear whether there were member votes taken on this issue.

Table 4-16 OMC Outages: January through September 2012 (See the 2011 SOM, Table 4-30)

OMC Cause Code	% of all Forced Outages
Lack of fuel	4.5%
Switchyard circuit breakers external	0.5%
Other switchyard equipment external	0.3%
Transmission line	0.2%
Transmission system problems other than catastrophes	0.2%
Transmission equipment beyond the 1st substation	0.2%
Storms	0.2%
Lightning	0.1%
Lack of water	0.1%
Transmission equipment at the 1st substation	0.1%
Switchyard system protection devices	0.0%
Switchyard transformers and associated cooling systems	0.0%
Other fuel quality problems	0.0%
Tornados	0.0%
Flood	0.0%
Other miscellaneous external problems	0.0%
Total	6.5%

An outage is an outage, regardless of the cause. Lack of fuel is especially noteworthy because the lack of fuel reasons are arguably not outside the control of management. Virtually any issue with fuel supply can be addressed by additional expenditures. It is significant that some OMC outages are classified as economic. Firm gas contracts could be used in place of interruptible gas contracts. Alternative fuels could be used as a supplement to primary fuels. Improved fuel management practices including additional investment could eliminate wet coal as a reason. Better diversification in supplies could eliminate interruptions from individual suppliers. But regardless of the reason, an outage is an outage. If a particular unit or set of units have outages on a regular basis for one of the OMC reasons, that is a real feature of the units that should be reflected in overall PJM system planning as well as in the economic fundamentals of the capacity market and the capacity market outcomes. Permitting OMC outages to be excluded from the forced outage metric skews the results of the capacity market towards less reliable units and away from more reliable units. This is exactly the wrong incentive. Paying for capacity from units using the EFORd, not the XEFORd, metric would provide a market incentive for unit owners to address all their outage issues in an efficient manner. Pretending that some outages simply do not exist distorts market outcomes. That is exactly the result of using OMC outages to reduce EFORd.[47]

If there were units in a constrained Locational Deliverability Area (LDA) that regularly had a higher rate of OMC outages than other units in the LDA and in PJM, and that cleared in the capacity auctions, the supply and demand in that LDA would be affected. The payments to the high OMC units would be too high and the payments to other units in the LDA would be too low. This market signal, based on the exclusion of OMC outages, favors generating units with high forced outage rates that result from causes classified as OMC, compared to generating units with no OMC outages.

With the OMC rules in place, if a new unit were considering entry into a constrained LDA and had choices about the nature of its fuel supply, the unit would not have an incentive to choose the most reliable fuel source or combination of fuel sources, but simply the cheapest. The OMC outage rules would provide the wrong incentive. While it is up to the generation investor to determine its fuel supply arrangements, the generation investor must also take on the risks associated with its fuel supply decisions rather than being able to shift those risks to other generation owners and to customers, which is exactly what occurs under the OMC rules as currently implemented. This issue is especially critical in a time when almost all incremental conventional generation in PJM is gas fired.

The NYISO does not classify any fuel related outages or derates as OMC under its capacity market rules.[48]

47 For more on this issue, see the IMM's White Paper included in: Monitoring Analytics, LLC and PJM Interconnection, LLC, "Capacity in the PJM Market," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012)

48 See New York Independent System Operator, "Manual 4: Installed Capacity Manual," Version 6.20. (January, 24 2012) <http://www.nyiso.com/public/webdocs/documents/manuals/operations/icap_mnl.pdf>. When a Generator, Energy/Capacity Limited Resource, System Resource, Intermittent Power Resource or Control Area System Resource is forced into an outage by an equipment failure that involves equipment located on the electric network beyond the step-up transformer, and including such step-up transformer, the NYISO shall not treat the outage as a forced outage for purposes of calculating the amount of Unforced Capacity such Installed Capacity Suppliers are qualified to supply in the NYCA. This exception is limited to an equipment failure that involves equipment located on the electric network beyond the generator step-up transformer, and including such step-up transformer on the output side of the Generator, Energy/Capacity Limited Resource, System Resource, Intermittent Power Resource or Control Area System Resource. This exception does not apply to fuel related outages or derates or other cause codes that might be classified as Outside Management Control in the NERC Data reporting Instructions. NYISO only accepts OMC outages for outages at or beyond the step-up transformer.

It is clear that OMC outages defined as lack of fuel should not be identified as OMC and should not be excluded from the calculation of XEFORd and EFORp.

All submitted OMC outages are reviewed by PJM's Resource Adequacy Department. The MMU recommends that PJM review all requests for OMC carefully, develop a clear, transparent set of written public rules governing the designation of outages as OMC and post those guidelines. Any resultant OMC outages may be considered by PJM but should not be reflected in forced outage metrics which affect system planning or market payments to generating units.

The MMU recommends that PJM immediately eliminate lack of fuel as an acceptable basis for an OMC outage. The MMU recommends that PJM eliminate all OMC outages from the calculation of forced outage rates used for any purpose in the PJM Capacity Market after appropriate notice.

Table 4-17 shows the impact of OMC outages on EFORd. The difference is especially noticeable for steam units and combustion turbine units.

Table 4-17 PJM EFORd vs. XEFORd: January through September 2012 (See the 2011 SOM, Table 4-31)

	EFORd	XEFORd	Difference
Combined Cycle	3.1%	3.0%	0.1%
Combustion Turbine	6.5%	5.4%	1.0%
Diesel	5.3%	4.3%	1.0%
Hydroelectric	4.0%	3.8%	0.2%
Nuclear	1.5%	1.5%	0.0%
Steam	10.2%	9.4%	0.7%
Total	6.8%	6.3%	0.5%

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.[49] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor.

For the nine months January through September 2012, PJM EFOF was 4.7 percent. This means there was 4.7 percent lost availability because of forced outages. Table 4-18 shows that forced outages for boiler tube leaks, at 18.6 percent of the systemwide EFOF, were the largest single contributor to EFOF.

49 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 4-18 Contribution to EFOF by unit type by cause: January through September 2012 (See the 2011 SOM, Table 4-27)

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	3.4%	0.0%	0.0%	0.0%	0.0%	23.4%	18.6%
Boiler Piping System	4.3%	0.0%	0.0%	0.0%	0.0%	7.7%	6.4%
Feedwater System	7.4%	0.0%	0.0%	0.0%	1.7%	7.0%	6.1%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	7.0%	5.5%
High Pressure Turbine	0.0%	0.0%	0.0%	0.0%	0.0%	6.8%	5.3%
Electrical	6.0%	11.9%	2.9%	8.4%	10.8%	3.8%	5.0%
Miscellaneous (Generator)	5.3%	6.5%	1.7%	66.7%	0.0%	2.8%	4.8%
Economic	0.5%	0.6%	0.9%	4.0%	0.0%	5.7%	4.7%
Reserve Shutdown	3.8%	18.0%	13.5%	2.2%	0.8%	3.0%	4.0%
Boiler Fuel Supply from Bunkers to Boiler	1.3%	0.0%	0.0%	0.0%	0.0%	3.7%	3.0%
Valves	7.7%	0.0%	0.0%	0.0%	1.9%	2.2%	2.3%
Circulating Water Systems	1.3%	0.0%	0.0%	0.0%	10.3%	1.9%	2.1%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	41.0%	0.0%	2.1%
Controls	5.2%	0.9%	0.2%	0.2%	4.2%	1.8%	2.0%
Miscellaneous (Steam Turbine)	1.7%	0.0%	0.0%	0.0%	0.3%	2.2%	1.8%
Other Operating Environmental Limitations	1.7%	0.0%	0.0%	0.3%	5.7%	1.8%	1.8%
Condensing System	1.6%	0.0%	0.0%	0.0%	5.0%	1.7%	1.7%
Miscellaneous (Gas Turbine)	3.9%	14.6%	0.0%	0.0%	0.0%	0.0%	1.3%
Precipitators	0.0%	0.0%	0.0%	0.0%	0.0%	1.5%	1.2%
All Other Causes	44.8%	47.4%	80.9%	18.1%	18.4%	16.1%	20.5%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 4-19 shows the categories which are included in the economic category.[50] Lack of fuel that is considered Outside Management Control accounted for 95.8 percent of all economic reasons while lack of fuel that was not Outside Management Control accounted for only 1.6 percent.

OMC lack of fuel is described as “Lack of fuel where the operator is not in control of contracts, supply lines, or delivery of fuels”.[51] Only a handful of units use other economic problems to describe outages. Other economic problems are not defined by NERC GADS and are best described as economic problems that cannot be classified by the other NERC GADS economic problem cause codes. Lack of water events occur when a hydroelectric plant does not have sufficient fuel (water) to operate.

Table 4-19 Contributions to Economic Outages: January through September 2012 (See the 2011 SOM, Table 4-28)

	Contribution to Economic Reasons
Lack of fuel (OMC)	95.8%
Lack of water (Hydro)	2.3%
Lack of fuel (Non-OMC)	1.6%
Fuel conservation	0.2%
Other economic problems	0.0%
Ground water or other water supply problems	0.0%
Total	100.0%

50 The classification and definitions of these outages are defined by NERC GADS.
51 The classification and definitions of these outages are defined by NERC GADS.

EFORd, XEFORd and 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. Like XEFORd, EFORp excludes OMC outages. PJM systemwide EFORp is a capacity-weighted average of individual unit 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.[52] 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 EFORd, 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 the incentives created by the PJM Capacity Market.

Table 4-20 shows the capacity-weighted class average of EFORd, XEFORd and EFORp. The impact of OMC outages is especially noticeable in the difference between EFORd and XEFORd for steam units and combustion turbine units.

52 See "Manual 22: Generator Resource Performance Indices," Revision 15 (June 1, 2007), Definitions.

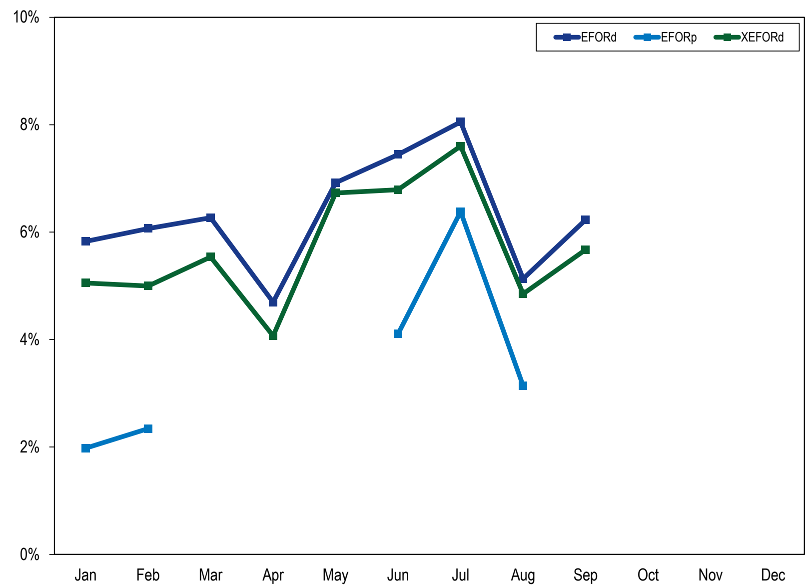
Table 4-20 PJM EFORd, XEFORd and EFORp data by unit type: January through September 2012[53] (See the 2011 SOM, Table 4-35)

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	3.1%	3.0%	2.0%	0.1%	1.0%
Combustion Turbine	6.5%	5.4%	2.9%	1.0%	3.6%
Diesel	5.3%	4.3%	2.7%	1.0%	2.6%
Hydroelectric	4.0%	3.8%	4.6%	0.2%	(0.7%)
Nuclear	1.5%	1.5%	1.8%	0.0%	(0.3%)
Steam	10.2%	9.4%	5.7%	0.7%	4.4%
Total	6.8%	6.3%	4.0%	0.5%	2.8%

Performance By Month

On a monthly basis, EFORp values were significantly less than EFORd and XEFORd values as shown in Figure 4-7.

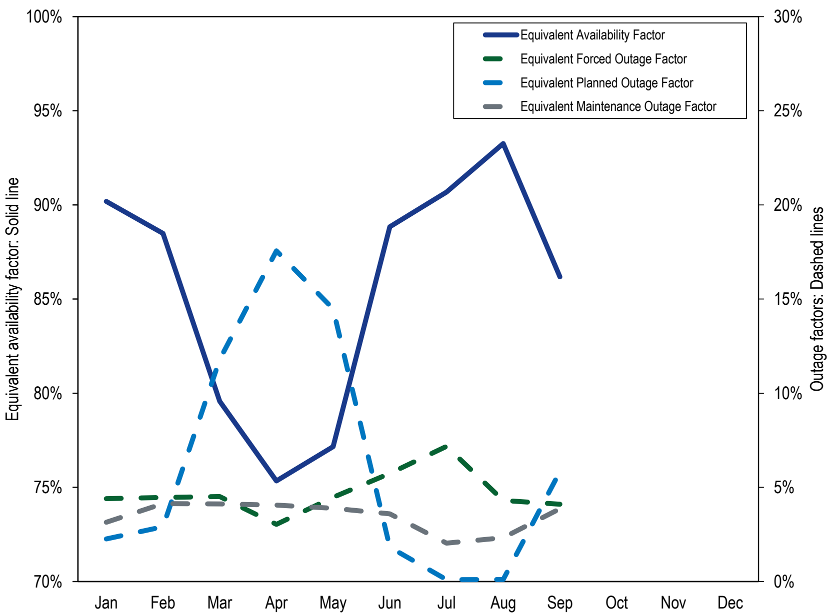
Figure 4-7 PJM EFORd, XEFORd and EFORp: 2012 (See the 2011 SOM, Figure 4-7)



53 EFORp is only calculated for the peak months of January, February, June, July, and August.

On a monthly basis, unit availability as measured by the equivalent availability factor increased during the summer months of June, July and August, primarily due to decreasing planned and maintenance outages, as illustrated in Figure 4-8.

Figure 4-8 PJM monthly generator performance factors: 2012 (See the 2011 SOM, Table 4-8)



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.

Highlights

- In January through September 2012, the total MWh of load reduction under the Economic Load Response Program increased by 84,620 MWh compared to the same period in 2011, from 15,376 MWh in 2011 to 99,996 MWh in 2012, a 550 percent increase. Total payments under the Economic Program increased by $4,896,597, from $1,943,507 in the first nine months of 2011 to $6,840,104 in 2012, a 252 percent increase, as a result of the implementation of Order 745 on April 1, 2012. The increased payments were concentrated in the summer months of 2012.
- In January through September 2012, total capacity payments to demand response resources under the PJM Load Management (LM) Program, which integrated Emergency Load Response Resources into the Reliability Pricing Model, decreased by $118.2 million, or 31.0 percent, compared to the same period in 2011, from $381 million in 2011 to $263 million in 2012. The decrease in capacity credits in 2012 was the result of a decrease in RPM clearing prices in the rest of RTO region. While prices increased for MAAC zones, the rest of the PJM RTO cleared at $16.46 in the 2012/2013 delivery year, an 85 percent decrease from the RTO wide $110.04 clearing price in the 2011/2012 delivery year.

Conclusions

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.

Most end use customers pay a fixed retail rate with no direct relationship to the hourly wholesale market locational marginal price (LMP). End use customers pay load serving entities (LSEs) an annual amount designed to recover, among other things, the total cost of wholesale power for the year.[1] End use customers paying fixed retail rates do not face even the hourly zonal average LMP. Thus, it would be a substantial step forward for customers to face the hourly zonal average price. But the actual market price of energy and the appropriate price signal for end use customers is the nodal locational marginal price. Within a zone, the actual costs of serving load, as reflected in the nodal hourly LMP, can vary substantially as a result of transmission constraints. A customer on the high price side of a constraint would have a strong incentive to add demand side resources if they faced the nodal price while that customer currently has an incentive to use more energy than is efficient, under either a flat retail rate or a rate linked to average zonal LMP. The nodal price provides a price signal with the actual locational marginal value of energy. In order to achieve the full benefits of nodal pricing on the supply and the demand side, load should ultimately pay nodal prices. However, a transition to nodal pricing could have substantial impacts and therefore must be managed carefully.

Today, most end use customers do not face the market price of energy, that is the locational marginal price of energy, or the market price of capacity, the locational price of capacity. Most end use customers pay a fixed retail rate with no direct relationship to the hourly wholesale market LMP, either on an average zonal or on a nodal basis. 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.

1 In PJM, load pays the average zonal LMP, which is the weighted average of the actual nodal locational marginal price. While individual customers have the option to pay nodal LMP, very few customers do so.

This market failure does not imply that PJM markets have failed. This market failure means that customers do not pay the actual hourly locational cost of energy as a result of the disconnect between wholesale markets and retail pricing. 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 actual hourly locational price of power used by customers is determined by the wholesale power market, regardless of the average price actually paid by customers. The transition to a more functional demand side in the wholesale power market 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. While the initial default energy price could be the zonal average LMP, the transition to nodal LMP pricing should begin.

PJM's Economic Load Response Program (ELRP) 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 zonal price of energy and by providing settlement services to facilitate the participation of third party Curtailment Service Providers (CSPs) in the market.[2] In PJM's Economic Load Response Program, participants have the option to receive credits for load reductions based on a more locationally defined pricing point than the zonal LMP. PJM's proposed PRD program does incorporate some aspects of nodal pricing, although the link between the nodal wholesale price and the retail price is extremely attenuated.

FERC Order 745 was implemented effective April 1, 2012. Order 745 requires RTOs and ISOs to pay full LMP to demand resources rather than LMP less the cost of generation and transmission paid by retail customers, if the demand resources are cost effective as determined by a "Net Benefits Test" (NBT) are eligible to receive the full LMP.[3] This approach is based on the view that dispatching demand resources may result in a net increase in cost to non-demand response loads, and requires the NBT as mitigation. This approach to compensating demand response, effective April 1, 2012, increased participation in the Economic Load Response Program. This change explicitly permitted subsidies to be paid to retail customers on fixed rates that incorporate a fixed price of wholesale power, and to customers paying LMP for wholesale power. While the subsidy has a rationale as an incentive for fixed rate retail customers, there is no reason to provide this subsidy to LMP customers who are already receiving the price signal from the wholesale power 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.[4]

PJM's demand side programs, by design, provide a work around for end use customers that are not otherwise exposed to the incremental, locational 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.

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 a PJM 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. The baseline methods used in PJM programs today, particularly in the Emergency Program which consists entirely of capacity resources, are not adequate to determine and quantify deliberate actions taken to reduce consumption.

2 While the primary purpose of the ELRP is to replicate the hourly zonal price signal to customers on fixed retail rate contracts, customers with zonal or nodal hourly LMP contracts are currently eligible to participate in the DA scheduling and the PJM dispatch options of the Program.

3 The NBT uses a single monthly price for PJM and does not reflect hourly, locational price differences in the Real-Time and Day-Ahead markets.

4 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Service Markets."

PJM Demand Side Programs

All load response programs in PJM can be grouped into the Economic and the Emergency Programs. Table 5-1 provides an overview of the key features of PJM load response programs.[5]

Table 5-1 Overview of Demand Side Programs[6] (See the 2011 SOM, Table 5-1)

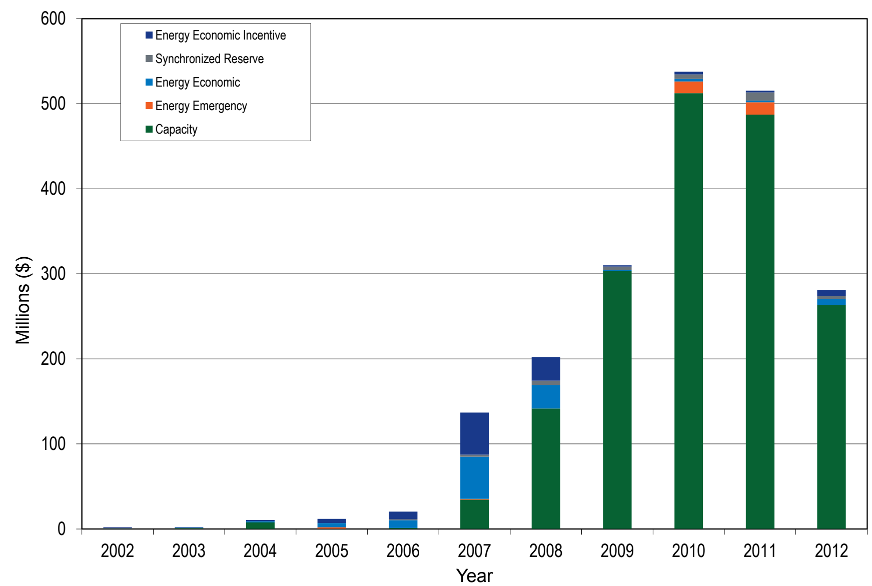
Emergency Load Response Program			Economic Load Response Program
Load Management (LM)			
Capacity Only	Capacity and Energy	Energy Only	Energy Only
Registered ILR only	DR cleared in RPM; Registered ILR	Not included in RPM	Not included in RPM
Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	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 during PJM declared Emergency Event mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments.	Energy payment based on full LMP. Energy payment for hours of voluntary curtailment.

Participation in Demand Side Programs

In the first nine months of 2012, in the Economic Program, participation became more concentrated by site compared to 2011. There were fewer settlements submitted and active registrations in 2012 compared to 2011, and credits decreased. The number of sites registered decreased more significantly than the level of registered MW.

Figure 5-1 shows all revenue from PJM Demand Side Response Programs by market for the period 2002 through the first nine months of 2012. Since the implementation of the RPM design on June 1, 2007, the capacity market has been the primary source of revenue to demand side participants, representing 96.3 percent of all revenue received through demand response programs in the first nine months of 2012. In the first nine months of 2012, total payments under the Economic Program increased by $4,896,597, from $1,943,507 in the first nine months of 2011 to $6,840,104 in 2012, a 252 percent increase, but still representing only 2.5 percent of all revenue received through demand response programs. Capacity revenue decreased $118.2 million, or 31.0 percent, from $381 million to $263 million. From January through September 2012, Synchronized Reserve credits for demand side resources decreased by $2.6 million compared to the same period in 2011, from $6.2 million in 2011 to $3.6 million in 2012. In the first nine months of 2012, there were two Load Management Event Days, occurring on July 17, and July 18, 2012.

Figure 5-1 Demand Response revenue by market: Calendar years 2002 through 2011 and the first nine months of 2012 (See the 2011 SOM, Figure 5-1)



5 For more detail on the historical development of PJM Load Response Programs see the *2011 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market" <*http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011.shtml*>.

6 Prior to April 1, 2012, payment for the Economic Load Response Program was based on LMP minus the generation and transmission components of the retail rate.

Economic Program

Table 5-2 shows the number of registered sites and MW per peak load day for calendar years 2002 through the first nine months of 2012.[7] On July 17, 2012, there were 2,305.5 MW registered in the Economic Program compared to the 2,041.8 MW on July 21, 2011, a 12.9 percent increase in peak load day capability. Program totals are subject to monthly and seasonal variation, as registrations begin, expire and renew. Table 5-3 shows registered sites and MW for the last day of each month for the period calendar years 2008 through the first nine months of 2012.[8] Historically, registered MW have declined in June but increased in August, which is likely the result of expirations and renewals. 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. During 2012, the implementation of Order 745 caused all participants to have to register again during April 2012, causing a drop in registration levels during that month.

Table 5-2 Economic Program registration on peak load days: Calendar years 2002 to 2011 and January through September 2012 (See the 2011 SOM, Table 5-2)

	Registrations	Peak-Day, Registered MW
14-Aug-02	96	335.4
22-Aug-03	240	650.6
3-Aug-04	782	875.6
26-Jul-05	2,548	2,210.2
2-Aug-06	253	1,100.7
8-Aug-07	2,897	2,498.0
9-Jun-08	956	2,294.7
10-Aug-09	1,321	2,486.6
6-Jul-10	899	1,725.7
21-Jul-11	1,237	2,041.8
17-Jul-12	893	2,305.5

Table 5-3 Economic Program registrations on the last day of the month: 2008 through September 2012 (See the 2011 SOM, Table 5-3)

	2008		2009		2010		2011		2012	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	4,906	2,959	4,862	3,303	1,841	2,623	1,609	2,432	1,993	2,385
Feb	4,902	2,961	4,869	3,219	1,842	2,624	1,612	2,435	1,995	2,384
Mar	4,972	3,012	4,867	3,227	1,845	2,623	1,612	2,519	1,996	2,356
Apr	5,016	3,197	2,582	3,242	1,849	2,587	1,611	2,534	189	1,313
May	5,069	3,588	1,250	2,860	1,875	2,819	1,687	3,166	371	1,661
Jun	3,112	3,014	1,265	2,461	813	1,608	1,143	1,912	803	2,337
Jul	4,542	3,165	1,265	2,445	1,192	2,159	1,228	2,062	948	2,319
Aug	4,815	3,232	1,653	2,650	1,616	2,398	1,987	2,194	1,014	2,364
Sep	4,836	3,263	1,879	2,727	1,609	2,447	1,962	2,183	1,054	2,418
Oct	4,846	3,266	1,875	2,730	1,606	2,444	1,954	2,179		
Nov	4,851	3,271	1,874	2,730	1,605	2,444	1,954	2,179		
Dec	4,851	3,290	1,853	2,627	1,598	2,439	1,992	2,259		
Avg.	4,727	3,185	2,508	2,852	1,608	2,435	1,696	2,338	1,151	2,171

7 Table 5-2 and Table 5-3 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.

8 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 5-4 shows the zonal distribution of capability in the Economic Program on June 20, 2012. The PPL Control Zone includes 227 sites and 355.4 MW, 24 percent of sites and 15 percent of registered MW in the Economic Program. The BGE Control Zone includes 59 sites and 626.6 MW, 7.5 percent of sites and 27 percent of registered MW in the Economic Program.

Table 5-4 Distinct registrations and sites in the Economic Program: July 17, 2012[9] (See the 2011 SOM, Table 5-4)

	Registrations	Sites	MW
AECO	9	9	35.1
AEP	15	15	100.7
AP	69	85	123.8
ATSI	23	23	78.3
BGE	59	83	626.6
ComEd	35	38	69.7
DAY	0	0	0.0
DEOK	1	1	35.0
DLCO	32	37	61.0
Dominion	36	50	236.2
DPL	16	16	85.2
JCPL	12	15	48.0
Met-Ed	81	92	71.6
PECO	164	218	128.2
PENELEC	79	83	55.5
Pepco	11	29	128.3
PPL	227	273	355.4
PSEG	24	40	67.0
RECO	0	0	0.0
Total	893	1,107	2,305.5

Total payments in Table 5-5 exclude incentive payments in the Economic Program for the years 2006 and 2007. The economic incentive program expired in December of 2007.[10]

Table 5-5 Performance of PJM Economic Program participants excluding incentive payments: Calendar years 2002 through 2011 and January through September 2012 (See the 2011 SOM, Table 5-5)

	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	452,222	$27,087,495	$60	197.1
2009	57,157	$1,389,136	$24	23.0
2010	74,070	$3,088,049	$42	42.9
2011	17,398	$2,052,996	$118	8.5
2012	99,987	$6,840,104	$68	43.4

Figure 5-2 shows monthly economic program payments, excluding incentive payments, for 2007 through September 2012. Economic Program credits declined from June 2008 through 2009. In 2009, payments were down significantly in every month compared to the same time period in 2007 and 2008.[11] Lower energy prices and growth in the capacity market program were the biggest factors. Energy prices declined significantly in 2008 and again in 2009, and have remained low through 2012.[12] In the first nine months of 2012, credits were up substantially compared to 2011, following the implementation of Order 745 on April 1, 2012.

9 The second column of Table 5-4 reflects the number of registered end-user sites, including sites that are aggregated to a single registration.

10 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.

11 September 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.

12 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.

Figure 5-2 Economic Program payments by month: Calendar years 2007[13] through 2011 and January through September 2012 (See the 2011 SOM, Figure 5-2)

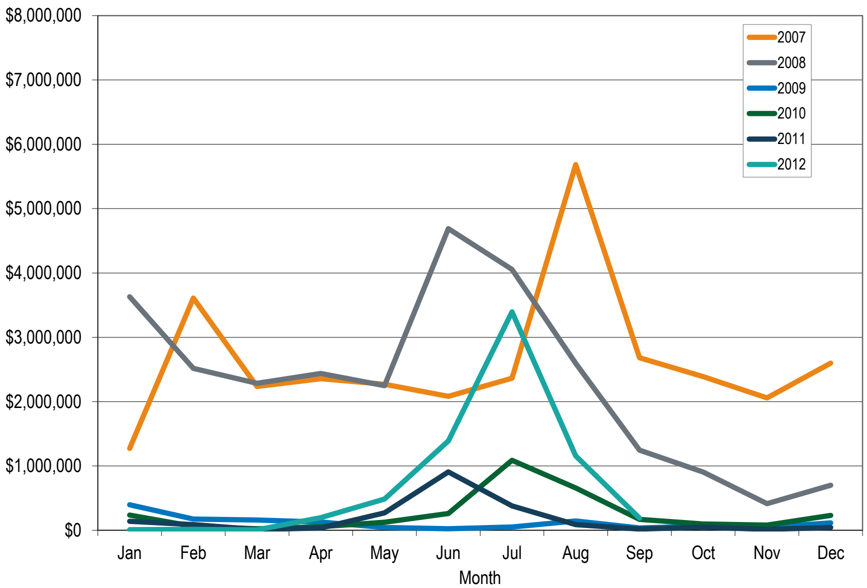


Table 5-6 shows the first nine months of 2012 performance in the Economic Program by control zone and participation type. The total number of curtailed MWh for the Economic Program was 99,996.3 and the total payment amount was $6,840,104.[14] The Dominion Control Zone accounted for $2,948,244 or 43 percent of all Economic Program credits, associated with 41,980.8 or 42 percent of total program MWh reductions. Since the implementation of Order 745 on April 1, 2012, credits to demand resources through the Economic Program were $4,896,597 more than in the first nine months of 2011, an increase of 252 percent.

13 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 retail rate, was charged to all LSEs. Economic Program payments for 2007 shown in Figure 5-2 do not include these incentive payments.

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

Table 5-6 PJM Economic Program participation by zone: January through September 2011 and 2012 (See the 2011 SOM, Table 5-6)

	Credits			MWh Reductions		
	2011	2012	Percent Change	2011	2012	Percent Change
AECO	$0	$20,555	0%	0.0	98.0	0%
AEP	$24,279	$13,272	0%	310.0	154.8	0%
AP	$17,758	$829,596	4,572%	350.1	12,117.5	3,361%
ATSI	$1,829	$1,890	0%	19.4	26.9	0%
BGE	$730,278	$56,834	0%	2,294.5	509.5	0%
ComEd	$2,420	$324,328	0%	197.4	5,771.0	0%
DAY	$13,435	$0	0%	18.8	0.0	0%
DEOK	$0	$0	0%	0.0	0.0	0%
DLCO	$534	$1,511	183%	12.9	17.1	32%
Dominion	$999,737	$2,948,244	195%	9,990.0	41,980.8	320%
DPL	$59	$31,555	0%	0.4	221.7	0%
JCPL	$1,075	$244,640	0%	3.3	2,061.9	0%
Met-Ed	$17,429	$154,961	NA	183.9	1,949.2	NA
PECO	$77,634	$468,292	503%	1,655.1	6,165.3	273%
PENELEC	$3,376	$355,361	0%	80.8	6,440.2	0%
Pepco	$2,637	$118,688	0%	38.0	1,049.0	0%
PPL	$46,041	$358,713	0%	188.1	3,818.8	1,930%
PSEG	$4,986	$911,666	0%	33.9	17,614.8	0%
RECO	$0	$0	0%	0.0	0.0	0%
Total	$1,943,507	$6,840,104	252%	15,376.4	99,996.3	550%

Table 5-7 shows total settlements submitted by month for calendar years 2007 through the first six months of 2012. For January through July of 2008, total monthly settlements were higher than the monthly totals for 2007, despite the 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. Settlements dropped off significantly after the summer period in 2009, and January through May of 2010 were generally lower than historical levels while summer of 2010 showed a moderate increase, consistent with 2009. February of 2012 showed the lowest level of settlements in the five year period, and 2011 and the first three months of 2012 overall showed a substantial decrease in the number of settlements submitted compared to previous years. Since the implementation of Order 745 in April 2012, settlements have increased, and settlements in July 2012 were consistent with summer settlements prior to 2011.

Table 5-7 Settlement days submitted by month in the Economic Program: Calendar years 2007 through 2011 and January through September 2012 (See the 2011 SOM, Table 5-7)

Month	2007	2008	2009	2010	2011	2012
Jan	937	2,916	1,264	1,415	562	62
Feb	1,170	2,811	654	546	148	30
Mar	1,255	2,818	574	411	82	46
Apr	1,540	3,406	337	338	102	93
May	1,649	3,336	918	673	298	144
Jun	1,856	3,184	2,727	1,221	743	1,475
Jul	2,534	3,339	2,879	3,007	1,411	2,899
Aug	3,962	3,848	3,760	2,158	790	1,680
Sep	3,388	3,264	2,570	660	294	555
Oct	3,508	1,977	2,361	699	66	
Nov	2,842	1,105	2,321	672	51	
Dec	2,675	986	1,240	894	40	
Total	27,316	32,990	21,605	12,694	4,587	6,984

Table 5-8 shows the number of distinct Curtailment Service Providers (CSPs) and distinct customers actively submitting settlements by month for the period 2008 through the first nine months of 2012. 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. There was less activity in the first three months of 2012 than in any year since 2009, however, this changed following the April 1 implementation of FERC Order 745 rules on demand resource compensation, with activity returning to historical summer levels during the 2012 summer months.

Table 5-8 Distinct customers and CSPs submitting settlements in the Economic Program by month: Calendar years 2008 through 2011 and January through September 2012 (See the 2011 SOM, Table 5-8)

	2008		2009		2010		2011		2012	
Month	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers	Active CSPs	Active Customers
Jan	13	261	17	257	11	162	5	40	5	15
Feb	13	243	12	129	9	92	6	29	3	9
Mar	11	216	11	149	7	124	3	15	3	12
Apr	12	208	9	76	5	77	3	15	3	8
May	12	233	9	201	6	140	6	144	5	20
Jun	17	317	20	231	11	152	10	304	16	338
Jul	16	295	21	183	18	243	15	214	21	383
Aug	17	306	15	400	14	302	14	186	17	361
Sep	17	312	11	181	11	97	7	47	11	127
Oct	13	226	11	93	8	37	3	9		
Nov	14	208	9	143	7	40	3	13		
Dec	13	193	10	160	7	46	5	12		
Total Distinct Active	24	522	25	747	24	438	20	610	23	505

Table 5-9 shows a frequency distribution of MWh reductions and credits at each hour for January through September 2012. The period from hour ending 0800 EPT to 2300 EPT accounts for 98 percent of MWh reductions and 99 percent of credits.

Table 5-9 Hourly frequency distribution of Economic Program MWh reductions and credits: January through September 2012 (See the 2011 SOM, Table 5-9)

	MWh Reductions				Program Credits			
Hour Ending (EPT)	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
1	104	0.10%	104	0.10%	$2,686	0.04%	$2,686	0.04%
2	105	0.10%	208	0.21%	$2,705	0.04%	$5,391	0.08%
3	105	0.11%	314	0.31%	$1,968	0.03%	$7,359	0.11%
4	108	0.11%	422	0.42%	$1,224	0.02%	$8,583	0.13%
5	107	0.11%	529	0.53%	$1,534	0.02%	$10,117	0.15%
6	153	0.15%	682	0.68%	$3,067	0.04%	$13,184	0.19%
7	902	0.90%	1,584	1.58%	$30,189	0.44%	$43,372	0.63%
8	1,808	1.81%	3,392	3.39%	$49,675	0.73%	$93,047	1.36%
9	2,350	2.35%	5,742	5.74%	$78,098	1.14%	$171,146	2.50%
10	2,501	2.50%	8,243	8.24%	$93,500	1.37%	$264,646	3.87%
11	2,931	2.93%	11,174	11.17%	$131,661	1.92%	$396,306	5.79%
12	3,549	3.55%	14,723	14.72%	$194,734	2.85%	$591,040	8.64%
13	5,810	5.81%	20,532	20.53%	$359,150	5.25%	$950,191	13.89%
14	9,631	9.63%	30,164	30.16%	$669,875	9.79%	$1,620,066	23.68%
15	13,106	13.11%	43,270	43.27%	$981,726	14.35%	$2,601,792	38.04%
16	13,926	13.93%	57,196	57.20%	$1,184,269	17.31%	$3,786,061	55.35%
17	13,921	13.92%	71,117	71.12%	$1,194,223	17.46%	$4,980,284	72.81%
18	13,542	13.54%	84,659	84.66%	$1,067,468	15.61%	$6,047,752	88.42%
19	6,119	6.12%	90,778	90.78%	$383,068	5.60%	$6,430,820	94.02%
20	4,018	4.02%	94,795	94.80%	$191,039	2.79%	$6,621,859	96.81%
21	2,362	2.36%	97,157	97.16%	$120,154	1.76%	$6,742,014	98.57%
22	1,566	1.57%	98,723	98.73%	$63,171	0.92%	$6,805,185	99.49%
23	743	0.74%	99,466	99.47%	$21,539	0.31%	$6,826,724	99.80%
24	530	0.53%	99,996	100.00%	$13,380	0.20%	$6,840,104	100.00%

Table 5-10 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 at all price levels. Approximately 73.9 percent of MWh reductions and 49.0 percent of program credits are associated with hours when the applicable zonal LMP was between $25 and $75. The Net Benefits Test result was on average, $24.80 from April-September 2012.

Table 5-10 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through September 2012 (See the 2011 SOM, Table 5-10)

	MWh Reductions				Program Credits			
LMP	MWh Reductions	Percent	Cumulative MWh	Cumulative Percent	Credits	Percent	Cumulative Credits	Cumulative Percent
$0 to $25	1,127	1.13%	1,127	1.13%	$9,524	0.14%	$9,524	0.14%
$25 to $50	49,808	49.81%	50,935	50.94%	$1,894,343	27.69%	$1,903,868	27.83%
$50 to $75	24,045	24.05%	74,980	74.98%	$1,456,278	21.29%	$3,360,146	49.12%
$75 to $100	8,801	8.80%	83,782	83.78%	$774,832	11.33%	$4,134,978	60.45%
$100 to $125	5,281	5.28%	89,062	89.07%	$615,153	8.99%	$4,750,131	69.45%
$125 to $150	3,503	3.50%	92,566	92.57%	$474,482	6.94%	$5,224,613	76.38%
$150 to $200	2,440	2.44%	95,005	95.01%	$404,477	5.91%	$5,629,090	82.30%
$200 to $250	2,622	2.62%	97,627	97.63%	$539,437	7.89%	$6,168,526	90.18%
$250 to $300	1,758	1.76%	99,385	99.39%	$453,147	6.62%	$6,621,673	96.81%
> $300	611	0.61%	99,996	100.00%	$218,431	3.19%	$6,840,104	100.00%

Load Management Program

Table 5-11 shows zonal monthly capacity credits that were paid during January through June 2012 to ILR and DR resources. Capacity revenue decreased by $118.2 million, or 31.0 percent, compared to the same period in 2011, from $381 million in 2011 to $263 million in 2012. Credits from January to May are associated with participation in the 2011/2012 RPM delivery year, and credits from June are associated with participation in the 2012/2013 RPM delivery year. The decrease in capacity credits in 2012 is the result of a decrease in RPM clearing prices in the rest of RTO region. While prices increased for MAAC zones, the rest of the PJM RTO cleared at $16.46 in the 2012/2013 delivery year, an 85 percent decrease from the RTO wide $110.04 clearing price in the 2011/2012 delivery year.

Table 5-11 Zonal monthly capacity credits: January through September 2012 (See the 2011 SOM, Table 5-13)

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$343,831	$321,649	$343,831	$332,740	$343,831	$397,836	$411,097	$411,097	$397,836	$3,303,747
AEP	$5,390,887	$5,043,088	$5,390,887	$5,216,988	$5,390,887	$411,388	$425,101	$425,101	$411,388	$28,105,714
APS	$3,410,799	$3,190,748	$3,410,799	$3,300,774	$3,410,799	$179,495	$185,478	$185,478	$179,495	$17,453,866
ATSI	$4,821	$4,510	$4,821	$4,665	$4,821	$19,218	$19,859	$19,859	$19,218	$101,789
BGE	$3,630,571	$3,396,340	$3,630,571	$3,513,455	$3,630,571	$5,254,943	$5,430,108	$5,430,108	$5,254,943	$39,171,608
ComEd	$6,180,266	$5,781,539	$6,180,266	$5,980,903	$6,180,266	$392,831	$405,926	$405,926	$392,831	$31,900,756
DAY	$824,485	$771,293	$824,485	$797,889	$824,485	$61,616	$63,670	$63,670	$61,616	$4,293,210
DEOK	$0	$0	$0	$0	$0	$7,921	$8,185	$8,185	$7,921	$32,210
DLCO	$2,418	$2,262	$2,418	$2,340	$2,418	$48,114	$49,718	$49,718	$48,114	$207,521
Dominion	$3,977,804	$3,721,172	$3,977,804	$3,849,488	$3,977,804	$297,028	$306,929	$306,929	$297,028	$20,711,987
DPL	$817,336	$764,605	$817,336	$790,970	$817,336	$1,475,222	$1,524,396	$1,524,396	$1,475,222	$10,006,819
JCPL	$883,220	$826,238	$883,220	$854,729	$883,220	$1,447,382	$1,495,628	$1,495,628	$1,447,382	$10,216,645
Met-Ed	$909,516	$850,837	$909,516	$880,176	$909,516	$1,010,595	$1,044,281	$1,044,281	$1,010,595	$8,569,312
PECO	$2,375,286	$2,222,042	$2,375,286	$2,298,664	$2,375,286	$2,574,260	$2,660,069	$2,660,069	$2,574,260	$22,115,223
PENELEC	$1,380,240	$1,291,192	$1,380,240	$1,335,716	$1,380,240	$1,107,926	$1,144,857	$1,144,857	$1,107,926	$11,273,193
Pepco	$1,174,938	$1,099,136	$1,174,938	$1,137,037	$1,174,938	$1,845,088	$1,906,591	$1,906,591	$1,845,088	$13,264,343
PPL	$2,739,610	$2,562,861	$2,739,610	$2,651,235	$2,739,610	$3,142,521	$3,247,272	$3,247,272	$3,142,521	$26,212,512
PSEG	$1,468,327	$1,373,596	$1,468,327	$1,420,962	$1,468,327	$2,245,202	$2,320,042	$2,320,042	$2,245,202	$16,330,028
RECO	$22,526	$21,072	$22,526	$21,799	$22,526	$14,415	$14,896	$14,896	$14,415	$169,069
Total	$35,536,881	$33,244,179	$35,536,881	$34,390,530	$35,536,881	$21,932,999	$22,664,099	$22,664,099	$21,932,999	$263,439,551

Net Revenue

The Market Monitoring Unit (MMU) analyzed measures of PJM Energy Market structure, participant conduct and market performance. As part of the review of market performance, the MMU analyzed the net revenues earned by combustion turbines (CT), combined cycle (CC), and coal plant (CP) generating units. Only quarterly energy market net revenues are provided in this report.

Highlights

- Average real time LMP decreased by 29.1 percent in the first nine months of 2012 over the first nine months of 2011.
- Natural gas prices decreased by more than coal prices in the first nine months of 2012 compared to the first nine months of 2011. The price of Northern Appalachian coal was 15.5 percent lower; the price of Central Appalachian coal was 19.4 percent lower; and the price of Powder River Basin coal was 34.1 percent lower. The price of eastern natural gas was 40.5 percent lower; and the price of western natural gas was 37.1 percent lower.[1]
- While average net revenues for all three technologies declined, only new entrant combined cycle units had net revenue increases in some zones. Comparing the first nine months of 2012 to the first nine months of 2011, energy net revenues for the new entrant combustion turbine unit were down 36.8 percent, energy net revenues for the new entrant combined cycle unit were down 8.7 percent, and energy net revenues for the new entrant coal unit were down 69.1 percent.[2]

Net Revenue

When compared to annualized 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 to serve PJM markets. Net revenue equals total revenue received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services less the variable costs of energy production. In other words, net revenue is the amount that remains, after short run variable costs of energy production have been subtracted from gross revenue, to cover fixed costs, which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Net revenue is the contribution to total fixed costs received by generators from all PJM markets.

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 annualized 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 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 annualized 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 above and below the equilibrium level based on actual conditions in all relevant markets.

Operating reserve payments are included when the analysis is based on the peak-hour, economic dispatch model and actual net revenues.[3]

Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Average real time LMP decreased by 29.1 percent in the first nine months of 2012 over the first nine months of 2011. Natural gas prices decreased by more than coal prices in the first nine months of 2012 compared to the first nine months of 2011. The price of Northern Appalachian coal was

1 Eastern natural gas and Western natural gas prices are the average of daily fuel price indices in the PJM footprint. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.

2 Changes are simple zonal averages.

3 The peak-hour, economic dispatch model is a realistic representation of market outcomes that 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.

15.5 percent lower; the price of Central Appalachian coal was 19.4 percent lower; and the price of Powder River Basin coal was 34.1 percent lower. The price of eastern natural gas was 40.5 percent lower; and the price of western natural gas was 37.1 percent lower.[4] The combination of lower energy prices, lower gas prices and lower coal prices resulted in lower energy net revenues for new entrant CC units in thirteen of seventeen zones and lower energy net revenues for the new entrant CT and CP unit in all zones in 2012.

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 new unit with specific characteristics would operate under economic dispatch. The economic dispatch uses technology-specific operating constraints in the calculation of a new entrant's operations and potential net revenue in PJM markets.

Analysis of 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.05 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.05 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.[5] The coal plant is a 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 hourly effect of actual hourly local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[6,7] Plant heat rates were calculated for each hour to account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost. 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.[8]

A forced outage rate for each class of plant was calculated from PJM data.[9] This class-specific outage rate was then incorporated into all revenue calculations. Each plant was also given a continuous 14 day planned annual outage in the fall season.

Ancillary service revenues for the provision of synchronized reserve service for all three plant types are set to zero. 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.

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. This offer price was compared to the hourly clearing price in the PJM Regulation Market. If the reference CP could provide regulation more profitably than energy, the unit was assumed to provide regulation during that hour.

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

4 Eastern natural gas and Western natural gas prices are the average of daily fuel price indices in the PJM footprint. Coal prices are the average of daily fuel prices for Central Appalachian coal, Northern Appalachian coal, and Powder River Basin coal. All fuel prices are from Platts.
5 The duct burner firing dispatch rate is developed using the same methodology as for the unfired dispatch rate, with adjustments to the duct burner fired heat rate and output.
6 Hourly ambient conditions supplied by Telvent DTN.
7 Heat rates provided by Pasteris Energy, Inc. 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. Therefore, there is a single offer point and no offer curve.
8 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
9 Outage figures obtained from the PJM eGADS database.

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. Reactive revenues are not included in energy market revenues.

Zonal net revenues reflect zonal fuel costs which consider a variety of locational fuel indices, actual unit consumption patterns, and zone specific delivery charges.[10] The delivered cost of natural gas reflects the estimated zonal, daily delivered price of natural gas and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[11] The delivered cost of coal incorporates the zone specific, delivered price of coal and was developed from the published prompt-month price, adjusted for rail transportation cost.[12]

Average zonal operating costs in 2012 for a CT were $35.79 per MWh, based on a design heat rate of 10,241 Btu per kWh and a VOM rate of $7.59 per MWh. Average zonal operating costs for a CP were $31.39 per MWh, based on a design heat rate of 9,240 Btu per kWh and a VOM rate of $3.22 per MWh. Average zonal operating costs for a CC were $20.85 per MWh, based on a design heat rate of 6,914 Btu per kWh and a VOM rate of $1.25 per MWh. VOM expenses include accrual of anticipated, routine major overhaul expenses.

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.

New Entrant Combustion Turbine

Energy market net revenue was calculated for a CT plant dispatched economically by PJM operations. It was assumed that the CT plant had a minimum run time of four hours. The unit was first committed day ahead in profitable blocks of at least four hours, including start up costs. If the unit was not already committed day ahead, it was then run in real time in stand-alone profitable blocks of at least four hours, or any hours bordering the profitable day ahead or real time block.

Table 6-1 Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year)[13] (See the 2011 SOM, Table 6-3)

Zone	2009 (Jan-Sep)	2010 (Jan-Sep)	2011 (Jan-Sep)	2012 (Jan-Sep)	Change in 2012 from 2011
AECO	$11,373	$35,954	$43,566	$22,494	(48%)
AEP	$3,275	$9,026	$19,150	$15,188	(21%)
AP	$10,188	$24,704	$30,656	$19,975	(35%)
ATSI	NA	NA	NA	$16,687	NA
BGE	$13,644	$45,815	$45,075	$34,183	(24%)
ComEd	$2,286	$8,696	$14,681	$12,767	(13%)
DAY	$2,866	$9,477	$19,874	$17,150	(14%)
DEOK	NA	NA	NA	$14,814	NA
DLCO	$3,366	$14,995	$21,487	$17,841	(17%)
Dominion	$14,315	$36,788	$36,232	$23,921	(34%)
DPL	$12,718	$36,445	$41,529	$29,848	(28%)
JCPL	$10,527	$34,096	$41,388	$21,380	(48%)
Met-Ed	$9,982	$34,786	$38,159	$22,141	(42%)
PECO	$9,703	$33,483	$43,260	$23,282	(46%)
PENELEC	$6,276	$17,766	$30,057	$20,768	(31%)
Pepco	$16,205	$43,945	$41,107	$30,397	(26%)
PPL	$9,104	$29,513	$40,482	$19,781	(51%)
PSEG	$9,172	$33,308	$35,126	$21,250	(40%)
RECO	$7,838	$30,977	$29,697	$19,616	(34%)
PJM	$8,990	$28,222	$33,619	$21,236	(37%)

New Entrant Combined Cycle

Energy market net revenue was calculated for a CC plant dispatched economically by PJM operations. It was assumed that the CC plant had a minimum run time of eight hours. The unit was first committed day ahead in profitable blocks of at least eight hours, including start up costs.[14] If the unit was not already committed day ahead, it was then run in real time in stand-

10 Startup fuel burns and emission rates provided by Pasteris Energy, Inc. Startup 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. All starts associated with combined cycle units are assumed to be hot starts.
11 Gas daily cash prices obtained from Platts.
12 Coal prompt prices obtained from Platts.
13 The energy net revenues presented for the PJM area in this section represent the simple average of all zonal energy net revenues.
14 All starts associated with combined cycle units are assumed to be hot starts.

alone profitable blocks of at least eight hours, or any hours bordering the profitable day ahead or real time block.

Table 6-2 PJM Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year) (See the 2011 SOM, Table 6-6)

Zone	2009 (Jan-Sep)	2010 (Jan-Sep)	2011 (Jan-Sep)	2012 (Jan-Sep)	Change in 2012 from 2011
AECO	$53,515	$88,338	$107,347	$80,452	(25%)
AEP	$25,716	$35,573	$62,446	$73,119	17%
AP	$51,473	$66,543	$90,974	$82,714	(9%)
ATSI	NA	NA	NA	$76,668	NA
BGE	$56,858	$101,942	$104,716	$101,505	(3%)
ComEd	$18,383	$30,284	$40,530	$55,224	36%
DAY	$23,596	$36,247	$61,394	$77,200	26%
DEOK	NA	NA	NA	$68,306	NA
DLCO	$22,923	$41,189	$61,422	$75,101	22%
Dominion	$58,612	$93,795	$92,412	$85,538	(7%)
DPL	$55,142	$88,420	$103,217	$91,883	(11%)
JCPL	$52,935	$85,690	$103,883	$79,381	(24%)
Met-Ed	$47,338	$83,009	$92,175	$76,556	(17%)
PECO	$49,620	$83,203	$102,744	$78,781	(23%)
PENELEC	$42,010	$57,593	$87,883	$84,378	(4%)
Pepco	$58,923	$100,141	$97,364	$95,582	(2%)
PPL	$45,115	$73,814	$93,820	$72,960	(22%)
PSEG	$50,355	$84,626	$94,513	$76,239	(19%)
RECO	$44,897	$78,524	$77,172	$71,813	(7%)
PJM	$44,553	$72,290	$86,707	$79,126	(9%)

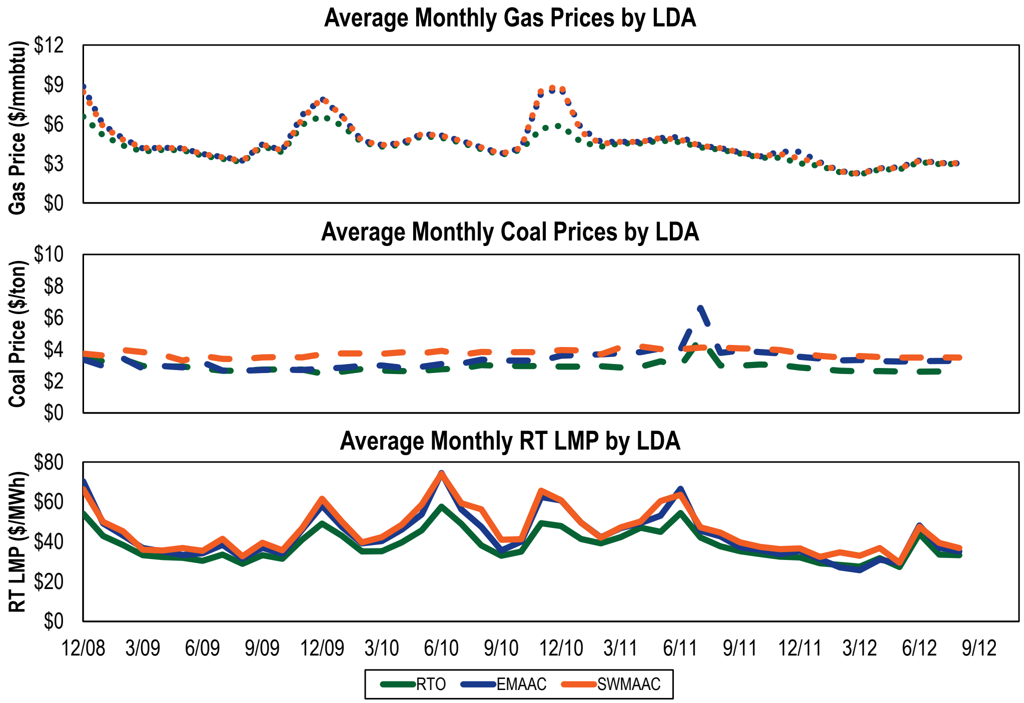
New Entrant Coal Plant

Energy market net revenue was calculated assuming that the CP plant had a 24-hour minimum run time and was dispatched by PJM operations in the Day Ahead Market for all available plant hours, both reasonable assumptions for a large, efficient 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. Regulation revenue is calculated for any hours in which the new entrant CP's regulation offer is below the regulation-clearing price.

Table 6-3 PJM Energy Market net revenue for a new entrant CP under economic dispatch (Dollars per installed MW-year) (See the 2011 SOM, Table 6-9)

Zone	2009 (Jan-Sep)	2010 (Jan-Sep)	2011 (Jan-Sep)	2012 (Jan-Sep)	Change in 2012 from 2011
AECO	$67,257	$123,525	$73,347	$14,444	(80%)
AEP	$13,379	$48,458	$63,670	$24,484	(62%)
AP	$36,322	$81,508	$88,159	$37,546	(57%)
ATSI	NA	NA	NA	$29,135	NA
BGE	$36,606	$65,752	$56,066	$13,594	(76%)
ComEd	$30,169	$92,893	$81,958	$43,279	(47%)
DAY	$19,206	$65,403	$55,551	$23,385	(58%)
DEOK	NA	NA	NA	$18,426	NA
DLCO	$14,410	$67,832	$44,901	$34,318	(24%)
Dominion	$36,506	$119,130	$75,015	$9,782	(87%)
DPL	$30,404	$121,440	$92,578	$22,366	(76%)
JCPL	$57,382	$121,034	$69,361	$15,598	(78%)
Met-Ed	$45,652	$117,561	$60,001	$18,987	(68%)
PECO	$60,767	$118,052	$73,109	$16,810	(77%)
PENELEC	$59,243	$99,175	$85,430	$25,579	(70%)
Pepco	$54,534	$133,117	$71,482	$15,413	(78%)
PPL	$55,246	$96,923	$75,822	$11,884	(84%)
PSEG	$135,308	$103,660	$47,426	$14,164	(70%)
RECO	$54,556	$118,402	$57,467	$15,142	(74%)
PJM	$47,467	$99,639	$68,902	$21,281	(69%)

Figure 6-1 Energy Market net revenue factor trends: December 2008 through September 2012 (New Figure)



Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets. The Mercury and Air Toxics Standards Rule (MATS) and the Cross-State Air Pollution Rule (CSAPR) will require significant investments for some fossil-fired power plants in the PJM footprint in order to reduce heavy metal and SO_2 and NO_X emissions. These investments may result in higher offers in the capacity market, and if units do not clear, in the retirement of some units. Renewable energy mandates and associated incentives by state and federal governments have resulted in the construction of substantial amounts of renewable capacity in the PJM footprint, especially wind and solar-powered resources. Renewable energy credit (REC) markets created by state programs and federal tax credits have had a significant impact on PJM wholesale markets.

Highlights

- In a decision dated August 21, 2012, the U.S. Court of Appeals for the D.C. Circuit vacated the Cross State Air Pollution Rule (CSAPR).[1] The court had found "fatal flaws" in the prior rule, the Clean Air Interstate Rule (CAIR), but allowed it to remain in effect until replaced.[2] The EPA filed a petition for review en banc with the court on October 5, 2012. CAIR remains in place, as does the requirement to replace it.
- On March 27, 2012, the EPA proposed a Carbon Pollution Standard for new fossil-fired electric utility generating units. The proposed standard would limit emissions from new electric generating units to 1,000 pounds of CO_2 per MWh. In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the GHG rule, rejecting challenges brought by industry groups and a number of states.[3]
- The EPA proposed to exempt certain small reciprocating engines participating in DR programs as behind-the-meter generation from otherwise applicable run time restrictions. On May 22, 2012, the EPA proposed to increase the existing 15-hour exemption to 100 hours. EPA justified this exemption based on concerns about the impact on reliability and efficient operation of the wholesale energy markets.[4] The Market Monitor testified on this issue explaining that such concerns are unwarranted, and that, by providing a special exemption to units participating in demand response programs, the exemption would harm efficiency and reliability.[5]
- NO_x and SO_2 emission prices declined in January through September 2012, compared to 2011, while RGGI CO_2 prices increased. NOx prices declined 75.9 percent in 2012 compared to 2011, and SO_2 prices declined 55.2 percent in 2012 compared to 2011. Spot average RGGI CO_2 prices increased by 2.6 percent in 2012 compared to 2011, partially as a result of the increase in the price floor for RGGI CO_2 allowances.
- The auction price of RGGI CO_2 allowances remained at the floor price of $1.93 during January through September 2012, and as of January 1, 2012, the state of New Jersey no longer participates in the RGGI program.
- Generation from wind units increased from 7,924.5 GWh in January through September 2011 to 8,944.7 GWh in January through September 2012, an increase of 12.9 percent. Generation from solar units increased from 37.9 GWh in January through September 2011 to 192.7 GWh in January through September 2012, an increase of 408.7 percent.

Conclusion

Initiatives at both the federal and state levels have an impact on the cost of energy and capacity in PJM markets. PJM markets provide a flexible mechanism for incorporating the costs of environmental controls and meeting environmental requirements in a cost effective manner. PJM markets also provide a flexible mechanism that could be used to incorporate renewable resource requirements to ensure that renewable resources have access to a broad market and are priced competitively so as to reflect their market value. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

1 EME Homer City Generation, L.P. v. EPA, et al., No. 11-1302.
2 State of North Carolina, et al. v. EPA, 531 F.3d 896 (D.C. Cir. 2008), *order on reh'g*, 550 F.3d 1176 (2008).
3 Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.
4 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines, Proposed Rule*, EPA Docket No. EPA-HQ-OAR-2008-0708, 77 Fed. Reg. 33812 (June 7, 2012).
5 Comments of the Independent Market Monitor for PJM, filed in EPA Docket No. EPA-HQ-OGC-2011-1030 (February 16, 2012).

Environmental Regulation

Federal Control of NO_x and SO_2 Emissions Allowances

The Clean Air Act (CAA) requires states to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). The CAA requires each State to prohibit emissions that significantly interfere with the ability of another State to meet NAAQS.[6] The EPA has promulgated default federal rules intended to achieve this objective.

On July 6, 2011, the U.S. Environmental Protection Agency (EPA) finalized the Cross-State Air Pollution Rule (CSAPR), which would have required specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_X that cross state lines and contribute to ozone and fine particle pollution in other states.[7] In a decision dated August 21, 2012, the U.S. Court of Appeals for the D.C. Circuit vacated the Cross-State Air Pollution Rule (CSAPR).[8] The court had found "fatal flaws" in the prior rule, the Clean Air Interstate Rule (CAIR), but allowed CAIR to remain in effect until replaced.[9] The EPA filed a petition for review en banc with the court on October 5, 2012. CAIR remains in place, as does the requirement for the EPA to replace it.

Federal Environmental Regulation of Greenhouse Gas Emissions

On April 2, 2007, the U.S. Supreme Court overruled the EPA's determination that it was not authorized to regulate greenhouse gas emissions under the CAA and remanded the matter to EPA to determine whether greenhouse gases endanger public health and welfare.[10] On December 7, 2009, the EPA determined that greenhouse gases, including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, endanger public health and welfare.[11] In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the endangerment finding, rejecting challenges brought by industry groups and a number of states.[12]

6 CAA § 110(a)(2)(D)(i)(I).
7 *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*, Final Rule, Docket No. EPA-HQ-OAR-2009-0491, 76 Fed. Reg. 48208 (August 8, 2011) (CSAPR).
8 EME Homer City Generation, L.P. v. EPA, et al., No. 11-1302.
9 State of North Carolina, et al. v. EPA, 531 F.3d 896 (D.C. Cir. 2008), ***order on reh'g***, 550 F.3d 1176 (2008).
10 Massachusetts v. EPA, 549 U.S. 497.
11 *See Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, 74 Fed. Reg. 66496, 66497 (December 15, 2009).
12 Coalition for Responsible Regulation, Inc., et al. v. EPA.

The EPA determined that in order to regulate greenhouse gas emissions, it would need to develop a different standard for determining major sources that require permits to emit greenhouse gases than the standards applied to other pollutants.[13] Application of the 100 or 250 tons per year (tpy) maximum annual emissions rate standards applied to other types of pollutants would have been so low compared to actual emissions as to impede the ability to construct or modify regulated facilities.[14]

On May 13, 2010, the EPA issued a rule addressing greenhouse gases (GHG) from the largest stationary sources, including power plants.[15] The Prevention of Significant Deterioration and Title V programs under the CAA impose certain permitting requirements on sources of pollutants. The EPA began phased implementation of this rule on January 2, 2011, referring to each phase as a step. In step 1, the EPA required affected facilities to include GHGs in their permit if they increase net GHG emissions by at least 75,000 tpy CO_2 equivalent and also significantly increase emissions of at least one non-GHG pollutant.[16] The U.S. Court of Appeals for the D.C. Circuit also upheld the Tailoring Rule in its June 26th decision.[17]

On December 23, 2010, the EPA entered a settlement agreement to resolve the requests by States and other litigants for performance standards and emission guidelines for GHG emissions for new and significantly modified sources, as provided under Sections 111(b) and (d) of the CAA. A proposed rule is expected to amend the standards of performance for electric utility steam generating units codified in EPA regulations to address regulation of GHG.

On July 1, 2011, the GHG Tailoring Rule was expanded under step 2 to cover all new facilities with GHG emissions of at least 100,000 tpy and modifications at existing facilities that would increase GHG emissions by at least 75,000 tpy.[18] These permits must demonstrate the use of best available control technology (BACT) to minimize GHG emission increases when facilities are constructed or significantly modified.[19]

13 EPA, Final Rule, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule*, Docket No. EPA-HQ-OAR-2009-0517, 75 Fed. Reg. 31514 (June 3, 2010) ("GHG Tailoring Rule").
14 *Id.* at 31516.
15 *Id.*
16 *Id.* at 31516.
17 Coalition for Responsible Regulation, Inc., et al. v. EPA.
18 *Id.*
19 *Id.* at 31520.

Effective August 13, 2012, the EPA implemented step 3.[20] Step 3 leaves the step 2 thresholds unchanged. Step 3 allows permitting on a plant wide basis so that changes at a facility that do not violate the plant wide limits do not require additional permitting.[21]

On March 27, 2012, the EPA proposed an emissions standard for CO_2 from new fossil-fired electric utility generating units.[22] The proposed standard limits emissions from new units to 1,000 pounds of CO_2 per MWh. The rule excludes units currently in service or that have acquired full preconstruction permits prior to issuance of the proposal and that commence construction during the next 12 months. New units covered by the rule include only certain types of units that meet certain sales thresholds. Covered unit types include fossil fuel fired steam and combined cycle (CC) units, but exclude stationary simple cycle combustion turbine units. Covered units include only units that supply to the grid "more than one-third of [the unit's] potential annual electric output and more than 25 MW net-electrical output (MWe)."[23] EPA states that new natural gas CC units should be able to meet the proposed standard without add-on controls, based in part on data showing that nearly 95 percent of the natural gas CC units built between 2006 and 2010 would meet the standard. EPA states that new coal or petroleum coke units that incorporate technology to reduce carbon dioxide emissions, such as carbon capture and storage (CCS), could meet the standard.[24] New units that use CCS would have the option under the proposed rule to show twelve-month compliance with reference to a level calculated to consider an estimated 30-year average of CO_2 emissions, the year in which CCS would be installed, and the "best demonstrated performance of a coal-fired facility without CCS."[25]

Federal Environmental Regulation of Reciprocating Internal Combustion Engines (RICE)

The EPA has promulgated national emission standards for hazardous air pollutants (NESHAP) for stationary reciprocating internal combustion engines (RICE) under section 112 of the CAA.[26] The existing regulation allows a 15-hour run time exemption for emergency RICE participating in demand response programs, such as those administered by PJM.[27] In an amendment filed May 22, 2012, the EPA proposed to raise this exemption to 100 hours.[28] The EPA explained that it accepted arguments that an exemption is needed to allow RICE generators to contribute to reliability and efficient operations through DR programs, and specifically in order to accommodate RTO/ISO rules, such as PJM's 60-hour run time required for Limited DR.[29]

The Market Monitor filed comments in an earlier related proceeding taking the position that there is no legitimate market-based rationale to exempt RICE participating in DR programs.[30] From the perspective of PJM markets, there is no reason that the same environmental regulations should not apply to RICE without regard to whether it is participating in DR programs. RICE participating in PJM DR programs offers no special benefits to markets. The exemption would exacerbate existing problems associated with the role of Limited DR in the capacity market. Limited DR inappropriately suppresses prices in the capacity market, and PJM has identified a reliability risk in its increasing reliance on Limited DR.[31] The Market Monitor raised the same issues in testimony to the EPA on the rule at a hearing convened July 10, 2012.

20 EPA, Final Rule, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule Step 3, GHG Plantwide Applicability Limitations and GHG Synthetic Minor Limitations*, Docket No. EPA-HQ-2009-0517, 77 Fed Reg 41051 (July 12, 2012).
21 *Id.* at 41055.
22 Standards for Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, EPA Docket No. EPA-HQ-OAR-2011-0660, 77 Fed. Reg. 22392 (April 13, 2012).
23 *Id.* at
24 *Id.* at 22405. EPA observes that PJM State Illinois currently requires CCS for new coal generation.
25 *Id.* at 22406.

26 *See, e.g.*, 40 CFR Part 63.
27 40 CFR § 63.6640(f)(1)(iii).
28 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 77 Fed. Reg. 33812 (June 7, 2012).
29 *Id.* at 33813 ("The 100 hours per year allowance would ensure that a sufficient number of hours are permitted for engines to meet independent system operator (ISO) and regional transmission organization (RTO) tariffs and other requirements for participating in various emergency demand response programs and would assist in stabilizing the grid, preventing electrical blackouts and supporting local electric system reliability.")
30 Comments of the Independent Market Monitor for PJM, filed in EPA Docket No. EPA-HQ-OGC-2011-1030 (February 16, 2012).
31 *See* PJM Resource Adequacy Planning Department, Demand Resource Saturation Analysis at 15 (May 2010) ("Given the current interruption requirements applicable to DR, these study results indicate that the reliability value of DR saturates at an 8.5% penetration level for the RTO."), which can be accessed at: <*http://www.pjm.com/~/media/committees-groups/committees/pc/20100811/20100811-item-10-demand-response-saturation-report.ashx*>.; *see also, PJM Interconnection, L.L.C.*, 134 FERC ¶61,066 at PP 2–4 (2011) ("Under the Reliability Pricing Model (RPM) rules, PJM conducts forward auctions to secure capacity for a future delivery year, thereby allowing both existing and proposed generation, demand response and energy efficiency resources to compete to meet the region's installed capacity needs. PJM provides for demand resources to be offered into the auction in competition with generation and energy efficiency resources.[footnote omitted] These demand resources must reduce load subsequent to a request for load reduction from PJM following the declaration of a Maximum Emergency Generation action, unless the resource has already reduced load pursuant to PJM's economic load response program.[footnote omitted] The level of demand resources committed to PJM has grown with the implementation of RPM. [footnote omitted] Under the current RPM rules, demand resources can qualify for the RPM provided they: []can be interrupted during the hours of 12:00 p.m. to 8:00 p.m. (Eastern Prevailing Time) on non-Holiday weekdays during the months of June through September; []can be called upon for interruptions up to ten times during that period each year; and []can remain interrupted for up to six hours when called upon. PJM contends that as more megawatts of resources that are only available during narrowly defined peak periods are committed, fewer megawatts of more broadly available resources are committed. As a result, PJM raises a concern that commitment of fewer resources that are more broadly available increases the risk that PJM may have to call on a resource at a time, or in a manner, in which the resource is not required to respond.").

State Regulation of Greenhouse Gas Emissions

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort established 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.[32] As of January 1, 2012, the State of New Jersey no longer participates in the RGGI program.

Since September 25, 2008, a total of 14 auctions have been held for 2009–2011 compliance period allowances, and three auctions have been held for 2012–2014 compliance period allowances.

Table 7-1 shows the RGGI CO_2 auction clearing prices and quantities for the 14 2009-2011 compliance period auctions held as of the end of calendar year 2011, and additional three auctions for the 2012-2014 compliance period held as of September 30, 2012. Prices for auctions held from January through September, 2012 for the 2012-2014 compliance period were $1.93 per allowance (equal to one ton), which is the current price floor for RGGI auctions. The average January through September 2012 spot price for a 2012-2014 compliance period allowance was $1.96 per ton. Monthly average spot prices for the 2012-2014 compliance period ranged from $2.00 per ton in February to $1.94 per ton in July.

Table 7-1 RGGI CO_2 allowance auction prices and quantities: 2009-2011 and 2012-2014 Compliance Periods[33] (See 2011 SOM, Table 7-3)

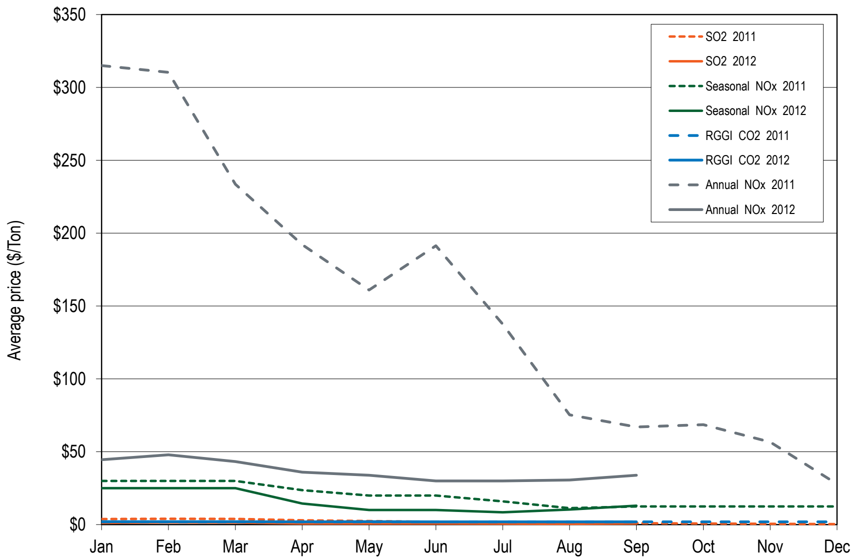
Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387
December 17, 2008	$3.38	31,505,898	31,505,898
March 18, 2009	$3.51	31,513,765	31,513,765
June 17, 2009	$3.23	30,887,620	30,887,620
September 9, 2009	$2.19	28,408,945	28,408,945
December 2, 2009	$2.05	28,591,698	28,591,698
March 10, 2010	$2.07	40,612,408	40,612,408
June 9, 2010	$1.88	40,685,585	40,685,585
September 10, 2010	$1.86	45,595,968	34,407,000
December 1, 2010	$1.86	43,173,648	24,755,000
March 9, 2011	$1.89	41,995,813	41,995,813
June 8, 2011	$1.89	42,034,184	12,537,000
September 7, 2011	$1.89	42,189,685	7,847,000
December 7, 2011	$1.89	42,983,482	27,293,000
March 14, 2012	$1.93	34,843,858	21,559,000
June 6, 2012	$1.93	36,426,008	20,941,000
September 5, 2012	$1.93	37,949,558	24,589,000

Figure 7-1 shows average, daily settled prices for NO_x and SO_2 emissions within PJM. In January through September 2012, NOx prices were 75.9 percent lower than in 2011. SO_2 prices were 55.2 percent lower in January through September 2012 than in 2011. Figure 7-1 also shows the average, daily settled price for RGGI CO_2 allowances.

32 A similar regional initiative was organized under the Western Climate Initiative, Inc. (WCI). The California Air Resources Board (ARB) has organized a cap and trade program that it will implement in 2012. That program will be coordinated with other U.S. states and Canadian provinces participating in WCI. One such participant, Quebec, adopted cap and trade rules on December 15, 2011. British Columbia, Manitoba and Ontario are also expected to coordinate cap and trade policies through WCI.

33 See "Regional Greenhouse Gas Initiative: Auction Results" <http://www.rggi.org/market/co2_auctions/results> (Accessed October 16, 2012).

Figure 7-1 Spot monthly average emission price comparison: 2011 and January through September 2012 (See 2011 SOM, Figure 7-1)



Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of utility load be served by renewable resources, for which there are many standards and definitions. These are typically known as Renewable Portfolio Standards, or RPS. As of 2012, Delaware, Illinois, Michigan, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards, ranging from 1.50 percent of all load served in Ohio, to 9.21 percent of all load served in New Jersey. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards. Indiana and West Virginia have enacted renewable portfolio standards that have yet to take effect by 2012. Indiana's renewable portfolio standard will take effect in 2013, and West Virginia's will take effect in 2015.

Under the proposed standards, a substantial amount of load in PJM is required to be served by renewable resources by 2022. As shown in Table 7-2, New Jersey will require 22.5 percent of load to be served by renewable resources, the most stringent standard of all PJM jurisdictions. Typically, renewable generation earns renewable energy credits (also known as alternative energy credits), or RECs, when they generate. These RECs are bought by utilities and load serving entities to fulfill the requirements for renewable generation. Standards for renewable portfolios differ from jurisdiction to jurisdiction. For example, Illinois requires only utilities to purchase renewable energy credits, while Pennsylvania requires all load serving entities to purchase renewable energy credits (known as alternative energy credits in Pennsylvania).

Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation or other market regulation or oversight. RECs markets are, as an economic fact, integrated with PJM markets including energy and capacity markets, but are not recognized as part of PJM markets. Revenues from RECs markets are in addition to revenues earned from the sale of the same MWh in PJM markets. Many jurisdictions allow various types of renewable resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, West Virginia allows one credit per MWh from generation from "alternative energy resources" such as waste coal or pumped-storage hydroelectric, but allows two credits per MWh of electricity generated by "renewable energy resources", which include resources such as wind, solar, and run-of-river hydroelectric. Pennsylvania allows both Tier I resources and non-traditional Tier II resources, such as waste coal, municipal solid waste, integrated gasification combined cycle, and large-scale hydro.[34] PJM Environmental Information Services (EIS), an unregulated subsidiary of PJM, operates the Generation Attribute Tracking System (GATS), which is used by many jurisdictions to track these renewable energy credits. The MMU recommends that renewable energy credit markets be brought into PJM markets as RECs are an increasingly critical component of wholesale energy markets.

34 Pennsylvania Tier I resources include solar water heat, solar space heat, solar thermal, solar thermal process heat, solar photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal, fuel cells, CHP/cogeneration, and anaerobic digestion.

Table 7-2 Renewable standards of PJM jurisdictions to 2022[35,36] (See 2011 SOM, Table 7-4)

Jurisdiction	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Delaware	8.50%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.00%	21.00%	22.00%
Illinois	7.00%	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.50%
Indiana		4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%
Kentucky	No Standard										
Maryland	9.00%	10.70%	12.80%	13.00%	15.20%	15.60%	18.30%	17.70%	18.00%	18.70%	20.00%
Michigan	<10.00%	<10.00%	<10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
New Jersey	9.21%	10.14%	11.10%	12.07%	13.08%	14.10%	16.16%	18.25%	20.37%	22.50%	22.50%
North Carolina	3.00%	3.00%	3.00%	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%	12.50%	12.50%
Ohio	1.50%	2.00%	2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%	10.50%
Pennsylvania	9.70%	10.20%	10.70%	11.20%	13.70%	14.20%	14.70%	15.20%	15.70%	18.00%	18.00%
Tennessee	No Standard										
Virginia	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	12.00%
Washington, D.C.	7.50%	9.00%	10.50%	12.00%	13.50%	15.00%	16.50%	18.00%	20.00%	20.00%	20.00%
West Virginia				10.00%	10.00%	10.00%	10.00%	10.00%	15.00%	15.00%	15.00%

Many PJM jurisdictions have also added requirements for the purchase of specific renewable resource technologies, specifically solar resources. These solar requirements are included in the standards shown in Table 7-2 but must be met by solar RECs only. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C., all have a requirement for the proportion of load served by solar units by 2022.[37] Indiana, Michigan, Virginia, and West Virginia have no specific solar standard. In 2012, Washington D.C. had the most stringent standard in PJM, requiring 0.5 percent of load to be served by solar resources. As Table 7-3 shows, by 2022, New Jersey will have the most stringent standard, requiring 3.56 percent of load to be served by solar. In 2012, New Jersey passed Senate Bill 1925 which increased the percentage of load in 2014 that must be served by solar resources in New Jersey from 1.99 percent to 2.05 percent.

Table 7-3 Solar renewable standards of PJM jurisdictions to 2022 (See 2011 SOM Table 7-5)

Jurisdiction	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Delaware	0.40%	0.60%	0.80%	1.00%	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%	2.75%
Illinois	0.00%	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%	1.23%
Indiana	No Solar Standard										
Kentucky	No Standard										
Maryland	0.10%	0.20%	0.30%	0.40%	0.50%	0.55%	0.90%	1.20%	1.50%	1.85%	2.00%
Michigan	No Solar Standard										
New Jersey	0.39%	0.75%	2.05%	2.45%	2.75%	3.00%	3.20%	3.29%	3.38%	3.47%	3.56%
North Carolina	0.07%	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio	0.06%	0.09%	0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%	0.42%
Pennsylvania	0.03%	0.05%	0.08%	0.14%	0.25%	0.29%	0.34%	0.39%	0.44%	0.50%	0.50%
Tennessee	No Standard										
Virginia	No Solar Standard										
Washington, D.C.	0.50%	0.50%	0.60%	0.70%	0.83%	0.98%	1.15%	1.35%	1.58%	1.85%	2.18%
West Virginia	No Solar Standard										

35 This analysis shows the total standard of renewable resources in all PJM jurisdictions, including Tier I and Tier II resources.
36 Michigan in 2012-2014 must make up the gap between 10 percent renewable energy and the renewable energy baseline in Michigan. In 2012, this means baseline plus 20 percent of the gap between baseline and 10 percent renewable resources, in 2013, baseline plus 33 percent and in 2014, baseline plus 50 percent.
37 Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill the jurisdiction's solar requirement.

Some PJM jurisdictions have also added specific requirements to their renewable portfolio standards for other technologies.

PJM jurisdictions include various methods to comply with required renewable portfolio standards. If an LSE is unable to comply with the renewable portfolio standards required by the LSE's jurisdiction, LSEs may make alternative compliance payments, with varying standards.

Table 7-4 shows generation by jurisdiction and renewable resource type in January through June 2012. This includes only units that would qualify for REC credits by primary fuel type, including waste coal, battery, and pumped-storage hydroelectric, which can qualify for Pennsylvania Tier II credits if they are located in the PJM footprint. Wind units account for 8,944.7 GWh of 15,486.7 Tier I GWh, or 57.8 percent, in the PJM footprint. As shown in Table 7-4, 31,734.7 GWh were generated by resources that were primarily renewable, including both Tier II and Tier I renewable credits, of which, Tier I type resources accounted for 48.8 percent.

Table 7-4 Renewable generation by jurisdiction and renewable resource type (GWh): January through September 2012 (See 2011 SOM, Table 7-8)

Jurisdiction	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	46.6	0.0	0.0	0.0	0.0	0.0	0.0	46.6	93.2
Illinois	104.3	0.0	0.0	0.0	0.0	0.0	3,848.5	3,952.8	3,952.8
Indiana	0.0	0.0	27.1	0.0	0.0	0.0	1,798.7	1,825.8	1,825.8
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	66.9	0.0	1,240.5	6.1	446.0	0.0	214.1	1,527.6	1,973.6
Michigan	22.0	0.0	42.0	0.0	0.0	0.0	0.0	64.0	64.0
New Jersey	285.2	328.2	8.4	173.8	1,039.7	0.0	6.1	473.6	1,841.4
North Carolina	0.0	0.0	298.3	0.0	0.0	0.0	0.0	298.3	298.3
Ohio	162.0	0.0	292.2	1.3	0.0	0.0	665.0	1,120.5	1,120.5
Pennsylvania	671.8	1,142.8	1,465.5	3.3	1,294.5	6,467.4	1,399.6	3,540.2	12,445.0
Tennessee	0.0	0.0	0.0	0.0	234.9	0.0	0.0	0.0	234.9
Virginia	311.1	3,626.0	541.4	8.1	879.0	0.0	0.0	860.6	5,365.6
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	8.1	0.0	755.9	0.0	0.0	789.5	1,012.7	1,776.7	2,566.2
Total	1,678.2	5,097.0	4,671.2	192.7	3,894.1	7,256.9	8,944.7	15,486.7	31,734.7

Table 7-5 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary or alternative fuel types.[38] The definition of renewables includes coal and natural gas units that have a renewable fuel as a secondary fuel, and thus are able to earn renewable energy credits. West Virginia has the largest amount of renewable capacity in PJM, 10,027.6 MW, or 27.3 percent of the total renewable capacity. New Jersey has the largest amount of solar capacity in PJM, 185.1 MW, or 87.6 percent of the total solar capacity. Wind resources are located primarily in the western PJM states of Illinois and Indiana, which include 3,307.6 MW, or 55.4 percent of the total wind capacity.

38 Defined fuel types result in designation as renewable as does the registration of a generator in the PJM GATS. The data include only units that are interconnected to the PJM system.

Table 7-5 PJM renewable capacity by jurisdiction (MW), on September 30, 2012 (See 2011 SOM, Table 7-9)

Jurisdiction	Coal	Landfill Gas	Natural Gas	Oil	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Total
Delaware	0.0	8.1	1,835.3	13.8	0.0	0.0	0.0	0.0	0.0	0.0	1,857.2
Illinois	0.0	72.9	0.0	0.0	0.0	0.0	0.0	20.0	0.0	2,254.4	2,347.3
Indiana	0.0	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	1,053.2	1,061.4
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0	185.0
Maryland	60.0	28.7	129.0	31.9	0.0	581.0	16.1	109.0	0.0	120.0	1,075.8
Michigan	0.0	4.8	0.0	0.0	0.0	11.8	0.0	0.0	0.0	0.0	16.6
New Jersey	0.0	85.5	0.0	0.0	400.0	5.0	162.1	191.1	0.0	7.5	851.2
North Carolina	0.0	0.0	0.0	0.0	0.0	315.0	0.0	94.0	0.0	0.0	409.0
Ohio	5,688.5	45.9	125.5	225.0	0.0	178.0	1.1	0.0	0.0	500.0	6,764.0
Pennsylvania	35.0	210.6	2,366.7	0.0	1,505.0	682.3	3.0	247.0	1,422.2	1,185.0	7,656.7
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
Virginia	0.0	121.6	80.0	16.9	3,588.0	457.1	2.7	215.0	0.0	0.0	4,481.3
West Virginia	8,539.0	2.0	450.0	0.0	0.0	243.1	0.0	0.0	130.0	663.5	10,027.6
PJM Total	14,322.5	580.0	4,986.5	287.6	5,493.0	2,481.5	185.1	926.1	1,552.2	5,968.6	36,783.1

Table 7-6 shows renewable capacity registered in the PJM Generation Attribute Tracking System (GATS), a system operated by PJM EIS, that are not interconnected to PJM. This includes solar capacity of 1,036.4 MW, of which 695.0 MW is in New Jersey. These resources can also earn renewable energy credits, and can be used to fulfill the renewable portfolio standards in PJM jurisdictions. All capacity shown in Table 7-6 is registered in PJM GATS, and may sell renewable energy credits through PJM EIS. The capacity that is not interconnected to PJM includes both behind the meter generation located inside PJM, and generation connected to other RTOs outside PJM.

Table 7-6 Renewable capacity by jurisdiction, non-PJM units registered in GATS[39,40] (MW), on September 30, 2012 (See 2011 SOM, Table 7-10)

Jurisdiction	Coal	Hydroelectric	Landfill Gas	Natural Gas	Other Gas	Other Source	Solar	Solid Waste	Wind	Total
Delaware	0.0	0.0	0.0	0.0	0.0	0.0	29.0	0.0	0.1	29.1
Illinois	0.0	6.6	100.4	0.0	0.0	0.0	31.3	0.0	302.5	440.8
Indiana	0.0	0.0	44.0	0.0	679.1	0.0	1.0	0.0	0.0	724.1
Kentucky	600.0	2.0	16.0	0.0	0.0	0.0	0.5	88.0	0.0	706.6
Maryland	0.0	0.0	7.0	0.0	0.0	0.0	58.2	0.0	0.3	65.5
Michigan	55.0	0.0	1.6	0.0	0.0	0.0	0.3	0.0	0.0	56.9
Minnesota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	0.0	39.9	0.0	0.0	23.3	695.0	0.0	0.4	758.6
New York	0.0	103.7	0.0	0.0	0.0	0.0	0.4	0.0	0.0	104.1
North Carolina	0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.0	0.0	2.0
Ohio	0.0	1.0	38.1	52.6	67.0	1.0	49.5	109.3	15.9	334.5
Pennsylvania	0.0	5.5	10.0	5.6	86.2	0.3	156.7	0.0	3.2	267.5
Virginia	0.0	12.5	14.8	0.0	0.0	0.0	5.5	318.1	0.0	351.0
West Virginia	0.0	0.0	0.0	0.0	0.0	0.0	1.2	0.0	0.0	1.2
Wisconsin	0.0	9.0	0.0	0.0	0.0	0.0	0.4	44.6	0.0	54.0
District of Columbia	0.0	0.0	0.0	0.0	0.0	0.0	5.3	0.0	0.0	5.3
Total	655.0	140.3	271.9	58.2	832.4	24.6	1,036.4	560.0	468.5	4,047.2

39 There is a 0.00216 MW solar facility registered in GATS from Minnesota that can sell solar RECs in the PJM jurisdictions of Pennsylvania and Illinois.
40 See "Renewable Generators Registered in GATS" <https://gats.pjm-eis.com/myModule/rpt/myrpt.asp?r=501> (Accessed October 02, 2012).

Emissions Controlled Capacity and Renewables in PJM Markets

Emission Controlled Capacity in the PJM Region

Due to environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. Environmental regulations may affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls.

Coal and heavy oil have the highest SO_2 emission rates, while natural gas and light oil have low to negligible SO_2 emission rates. Many coal steam units in PJM have installed FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units. Of the current 78,962.7 MW of coal steam capacity in PJM, 53,542.2 MW of capacity, 67.8 percent, has some form of FGD technology. Table 7-7 shows emission controls by unit type, of fossil fuel units in PJM.

Table 7-7 SO_2 emission controls (FGD) by unit type (MW), as of September 30, 2012 (See 2011 SOM, Table 7-11)

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal Steam	53,542.2	25,420.5	78,962.7	67.8%
Combined Cycle	0.0	27,032.1	27,032.1	0.0%
Combustion Turbine	0.0	31,446.8	31,446.8	0.0%
Diesel	0.0	365.8	365.8	0.0%
Non-Coal Steam	0.0	8,912.6	8,912.6	0.0%
Total	53,542.2	93,177.8	146,720.0	36.5%

NO_x emission control technology is used by nearly all fossil fuel unit types. Coal steam, combined cycle, combustion turbine, and non-coal steam units in PJM have NO_x controls. Of current fossil fuel units in PJM, 132,553.6 MW, or 90.3 percent, of 146,720.0 MW of capacity in PJM, have emission controls for NO_x (Table 7-8). While most units in PJM have NO_x emission controls, many of these controls will need to be upgraded in order to meet forthcoming emission compliance standards such as MATS. Future NO_x compliance standards will require SCRs or SCNRs for coal steam units, as well as SCRs or water injection technology for HEDD combustion turbine units.

Table 7-8 NO_x emission controls by unit type (MW), as of September 30, 2012 (See 2011 SOM, Table 7-12)

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal Steam	76,061.3	2,901.4	78,962.7	96.3%
Combined Cycle	26,286.1	746.0	27,032.1	97.2%
Combustion Turbine	25,835.4	5,611.4	31,446.8	82.2%
Diesel	0.0	365.8	365.8	0.0%
Non-Coal Steam	4,370.8	4,541.8	8,912.6	49.0%
Total	132,553.6	14,166.4	146,720.0	90.3%

Coal steam units in PJM generally have particulate controls. Typically, technologies such as electrostatic precipitators (ESP) or baghouses are used to reduce particulate matter in coal steam units. In PJM, 78,962.7 MW, 97.4 percent, of all coal steam unit MW, have some type of particulate emissions control technology. Table 7-9 shows particulate emission controls by unit type of fossil fuel units in PJM. Most coal steam units in PJM have particulate emission controls in the form of ESPs, but many of these controls will need to be upgraded in order to meet forthcoming emission compliance standards. Future particulate compliance standards will require baghouse technology or a combination of an FGD and SCR to meet EPA regulations, which many coal steam units have not installed.

Table 7-9 Particulate emission controls by unit type (MW), as of September 30, 2012 (See 2011 SOM, Table 7-13)

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal Steam	76,934.9	2,027.8	78,962.7	97.4%
Combined Cycle	0.0	27,032.1	27,032.1	0.0%
Combustion Turbine	0.0	31,446.8	31,446.8	0.0%
Diesel	0.0	365.8	365.8	0.0%
Non-Coal Steam	3,047.0	5,865.6	8,912.6	34.2%
Total	79,981.9	66,738.1	146,720.0	54.5%

Wind Units

Table 7-10 shows the capacity factor of wind units in PJM. In January through September 2012, the capacity factor of wind units in PJM was 25.2 percent. Wind units that were capacity resources had a capacity factor of 25.2 percent and an installed capacity of 4,738 MW. Wind units that were classified as energy only had a capacity factor of 21.6 percent and an installed capacity of 1,030 MW. Much of this wind capacity does not appear in the Capacity Market, as wind capacity in RPM is derated to 13 percent of nameplate capacity, and energy only resources are not included. The capacity factors in Table 7-10 are calculated based on the full nameplate capacity and on the amount of derated capacity (cleared MW).

Table 7-10 Capacity[41] factor[42] of wind units in PJM, January through September 2012 (See 2011 SOM, Table 7-14)

Type of Resource	Capacity Factor	Capacity Factor by cleared MW	Installed Capacity (MW)
Energy-Only Resource	21.6%	NA	1,030
Capacity Resource	25.7%	147.5%	4,738
All Units	25.2%	147.5%	5,769

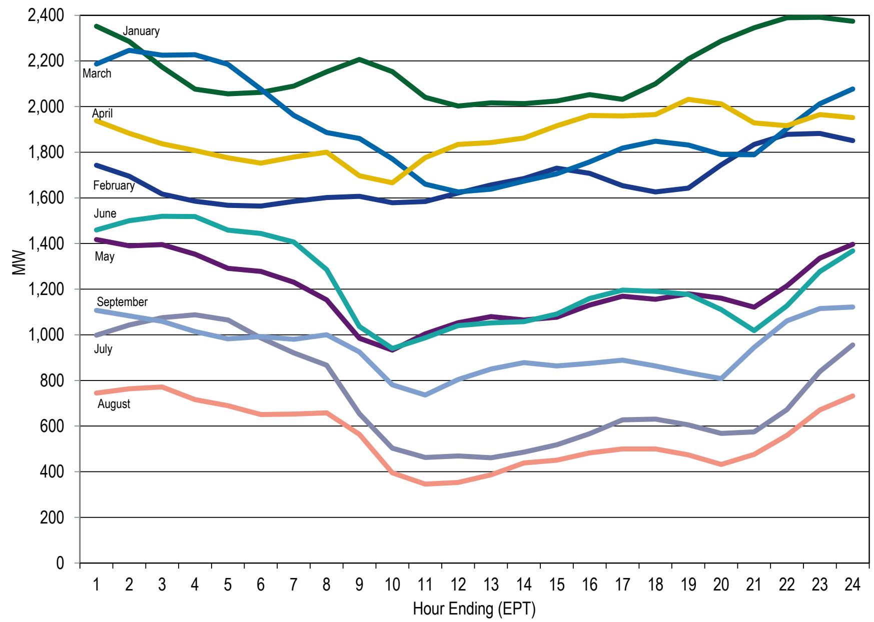
Beginning June 1, 2009, PJM rules allowed units to submit negative price offers. Table 7-11 presents data on negative offers by wind units. Wind and solar units were the only unit types to make negative offers. On average, 819.3 MW of wind were offered daily at a negative price. Wind units with negative offers were marginal in 4,425 separate five minute intervals, or 5.6 percent of all intervals. On average, 2,443.1 MW of wind were offered daily. Overall, wind units were marginal in 12,093 separate five minute intervals, or 15.4 percent of all intervals. Renewable energy credits give wind and solar resources the incentive to make negative price offers, as they offer a payment to renewable resources in addition to the wholesale price of energy. The out of market payments in the form of RECs and federal production tax credits mean these units have an incentive to generate MWh until the negative LMP is equal to the credit received for each MWh adjusted for any marginal costs. These subsidies affect the offer behavior of these resources in PJM markets.

Table 7-11 Wind resources in real time offering at a negative price in PJM, January through September 2012 (See 2011 SOM, Table 7-15)

	Average MW Offered	Intervals Marginal	Percent of Intervals
At Negative Price	819.3	4,425	5.6%
All Wind	2,443.1	12,093	15.4%

Wind output differs from month to month, based on weather conditions. Figure 7-2 shows the average hourly real time generation of wind units in PJM, by month. On average, wind generation was highest in January, and lowest in August. The highest average hour, 2,391.2 MW, occurred in January, and the lowest average hour, 344.5 MW, occurred in August. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

Figure 7-2 Average hourly real-time generation of wind units in PJM: January through September 2012 (See 2011 SOM, Figure 7-2)



41 Capacity factor does not include external resources which only offer in the DA market. Capacity factor is calculated based on online date of the resource.

42 Capacity factor by cleared MW is calculated during peak periods (peak hours during January, February, June, July and August) and includes only MW cleared in RPM.

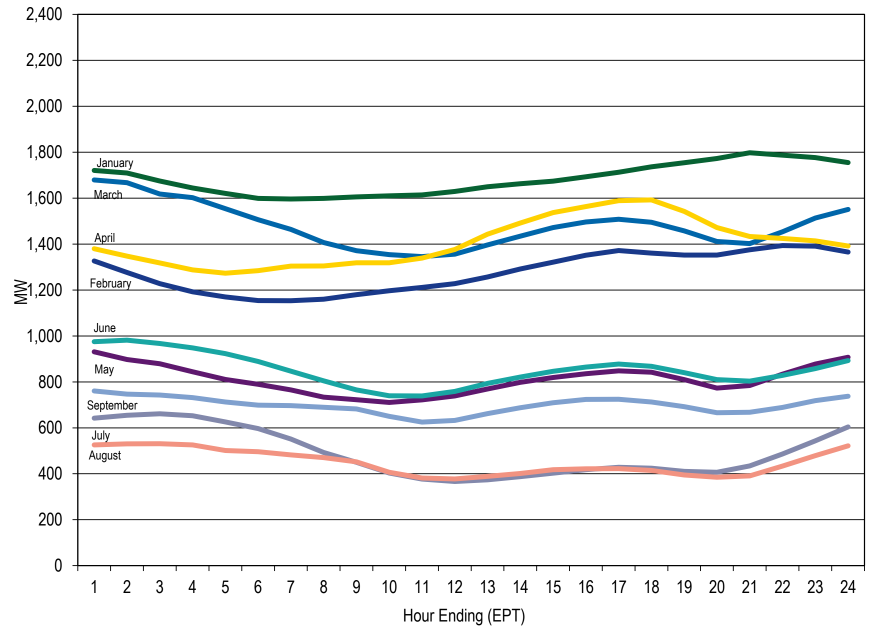
Table 7-12 shows the generation and capacity factor of wind units in each month of 2011 and January through September 2012. Capacity factors of wind units vary substantially by month. The highest capacity factor of wind units was 41.9 percent in January, and the lowest capacity factor was 10.1 percent in August. Overall, the capacity factor in winter months was higher than that of summer months. New wind farms came on line throughout 2012, and are included in this analysis as they were added.

Table 7-12 Capacity factor of wind units in PJM by month, 2011 and 2012[43] (See 2011 SOM, Table 7-16)

	2011		2012	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	950,441.9	29.7%	1,608,349.8	41.9%
February	1,237,813.0	42.4%	1,167,011.9	32.4%
March	1,175,567.0	36.4%	1,416,278.0	35.6%
April	1,399,217.0	44.7%	1,345,643.3	34.7%
May	893,485.1	27.6%	885,583.1	21.6%
June	713,713.8	22.0%	882,597.0	22.2%
July	416,695.8	12.2%	546,676.9	13.3%
August	447,575.2	13.1%	415,544.3	10.1%
September	689,962.6	20.9%	677,001.8	17.0%
October	946,406.3	26.3%		
November	1,507,766.4	41.8%		
December	1,182,421.6	31.5%		
Annual	11,561,065.8	28.9%	8,944,685.9	25.2%

Wind units that are capacity resources are required, like all capacity resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market. In addition, the owners of wind resources have the flexibility to offer the non-capacity related wind energy at their discretion. Figure 7-3 shows the average hourly day-ahead time generation of wind units in PJM for January through September, 2012.

Figure 7-3 Average hourly day-ahead generation of wind units in PJM: January through September 2012 (See 2011 SOM, Figure 7-3)

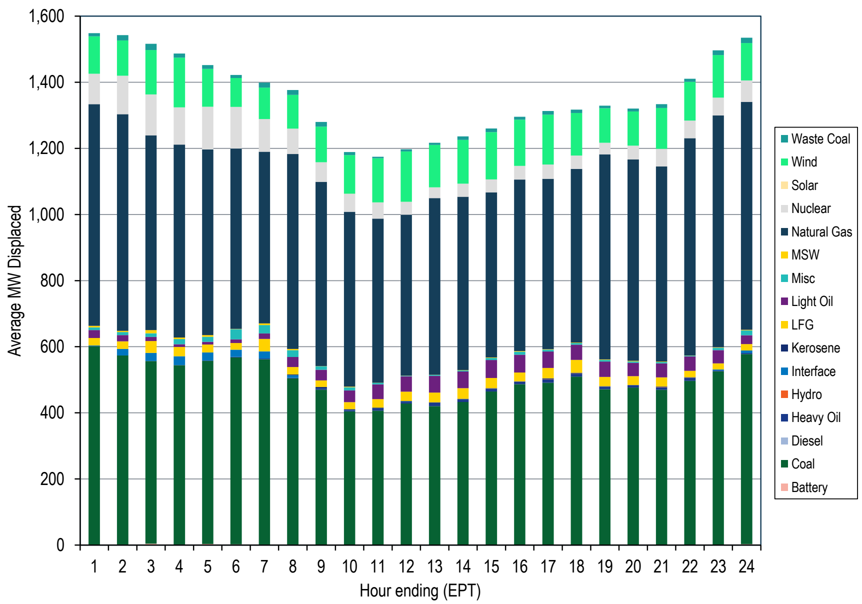


Output from wind turbines displaces output from other generation types. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output will depend on the level of the wind turbine output, its location, the time of the output and its duration. One measure of this displacement is based on the mix of marginal units when wind is producing output. Figure 7-4 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real time wind generation during January through September 2012. This provides, on an hourly average basis, potentially displaced marginal unit MW by fuel type in 2012. Wind output varies daily, and on average is about 347 MW lower from peak average output (2300 EPT) to lowest average output (1000 EPT). This is not an exact measure because it is not based on a redispatch of the system without wind resources. One result is that wind appears as the

43 Capacity factor shown in Table 7-12 is based on all hours in January through September, 2012.

displaced fuel at times when wind resources were on the margin. This means that wind was already on the margin and that there was no displacement of other fuel types for those hours.

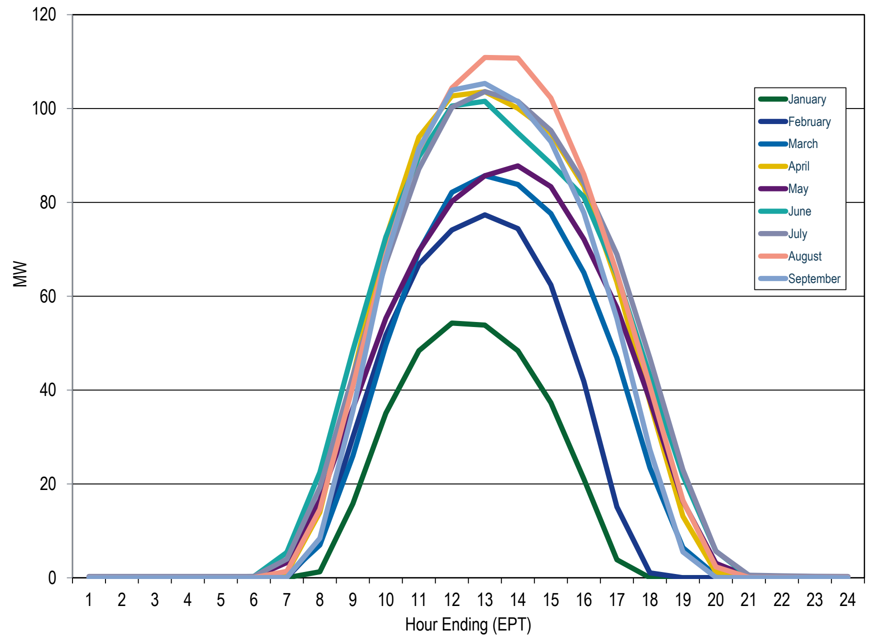
Figure 7-4 Marginal fuel at time of wind generation in PJM: January through September 2012 (See 2011 SOM, Figure 7-4)



Solar Units

Solar output differs from month to month, based on seasonal variation and daylight hours during the month. Figure 7-5 shows the average hourly real time generation of solar units in PJM, by month. On average, solar generation was highest in August. The highest average hour, 109.2 MW, occurred in August. In general, solar generation in PJM is highest during the hours of 1100 through 1300 EPT.

Figure 7-5 Average hourly real-time generation of solar units in PJM: January through September 2012 (See 2011 SOM, Figure 7-5)



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.

Highlights

- During the first nine months of 2012, PJM was a net exporter of energy in the Real-Time Energy Market in January, August and September, and a net importer of energy in the remaining months. During the first nine months of 2011, PJM was a net importer of energy in the Real-Time Energy Market in January, and a net exporter of energy in the remaining months.
- During the first nine months of 2012, PJM was a net exporter of energy in the Day-Ahead Energy Market in January through April and July through September, and a net importer of energy in May and June. During the first nine months of 2011, PJM was a net importer of energy in the Day-Ahead Energy Market in January through June, and a net exporter of energy in July through September.
- The direction of power flows was not consistent with real-time energy market price differences in 55 percent of hours at the border between PJM and MISO and in 48 percent of hours at the border between PJM and NYISO during the first nine months of 2012.
- During the first nine months of 2012, net scheduled interchange was 1,051 GWh and net actual interchange was 801 GWh, a difference of 251 GWh. During the first nine months of 2011, net scheduled interchange was -4,176 GWh and net actual interchange was -4,524 GWh, a difference of 348 GWh.
- PJM initiated 29 TLRs during the first nine months of 2012, a reduction from the 58 TLRs initiated during the first nine months of 2011.
- The average daily volume of up-to congestion bids increased from 26,553 bids per day, during the first nine months of 2011, to 58,273 bids per day during the first nine months of 2012.
- During the first nine months of 2012, there were no balancing operating reserve credits paid to dispatchable transactions, a decrease from $1.3 million for the first nine months of 2011. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and that dispatchable schedules were only submitted on three days during the first nine months of 2012.

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 congestion hedging tools (FTRs and Auction Revenue Rights (ARRs) in PJM) and transparent, least cost, security constrained economic dispatch for all available generation. Non-market areas do not include these features. The market areas are extremely transparent and the non-market areas are not transparent.

The MMU analyzed the transactions between PJM and its neighboring balancing authorities during the first nine months of 2012, including evolving transaction patterns, economics and issues. In the first nine months of 2012, PJM was a net importer of energy in the Real-Time Market and a net exporter of energy in the Day-Ahead Market.

In the first nine months of 2012, the direction of power flows at the borders between PJM and MISO and between PJM and NYISO was not consistent with real-time energy market price differences for 55 percent of the hours for transactions between PJM and MISO and for 48 percent of the hours for transactions between PJM and NYISO. The MMU recommends that PJM work with both MISO and NYISO to improve the ways in which interface flows and prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to an LMP market. In an LMP market, redispatch based on LMP and generator offers would result in an efficient dispatch and efficient prices. Price differences at the seams continue to be determined by relying on market participants to see the prices and react to the prices by scheduling transactions with both an internal lag and an RTO administrative lag.

Interchange Transaction Activity

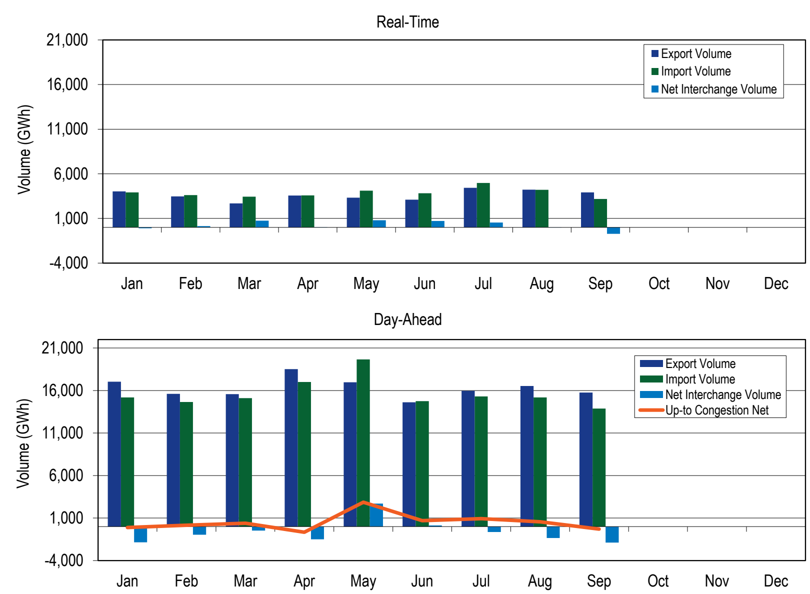
Aggregate Imports and Exports

During the first nine months of 2012, PJM was a net exporter of energy in the Real-Time Energy Market in January, August and September, and a net importer of energy in the remaining months. During the first nine months of 2011, PJM was a net importer of energy in the Real-Time Energy Market in January, and a net exporter of energy in the remaining months. In the Real-Time Energy Market, monthly net interchange averaged 239.2 GWh for the first nine months of 2012 compared to -790.4 GWh for the first nine months of 2011.[1] Gross monthly import volumes during the first nine months of 2012 averaged 3,878.7 GWh compared to 3,479.5 GWh for the first nine months of 2011 while gross monthly exports averaged 3,639.6 GWh for the first nine months of 2012 compared to 4,269.9 GWh for the first nine months of 2011.

During the first nine months of 2012, PJM was a net exporter of energy in the Day-Ahead Energy Market in January through April and July through September, and a net importer of energy in May and June. During the first nine months of 2011, PJM was a net importer of energy in the Day-Ahead Energy Market in January through June, and a net exporter of energy in July through September. In the Day-Ahead Energy Market, for the first nine months of 2012, monthly net interchange averaged -647.2 GWh compared to 1,007.4 GWh for the first nine months of 2011. Gross monthly import volumes averaged 15,639.8 GWh for the first nine months of 2012 compared to 10,561.2 GWh for the first nine months of 2011 while gross monthly exports averaged 16,287.0 GWh for the first nine months of 2012 compared to 9,553.8 GWh for the first nine months of 2011.

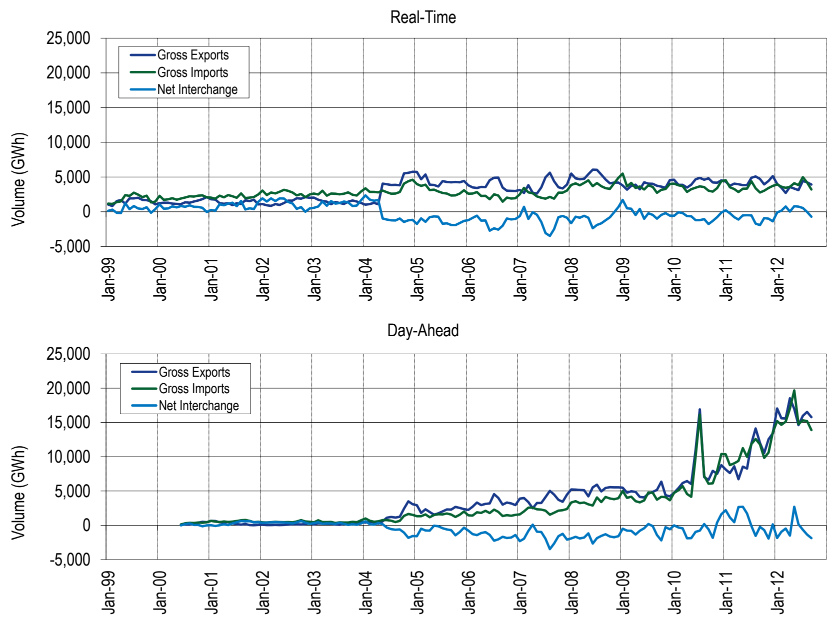
In the first nine months of 2012, gross imports in the Day-Ahead Energy Market were 403.2 percent of gross imports in the Real-Time Energy Market (307.0 percent for the first nine months of 2011). In the first nine months of 2012, gross exports in the Day-Ahead Energy Market were 447.5 percent of gross exports in the Real-Time Energy Market (224.0 percent for the first nine months of 2011). In the first nine months of 2012, net interchange was -5,824.8 GWh in the Day-Ahead Energy Market and 2,152.5 GWh in the Real-Time Energy Market compared to 9,066.0 GWh in the Day-Ahead Energy Market and -7,113.9 GWh in the Real-Time Energy Market for the first nine months of 2011.

Figure 8-1 PJM real-time and day-ahead scheduled imports and exports: January through September, 2012 (See 2011 SOM, Figure 8-1)



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.

Figure 8-2 PJM real-time and day-ahead scheduled import and export transaction volume history: January 1999, through September 2012 (See 2011 SOM, Figure 8-2)



Real-Time Interface Imports and Exports

In the Real-Time Energy Market, scheduled imports and exports are determined by the scheduled market path, which is the transmission path a market participant selects from the original source to the final sink. These scheduled flows are measured at each of PJM's interfaces with neighboring balancing authorities. See Table 8-16 for a list of active interfaces in 2012. Figure 8-3 shows the approximate geographic location of the interfaces. In the first nine months of 2012, PJM had 20 interfaces with neighboring balancing authorities. While the Linden (LIND) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface, all three are interfaces between PJM and the NYISO. Table 8-1 through Table 8-3 show the Real-Time Market interchange totals at the individual NYISO interfaces, as well as with the NYISO as a whole. Similarly, the interchange totals at the individual interfaces between PJM and MISO are shown, as well as with MISO as a whole. Net interchange in the Real-Time Market is shown by interface for the first nine months of 2012 in Table 8-1, while gross imports and exports are shown in Table 8-2 and Table 8-3.

In the Real-Time Energy Market, for the first nine months of 2012, there were net scheduled exports at ten of PJM's 20 interfaces. The top four net exporting interfaces in the Real-Time Energy Market accounted for 79.0 percent of the total net exports: PJM/Eastern Alliant Energy Corporation with 27.6 percent, PJM/MidAmerican Energy Company (MEC) with 22.3 percent, PJM/New York Independent System Operator, Inc. (NYIS) with 19.2 percent and PJM/Neptune (NEPT) with 9.9 percent of the net export volume. The three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 31.5 percent of the total net PJM exports in the Real-Time Energy Market. Nine PJM interfaces had net scheduled imports, with two importing interfaces accounting for 61.9 percent of the total net imports: PJM/Tennessee Valley Authority (TVA) with 31.5 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 30.4 percent of the net import volume.[2]

2 In the Real-Time Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).

Table 8-1 Real-time scheduled net interchange volume by interface (GWh): January through September, 2012 (See 2011 SOM, Table 8-1)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(52.5)	(29.2)	(27.8)	(34.3)	(15.3)	(22.7)	238.8	232.1	(30.4)	258.6
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1
DUK	98.9	(85.3)	(13.0)	(73.2)	160.6	46.6	114.7	(9.7)	30.1	269.7
EKPC	(37.5)	(19.2)	(14.3)	(61.9)	(52.8)	(71.2)	(59.8)	(69.8)	(165.8)	(552.4)
LGEE	357.0	141.4	128.3	181.6	35.0	194.3	279.5	239.8	239.8	1,796.6
MEC	(468.8)	(446.6)	(430.5)	(400.2)	(482.9)	(467.3)	(485.4)	(475.5)	(475.9)	(4,133.1)
MISO	(368.7)	(141.8)	452.0	(380.6)	(366.1)	(154.8)	(1,028.6)	(214.7)	(236.7)	(2,439.9)
ALTE	(693.8)	(557.5)	(179.2)	(651.7)	(653.7)	(453.4)	(799.3)	(599.4)	(516.2)	(5,104.3)
ALTW	(49.7)	(22.7)	(4.9)	(12.9)	(32.6)	(12.1)	(9.5)	(42.6)	(16.4)	(203.4)
AMIL	17.7	39.9	106.3	(55.2)	(17.0)	(17.1)	146.1	151.3	133.3	505.3
CIN	377.7	179.8	300.2	241.2	13.5	87.1	(254.9)	161.4	41.5	1,147.4
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	(172.2)	(76.5)	27.6	(123.5)	(162.6)	(72.9)	(224.2)	(98.3)	(202.1)	(1,104.8)
MECS	378.4	488.4	348.5	366.7	551.8	494.4	355.0	436.8	472.1	3,892.1
NIPS	(18.4)	(17.4)	14.3	10.4	19.3	(39.8)	(83.9)	(30.9)	76.8	(69.6)
WEC	(208.4)	(175.8)	(160.7)	(155.5)	(84.7)	(140.9)	(157.9)	(193.1)	(225.6)	(1,502.6)
NYISO	(1,127.3)	(750.9)	(508.4)	(317.8)	(110.0)	(396.7)	(577.6)	(1,168.5)	(869.2)	(5,826.3)
LIND	(63.9)	(6.3)	(64.5)	(60.6)	33.1	(39.4)	(62.6)	(119.1)	(77.0)	(460.3)
NEPT	(415.7)	(329.7)	(288.4)	(155.4)	(119.8)	0.0	(1.4)	(275.7)	(237.1)	(1,823.0)
NYIS	(647.8)	(414.9)	(155.5)	(101.8)	(23.3)	(357.3)	(513.5)	(773.8)	(555.1)	(3,543.0)
OVEC	712.5	693.4	588.3	627.1	835.8	714.4	834.9	745.2	526.7	6,278.1
TVA	783.0	787.2	580.6	485.4	794.0	883.5	1,229.6	703.0	254.9	6,501.2
Total	(103.4)	149.0	755.1	26.1	798.4	726.0	546.2	(18.2)	(726.5)	2,152.5

Table 8-2 Real-time scheduled gross import volume by interface (GWh): January through September, 2012 (See 2011 SOM, Table 8-2)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	0.3	0.0	0.4	1.6	2.1	2.7	274.0	256.4	0.0	537.5
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1
DUK	277.1	168.8	134.8	187.5	288.2	142.0	268.7	167.6	120.5	1,755.2
EKPC	41.0	31.5	26.7	3.2	8.1	7.6	30.2	24.2	3.4	175.9
LGEE	365.4	147.0	149.7	186.2	94.6	204.4	282.2	244.2	243.3	1,916.9
MEC	16.9	7.3	0.1	0.2	0.2	0.0	0.0	0.3	1.3	26.2
MISO	1,179.1	1,022.7	1,025.3	1,229.0	1,147.9	929.4	991.6	1,112.4	1,187.9	9,825.2
ALTE	1.3	4.8	0.2	0.0	0.6	0.0	0.0	3.8	3.9	14.6
ALTW	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
AMIL	46.5	78.1	134.2	13.5	24.3	34.1	201.4	172.2	183.7	888.0
CIN	526.9	330.4	340.5	530.7	379.8	314.7	216.9	288.7	312.4	3,241.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	127.3	88.2	126.3	94.8	60.7	58.4	67.5	52.9	58.5	734.5
MECS	408.3	520.4	390.7	519.7	598.0	521.5	504.1	587.9	503.9	4,554.5
NIPS	59.4	0.7	32.5	70.2	84.0	0.7	1.6	6.3	125.5	380.9
WEC	9.6	0.0	0.9	0.0	0.6	0.0	0.0	0.7	0.0	11.6
NYISO	506.4	678.3	887.4	824.9	886.8	883.2	1,004.0	900.4	818.0	7,389.5
LIND	10.7	19.6	12.2	18.6	52.2	25.0	33.4	21.0	14.1	207.0
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	495.6	658.7	875.1	806.3	834.6	858.2	970.6	879.5	803.9	7,182.5
OVEC	738.2	716.7	611.5	647.2	855.9	731.7	853.5	763.8	544.3	6,462.9
TVA	802.8	845.0	610.7	509.9	835.2	927.7	1,272.0	742.8	273.1	6,819.2
Total	3,927.2	3,617.4	3,446.6	3,589.7	4,118.8	3,828.7	4,976.3	4,212.1	3,191.9	34,908.6

Table 8-3 Real-time scheduled gross export volume by interface (GWh): January through September, 2012 (See 2011 SOM, Table 8-3)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	52.8	29.2	28.2	35.9	17.4	25.5	35.2	24.3	30.5	278.9
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	178.2	254.1	147.7	260.6	127.6	95.4	154.0	177.3	90.5	1,485.5
EKPC	78.5	50.7	41.1	65.1	60.8	78.8	90.0	94.0	169.2	728.3
LGEE	8.4	5.6	21.4	4.6	59.6	10.1	2.7	4.4	3.5	120.3
MEC	485.7	453.9	430.5	400.4	483.0	467.3	485.4	475.8	477.2	4,159.3
MISO	1,547.8	1,164.5	573.3	1,609.6	1,513.9	1,084.1	2,020.2	1,327.2	1,424.6	12,265.1
ALTE	695.1	562.3	179.5	651.7	654.4	453.4	799.3	603.2	520.1	5,118.9
ALTW	49.7	22.8	4.9	12.9	32.6	12.1	9.5	42.6	16.4	203.5
AMIL	28.7	38.3	28.0	68.7	41.2	51.2	55.3	20.9	50.4	382.7
CIN	149.2	150.6	40.3	289.6	366.4	227.6	471.9	127.3	270.9	2,093.6
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	299.5	164.7	98.7	218.3	223.3	131.3	291.7	151.2	260.6	1,839.3
MECS	29.9	32.0	42.2	153.0	46.1	27.1	149.1	151.1	31.9	662.4
NIPS	77.8	18.1	18.2	59.8	64.7	40.5	85.5	37.2	48.7	450.5
WEC	218.0	175.8	161.6	155.5	85.3	140.9	157.9	193.7	225.6	1,514.3
NYISO	1,633.7	1,429.2	1,395.7	1,142.7	996.8	1,279.9	1,581.6	2,069.0	1,687.2	13,215.8
LIND	74.6	26.0	76.7	79.2	19.1	64.4	96.0	140.0	91.1	667.2
NEPT	415.7	329.7	288.4	155.4	119.8	0.0	1.4	275.7	237.1	1,823.0
NYIS	1,143.4	1,073.6	1,030.7	908.1	857.9	1,215.6	1,484.1	1,653.2	1,359.0	10,725.5
OVEC	25.7	23.3	23.3	20.1	20.1	17.3	18.6	18.6	17.7	184.8
TVA	19.8	57.8	30.2	24.6	41.2	44.1	42.4	39.8	18.2	318.0
Total	4,030.6	3,468.4	2,691.5	3,563.6	3,320.4	3,102.7	4,430.2	4,230.3	3,918.4	32,756.1

Real-Time Interface Pricing Point Imports and Exports

Interfaces differ from interface pricing points. An interface is a point of interconnection between PJM and a neighboring balancing authority which market participants may designate as a market path on which scheduled imports or exports will flow.[3] An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled market path from a generation control area (GCA) to a load control area (LCA), this market path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. For example, the import transmission path from LG&E Energy, L.L.C. (LGEE), through MISO and into PJM would show the transfer of power into PJM at the LGEE/PJM Interface based on the scheduled market path of the transaction. However, the physical flow of energy does not enter the PJM footprint at the LGEE/PJM Interface, but enters PJM at the southern boundary. For this reason, PJM prices an import with the GCA of LGEE at the SouthIMP interface pricing point rather than the MISO pricing point.

Interfaces differ from interface pricing points. The challenge is to create interface prices, composed of external pricing points, which 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.[4]

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.[5] PJM establishes prices for transactions with external balancing authorities by assigning interface pricing points to the 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.[6] 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. Table 8-17 presents the interface pricing points used in the first nine months of 2012.

3 A market path is the scheduled path rather than the actual path on which power flows. A market path contains the generation balancing authority, all required transmission segments and the load balancing authority. There are multiple market paths between any generation and load balancing authority. Market participants select the market path based on transmission service availability and the transmission costs for moving energy from generation to load.

4 See the *2007 State of the Market Report for PJM*, Volume II, Appendix D, "Interchange Transactions," for a more complete discussion of the development of pricing points.

5 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed October 16, 2012). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

6 See "PJM Interface Pricing Definition Methodology." (September 29, 2006) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20060929-interface-definition-methodology1.ashx>. (Accessed October 16, 2012)

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 by PJM only occasionally.

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. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag. This approach will not correctly identify the interface pricing point if the market participant breaks the transaction into portions, each with a separate Tag. The result of such behavior can be incorrect pricing of transactions.

In the Real-Time Energy Market, for the first nine months of 2012, there were net exports at ten of PJM's 17 interface pricing points eligible for real-time transactions.[7] The top three net exporting interface pricing points in the Real-Time Energy Market accounted for 85.3 percent of the total net exports: PJM/MISO with 63.6 percent, PJM/NYIS with 14.1 percent and PJM/NEPTUNE (NEPT) with 7.5 percent of the net export volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 23.6 percent of the total net PJM exports in the Real-Time Energy Market. Six PJM interface pricing points had net imports, with two importing interface pricing points accounting for 78.4 percent of the total net imports: PJM/SouthIMP with 54.6 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 23.8 percent of the net import volume.[8]

Table 8-4 Real-time scheduled net interchange volume by interface pricing point (GWh): January through September, 2012 (See 2011 SOM, Table 8-4)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	479.8	485.2	431.3	551.8	426.9	377.8	420.8	370.8	379.2	3,923.6
LINDENVFT	(63.9)	(6.3)	(64.5)	(60.6)	33.1	(39.4)	(62.6)	(119.1)	(77.0)	(460.3)
MISO	(1,992.3)	(1,601.0)	(940.0)	(1,985.0)	(1,934.8)	(1,496.7)	(2,196.9)	(1,565.4)	(1,671.9)	(15,384.1)
NEPTUNE	(415.7)	(329.7)	(288.4)	(155.4)	(119.8)	0.0	(1.4)	(275.7)	(237.1)	(1,823.0)
NORTHWEST	(1.6)	(1.5)	(1.2)	(3.5)	(21.2)	(0.3)	(55.0)	(25.2)	(1.5)	(110.9)
NYIS	(648.1)	(415.3)	(166.8)	(103.3)	(30.2)	(355.7)	(482.9)	(722.7)	(489.3)	(3,414.3)
OVEC	712.5	693.4	588.3	627.1	835.8	714.4	834.9	745.2	526.7	6,278.1
SOUTHIMP	2,164.4	1,722.9	1,465.1	1,550.6	1,920.1	1,783.4	2,432.6	1,919.0	1,163.6	16,121.6
CPLEIMP	0.0	0.0	0.4	1.0	1.4	2.4	273.5	256.4	0.0	535.0
DUKIMP	106.7	88.6	56.7	61.8	111.9	56.9	219.9	129.2	74.3	905.9
NCMPAIMP	44.7	44.2	25.2	21.8	72.6	41.5	25.6	24.8	15.8	316.2
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	2,013.0	1,590.1	1,382.9	1,465.9	1,734.2	1,682.5	1,913.7	1,508.6	1,073.5	14,364.6
SOUTHEXP	(338.5)	(398.7)	(268.6)	(395.7)	(311.7)	(257.4)	(343.3)	(345.2)	(319.2)	(2,978.3)
CPLEEXP	(52.8)	(26.6)	(26.0)	(31.3)	(16.9)	(24.3)	(30.9)	(24.0)	(29.0)	(261.9)
DUKEXP	(172.0)	(233.9)	(141.2)	(243.9)	(108.8)	(74.2)	(129.2)	(157.4)	(74.7)	(1,335.3)
NCMPAEXP	0.0	0.0	0.0	(2.6)	0.0	0.0	0.0	0.0	0.0	(2.6)
SOUTHWEST	(1.6)	(1.3)	0.0	(4.2)	(4.7)	(3.5)	(10.9)	(5.1)	(7.4)	(38.5)
SOUTHEXP	(112.1)	(136.9)	(101.4)	(113.7)	(181.2)	(155.5)	(172.3)	(158.7)	(208.2)	(1,340.0)
Total	(103.4)	149.0	755.1	26.1	798.4	726.0	546.2	(18.2)	(726.5)	2,152.5

7 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).
8 In the Real-Time Market, one PJM interface pricing point (Southwest) had a net interchange of zero.

Table 8-5 Real-time scheduled gross import volume by interface pricing point (GWh): January through September, 2012 (See 2011 SOM, Table 8-5)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	480.4	486.8	434.3	554.0	433.1	385.6	443.5	389.1	400.8	4,007.6
LINDENVFT	10.7	19.6	12.2	18.6	52.2	25.0	33.4	21.0	14.1	207.0
MISO	38.8	14.6	62.0	15.3	31.4	47.6	225.4	205.4	210.7	851.1
NEPTUNE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NORTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.2
NYIS	494.6	656.7	861.4	804.0	826.0	855.5	987.8	913.8	858.3	7,258.2
OVEC	738.2	716.7	611.5	647.2	855.9	731.7	853.5	763.8	544.3	6,462.9
SOUTHIMP	2,164.4	1,722.9	1,465.1	1,550.6	1,920.1	1,783.4	2,432.6	1,919.0	1,163.6	16,121.6
CPLEIMP	0.0	0.0	0.4	1.0	1.4	2.4	273.5	256.4	0.0	535.0
DUKIMP	106.7	88.6	56.7	61.8	111.9	56.9	219.9	129.2	74.3	905.9
NCMPAIMP	44.7	44.2	25.2	21.8	72.6	41.5	25.6	24.8	15.8	316.2
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	2,013.0	1,590.1	1,382.9	1,465.9	1,734.2	1,682.5	1,913.7	1,508.6	1,073.5	14,364.6
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	3,927.2	3,617.4	3,446.6	3,589.7	4,118.8	3,828.7	4,976.3	4,212.1	3,191.9	34,908.6

Table 8-6 Real-time scheduled gross export volume by interface pricing point (GWh): January through September, 2012 (See 2011 SOM, Table 8-6)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	0.7	1.6	3.1	2.2	6.2	7.7	22.6	18.3	21.6	84.0
LINDENVFT	74.6	26.0	76.7	79.2	19.1	64.4	96.0	140.0	91.1	667.2
MISO	2,031.1	1,615.6	1,002.0	2,000.3	1,966.2	1,544.3	2,422.3	1,770.8	1,882.7	16,235.2
NEPTUNE	415.7	329.7	288.4	155.4	119.8	0.0	1.4	275.7	237.1	1,823.0
NORTHWEST	1.6	1.5	1.2	3.5	21.2	0.3	55.1	25.2	1.5	111.0
NYIS	1,142.8	1,072.0	1,028.2	907.3	856.2	1,211.2	1,470.7	1,636.5	1,347.6	10,672.5
OVEC	25.7	23.3	23.3	20.1	20.1	17.3	18.6	18.6	17.7	184.8
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	338.5	398.7	268.6	395.7	311.7	257.4	343.3	345.2	319.2	2,978.3
CPLEEXP	52.8	26.6	26.0	31.3	16.9	24.3	30.9	24.0	29.0	261.9
DUKEXP	172.0	233.9	141.2	243.9	108.8	74.2	129.2	157.4	74.7	1,335.3
NCMPAEXP	0.0	0.0	0.0	2.6	0.0	0.0	0.0	0.0	0.0	2.6
SOUTHWEST	1.6	1.3	0.0	4.2	4.7	3.5	10.9	5.1	7.4	38.5
SOUTHEXP	112.1	136.9	101.4	113.7	181.2	155.5	172.3	158.7	208.2	1,340.0
Total	4,030.6	3,468.4	2,691.5	3,563.6	3,320.4	3,102.7	4,430.2	4,230.3	3,918.4	32,756.1

Day-Ahead Interface Imports and Exports

In the Day-Ahead Energy Market, as in the Real-Time Energy Market, scheduled imports and exports are determined by the scheduled market path, which is the transmission path a market participant selects from the original source to the final sink. Entering external energy transactions in the Day-Ahead Energy Market requires fewer steps than the Real-Time Energy 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 Energy Market.[9] Day-Ahead Energy Market schedules need to be cleared through the Day-Ahead Energy Market process in order to become an approved schedule. The Day-Ahead Energy Market transactions are financially binding, but will not physically flow. In the Day-Ahead Energy 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.

Because market participants choose the interface pricing point(s) they wish to have associated with their transaction in the Day-Ahead Energy Market, the scheduled interface is less meaningful than in the Real-Time Energy Market. In Table 8-7, Table 8-8 and Table 8-9, the interface designation is determined by the transmission reservation that was acquired and associated with the Day-Ahead Market transaction, and does not necessarily match that of the pricing point designation selected at the time the transaction is submitted to PJM in real time. For example, a market participant may have a transmission reservation with a point of receipt of MISO and a point of delivery of PJM. If the market participant knows that the source of the energy in the Real-Time Market will be associated with the SouthIMP interface pricing point, they may select SouthIMP as the import pricing point when submitting the transaction. In the interface tables, the import transaction would appear as scheduled through the MISO Interface, and in the interface pricing point tables, the import transaction would appear

9 Effective September 17, 2010, up-to congestion transactions no longer required a willing to pay congestion transmission reservation. Additional details can be found under the "Up-to Congestion" heading in this report.

as scheduled through the SouthIMP Interface Pricing Point, which reflects the expected power flow.

On May 15, 2012, the submission of up-to congestion transactions was moved to the eMKT application. The submission of up-to congestion transactions in eMKT no longer requires market participants to acquire the up-to congestion OASIS reservation. This change eliminates all references to any specific interface previously identified by the OASIS reservation, and only identifies the relevant interface pricing points for the up-to congestion transaction as specified by the market participants at the time of submission. As a result, the up-to congestion transactions shown in the tables have been removed from the interface specific totals, and are now represented only as a single monthly total. Table 8-7 through Table 8-9 show the Day-Ahead interchange totals at the individual interfaces. Net interchange in the Day-Ahead Market is shown by interface for the first nine months of 2012 in Table 8-7, while gross imports and exports are shown in Table 8-8 and Table 8-9.

Table 8-7 Day-Ahead scheduled net interchange volume by interface (GWh): January through September, 2012 (See 2011 SOM, Table 8-7)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(46.5)	(16.3)	(12.4)	(29.6)	(15.3)	(23.9)	(8.8)	182.6	(27.6)	2.3
CPLW	(0.1)	3.4	7.0	8.9	8.9	(0.0)	0.0	0.0	0.0	28.1
DUK	39.0	18.6	20.7	28.4	41.0	35.5	29.5	96.6	35.2	344.4
EKPC	(35.6)	(34.8)	(37.2)	(36.0)	(37.2)	(36.0)	(37.2)	(36.6)	(36.0)	(326.6)
LGEE	48.4	0.0	(18.6)	4.6	12.3	39.2	50.8	18.1	48.4	203.2
MEC	(492.3)	(444.0)	(432.6)	(392.7)	(484.8)	(462.9)	(470.7)	(472.7)	(461.3)	(4,114.1)
MISO	(584.3)	(364.5)	(41.9)	(162.4)	4.6	(85.2)	(609.4)	(455.1)	(300.4)	(2,598.6)
ALTE	(462.3)	(470.3)	(107.3)	(424.6)	(308.4)	(231.9)	(532.3)	(514.3)	(258.3)	(3,309.7)
ALTW	(35.8)	(15.9)	(5.5)	(10.3)	(10.1)	(6.6)	(0.8)	(22.5)	(1.7)	(109.2)
AMIL	(3.2)	0.0	0.0	0.8	0.0	2.4	0.0	0.8	3.6	4.4
CIN	130.9	203.1	234.4	305.1	60.1	131.0	(90.5)	91.3	91.4	1,156.8
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	(15.0)	(10.2)	(4.3)	(5.2)	(10.9)	(7.9)	(27.0)	(13.8)	(16.6)	(110.9)
MECS	(45.8)	33.6	(92.6)	48.1	181.9	116.5	128.7	133.8	58.2	562.5
NIPS	(0.3)	3.2	(2.3)	(0.7)	(3.4)	(21.1)	(12.5)	(51.0)	(104.5)	(192.6)
WEC	(152.7)	(108.1)	(64.2)	(75.7)	95.4	(67.7)	(75.0)	(79.4)	(72.6)	(600.0)
NYISO	(1,171.0)	(931.2)	(672.2)	(355.7)	(274.1)	(299.5)	(602.7)	(905.1)	(752.0)	(5,963.6)
LIND	(10.3)	(2.3)	(7.4)	(0.9)	33.1	4.9	(4.4)	(12.3)	(11.4)	(10.9)
NEPT	(425.2)	(355.9)	(314.5)	(160.0)	(137.7)	32.8	20.9	(218.5)	(203.0)	(1,761.0)
NYIS	(735.6)	(573.1)	(350.4)	(194.8)	(169.4)	(337.1)	(619.3)	(674.3)	(537.7)	(4,191.7)
OVEC	354.5	584.2	375.8	110.1	291.2	345.0	91.1	(380.1)	(33.7)	1,738.0
TVA	146.6	60.5	(61.7)	(9.9)	284.6	(65.7)	(14.6)	46.9	(63.3)	323.3
Total without Up-To Congestion	(1,741.3)	(1,124.2)	(873.0)	(834.3)	(168.8)	(553.7)	(1,572.1)	(1,905.5)	(1,590.6)	(10,363.4)
Up-To Congestion	(106.2)	161.5	397.9	(670.7)	2,869.6	695.2	924.4	556.4	(289.6)	4,538.6
Total	(1,847.5)	(962.7)	(475.1)	(1,505.0)	2,700.9	141.5	(647.7)	(1,349.0)	(1,880.2)	(5,824.8)

In the Day-Ahead Energy Market, for the first nine months of 2012, there were net scheduled exports at ten of PJM's 20 interfaces. The top three net exporting interfaces accounted for 78.9 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 28.5 percent, PJM/MidAmerican Energy Company (MEC) with 27.9 percent and PJM/Eastern Alliant Energy Corporation (ALTE) with 22.5 percent of the net export volume. The three separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/LIND) together represented 40.5 percent of the total net PJM exports in the Day-Ahead Energy Market. Nine PJM interfaces had net scheduled imports in the Day-Ahead Energy Market, with three interfaces accounting for 79.2 percent of the total net imports: PJM/OVEC with 39.8 percent, PJM/Cinergy Corporation (CIN) with 26.5 percent and PJM/Michigan Electric Coordinated System (MECS) with 12.9 percent of the net import volume.[10]

10 In the Day-Ahead Market, one PJM interface (PJM/City Water Light & Power (CWLP)) had a net interchange of zero.

Table 8-8 Day-Ahead scheduled gross import volume by interface (GWh): January through September, 2012 (See 2011 SOM, Table 8-8)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	0.3	3.6	12.5	0.0	0.0	0.0	27.6	204.2	0.0	248.2
CPLW	0.0	3.6	7.2	9.9	10.2	0.1	0.0	0.0	0.0	31.0
DUK	40.8	47.9	33.8	36.0	42.3	35.5	35.4	116.5	35.2	423.5
EKPC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LGEE	52.9	0.0	0.0	4.6	12.3	39.2	50.8	18.1	48.4	226.3
MEC	2.6	10.5	0.2	0.6	0.0	0.0	0.0	0.0	0.8	14.8
MISO	526.3	770.8	713.1	934.6	810.6	409.5	333.4	394.1	323.2	5,215.5
ALTE	82.2	111.2	112.6	136.1	87.7	42.5	33.5	64.8	40.9	711.6
ALTW	0.0	0.0	0.7	0.5	0.1	0.0	0.0	0.0	0.0	1.2
AMIL	0.4	0.0	0.0	0.8	0.0	2.4	0.0	0.8	3.6	7.9
CIN	140.4	219.1	247.0	337.5	210.0	218.7	120.8	149.6	210.2	1,853.2
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.2	0.0	0.0	0.1	0.0	0.0	0.3
MECS	263.8	366.3	322.3	428.5	341.8	116.5	129.0	144.5	59.3	2,171.9
NIPS	0.1	3.4	0.2	0.5	6.1	26.6	50.0	34.4	9.2	130.6
WEC	39.4	70.9	30.3	30.7	164.9	2.7	0.0	0.0	0.0	338.9
NYISO	371.3	559.4	745.7	742.8	797.8	935.0	933.1	926.4	850.1	6,861.6
LIND	0.0	1.4	1.7	7.7	42.7	24.2	28.1	26.8	23.0	155.4
NEPT	0.0	0.0	0.0	0.0	9.4	49.1	39.6	69.0	62.4	229.4
NYIS	371.3	558.0	744.0	735.1	745.8	861.7	865.3	830.7	764.8	6,476.8
OVEC	626.5	789.5	606.7	947.3	1,081.5	1,090.8	1,137.7	957.8	760.9	7,998.6
TVA	234.0	250.5	121.3	185.5	456.7	276.4	295.6	357.0	242.4	2,419.4
Total without Up-To Congestion	1,854.8	2,435.7	2,240.4	2,861.4	3,211.5	2,786.4	2,813.6	2,974.2	2,261.1	23,438.9
Up-To Congestion	13,332.7	12,217.6	12,863.0	14,150.6	16,454.3	11,970.1	12,495.5	12,211.6	11,624.0	117,319.3
Total	15,187.4	14,653.3	15,103.4	17,011.9	19,665.8	14,756.4	15,309.1	15,185.8	13,885.1	140,758.2

Table 8-9 Day-Ahead scheduled gross export volume by interface (GWh): January through September, 2012 (See 2011 SOM, Table 8-9)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	46.8	19.9	24.9	29.6	15.3	23.9	36.4	21.5	27.6	245.9
CPLW	0.1	0.2	0.1	1.0	1.4	0.1	0.0	0.0	0.0	2.9
DUK	1.8	29.3	13.0	7.6	1.3	0.0	5.9	20.0	0.0	79.0
EKPC	35.6	34.8	37.2	36.0	37.2	36.0	37.2	36.6	36.0	326.6
LGEE	4.5	0.0	18.6	0.0	0.0	0.0	0.0	0.0	0.0	23.1
MEC	494.8	454.5	432.8	393.4	484.8	462.9	470.7	472.7	462.1	4,128.8
MISO	1,110.6	1,135.3	754.9	1,097.0	806.0	494.7	942.8	849.2	623.6	7,814.2
ALTE	544.5	581.5	220.0	560.7	396.1	274.5	565.8	579.1	299.2	4,021.3
ALTW	35.8	15.9	6.1	10.7	10.2	6.6	0.8	22.5	1.7	110.3
AMIL	3.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.5
CIN	9.5	16.0	12.6	32.4	149.9	87.7	211.3	58.2	118.8	696.4
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	15.0	10.2	4.3	5.3	10.9	7.9	27.1	13.8	16.6	111.2
MECS	309.6	332.6	414.9	380.3	159.9	0.0	0.3	10.7	1.1	1,609.5
NIPS	0.5	0.2	2.5	1.2	9.5	47.8	62.4	85.4	113.7	323.1
WEC	192.2	178.9	94.6	106.3	69.5	70.4	75.0	79.4	72.6	938.8
NYISO	1,542.4	1,490.6	1,417.9	1,098.5	1,071.8	1,234.4	1,535.8	1,831.5	1,602.1	12,825.1
LIND	10.3	3.6	9.0	8.6	9.6	19.3	32.5	39.0	34.4	166.2
NEPT	425.2	355.9	314.5	160.0	147.0	16.3	18.7	287.5	265.3	1,990.5
NYIS	1,106.9	1,131.2	1,094.4	929.9	915.2	1,198.8	1,484.7	1,505.0	1,302.4	10,668.4
OVEC	272.0	205.3	230.8	837.2	790.3	745.8	1,046.6	1,337.9	794.6	6,260.6
TVA	87.3	190.0	183.0	195.4	172.1	342.1	310.2	310.2	305.6	2,096.0
Total without Up-To Congestion	3,596.1	3,559.9	3,113.4	3,695.7	3,380.2	3,340.0	4,385.6	4,879.6	3,851.7	33,802.3
Up-To Congestion	13,438.8	12,056.1	12,465.1	14,821.2	13,584.7	11,274.9	11,571.1	11,655.2	11,913.6	112,780.8
Total	**17,034.9**	**15,616.0**	**15,578.5**	**18,516.9**	**16,964.9**	**14,614.9**	**15,956.8**	**16,534.8**	**15,765.3**	**146,583.0**

Day-Ahead Interface Pricing Point Imports and Exports

Table 8-10 through Table 8-15 show the Day-Ahead Market interchange totals at the individual interface pricing points. Net interchange in the Day-Ahead Market, including up-to congestion transactions, is shown by interface pricing point for the first nine months of 2012 in Table 8-10. Up-to congestion transactions by interface pricing point for the first nine months of 2012 are shown in Table 8-11. Gross imports and exports, including up-to congestion transactions, for the Day-Ahead Market are shown in Table 8-12 and Table 8-14 while gross import up-to congestion transactions are show in Table 8-13 and gross export up-to congestion transactions are shown in Table 8-15.

In the Day-Ahead Energy Market, for the first nine months of 2012, there were net exports at ten of PJM's 20 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 68.5 percent of the total net exports: PJM/SouthEXP with 34.2 percent, PJM/Southwest with 23.4 percent and PJM/Northwest with 11.0 percent of the net export volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 7.1 percent of the total net PJM exports in the Day-Ahead Energy Market (PJM/NEPTUNE with 7.1 percent. The PJM/NYIS and the PJM/LINDEN interface pricing points had net imports in the Day-Ahead Energy Market). Ten PJM interface pricing points had net imports, with four importing interface pricing points accounting for 74.7 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 20.8 percent, PJM/SouthIMP with 19.1 percent, PJM/MISO with 17.4 percent and PJM/Southwest with 17.3 percent of the net import volume.

Up-to congestion transactions account for 83.4 percent of all scheduled import MW transactions and 76.9 percent of all scheduled export MW transactions in the Day-Ahead Market. The Day-Ahead Market interchange totals at the individual interface pricing points for up-to congestion transactions are shown in the Day-Ahead Market tables. Net interchange for up-to congestion transactions that were accepted in the Day-Ahead Market for the first nine months of 2012 are shown in Table 8-11. Gross imports and exports for the up-to congestion transactions are shown in Table 8-13 and Table 8-15.

In the Day-Ahead Market, for the first nine months of 2012, up-to congestion transactions had net exports at eight of PJM's 20 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points for up-to congestion transactions accounted for 77.5 percent of the total net up-to congestion exports: PJM/SouthEXP with 36.1 percent, PJM/Southwest with 27.3 percent and PJM/Ontario Independent Electricity System Operator (IMO) with 14.1 percent of the net export up-to congestion volume. The three separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT and PJM/Linden (LIND)) together represented 4.4 percent of the net up-to congestion PJM exports in the Day-Ahead Energy Market (PJM/NEPTUNE with 4.4 percent. The PJM/NYIS and the PJM/LINDEN interface pricing points had net imports in the Day-Ahead Energy Market). Eight PJM interface pricing points had net up-to congestion imports, with four importing interface pricing points accounting for 74.2 percent of the total net up-to congestion imports: PJM/MISO with 24.6 percent, PJM/NYIS with 17.0 percent, PJM/Ohio Valley Electric Corporation (OVEC) with 16.4 percent and PJM/Southwest with 16.3 percent of the net import volume. [11]

Table 8-10 Day-Ahead scheduled net interchange volume by interface pricing point (GWh): January through September, 2012 (See 2011 SOM, Table 8-10)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	(1,019.1)	(410.0)	(868.4)	(952.1)	(919.2)	(584.3)	(511.5)	(161.3)	(381.0)	(5,806.9)
LINDENVFT	9.2	(51.2)	23.5	74.6	97.9	77.2	113.1	29.3	12.3	385.9
MISO	1,268.5	1,277.6	1,419.8	1,454.3	1,351.1	782.5	384.0	81.6	527.4	8,546.8
NEPTUNE	(891.7)	(837.7)	(870.3)	(492.9)	(436.7)	(181.7)	(32.0)	(36.6)	(116.9)	(3,896.5)
NIPSCO	(47.9)	(33.1)	(630.3)	(902.3)	(479.9)	(435.1)	(238.4)	(374.2)	(495.0)	(3,636.3)
NORTHWEST	(524.9)	(370.7)	(543.2)	(751.2)	(644.5)	(750.1)	(776.1)	(880.8)	(770.4)	(6,011.9)
NYIS	(35.0)	300.8	573.1	528.3	1,717.1	882.6	231.6	40.2	78.7	4,317.3
OVEC	1,236.4	779.2	1,898.6	1,205.3	3,017.4	1,284.3	894.6	181.9	(271.9)	10,225.8
SOUTHIMP	2,041.5	2,471.4	2,283.8	2,888.6	3,375.8	2,915.1	3,635.1	3,249.3	2,718.9	25,579.6
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	27.3	204.2	0.0	231.4
DUKIMP	3.9	12.2	3.5	1.6	4.0	1.0	8.6	78.8	3.6	117.1
NCMPAIMP	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
SOUTHEAST	552.6	756.9	613.5	769.7	990.1	1,014.4	1,150.3	901.7	625.8	7,375.2
SOUTHWEST	707.2	900.6	815.6	989.1	920.6	842.9	1,208.7	1,038.3	1,042.1	8,465.0
SOUTHIMP	777.6	801.7	851.2	1,128.0	1,461.1	1,056.9	1,240.2	1,026.3	1,047.5	9,390.6
SOUTHEXP	(3,884.4)	(4,089.1)	(3,761.8)	(4,557.5)	(4,378.1)	(3,848.9)	(4,348.1)	(3,478.4)	(3,182.3)	(35,528.6)
CPLEEXP	(46.7)	(19.8)	(24.9)	(30.3)	(15.7)	(23.5)	(36.0)	(21.1)	(27.2)	(245.2)
DUKEXP	(1.8)	(27.4)	(13.0)	(7.6)	(0.8)	0.0	(5.9)	(20.0)	0.0	(76.5)
NCMPAEXP	(0.1)	(0.1)	0.0	(0.5)	(0.8)	(0.4)	(0.4)	(0.4)	(0.4)	(3.1)
SOUTHEAST	(530.7)	(546.3)	(488.7)	(588.0)	(566.5)	(334.4)	(287.6)	(166.4)	(124.7)	(3,633.3)
SOUTHWEST	(1,146.0)	(1,425.1)	(912.1)	(1,485.4)	(1,504.2)	(1,251.0)	(1,871.3)	(1,647.9)	(1,581.1)	(12,824.1)
SOUTHEXP	(2,159.1)	(2,070.5)	(2,323.0)	(2,445.7)	(2,290.0)	(2,239.7)	(2,146.9)	(1,622.6)	(1,448.9)	(18,746.4)
Total	(1,847.5)	(962.7)	(475.1)	(1,505.0)	2,700.9	141.5	(647.7)	(1,349.0)	(1,880.2)	(5,824.8)

11 In the Day-Ahead Market, four PJM interface pricing points (PJM/CPLE, PJM/DUKIMP, PJM/DUKEXP and PJM/NCMPAEXP) had a net interchange of zero.

Table 8-11 Up-to Congestion scheduled net interchange volume by interface pricing point (GWh): January through September, 2012 (New Table)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	(1,021.1)	(523.8)	(871.0)	(1,019.4)	(1,042.7)	(662.6)	(589.4)	(270.2)	(427.1)	(6,427.3)
LINDENVFT	(14.7)	(74.3)	(4.3)	52.3	62.5	72.3	117.4	40.1	23.7	275.0
MISO	1,776.8	1,700.3	1,436.5	1,848.8	1,650.7	1,108.3	1,160.3	661.7	995.8	12,339.2
NEPTUNE	(449.9)	(442.1)	(498.1)	(309.5)	(286.2)	(214.4)	(52.9)	182.0	86.0	(1,985.1)
NIPSCO	(78.6)	(51.0)	(611.7)	(885.6)	(476.5)	(414.5)	(229.7)	(356.5)	(437.0)	(3,541.1)
NORTHWEST	(55.5)	61.3	(104.0)	(350.2)	(134.7)	(246.4)	(281.2)	(284.6)	(269.5)	(1,664.7)
NYIS	705.3	890.0	904.8	770.0	1,855.0	1,219.1	850.9	716.0	616.4	8,527.4
OVEC	937.4	176.3	1,440.1	1,011.8	2,570.5	938.1	803.5	562.0	(238.2)	8,201.5
SOUTHIMP	1,663.3	2,048.5	2,034.1	2,318.0	2,729.5	2,342.0	3,103.8	2,396.2	2,173.3	20,808.7
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
SOUTHEAST	543.8	730.4	586.8	729.6	901.9	936.5	1,071.2	794.6	560.3	6,855.1
SOUTHWEST	669.9	878.8	787.2	912.4	904.7	815.7	1,181.7	1,014.6	994.6	8,159.6
SOUTHIMP	449.4	439.3	660.1	676.0	922.8	589.7	850.9	587.1	618.4	5,793.7
SOUTHEXP	(3,569.2)	(3,623.7)	(3,328.5)	(4,106.8)	(4,058.5)	(3,446.8)	(3,958.4)	(3,090.2)	(2,813.0)	(31,995.1)
CPLEEXP	0.0	0.0	0.0	(1.2)	0.0	0.0	0.0	0.0	0.0	(1.2)
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	(444.9)	(426.5)	(416.7)	(508.6)	(529.8)	(256.6)	(238.5)	(133.9)	(100.7)	(3,056.2)
SOUTHWEST	(1,133.7)	(1,410.6)	(879.7)	(1,453.7)	(1,477.3)	(1,202.8)	(1,815.7)	(1,577.1)	(1,514.5)	(12,464.9)
SOUTHEXP	(1,990.6)	(1,786.7)	(2,032.1)	(2,143.3)	(2,051.5)	(1,987.4)	(1,904.2)	(1,379.2)	(1,197.9)	(16,472.8)
Total	(106.2)	161.5	397.9	(670.7)	2,869.6	695.2	924.4	556.4	(289.6)	4,538.6

Table 8-12 Day-Ahead scheduled gross import volume by interface pricing point (GWh): January through September, 2012 (See 2011 SOM, Table 8-11)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	545.7	587.1	505.6	549.9	792.8	623.9	610.5	804.1	524.1	5,543.7
LINDENVFT	350.2	372.2	459.9	514.9	577.6	520.9	627.9	508.6	477.9	4,410.2
MISO	4,021.4	3,236.4	3,339.4	3,847.6	3,669.5	2,551.1	2,146.4	1,882.8	2,373.8	27,068.4
NEPTUNE	0.0	0.0	0.0	0.0	13.4	86.9	250.9	436.3	418.9	1,206.4
NIPSCO	456.4	514.0	364.9	292.8	235.4	259.8	302.7	312.2	339.0	3,077.2
NORTHWEST	769.8	664.5	502.0	432.2	596.9	442.7	306.7	354.9	370.6	4,440.3
NYIS	1,592.7	1,890.4	2,212.4	1,963.8	3,173.2	2,504.8	2,037.3	2,025.9	1,973.7	19,374.2
OVEC	5,409.6	4,917.3	5,435.3	6,522.2	7,231.1	4,851.3	5,391.6	5,611.7	4,688.1	50,058.2
SOUTHIMP	2,041.5	2,471.4	2,283.8	2,888.6	3,375.8	2,915.1	3,635.1	3,249.3	2,718.9	25,579.6
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	27.3	204.2	0.0	231.4
DUKIMP	3.9	12.2	3.5	1.6	4.0	1.0	8.6	78.8	3.6	117.1
NCMPAIMP	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
SOUTHEAST	552.6	756.9	613.5	769.7	990.1	1,014.4	1,150.3	901.7	625.8	7,375.2
SOUTHWEST	707.2	900.6	815.6	989.1	920.6	842.9	1,208.7	1,038.3	1,042.1	8,465.0
SOUTHIMP	777.6	801.7	851.2	1,128.0	1,461.1	1,056.9	1,240.2	1,026.3	1,047.5	9,390.6
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	15,187.4	14,653.3	15,103.4	17,011.9	19,665.8	14,756.4	15,309.1	15,185.8	13,885.1	140,758.2

Table 8-13 Up-to Congestion scheduled gross import volume by interface pricing point (GWh): January through September, 2012 (New Table)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	452.7	419.8	375.7	352.4	585.9	489.7	461.9	646.1	463.9	4,248.1
LINDENVFT	310.8	324.4	414.1	473.3	524.9	496.8	599.8	481.9	454.9	4,080.8
MISO	3,858.6	3,019.2	3,100.5	3,686.7	3,480.4	2,527.7	2,133.5	1,844.0	2,345.5	25,996.1
NEPTUNE	0.0	0.0	0.0	0.0	4.1	37.8	211.3	367.3	356.5	977.0
NIPSCO	422.7	486.5	339.6	279.4	210.2	232.6	252.8	277.7	329.8	2,831.3
NORTHWEST	737.8	627.9	494.5	431.2	589.7	442.6	306.7	349.2	363.8	4,343.6
NYIS	1,170.1	1,321.3	1,436.5	1,268.7	2,420.3	1,642.6	1,171.9	1,195.2	1,208.9	12,835.6
OVEC	4,716.8	3,970.0	4,668.0	5,340.9	5,909.1	3,758.3	4,253.8	4,653.9	3,927.2	41,198.1
SOUTHIMP	1,663.3	2,048.5	2,034.1	2,318.0	2,729.5	2,342.0	3,103.8	2,396.2	2,173.3	20,808.7
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
SOUTHEAST	543.8	730.4	586.8	729.6	901.9	936.5	1,071.2	794.6	560.3	6,855.1
SOUTHWEST	669.9	878.8	787.2	912.4	904.7	815.7	1,181.7	1,014.6	994.6	8,159.6
SOUTHIMP	449.4	439.3	660.1	676.0	922.8	589.7	850.9	587.1	618.4	5,793.7
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	13,332.7	12,217.6	12,863.0	14,150.6	16,454.3	11,970.1	12,495.5	12,211.6	11,624.0	117,319.3

Table 8-14 Day-Ahead scheduled gross export volume by interface pricing point (GWh): January through September, 2012 (See 2011 SOM, Table 8-12)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	1,564.8	997.1	1,374.0	1,502.0	1,711.9	1,208.3	1,122.0	965.4	905.1	11,350.6
LINDENVFT	341.0	423.5	436.3	440.3	479.7	443.7	514.9	479.3	465.6	4,024.3
MISO	2,753.0	1,958.8	1,919.6	2,393.3	2,318.5	1,768.5	1,762.3	1,801.2	1,846.4	18,521.6
NEPTUNE	891.7	837.7	870.3	492.9	450.2	268.6	282.9	472.9	535.8	5,103.0
NIPSCO	504.3	547.1	995.3	1,195.1	715.3	694.8	541.1	686.4	834.1	6,713.5
NORTHWEST	1,294.7	1,035.1	1,045.3	1,183.3	1,241.3	1,192.8	1,082.9	1,235.7	1,141.1	10,452.2
NYIS	1,627.7	1,589.6	1,639.4	1,435.5	1,456.1	1,622.2	1,805.7	1,985.7	1,895.0	15,056.9
OVEC	4,173.2	4,138.0	3,536.6	5,317.0	4,213.8	3,567.0	4,497.0	5,429.8	4,960.0	39,832.4
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	3,884.4	4,089.1	3,761.8	4,557.5	4,378.1	3,848.9	4,348.1	3,478.4	3,182.3	35,528.6
CPLEEXP	46.7	19.8	24.9	30.3	15.7	23.5	36.0	21.1	27.2	245.2
DUKEXP	1.8	27.4	13.0	7.6	0.8	0.0	5.9	20.0	0.0	76.5
NCMPAEXP	0.1	0.1	0.0	0.5	0.8	0.4	0.4	0.4	0.4	3.1
SOUTHEAST	530.7	546.3	488.7	588.0	566.5	334.4	287.6	166.4	124.7	3,633.3
SOUTHWEST	1,146.0	1,425.1	912.1	1,485.4	1,504.2	1,251.0	1,871.3	1,647.9	1,581.1	12,824.1
SOUTHEXP	2,159.1	2,070.5	2,323.0	2,445.7	2,290.0	2,239.7	2,146.9	1,622.6	1,448.9	18,746.4
Total	17,034.9	15,616.0	15,578.5	18,516.9	16,964.9	14,614.9	15,956.8	16,534.8	15,765.3	146,583.0

Table 8-15 Up-to Congestion scheduled gross export volume by interface pricing point (GWh): January through September, 2012 (New Table)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
IMO	1,473.8	943.6	1,246.7	1,371.9	1,628.6	1,152.3	1,051.2	916.3	891.0	10,675.5
LINDENVFT	325.4	398.6	418.4	421.0	462.4	424.4	482.4	441.8	431.2	3,805.8
MISO	2,081.8	1,318.9	1,664.0	1,837.9	1,829.7	1,419.4	973.2	1,182.3	1,349.8	13,656.9
NEPTUNE	449.9	442.1	498.1	309.5	290.3	252.2	264.2	185.4	270.5	2,962.1
NIPSCO	501.3	537.5	951.3	1,164.9	686.8	647.1	482.5	634.2	766.8	6,372.4
NORTHWEST	793.3	566.6	598.6	781.4	724.4	689.0	587.9	633.9	633.3	6,008.3
NYIS	464.7	431.3	531.7	498.8	565.4	423.5	321.0	479.2	592.5	4,308.2
OVEC	3,779.4	3,793.7	3,227.8	4,329.1	3,338.7	2,820.2	3,450.4	4,091.9	4,165.4	32,996.5
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	3,569.2	3,623.7	3,328.5	4,106.8	4,058.5	3,446.8	3,958.4	3,090.2	2,813.0	31,995.1
CPLEEXP	0.0	0.0	0.0	1.2	0.0	0.0	0.0	0.0	0.0	1.2
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	444.9	426.5	416.7	508.6	529.8	256.6	238.5	133.9	100.7	3,056.2
SOUTHWEST	1,133.7	1,410.6	879.7	1,453.7	1,477.3	1,202.8	1,815.7	1,577.1	1,514.5	12,464.9
SOUTHEXP	1,990.6	1,786.7	2,032.1	2,143.3	2,051.5	1,987.4	1,904.2	1,379.2	1,197.9	16,472.8
Total	13,438.8	12,056.1	12,465.1	14,821.2	13,584.7	11,274.9	11,571.1	11,655.2	11,913.6	112,780.8

Table 8-16 Active interfaces: January through September, 2012 (See 2011 SOM, Table 8-13)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active
EKPC	Active	Active	Active	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active

Figure 8-3 PJM's footprint and its external interfaces (See 2011 SOM, Figure 8-3)

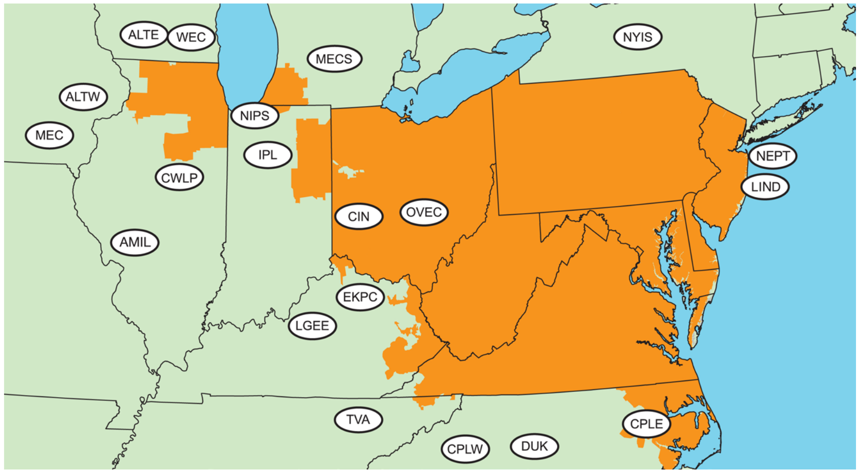


Table 8-17 Active pricing points: January through September, 2012 (See 2011 SOM, Table 8-14)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
CPLEEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLEIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active

PJM and MISO Interface Prices

If interface prices were defined in a comparable manner by PJM and MISO, and if time lags were not built into the rules governing interchange 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 these conditions do not exist is important in explaining the observed relationship between interface prices and inter-RTO power flows, and those price differentials.

Both the PJM/MISO and MISO/PJM Interface pricing points represent the value of power at the relevant border, as determined in each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from MISO would receive the PJM/MISO Interface price upon entering PJM, while a transaction into MISO from PJM would receive the MISO/PJM Interface price. PJM and MISO use network models to determine these prices and to attempt to ensure that the prices are consistent with the underlying electrical flows. PJM uses the LMP at nine buses[12] within MISO to calculate the PJM/MISO Interface price, while MISO uses prices at all of the PJM generator buses to calculate the MISO/PJM Interface price.[13]

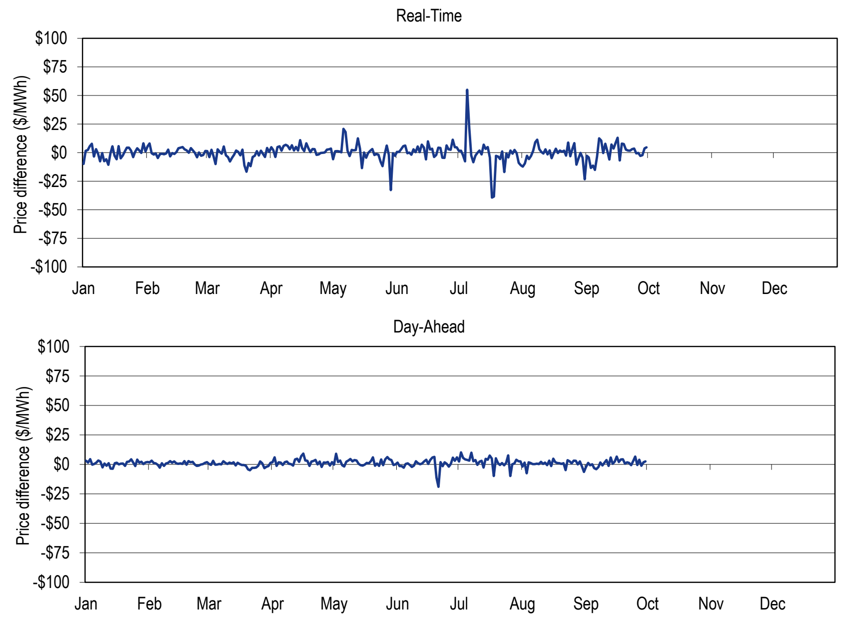
Real-Time and Day-Ahead PJM/MISO Interface Prices

In the first nine months of 2012, the direction of the average hourly flow was consistent with the average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. In the first nine months of 2012, the PJM/MISO average hourly Locational Marginal Price (LMP) was $26.66 while the MISO/PJM LMP was $26.70, a difference of $0.04. The average hourly flow during the first nine months of 2012 was -1,745 MW. (The negative sign means that the flow was an export from PJM to MISO, which is consistent with the fact that the average MISO/PJM price was higher than the average PJM/MISO price.) The direction of hourly energy flows was consistent with the interface price differentials in 45 percent of hours during the first nine months of 2012.

12 See "LMP Aggregate Definitions" (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed October 16, 2012). PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.

13 Based on information obtained from MISO's Extranet <http://extranet.midwestiso.org> (January 15, 2010). (Accessed July 18, 2012)

Figure 8-4 Real-time and day-ahead daily hourly average price difference (MISO Interface minus PJM/MISO): January through September, 2012 (See 2011 SOM, Figure 8-4)



Distribution of Economic and Uneconomic Hourly Flows

During the first nine months of 2012, the direction of hourly energy flows was consistent with PJM and MISO Interface Price differentials in 2,948 hours (45 percent of all hours), and was inconsistent with price differentials in 3,627 hours (55 percent of all hours). Table 8-18 shows the distribution of economic and uneconomic hours of energy flow between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM Interface prices. Of the 3,627 hours where flows were uneconomic, 3,104 of those hours (85.6 percent) had a price difference greater than or equal to $1.00 and 1,324 of all uneconomic hours (36.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $949.61. Of the 2,948 hours where flows were economic, 2,472 of those hours (83.9

percent) had a price difference greater than or equal to $1.00 and 1,362 of all economic hours (46.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $440.39.

Table 8-18 Distribution of economic and uneconomic hourly flows between PJM and MISO: January through September, 2012 (New Table)

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	3,627	100.0%	2,948	100.0%
$1.00	3,104	85.6%	2,472	83.9%
$5.00	1,324	36.5%	1,362	46.2%
$10.00	604	16.7%	773	26.2%
$15.00	366	10.1%	464	15.7%
$20.00	265	7.3%	333	11.3%
$25.00	201	5.5%	254	8.6%
$50.00	80	2.2%	93	3.2%
$75.00	38	1.0%	45	1.5%
$100.00	26	0.7%	32	1.1%
$200.00	6	0.2%	7	0.2%
$300.00	2	0.1%	3	0.1%
$400.00	2	0.1%	2	0.1%
$500.00	1	0.0%	0	0.0%

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.

The NYISO Locational Based Marginal Pricing (LBMP) calculation methodology differs from the PJM LMP calculation methodology. PJM uses real-time operating conditions and real-time energy flows to calculate LMPs. The NYISO software calculates LBMP using expected flows derived from Real-Time Commitment (RTC) software based on the assumption that phase angle regulators (PARs) can be set such that the average actual flows match the expected interchange on PAR controlled lines. The NYISO also calculates the flows across their free-flowing A/C tie lines using current network configurations for the purposes of calculating line loadings and the resulting congestion costs. The NYISO calculates the PJM interface price (represented by the Keystone proxy bus) using the assumption that 40 percent of the scheduled energy will flow across the PJM/NYISO border on the Branchburg to Ramapo PAR controlled tie, and the remaining 60 percent will enter the NYISO on their free flowing A/C tie lines. This Keystone proxy bus is an aggregate pricing point, representing the price of energy between PJM and the NYISO, with a 40 percent weighting on the Branchburg to Ramapo line and a 60 percent weighting on the remaining free flowing ties. PJM calculates the NYISO Interface Price using an 80 percent weighting on the Roseton 345 KV bus, and a 20 percent weighting on the Dunkirk 115 KV bus.

Effective June 27, 2012, the NYISO implemented 15-minute scheduling of external energy transactions between the NYISO and PJM.[14] However, the timing requirements for market participants to submit external energy transactions did not change as a result of the new process. All transactions must continue to be submitted to the NYISO 75 minutes prior to the operating hour, and the NYISO's RTC application commits (or decommits) external energy transactions for each 15-minute interval of the operating hour. While this modification provides a better economic mix of generation and interchange transactions during the operating hour, it does not allow market participants to react to real-time pricing, as all transactions must be submitted in advance of real-time price signals.

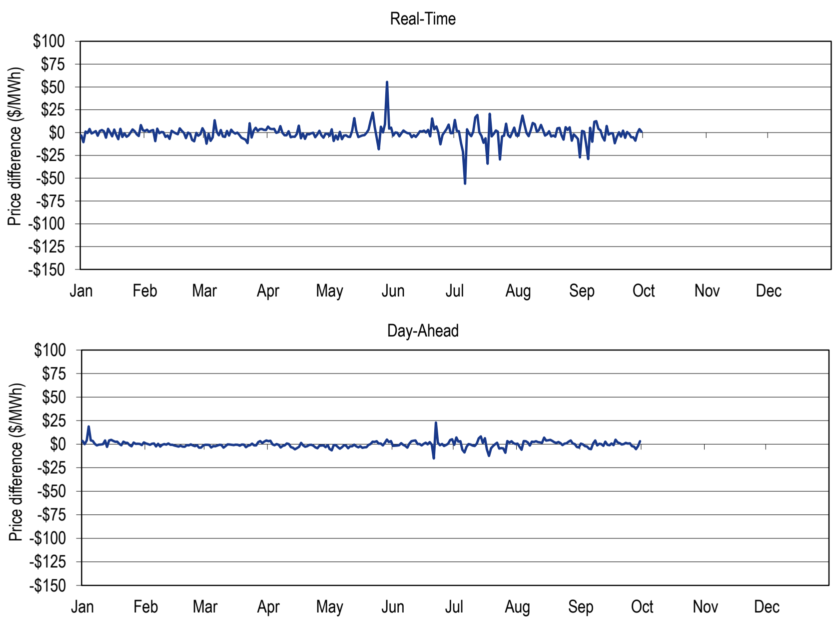
Real-Time and Day-Ahead PJM/NYISO Interface Prices

In the first nine months of 2012, the direction of the average hourly flow was not consistent with the average hourly price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. In the first nine months of 2012, the PJM/NYISO average hourly LMP was $32.56 while the NYISO/PJM average hourly LMP was $31.92, a difference of $0.64. The average hourly flow during the first nine months of 2012 was -580 MW. (The negative sign

14 See *New York Independent System Operator, Inc.* Docket No. ER11-2547-001 (June 6, 2012).

means that the flow was an export from PJM to NYISO, which is inconsistent with the fact that the average PJM/NYISO price was higher than the average NYISO/PJM price.) The direction of hourly energy flows was consistent with interface price differentials in 52 percent of the hours during the first nine months of 2012.

Figure 8-5 Real-time and day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): January through September, 2012 (See 2011 SOM, Figure 8-5)



Distribution of Economic and Uneconomic Hourly Flows

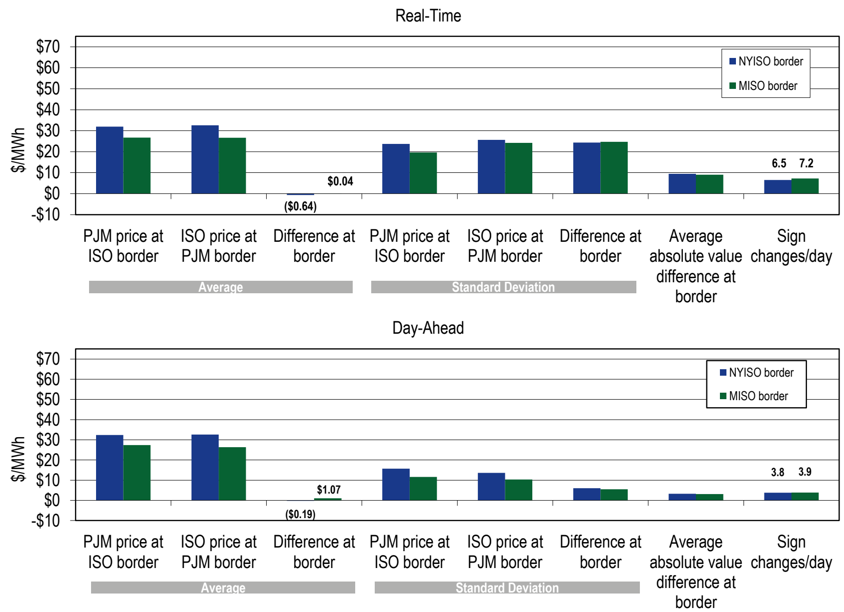
During the first nine months of 2012, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 3,399 hours (52 percent of all hours), and was inconsistent with price differences in 3,176 hours (48 percent of all hours). Table 8-19 shows the distribution of economic and uneconomic hours of energy flow between PJM and NYISO based on the price differences between the PJM/NYISO and NYISO/PJM prices. Of the 3,176 hours where flows were uneconomic, 2,757 of those hours (86.8 percent) had a price difference greater than or equal to $1.00 and 1,432 of all uneconomic hours (45.1 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $389.38. Of the 3,399 hours where flows were economic, 2,974 of those hours (87.5 percent) had a price difference greater than or equal to $1.00 and 1,402 of all economic hours (41.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $597.32.

Table 8-19 Distribution of economic and uneconomic hourly flows between PJM and NYISO: January through September, 2012 (New Table)

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	3,176	100.0%	3,399	100.0%
$1.00	2,757	86.8%	2,974	87.5%
$5.00	1,432	45.1%	1,402	41.2%
$10.00	722	22.7%	652	19.2%
$15.00	477	15.0%	384	11.3%
$20.00	324	10.2%	264	7.8%
$25.00	239	7.5%	203	6.0%
$50.00	116	3.7%	89	2.6%
$75.00	64	2.0%	52	1.5%
$100.00	28	0.9%	35	1.0%
$200.00	4	0.1%	12	0.4%
$300.00	1	0.0%	4	0.1%
$400.00	0	0.0%	2	0.1%
$500.00	0	0.0%	1	0.0%

Summary of Interface Prices between PJM and Organized Markets

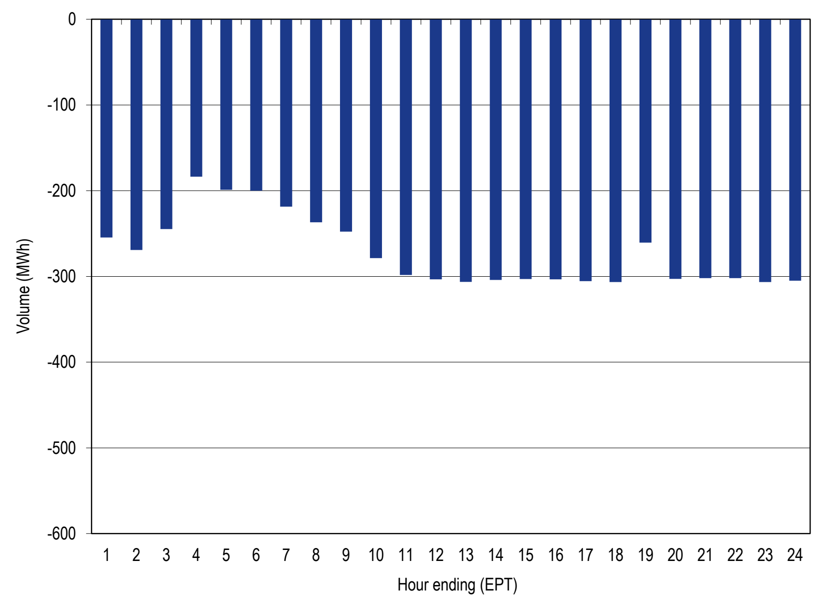
Figure 8-6 PJM, NYISO and MISO real-time and day-ahead border price averages: January through September, 2012 (See 2011 SOM, Figure 8-6)



Neptune Underwater Transmission Line to Long Island, New York

The Neptune line is a 65 mile direct current (DC) merchant 230 kV transmission line, with a capacity of 660 MW, providing a direct connection between PJM (Sayreville, New Jersey), and NYISO (Nassau County on Long Island). Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. In the first nine months of 2012, the average hourly difference between the PJM/Neptune price and the NYISO/Neptune price was consistent with the direction of the average hourly flow. In the first nine months of 2012, the PJM average hourly LMP at the Neptune Interface was $32.76 while the NYISO LMP at the Neptune Bus was $42.98, a difference of $10.22. The average hourly flow during the first nine months of 2012 was -277 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is consistent with the fact that the average PJM price was lower than the average Neptune price.) The direction of hourly energy flows was consistent with interface price differentials in 60 percent of the hours during the first nine months of 2012.

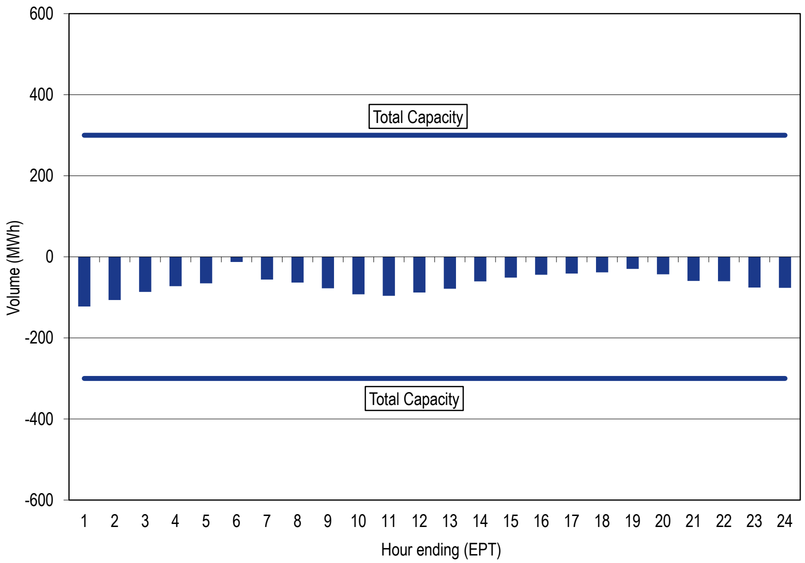
Figure 8-7 Neptune hourly average flow: January through September, 2012 (See 2011 SOM, Figure 8-7)



Linden Variable Frequency Transformer (VFT) facility

The Linden VFT facility is a merchant transmission facility, with a capacity of 300 MW, providing a direct connection between PJM and NYISO. In the first nine months of 2012, the average hourly price difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average hourly flow. In the first nine months of 2012, the PJM average hourly LMP at the Linden Interface was $33.25 while the NYISO LMP at the Linden Bus was $35.71, a difference of $2.46. The average hourly flow during the first nine months of 2012 was -70 MW. (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 57 percent of the hours during the first nine months of 2012.

Figure 8-8 Linden hourly average flow: January through September, 2012 (See 2011 SOM, Figure 8-8)



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 MISO, an implemented reliability agreement with TVA, an operating agreement with Progress Energy Carolinas, Inc., and a reliability coordination agreement with VACAR South.

PJM and MISO Joint Operating Agreement[15]

The Joint Operating Agreement between MISO and PJM Interconnection, L.L.C. was executed on December 31, 2003. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates within MISO and PJM, allow for redispatch of units within the PJM and MISO regions to jointly manage congestion on these flowgates and to assign the costs of congestion management appropriately.

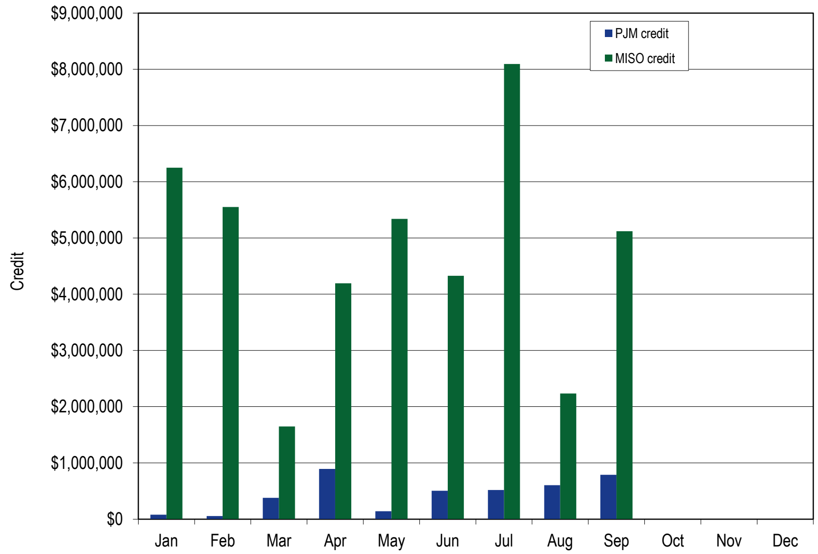
In 2011, PJM and MISO hired an independent auditor to review and identify any areas of the market to market coordination process that were not conforming to the JOA, and to identify differing interpretations of the JOA between PJM and MISO that may lead to inconsistencies in the operation and settlements of the market to market process. The final report, which was completed and distributed on January 20, 2012, showed that both PJM and MISO are conforming to the JOA.[16] The report also provided some potential areas of improvement including improved internal documentation, enhanced transparency, and an increase of knowledge sharing, data exchange and attention to modeling differences.

In the first nine months of 2012, the market to market operations resulted in MISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. Figure 8-9 shows credits for coordinated congestion management between PJM and MISO.

15 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx. (Accessed October 16, 2012)

16 See "Utilicast Final Report - JOA Baseline Review" (January 20, 2012) <http://www.pjm.com/documents/~/media/documents/reports/20120120-utilcast-final-report-joa-baseline-review.ashx> (Accessed October 16, 2012)

Figure 8-9 Credits for coordinated congestion management: January through September, 2012 (See 2011 SOM, Figure 8-9)



PJM and New York Independent System Operator Joint Operating Agreement (JOA)[17]

On May 22, 2007, the PJM/NYISO JOA became effective. This agreement was developed to improve reliability. It formalized 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.

The PJM/NYISO JOA did not include provisions for market based congestion management or other market to market activity, so, in 2008, at the request of PJM, PJM and the NYISO began discussion of a market based congestion management protocol.[18] On December 30, 2011, PJM and the NYISO filed JOA revisions with FERC that included a draft market to market process.[19] On May 1, 2012, PJM and the NYISO filed a second revision to the JOA that included resolutions to several outstanding issues, present in the December 30, 2011 filing, which they requested additional time to resolve.[20] Some of the resolved issues were how to calculate firm flow entitlements (FFE), how to model external capacity resources in developing FFE's and how to include the Ontario/Michigan PAR operations in the market flow calculation. On September 20, 2012, FERC issued an Order On Compliance Filing, accepting the implementation date of a market to market coordination process to be effective no later than January 15, 2013.[21] The September 20, 2012, Order requires modifications to the JOA to provide for incremental impacts of the Ontario/Michigan PARs when any of the PARs are in service.

Other Agreements/Protocols with Bordering Areas

Consolidated Edison Company of New York, Inc. (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.[22] 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.

PJM filed a settlement on February 23, 2009, on behalf of the parties to resolve remaining issues with these contracts.[23] By order issued September 16, 2010, the Commission approved this settlement, which extends Con Edison's special

17 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C." (September 14, 2007) <http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/nyiso_pjm_joa_final.pdf>. (Accessed October 16, 2012)
18 See the *2010 State of the Market Report*, Volume II, "Interchange Transactions," for the relevant history.
19 See "Jointly Submitted Market-to Market Coordination Compliance Filing," Docket No. ER12-718-000- (December 30, 2011).
20 See "Second Jointly Submitted Market-to Market Coordination Compliance Filing," Docket No. ER12-718-000- (May 1, 2012).
21 140 FERC ¶ 61,205 (2012).
22 See "Section 3 – Operating Reserve" of this report for the operating reserve credits paid to maintain the power flow established in the Con Edison/PSE&G wheeling contracts.
23 See Docket Nos. ER08-858-000, et al. The settling parties are the New York Independent System Operator, Inc. (NYISO), Con Ed, PSE&G, PSE&G Energy Resources & Trading LLC and the New Jersey Board of Public Utilities.

protocol indefinitely.[24] The settlement defined ConEd's cost responsibility for upgrades included in the PJM Regional Transmission Expansion Plan. ConEd is responsible for required transmission enhancements, and must pay the associated charges during the term of its service, and any subsequent roll over of the service.[25] ConEd's rolled over service became effective on May 1, 2012. The additional transmission charges have been included in the wheeling agreement data as shown in Table 8-20 below reflecting those charges effective May 1, 2012.

Table 8-20 Con Edison and PSE&G wheeling agreement data: January through September, 2012 (See 2011 SOM, Table 8-15)

	Con Edison			PSE&G		
Billing Line Item	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	$4,196,829	$235,030	$4,431,859	$865,217	$0	$865,217
Congestion Credit			$1,274,425			$953,303
Adjustments and Transmission Charges			($14,293,231)			($7,368)
Net Charge			$17,450,665			($80,718)

Interchange Transaction Issues

Loop Flows

Actual energy flows are the real-time metered flows at an interface for a defined period. The comparable scheduled flows are the real-time 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 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 by the same amount. The result is loop flow, despite the fact that system actual and scheduled flow net to a zero difference.

PJM tries to balance overall actual and scheduled interchange, but does not have a mechanism to control loop flows, the balance between actual and scheduled interchange at individual interfaces, because the interfaces are free flowing ties with contiguous balancing authorities.

24 132 FERC ¶ 61,221 (2010).

25 The terms of the settlement state that ConEd shall have no liability for transmission enhancement charges prior to the commencement of, or after the termination of, the term of the rolled over service.

Table 8-21 Net scheduled and actual PJM flows by interface (GWh): January through September, 2012 (See 2011 SOM, Table 8-16)

	Actual	Net Scheduled	Difference (GWh)
CPLE	5,746	29	5,717
CPLW	(976)	0	(977)
DUK	(67)	270	(336)
EKPC	1,830	(335)	2,165
LGEE	979	1,797	(817)
MEC	(2,104)	(4,128)	2,024
MISO	(11,169)	(2,785)	(8,384)
ALTE	(4,280)	(5,104)	824
ALTW	(1,854)	(203)	(1,651)
AMIL	7,843	442	7,401
CIN	(4,519)	953	(5,473)
CWLP	(380)	0	(380)
IPL	(70)	(1,192)	1,122
MECS	(6,850)	3,892	(10,742)
NIPS	(4,757)	(70)	(4,688)
WEC	3,699	(1,503)	5,202
NYISO	(6,081)	(5,949)	(132)
LIND	(460)	(460)	0
NEPT	(1,823)	(1,823)	0
NYIS	(3,798)	(3,665)	(132)
OVEC	8,215	6,278	1,937
TVA	4,428	5,874	(1,446)
Total	801	1,051	(251)

Every external balancing authority is mapped to an import and export interface pricing point. The mapping is designed to reflect the physical flow of energy between PJM and each balancing authority. The net scheduled values for interface pricing points are defined as the flows that will receive the specific interface price.[26] The actual flow on an interface pricing point is defined as the metered flow across the transmission lines that are included in the interface pricing point.

Table 8-22 shows the net scheduled and actual PJM flows by interface pricing point. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP, and NCMPAIMP Interface Pricing Points were created as part of operating agreements with external balancing authorities, and do not reflect physical ties different from the SouthIMP and SouthEXP interface pricing points. Following the consolidation of the Southeast and Southwest pricing points, a market participant requested grandfathered treatment to allow them to continue to receive the Southwest Interface Pricing Point. This pricing point is also a subset of the larger SouthIMP and SouthEXP Interface Pricing Points, and does not have physical ties that differ from the SouthIMP and SouthEXP Interaface Pricing Points.

Because the SouthIMP and SouthEXP Interface Pricing Points are the same physical point, if there are net actual exports from the PJM footprint to the southern region, by definition, there cannot be net actual imports into the PJM footprint from the southern region and therefore there will not be actual flows at the SouthIMP Interface Pricing Point. Conversely, if there are net actual imports into the PJM footprint from the southern region, there cannot be net actual exports to the southern region and therefore there will not be actual flows on the SouthEXP interface pricing point. However, when analyzing the interface pricing points with the southern region, comparing the net scheduled and net actual flows at the aggregate pricing points provides some insight on how effective the interface pricing point mappings are.

The IMO Interface Pricing Point with the IESO was created to reflect the fact that transactions that originate or sink in the IMO balancing authority create flows that are split between the MISO and NYISO Interface Pricing Points, so a mapping to a single interface pricing point did not reflect the actual flows. PJM created the IMO Interface Pricing Point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO does not have physical ties with PJM because it is not contiguous. Actual flows associated with the IMO Interface Pricing Point are shown as zero because there is no PJM/IMO interface. The actual flows between IMO and PJM are included in the actual flows at the MISO and NYISO interface pricing points.

26 The terms balancing authority and control area are used interchangeably in this section. The NERC tag applications maintained the terminology of GCA and LCA after the implementation of the NERC functional model. 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" <http://www.nerc.com/files/Functional_Model_V4_CLEAN_2008Dec01.pdf>. (August 2008) (Accessed October 16, 2012)

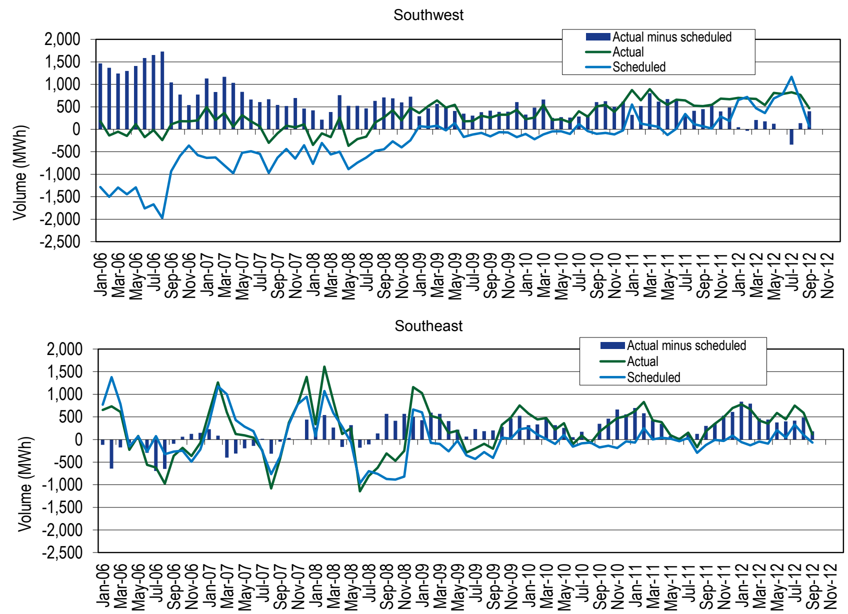
Table 8-22 Net scheduled and actual PJM flows by interface pricing point (GWh): January through September, 2012 (See 2011 SOM, Table 8-17)

	Actual	Net Scheduled	Difference (GWh)
IMO	0	3,924	(3,924)
LINDENVFT	(460)	(460)	0
MISO	(9,339)	(15,512)	6,173
NEPTUNE	(1,823)	(1,823)	0
NORTHWEST	(2,104)	(105)	(1,999)
NYIS	(3,798)	(3,537)	(261)
OVEC	8,215	6,278	1,937
SOUTHIMP	10,109	15,265	(5,155)
CPLEIMP	0	535	(535)
DUKIMP	0	906	(906)
NCMPAIMP	0	316	(316)
SOUTHWEST	0	0	0
SOUTHIMP	10,109	13,508	(3,398)
SOUTHEXP	0	(2,978)	2,978
CPLEEXP	0	(262)	262
DUKEXP	0	(1,335)	1,335
NCMPAEXP	0	(3)	3
SOUTHWEST	0	(39)	39
SOUTHEXP	0	(1,340)	1,340
Total	801	1,051	(251)

Loop Flows at PJM's Southern Interfaces

Figure 8-10 shows the 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). 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).

Figure 8-10 Southwest and southeast actual and scheduled flows: January, 2006 through September, 2012 (See 2011 SOM, Figure 8-10)



PJM Transmission Loading Relief Procedures (TLRs)

In the first nine months of 2012, PJM issued 29 TLRs of level 3a or higher, compared to 58 for the first nine months of 2011. Of the 29 TLRs issued, 13 events were TLR level 3a, and the remaining 16 events were TLR level 3b. TLRs are used to control congestion on the transmission system when it cannot be controlled via market forces.[27]

27 See the *2011 Annual State of the Market Report for PJM*, Appendix E, "Interchange Transactions" for a more complete description of Transmission Loading Relief procedures.

Table 8-23 PJM and MISO TLR procedures: January, 2010 through September, 2012[28] (See 2011 SOM, Table 8-19)

	Number of TLRs Level 3 and Higher		Number of Unique Flowgates That Experienced TLRs		Curtailment Volume (MWh)	
Month	PJM	MISO	PJM	MISO	PJM	MISO
Jan-10	6	23	3	5	18,393	13,387
Feb-10	1	9	1	7	1,249	13,095
Mar-10	6	18	3	10	2,376	27,412
Apr-10	15	40	7	11	26,992	29,832
May-10	11	20	4	12	22,193	54,702
Jun-10	19	19	6	8	64,479	183,228
Jul-10	15	25	8	8	44,210	169,667
Aug-10	12	22	9	7	32,604	189,756
Sep-10	11	15	7	7	82,066	32,782
Oct-10	4	26	3	12	2,305	29,574
Nov-10	1	25	1	10	59	66,113
Dec-10	9	7	6	5	18,509	5,972
Jan-11	7	8	5	5	75,057	14,071
Feb-11	6	7	5	4	6,428	23,796
Mar-11	0	14	0	5	0	10,133
Apr-11	3	23	3	9	8,129	44,855
May-11	9	15	4	7	18,377	36,777
Jun-11	15	14	7	6	17,865	19,437
Jul-11	7	8	4	7	18,467	3,697
Aug-11	4	6	4	4	3,624	11,323
Sep-11	7	17	6	7	6,462	25,914
Oct-11	4	16	2	6	16,812	27,392
Nov-11	0	10	0	5	0	22,672
Dec-11	0	5	0	3	0	8,659
Jan-12	1	9	1	6	4,920	6,274
Feb-12	4	6	2	6	0	5,177
Mar-12	1	11	1	6	398	31,891
Apr-12	0	14	0	7	0	8,408
May-12	2	17	1	10	3,539	30,759
Jun-12	0	24	0	7	0	31,502
Jul-12	11	19	5	4	34,197	46,512
Aug-12	8	13	1	6	61,151	13,403
Sep-12	2	5	1	4	21,134	12,494

28 The curtailment volume for PJM TLR's was taken from the individual NERC TLR history reports as posted in the Interchange Distribution Calculator (IDC). Due to the lack of historical TLR report availability, the curtailment volume for MISO TLR's was taken from the MISO monthly reports to their Reliability Subcommittee. These reports can be found at <https://www.midwestiso.org/STAKEHOLDERCENTER/COMMITTEESWORKGROUPSTASKFORCES/RSC/Pages/home.aspx>. (Accessed October 16, 2012)

Table 8-24 Number of TLRs by TLR level by reliability coordinator: January through September, 2012 (See 2011 SOM, Table 8-18)

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2012	ICTE	24	7	8	61	37	0	137
	MISO	51	16	0	12	40	0	119
	NYIS	55	0	0	0	0	0	55
	ONT	42	1	0	0	0	0	43
	PJM	13	16	0	0	0	0	29
	SOCO	0	1	0	0	0	0	1
	SWPP	183	124	3	66	25	0	401
	TVA	45	29	9	7	3	0	93
	VACS	4	3	0	0	0	0	7
Total		417	197	20	146	105	0	885

Up-To Congestion

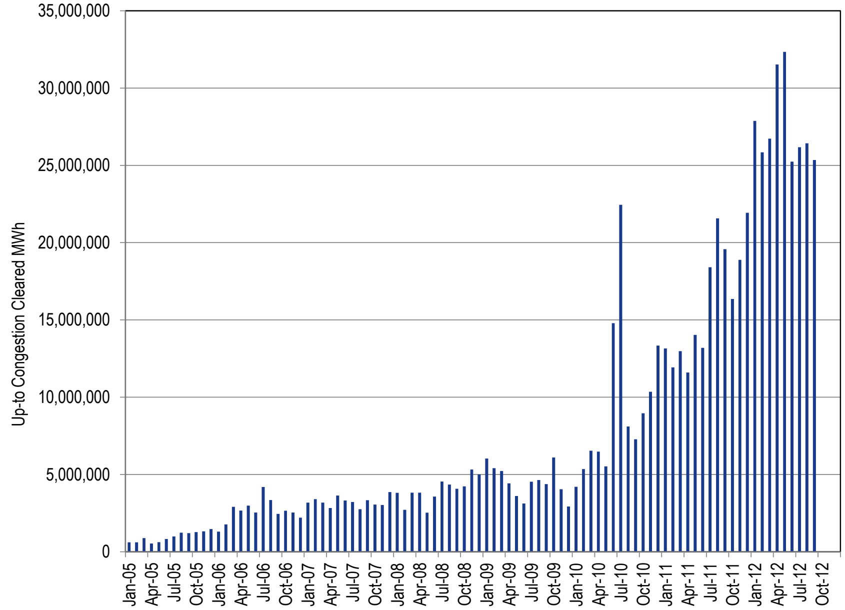
The original purpose of up-to congestion transactions was to allow market participants to submit a maximum congestion charge, up to $25 per MWh, they were willing to pay on an import, export or wheel through transaction in the Day-Ahead Energy Market. This product was offered as a tool for market participants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

An up-to congestion transaction is analogous to a matched set of incremental offers (INC) and decrement bids (DEC) that are 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 an INC offer and the sink looks like a DEC bid. For export transactions, the specified source looks like an INC offer, and the export pricing point looks like a DEC bid. Similarly, for wheel through up-to congestion transactions, the import pricing point chosen looks like an INC offer, and the export pricing point specified looks like a DEC bid. 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. Conversely, an up-to congestion export transaction is submitted and modeled as a withdrawal at the interface, and an injection at a specific PJM node. Wheel through up-to congestion transactions are modeled as an injection at the importing interface and a withdrawal at the exporting interface.

While an up-to congestion bid is analogous to a matched pair of INC offers and DEC bids, there are a number of advantages to using the up-to congestion product. For example, an up-to congestion transaction is approved or denied as a single transaction, will only clear the Day-Ahead Energy Market if the maximum congestion bid criteria is met, is not subject to day-ahead or balancing operating reserve charges and does not have clear rules governing credit requirements. Effective September 17, 2010, up-to congestion transactions are no longer required to pay for transmission.[29]

Following elimination of the requirement to procure transmission for up-to congestion transactions in 2010, the volume of transactions increased significantly. The average number of up-to congestion bids submitted in the Day-Ahead Market increased to 58,273 bids per day, with an average cleared volume of 903,220 MWh per day, in the first nine months of 2012, compared to an average of 26,553 bids per day, with an average cleared volume of 499,824 MWh per day, for the first nine months of 2011.

Figure 8-11 Monthly up-to congestion cleared bids in MWh: January, 2006 through September, 2012 (See 2011 SOM, Figure 8-11)

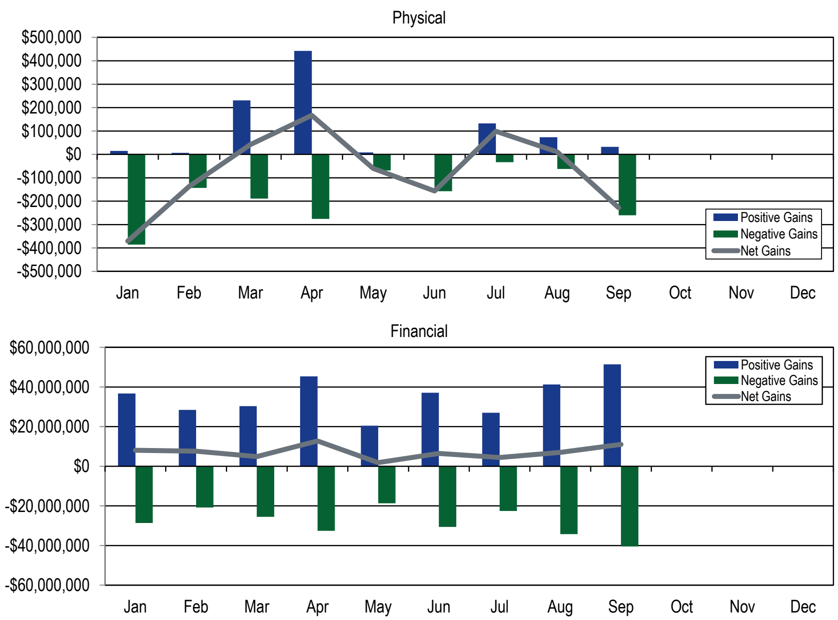


29 In addition to the cost of transmission, transactions utilizing transmission also incur additional ancillary service charges such as black start and reactive services.

Table 8-25 Monthly volume of cleared and submitted up-to congestion bids: January, 2009 through September, 2012 (See 2011 SOM, Table 8-20)

	Bid MW				Bid Volume				Cleared MW				Cleared Volume			
Month	Import	Export	Wheel	Total	Import	Export	Wheel	Total	Import	Export	Wheel	Total	Import	Export	Wheel	Total
Jan-09	4,218,910	5,787,961	319,122	10,325,993	90,277	74,826	6,042	171,145	2,591,211	3,242,491	202,854	6,036,556	56,132	45,303	4,210	105,645
Feb-09	3,580,115	4,904,467	318,440	8,803,022	64,338	70,874	6,347	141,559	2,374,734	2,836,344	203,907	5,414,985	42,101	44,423	4,402	90,926
Mar-09	3,649,978	5,164,186	258,701	9,072,865	64,714	72,495	5,531	142,740	2,285,412	2,762,459	178,507	5,226,378	42,408	42,007	4,299	88,714
Apr-09	2,607,303	5,085,912	73,931	7,767,146	47,970	67,417	2,146	117,533	1,797,302	2,582,294	48,478	4,428,074	32,088	35,987	1,581	69,656
May-09	2,196,341	4,063,887	106,860	6,367,088	40,217	54,745	1,304	96,266	1,496,396	2,040,737	77,553	3,614,686	26,274	29,720	952	56,946
Jun-09	2,598,234	3,132,478	164,903	5,895,615	47,625	44,755	2,873	95,253	1,540,169	1,500,560	88,723	3,129,452	28,565	23,307	1,522	53,394
Jul-09	3,984,680	3,776,957	296,910	8,058,547	67,039	56,770	5,183	128,992	2,465,891	1,902,807	163,129	4,531,826	41,924	31,176	2,846	75,946
Aug-09	3,551,396	4,388,435	260,184	8,200,015	64,652	64,052	3,496	132,200	2,278,431	2,172,133	194,415	4,644,978	41,774	34,576	2,421	78,771
Sep-09	2,948,353	4,179,427	156,270	7,284,050	51,006	64,103	2,405	117,514	1,774,589	2,479,898	128,344	4,382,831	31,962	40,698	1,944	74,604
Oct-09	3,172,034	6,371,230	154,825	9,698,089	46,989	100,350	2,217	149,556	2,060,371	3,931,346	110,646	6,102,363	31,634	70,964	1,672	104,270
Nov-09	3,447,356	3,851,334	103,325	7,402,015	53,067	61,906	1,236	116,209	2,065,813	1,932,595	51,929	4,050,337	33,769	32,916	653	67,338
Dec-09	2,323,383	2,502,529	66,497	4,892,409	47,099	47,223	1,430	95,752	1,532,579	1,359,936	34,419	2,926,933	31,673	28,478	793	60,944
Jan-10	3,794,946	3,097,524	212,010	7,104,480	81,604	55,921	3,371	140,896	2,250,689	1,789,018	161,977	4,201,684	49,064	33,640	2,318	85,022
Feb-10	3,841,573	3,937,880	316,150	8,095,603	80,876	80,685	2,269	163,830	2,627,101	2,435,650	287,162	5,349,913	50,958	48,008	1,812	100,778
Mar-10	4,877,732	4,454,865	277,180	9,609,777	97,149	74,568	2,239	173,956	3,209,064	3,071,712	263,516	6,544,292	60,277	48,596	2,064	110,937
Apr-10	3,877,306	5,558,718	210,545	9,646,569	67,632	85,358	1,573	154,563	2,622,113	3,690,889	170,020	6,483,022	42,635	54,510	1,154	98,299
May-10	3,800,870	5,062,272	149,589	9,012,731	74,996	78,426	1,620	155,042	2,366,149	3,049,405	112,700	5,528,253	47,505	48,996	1,112	97,613
Jun-10	9,126,963	9,568,549	1,159,407	19,854,919	95,155	89,222	6,960	191,337	6,863,803	6,850,098	1,072,759	14,786,660	59,733	55,574	5,831	121,138
Jul-10	12,818,141	11,526,089	5,420,410	29,764,640	124,929	106,145	18,948	250,022	8,971,914	8,237,557	5,241,264	22,450,734	73,232	60,822	16,526	150,580
Aug-10	8,231,393	6,767,617	888,591	15,887,601	115,043	87,876	10,664	213,583	4,430,832	2,894,314	785,726	8,110,871	62,526	40,485	8,884	111,895
Sep-10	7,768,878	7,561,624	349,147	15,679,649	184,697	161,929	4,653	351,279	3,915,814	3,110,580	256,039	7,282,433	63,405	45,264	3,393	112,062
Oct-10	8,732,546	9,795,666	476,665	19,004,877	189,748	154,741	7,384	351,873	4,150,104	4,564,039	246,594	8,960,736	76,042	65,223	3,670	144,935
Nov-10	11,636,949	9,272,885	537,369	21,447,203	253,594	170,470	9,366	433,430	5,765,905	4,312,645	275,111	10,353,661	112,250	71,378	4,045	187,673
Dec-10	17,769,014	12,863,875	923,160	31,556,049	307,716	215,897	15,074	538,687	7,851,235	5,150,286	337,157	13,338,678	136,582	93,299	7,380	237,261
Jan-11	20,275,932	11,807,379	921,120	33,004,431	351,193	210,703	17,632	579,528	7,917,986	4,925,310	315,936	13,159,232	151,753	91,557	8,417	251,727
Feb-11	18,418,511	13,071,483	800,630	32,290,624	345,227	226,292	17,634	589,153	6,806,039	4,879,207	248,573	11,933,818	151,003	99,302	8,851	259,156
Mar-11	17,330,353	12,919,960	749,276	30,999,589	408,628	274,709	15,714	699,051	7,104,642	5,603,583	275,682	12,983,906	178,620	124,990	7,760	311,370
Apr-11	17,215,352	9,321,117	954,283	27,490,752	513,881	265,334	17,459	796,674	7,452,366	3,797,819	351,984	11,602,168	229,707	113,610	8,118	351,435
May-11	21,058,071	11,204,038	2,937,898	35,200,007	562,819	304,589	24,834	892,242	8,294,422	4,701,077	1,031,519	14,027,018	261,355	143,956	11,116	416,427
Jun-11	20,455,508	12,125,806	395,833	32,977,147	524,072	285,031	12,273	821,376	7,632,235	5,361,825	198,482	13,192,543	226,747	132,744	6,363	365,854
Jul-11	24,273,892	16,837,875	409,863	41,521,630	603,519	338,810	13,781	956,110	9,585,027	8,617,284	205,599	18,407,910	283,287	186,866	7,008	477,161
Aug-11	23,790,091	21,014,941	229,895	45,034,927	591,170	403,269	8,278	1,002,717	10,594,771	10,875,384	103,141	21,573,297	274,398	208,593	3,648	486,639
Sep-11	21,740,208	18,135,378	232,626	40,108,212	526,945	377,158	7,886	911,989	10,219,806	9,270,121	82,200	19,572,127	270,088	185,585	3,444	459,117
Oct-11	20,240,161	19,476,556	333,077	40,049,794	540,877	451,507	8,609	1,000,993	8,376,208	7,853,947	126,718	16,356,873	255,206	198,778	4,236	458,220
Nov-11	27,007,141	28,994,789	507,788	56,509,718	594,397	603,029	13,379	1,210,805	9,064,570	9,692,312	131,670	18,888,552	254,851	256,270	5,686	516,807
Dec-11	34,990,790	34,648,433	531,616	70,170,839	697,524	655,222	14,187	1,366,933	11,738,910	10,049,685	137,689	21,926,284	281,304	248,008	6,309	535,621
Jan-12	38,906,228	36,928,145	620,448	76,454,821	745,424	689,174	16,053	1,450,651	13,610,725	14,120,791	145,773	27,877,288	289,524	304,072	5,078	598,674
Feb-12	37,231,115	36,736,507	323,958	74,291,580	739,200	724,477	8,572	1,472,249	12,883,355	12,905,553	54,724	25,843,632	299,055	276,563	2,175	577,793
Mar-12	38,824,528	39,163,001	297,895	78,285,424	802,983	842,857	8,971	1,654,811	13,328,968	13,306,689	89,262	26,724,918	320,210	320,252	3,031	643,493
Apr-12	42,085,326	44,565,341	436,632	87,087,299	884,004	917,430	12,354	1,813,788	15,050,798	16,297,303	171,252	31,519,354	369,273	355,669	4,655	729,597
May-12	44,436,245	43,888,405	489,938	88,814,588	994,735	885,319	10,294	1,890,348	17,416,386	14,733,838	189,667	32,339,891	434,919	343,872	4,114	782,905
Jun-12	38,962,548	32,828,393	975,776	72,766,718	872,764	684,382	21,781	1,578,927	12,675,852	12,311,609	250,024	25,237,485	355,731	295,911	6,891	658,533
Jul-12	45,565,682	41,589,191	855,676	88,010,549	1,077,721	911,300	27,173	2,016,194	13,001,225	12,823,361	348,946	26,173,532	399,135	321,062	9,958	730,155
Aug-12	44,972,628	45,204,886	931,161	91,108,675	1,054,472	987,293	31,580	2,073,345	12,768,023	13,354,850	300,038	26,422,911	377,146	343,717	12,738	733,601
Sep-12	40,796,522	39,411,713	957,800	81,166,035	1,037,179	949,941	29,246	2,016,366	12,089,136	12,961,955	292,095	25,343,186	341,925	329,217	9,620	680,762
Total	773,131,224	712,549,704	28,093,380	1,513,774,308	16,826,866	14,128,580	462,021	31,417,467	306,899,070	286,343,294	15,743,901	608,986,264	7,279,750	6,005,944	224,700	13,510,394

Figure 8-12 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Energy Market transaction (physical) and without a matching Real-Time Energy Market transaction (financial): January through September, 2012 (See 2011 SOM, Figure 8-12)



Interface Pricing Agreements with Individual Balancing Authorities

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.[30] Table 8-26 shows the historical differences in Real-Time Energy Market 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.

30 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>. (Accessed October 16, 2012)

Table 8-26 Real-time average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP interface pricing points: January through September, 2007 through 2012 (See 2011 SOM, Table 8-21)

Year	Southeast LMP	Southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference Southeast LMP - SOUTHIMP	Difference Southwest LMP - SOUTHIMP	Difference Southeast LMP - SOUTHEXP	Difference Southwest LMP - SOUTHEXP
2007	$54.99	$45.44	$49.32	$48.55	$5.67	($3.88)	$6.44	($3.11)
2008	$68.00	$54.54	$59.19	$59.15	$8.81	($4.65)	$8.84	($4.62)
2009	$36.41	$32.04	$33.58	$33.58	$2.83	($1.54)	$2.83	($1.54)
2010	$44.30	$37.18	$40.18	$39.99	$4.11	($3.01)	$4.31	($2.81)
2011	$43.12	$38.26	$40.41	$40.41	$2.71	($2.15)	$2.71	($2.15)
2012	$30.79	$29.72	$30.30	$30.30	$0.50	($0.57)	$0.50	($0.57)

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 and the effective date of their agreements are: Duke Energy Carolinas, January 5, 2007;[31] Progress Energy Carolinas, February 13, 2007;[32] and North Carolina Municipal Power Agency (NCMPA), March 19, 2007.[33] 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. On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[34] [35] On January 20, 2011, the Commission issued an Order conditionally accepting the compliance filing submitted by PJM and PEC.[36]

The PJM/PEC JOA allows for the PECIMP and PECEXP interface pricing points to be calculated using the "Marginal Cost Proxy Pricing" methodology.[37] The DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP interface pricing points are calculated based on the "high-low" pricing methodology as defined in the PJM Tariff.

31 See "Duke Energy Carolinas Interface Pricing Arrangements" (January 5, 2007) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/duke-pricing-agreement.ashx>. (Accessed October 16, 2012)
32 See "Progress Energy Carolinas, Inc. Interface Pricing Arrangements" (February 13, 2007) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/pec-pricing-agreement.ashx>. (Accessed October 16, 2012)
33 See "North Carolina Municipal Power Agency Number 1 Interface Pricing Arrangement" (March 19, 2007) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/electricities-pricing-agreement.ashx>. (Accessed October 16, 2012)
34 See *PJM Interconnection, L.L.C., and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).
35 See the *2010 State of the Market Report*, Volume II, "Interchange Transactions," for the relevant history.
36 134 FERC ¶ 61,048 (2011).
37 See *PJM Interconnection, L.L.C*, Docket No. ER10-2710-000 (September 17, 2010).

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies plan to operate separately for a period of time, they have a Joint Dispatch Agreement, and a Joint Open Access Transmission Tariff.[38] The MMU recommends the termination of the existing PJM/PEC JOA, as some of the assumptions used in the development of the JOA were based on explicit assumptions about the Progress generation fleet, and its dispatch. Those assumptions are no longer correct, as is evident by the Progress/DUK joint dispatch agreement, and thus the PJM/PEC JOA should be terminated. If appropriate, new agreements should be developed, including PJM stakeholder input.

Table 8-27 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through September, 2012 (See 2011 SOM, Table 8-22)

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$30.48	$30.55	$30.29	$30.29	$0.19	$0.25
PEC	$30.79	$30.67	$30.29	$30.29	$0.50	$0.38
NCMPA	$30.56	$30.55	$30.29	$30.29	$0.26	$0.25

38 See Docket Nos. ER12-1338-000 and ER12-1343-000.

Figure 8-13 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: January through September, 2012 (See 2011 SOM, Figure 8-13)

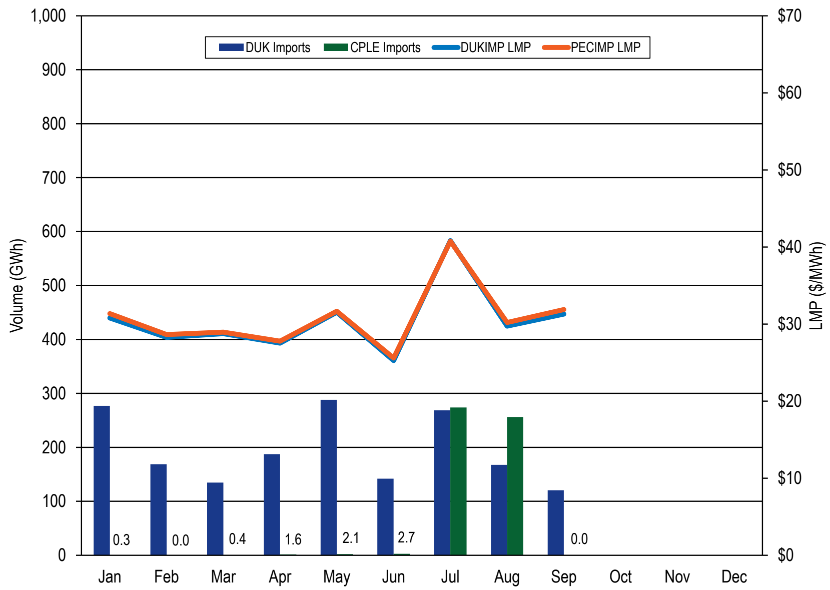


Figure 8-14 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: January through September, 2012 (See 2011 SOM, Figure 8-14)

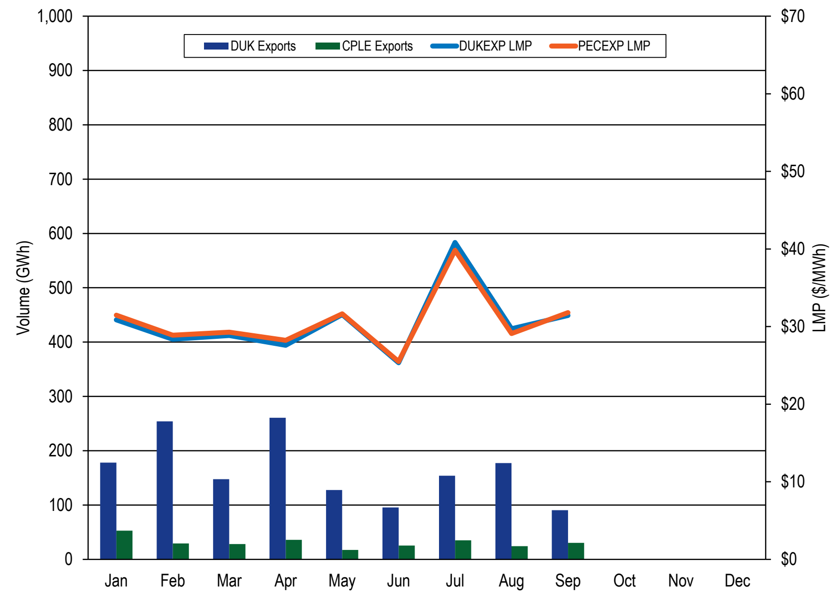


Figure 8-15 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: January through September, 2012 (See 2011 SOM, Figure 8-15)

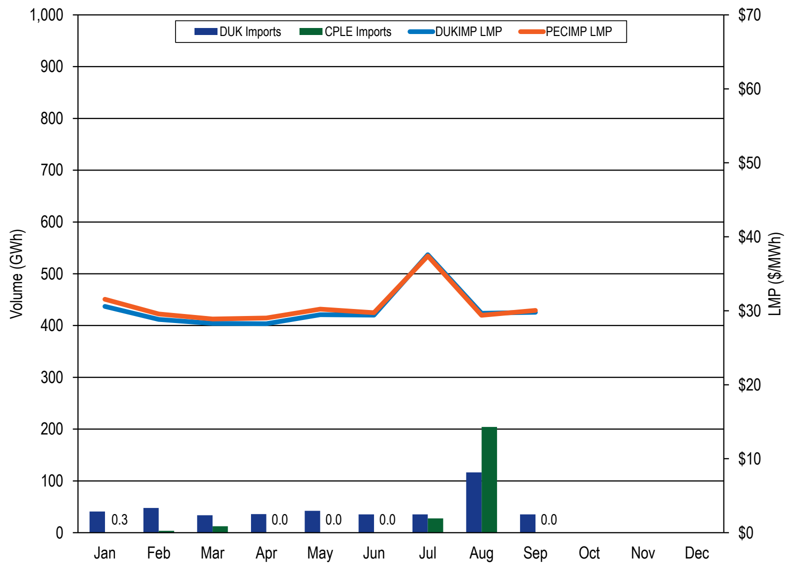


Figure 8-16 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: January through September, 2012 (See 2011 SOM, Figure 8-16)

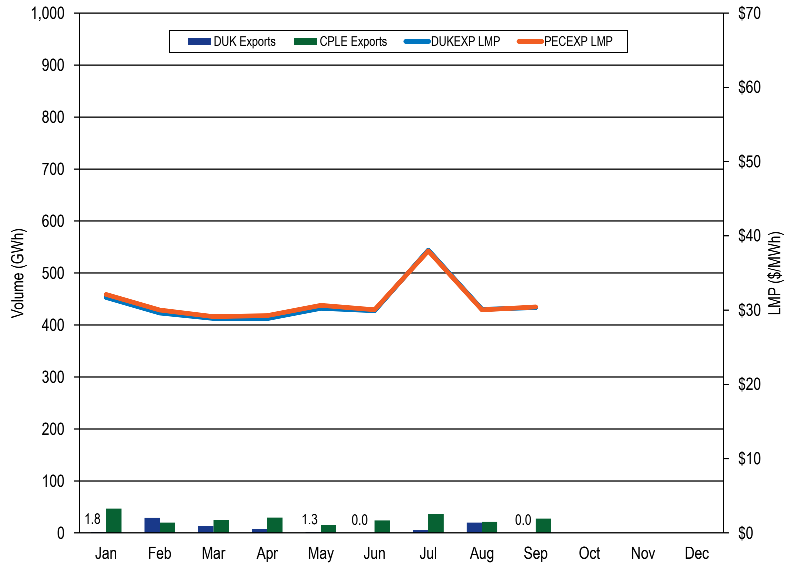


Table 8-29 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through September, 2012 (See 2011 SOM, Table 8-24)

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$30.23	$30.88	$30.00	$30.00	$0.23	$0.88
PEC	$30.66	$31.09	$30.00	$30.00	$0.67	$1.09
NCMPA	$30.52	$30.60	$30.00	$30.00	$0.52	$0.60

Table 8-28 Day-ahead average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: January through September, 2007 through 2012 (See 2011 SOM, Table 8-23)

Year	Southeast LMP	Southwest LMP	SOUTHIMP LMP	SOUTHEXP LMP	Difference Southeast LMP - SOUTHIMP	Difference Southwest LMP - SOUTHIMP	Difference Southeast LMP - SOUTHEXP	Difference Southwest LMP - SOUTHEXP
2007	$53.50	$45.05	$48.60	$47.68	$4.90	($3.55)	$5.82	($2.63)
2008	$68.22	$55.57	$60.09	$60.09	$8.12	($4.53)	$8.12	($4.53)
2009	$36.78	$32.20	$33.83	$33.83	$2.95	($1.63)	$2.95	($1.63)
2010	$45.32	$37.57	$40.24	$40.24	$5.09	($2.66)	$5.09	($2.66)
2011	$43.45	$38.70	$40.30	$40.30	$3.15	($1.61)	$3.15	($1.61)
2012	$30.95	$29.37	$30.00	$30.00	$0.96	($0.62)	$0.96	($0.62)

Willing to Pay Congestion and Not Willing to Pay Congestion

When reserving non-firm transmission, market participants have 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.

Total uncollected congestion charges in the first nine months of 2012 were -$32.00, compared to $11,942 for the first nine months of 2011. Uncollected congestion charges are accrued when not willing to pay congestion transactions are not curtailed when congestion between the specified source and sink is present. Uncollected congestion charges also apply when there is negative congestion (when the LMP at the source is greater than the LMP at the sink) which was the case in for the net uncollected congestion charges in the first nine months of 2012.

Table 8-30 Monthly uncollected congestion charges: Calendar years 2010 and 2011 and January through September, 2012 (See 2011 SOM, Table 8-25)

Month	2010	2011	2012
Jan	$148,764	$3,102	$0
Feb	$542,575	$1,567	($15)
Mar	$287,417	$0	$0
Apr	$31,255	$4,767	($68)
May	$41,025	$0	($27)
Jun	$169,197	$1,354	$78
Jul	$827,617	$1,115	$0
Aug	$731,539	$37	$0
Sep	$119,162	$0	$0
Oct	$257,448	($31,443)	
Nov	$30,843	($795)	
Dec	$127,176	($659)	
Total	$3,314,018	($20,955)	($32)

Spot Imports

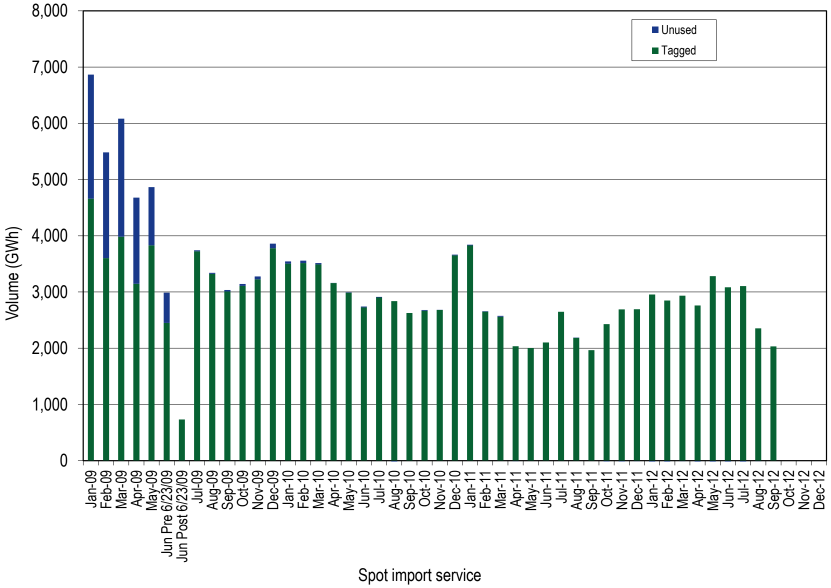
Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. Spot market imports, non-firm point-to-point and network services that are willing to pay congestion, collectively Willing to Pay Congestion (WPC), were part of the PJM LMP energy market design implemented on April 1, 1998. Under this approach, market participants could 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, were the only limits on interchange. However, PJM interpreted its JOA with MISO to require restrictions on spot imports and exports.[39] The result was that the availability of spot import service was limited by ATC and not all spot transactions were approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

After a series of rule changes intended to address the hoarding of spot in service that resulted from this change, and as an alternative to creating an unlimited amount of ATC, PJM suggested including a utilization factor in the ATC calculation for non-firm service. This utilization factor is the ratio of utilized transmission on a particular path to the amount of that transmission reserved when determining how much transmission should be granted. For example, if a path has 1,000 MW of ATC available, and the utilization factor is ninety percent, rather than reducing the ATC to zero when a 1,000 MW reservation is made, there would still be 100 MW of ATC available to be requested. Including the utilization factor will allow PJM to adjust the amount of ATC available to permit a more efficient use of the transmission system. This proposed methodology was approved by PJM stakeholders during the third quarter of 2011. It was expected that implementation of these changes would occur by the end of the third quarter 2012. There is not currently a planned implementation date for these changes, however, the changes are expected to occur in 2013.

The MMU continues to recommend that PJM permit unlimited spot market imports and exports.

39 See "Modifications to the Practices of Non-Firm and Spot Market Import Service" (April 20, 2007) <http://www.pjm.com/~/media/etools/oasis/wpc-white-paper.ashx>. (Accessed October 16, 2012)

Figure 8-17 Spot import service utilization: January, 2009 through September, 2012 (See 2011 SOM, Figure 8-17)



Real-Time Dispatchable Transactions

Real-Time Dispatchable Transactions, also known as "real-time with price" transactions, allow market participants to specify a floor or ceiling price which PJM dispatch will evaluate on an hourly basis prior to implementing the transaction.

Dispatchable transactions were a valuable tool for market participants when implemented. The transparency of real-time LMPs and the reduction of the required notification period from 60 minutes to 20 minutes have eliminated the value that dispatchable transactions once provided market participants, but the risk to other market participants is substantial, as they are subject to paying the resultant operating reserve credits.

Dispatchable transactions now serve only as a potential mechanism for receiving operating reserve credits. Dispatchable transactions are made whole through the payment of balancing operating reserve credits when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. During the first nine months of 2012, there were no balancing operating reserve credits paid to dispatchable transactions, a decrease from $1.3 million for the first nine months of 2011. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and that dispatchable schedules were only submitted for three days during the first nine months of 2012.

Ancillary Service Markets

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order No. 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 the basis of incentive rates or cost.

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 (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.

1 75 FERC ¶ 61,080 (1996).
2 See the *2011 State of the Market Report for PJM* for a full discussion of Ancillary Service markets and issues.

The purpose of the Day-Ahead Scheduling Reserve (DASR) 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.[3]

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 the first six months of 2012.

Table 9-1 The Regulation Market results were not competitive[4] (See 2011 SOM, Table 9-1)

Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	**Not Competitive**	**Flawed**

3 See 117 FERC ¶ 61,331 at P 29 n32 (2006).
4 As Table 9-1 indicates, the Regulation Market results are not the result of the offer behavior of market participants, which was 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 in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic. 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 a combination of the competitive offers from market participants and 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 or lower opportunity cost than its owner does, depending on the direction the unit was dispatched to provide regulation. If the market rules and/or their implementation produce inefficient outcomes, then no amount of competitive behavior will produce a competitive outcome.

- The Regulation Market structure was evaluated as not competitive because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 44 percent of the hours in January through September 2012.[5]
- Participant behavior was evaluated as competitive because market power mitigation requires competitive offers when the three pivotal supplier test is failed and there was no evidence of generation owners engaging in anti-competitive behavior.
- Market performance was evaluated as not competitive, despite competitive participant behavior, 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 in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic logic.[6]
- Market design was evaluated as flawed because while PJM has improved the market by modifying the schedule switch determination, the lost opportunity cost calculation is inconsistent with economic logic and there are additional issues with the order of operation in the assignment of units to provide regulation prior to market clearing.

Table 9-2 The Synchronized Reserve Markets results were competitive (See 2011 SOM, Table 9-2)

Market Element	Evaluation	Market Design
Market Structure: Regional Markets	Not Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Effective

- The Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration and inelastic demand. The Synchronized Reserve Market had one or more pivotal suppliers which failed the three pivotal supplier test in 24 percent of the hours in January through September of 2012.
- Participant behavior was evaluated as competitive because the market rules require competitive, cost based offers.
- Market performance was evaluated as competitive because the interaction of the participant behavior with the market design results in prices that reflect marginal costs.
- Market design was evaluated as effective because market power mitigation rules result in competitive outcomes despite high levels of supplier concentration.

Table 9-3 The Day-Ahead Scheduling Reserve Market results were competitive (See 2011 SOM, Table 9-3)

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Mixed	
Market Performance	Competitive	Mixed

- The Day-Ahead Scheduling Reserve Market structure was evaluated as competitive because the market did not fail the three pivotal supplier test.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs (zero), about 17 percent of offers reflected economic withholding, with offer prices above $5.00.
- Market performance was evaluated as competitive because there were adequate offers at reasonable levels in every hour to satisfy the requirement and the clearing price reflected those offers.
- Market design was evaluated as mixed because while the market is functioning effectively to provide DASR, the three pivotal supplier test and cost-based offer capping when the test is failed, should be added to the market to ensure that market power cannot be exercised at times of system stress.

5 These TPS results reflect MMU estimates for the period between May 6 and July 21, 2012, when the TPS test was not correctly applied by PJM.

6 PJM agrees that the definition of opportunity cost should be consistent across all markets and should, in all markets, be based on the offer schedule accepted in the market. This would require a change to the definition of opportunity cost in the Regulation Market which is the change that the MMU has recommended. The MMU also agrees that the definition of opportunity cost should be consistent across all markets.

Highlights

- The weighted average Regulation Market clearing price, including opportunity cost, for January through September 2012 was $14.92 per MW.[7] This was a decrease of $2.11, or 12.4 percent, from the average price for regulation in January through September 2011. The total cost of regulation decreased by $12.13 from $32.71 per MW in January through September 2011, to $20.58, or 37.1 percent. In January through September 2012, the weighted Regulation Market clearing price was 72 percent of the total regulation cost per MW, compared to 52 percent of the total regulation cost per MW in January through September 2011.
- The weighted average Tier 2 Synchronized Reserve Market clearing price in the Mid-Atlantic Subzone was $7.06 per MW in January through September 2012, a $4.94 per MW decrease from January through September 2011.[7] The total cost of synchronized reserves per MW in January through September 2012, was $10.96, a 23 percent decrease from the total cost of synchronized reserves ($14.21) during January through September 2011. The weighted average Synchronized Reserve Market clearing price was 64 percent of the weighted average total cost per MW of synchronized reserve in January through September 2012. The price to cost ratio was 84 percent in January through September 2011.
- The weighted DASR market clearing price was $0.91 per MW in January through September 2012. In January through September 2011, the weighted price of DASR was $1.04 per MW. The average hourly purchased DASR was 7,042 MW, an increase from 6,622 MW during the same period of 2011, reflecting PJM's larger footprint with the integration of DEOK on January 1, 2012.
- Black start zonal charges in January through September 2012 ranged from $0.02 per MW in the ATSI zone to $1.80 per MW in the BGE zone.

7 The term "weighted" when applied to clearing prices in the Synchronized Reserve Market means clearing prices weighted by the MW of cleared synchronized reserve.

Ancillary services costs per MW of load: 2001 - 2012

Table 9-4 shows PJM ancillary services costs for January through September for 2001 through 2012 on a per MW of load basis. The Scheduling, System Control, and Dispatch category of costs is comprised of PJM Scheduling, PJM System Control and PJM Dispatch; Owner Scheduling, Owner System Control and Owner Dispatch; Other Supporting Facilities; Black Start Services; Direct Assignment Facilities; and Reliability*First* Corporation charges. Supplementary Operating Reserve includes Day-Ahead Operating Reserve; Balancing Operating Reserve; and Synchronous Condensing.

Table 9-4 History of ancillary services costs per MW of Load[8]: January through September, 2001 through 2012 (See 2011 SOM, Table 9-4)

Year (Jan-Sep)	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve
2001	$0.55	$0.43	$0.22	$0.00	$1.18
2002	$0.47	$0.52	$0.21	$0.00	$0.66
2003	$0.53	$0.59	$0.23	$0.09	$0.88
2004	$0.50	$0.64	$0.25	$0.14	$0.90
2005	$0.78	$0.47	$0.25	$0.11	$0.88
2006	$0.55	$0.48	$0.28	$0.07	$0.44
2007	$0.65	$0.47	$0.29	$0.06	$0.58
2008	$0.75	$0.34	$0.29	$0.07	$0.55
2009	$0.36	$0.36	$0.36	$0.05	$0.47
2010	$0.37	$0.38	$0.36	$0.06	$0.75
2011	$0.35	$0.36	$0.39	$0.09	$0.87
2012	$0.23	$0.44	$0.44	$0.03	$0.75

Conclusion

The MMU continues to conclude that the results of the Regulation Market are not competitive.[9] 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 in some hours, resulted in a price less than the competitive price in some hours, and because the revised market rules are inconsistent with basic economic

8 Results in this table differ slightly from the results reported previously because accounting load is used in the denominator in this table.
9 The *2009 State of the Market Report for PJM* provided the basis for this recommendation. The *2009 State of the Market Report for PJM* summarized the history of the issues related to the Regulation Market. See the *2009 State of the Market Report for PJM*, Volume II, Section 6, "Ancillary Service Markets."

logic and the definition of opportunity cost elsewhere in the PJM tariff. This conclusion is not based on the behavior of market participants, which remains competitive.

PJM agrees that the definition of opportunity cost should be consistent across all markets and should, in all markets, be based on the offer schedule accepted in the market. This would require a change to the definition of opportunity cost in the Regulation Market which is the change that the MMU has recommended. The MMU also agrees that the definition of opportunity cost should be consistent across all markets.

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. However, compliance with calls to respond to actual spinning events has been an issue. As a result, the MMU is recommending that the rules for compliance be reevaluated.

The MMU concludes that the DASR Market results were competitive in January through September 2012, although concerns remain about economic withholding and the absence of the three pivotal supplier test in this market.

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 January through September 2012 as a result of the identified market design issues. This conclusion is not the result of participant behavior, which was generally competitive. The MMU is hopeful that the opportunity cost issue can be resolved in 2012 as part of the regulation market redesign. The MMU concludes that the Synchronized Reserve Market results were competitive in January through September 2012. The MMU concludes that the DASR Market results were competitive in January through September 2012.

Regulation Market

The PJM Regulation Market in January through September, 2012, continued to be operated as a single market. There have been no structural changes since December 1, 2008.[10]

Proposed Market Design Changes

Although the current market design satisfies the requirements of regulation, namely that it keep the reportable metrics CPS1 and BAAL within acceptable limits, a new market design initiative began in 2011 in response to a FERC rulemaking.[11] On October 20, 2011, FERC issued Order No. 755 directing PJM and other RTOs/ISOs to modify their regulation markets so as to make use of and properly compensate a mix of fast and traditional response regulation resources.[12]

On March 5, 2012, PJM filed proposed tariff revisions intended to implement Order No. 755.[13] The MMU protested that the Commission should not approve PJM's filing until PJM completed and filed undeveloped aspects of its proposal.[14] The MMU also protested that PJM's proposal failed to reflect the incremental cost of providing capability or the true lost opportunity cost of capability. The Commission required that PJM, through the stakeholder process, address the issues raised by the MMU and other parties and resubmit

10 All existing PJM tariffs, and any changes to these tariffs, are approved by FERC. The MMU describes the full history of the changes to the tariff provisions governing the Regulation Market in the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Service Markets."
11 See *2011 State of the Market Report for PJM*, Appendix F, "Ancillary Service Markets".
12 *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, 137 FERC ¶ 61,064 (2011) ("Order No. 755").
13 PJM filing in Docket No. ER12-1204.
14 Protest of the Independent Market Monitor for PJM filed in Docket No. ER12-1204 (March 26, 2012); Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM filed in Docket No. ER12-1204 (April 25, 2012).

their proposal.[15] Since this decision, PJM and the MMU have worked with the membership to address the issues identified by the Commission. At the time of this report, the only remaining difference between PJM and the MMU is the definition of performance related costs which both PJM and the MMU have agreed will be resolved in the Cost Development Subcommittee (CDS).

Market Structure

Supply

Table 9-5 shows capability, average daily offer and average hourly eligible MW for all hours as well as for off-peak and on-peak hours. The average hourly regulation capability increased in January through September of 2012, to 9,413 MW from 8,808 MW in the same time period of 2011.

Table 9-5 PJM regulation capability, daily offer[16] and hourly eligible: January through September 2012 (See 2011 SOM, Table 9-5)[17]

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	9,413	6,656	71%	3,089	33%
Off Peak	9,413			3,025	32%
On Peak	9,413			3,164	34%

The supply of regulation can be affected by regulating units retiring from service. Table 9-6 shows what the impact on the Regulation Market would be if all units retire that are requesting retirement through the end of 2015.

15 139 FERC ¶ 61,130 (2012) at PP 71, 73–74 ("[W]e agree with the IMM that PJM's performance payment fails to specify how clearing prices will reflect the actual requested mileage based on the regulation signal. While PJM describes the basic components of its proposal, PJM fails to explain how these components will be combined to calculate the accuracy score. While PJM's Manual 12 provides that the accuracy score will be the weighted average of the three components (i.e., the Energy Score, the Delay Score and the Correlation Score), PJM's proposal fails to define the process for calculating the various component scalars. Accordingly, we direct PJM to include in its compliance filing additional tariff language detailing each component of the accuracy score, and describing how each component scalar in the accuracy score calculation will be determined. As to the IMM's argument that the interaction between the performance offer and performance clearing price erroneously assumes a fixed relationship before the actual hour between a MW of cleared capability and the amount of work done, as we state above, we direct PJM to submit a compliance filing regarding the components of the accuracy score. Similarly, because the accuracy score affects eventual settlement, we will require PJM to submit as part of its compliance filing, additional tariff language outlining the settlement process. This should include how the accuracy score is used to determine payments and how settlement is affected by make-whole payments.")

16 Average Daily Offer MW exclude units that have offers but make themselves unavailable for the day.

17 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 9-6 Impact on PJM Regulation Market of currently regulating units scheduled to retire through 2015 (New Table)

Current Regulation Units, Jan-Sep, 2012	Settled MW, Jan-Sep, 2012	Units Scheduled To Retire Through 2015	Settled MW of Units Scheduled To Retire Through 2015	Percent Of Regulation MW To Retire Through 2015
296	7,608,983	52	171,402	2.25%

Demand

Demand for regulation does not change with price. The regulation requirement is set by PJM in accordance with NERC control standards, based on reliability objectives and forecast load. The requirement is 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. Table 9-7 shows the required regulation and its relationship to the supply of regulation.

Table 9-7 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through September 2012 and 2011 (See 2011 SOM, Table 9-6)

Month	Average Required Regulation, January Through September 2011	Average Required Regulation, January Through September 2012	Ratio of Supply To Requirement, January Through September 2011	Ratio of Supply To Requirement, January Through September 2012
Jan	960	1,005	3.19	3.29
Feb	897	979	3.06	3.45
Mar	823	876	3.02	3.14
Apr	748	826	2.88	3.19
May	786	918	2.84	3.26
Jun	1,037	1,055	2.81	3.21
Jul	1,214	1,246	2.79	2.94
Aug	1,093	1,134	2.83	2.97
Sep	922	941	2.74	3.33

Market Concentration

Table 9-8 shows Herfindahl-Hirschman Index (HHI) results for the January through September 2012 period. The average HHI of 1529 is classified as moderately concentrated.

Table 9-8 PJM cleared regulation HHI: January through September 2012 and 2011 (See 2011 SOM, Table 9-7)

Market Type	Minimum HHI	Weighted Average HHI	Maximum HHI
Cleared Regulation, January through September, 2012	810	1529	4962
Cleared Regulation, January through September, 2011	818	1645	3683

Figure 9-1 compares the January through September 2012 HHI distribution curve with distribution curves for the same period of 2011 and 2010.

Figure 9-1 PJM Regulation Market HHI distribution: January through September of 2010, 2011 and 2012 (See 2011 SOM, Figure 9-1)

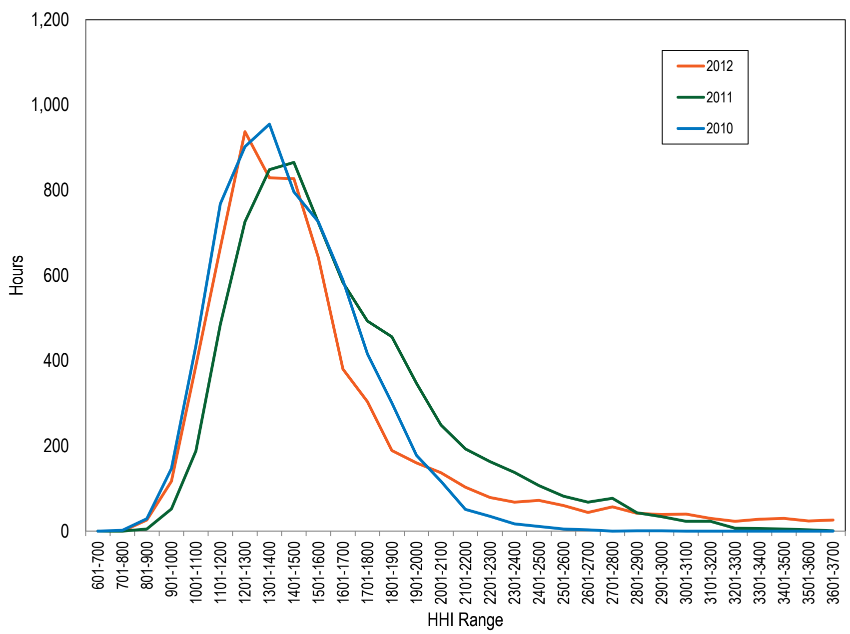


Table 9-9 includes a monthly summary of three pivotal supplier results. In January through September 2012, 44 percent of hours had one or more pivotal suppliers which failed or should have failed PJM's three pivotal supplier test.[18]

The MMU concludes from these results that the PJM Regulation Market in January through September 2012 was characterized by structural market power in 44 percent of the hours.

Table 9-9 Regulation market monthly three pivotal supplier results: January through September 2010, 2011 and 2012 (See 2011 SOM, Table 9-9)[19]

	2012	2011	2010
Month	2012 Percent of Hours Pivotal	2011 Percent of Hours Pivotal	2010 Percent of Hours Pivotal
Jan	71%	95%	74%
Feb	67%	93%	70%
Mar	64%	94%	83%
Apr	41%	97%	82%
May	*37%	95%	79%
Jun	*40%	89%	81%
Jul	*13%	89%	75%
Aug	32%	83%	69%
Sep	35%	87%	70%

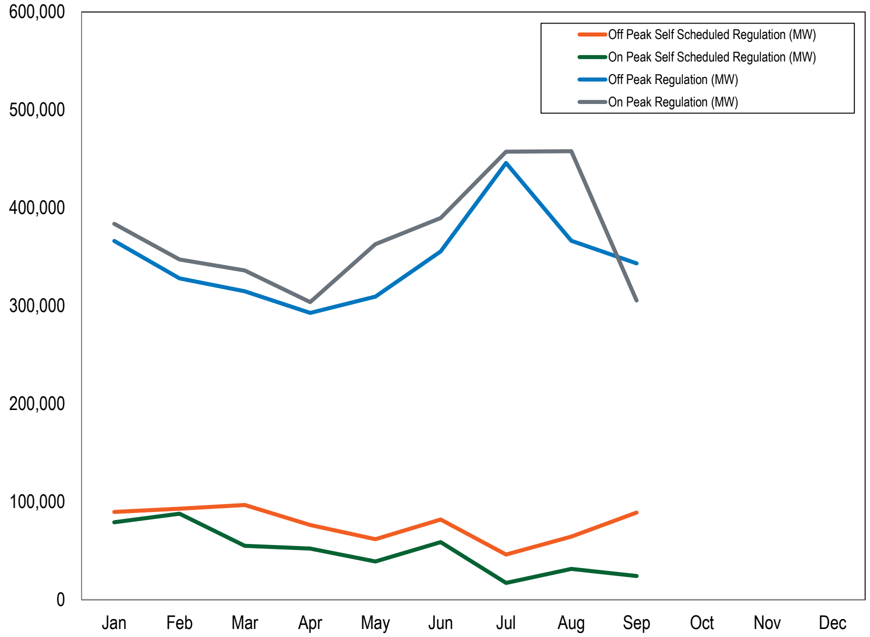
Market Conduct

Offers

Regulation Market participation is a function of the obligation of all LSEs to provide regulation in proportion to their load share. LSEs can purchase regulation in the Regulation Market, purchase regulation from other providers bilaterally, or self-schedule regulation to satisfy their obligation (Figure 9-2)[20]

18 The MMU monitors the application of the TPS test by PJM and brings any issues to the attention of PJM.
19 The results for May, June and July, 2012 are MMU estimates.
20 See PJM "Manual 28: Operating Agreement Accounting," Revision 54, (October 1, 2012); para 4.2, pp 15-16.

Figure 9-2 Off peak and on peak regulation levels: January through September 2012 (See 2011 SOM, Figure 9-2)



Increased self-scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Of the LSEs' obligation to provide regulation during January through September 2012, 80 percent was purchased in the spot market (84 percent in January through September 2011), 17 percent was self-scheduled (13 percent in January through September 2011), and 3 percent was purchased bilaterally (3 percent in January through September 2011) (Table 9-10).

Table 9-10 Regulation sources: spot market, self-scheduled, bilateral purchases: January through September 2012 (See 2011 SOM, Table 9-10)

Month	Spot Regulation (MW)	Self Scheduled Regulation (MW)	Bilateral Regulation (MW)	Total Regulation (MW)
Jan	553,686	164,806	21,261	739,753
Feb	481,004	175,757	20,456	677,217
Mar	477,564	144,408	19,683	641,655
Apr	426,564	124,750	21,083	572,397
May	542,585	97,574	17,849	658,008
Jun	582,078	140,769	22,309	745,156
Jul	819,897	63,415	19,711	903,024
Aug	710,715	95,949	17,687	824,350
Sep	515,732	113,351	19,726	648,809

Demand resources offered and cleared regulation for the first time in November 2011. Since they do not offer energy, demand resources self schedule rather than offer into the market.[21] The impact of demand response on the Regulation Market has been negligible.

The Minimum Regulation MW parameter was reintroduced in 2012. This parameter allows regulation owners to specify a minimum amount of regulation that can be cleared, which imposes a constraint on the ASO's three product optimization. For the marginal unit, the ASO may need to clear less than an individual unit's offered amount of regulation in order to meet the regulation requirement. As a result of this parameter, there are a significant number of hours in which the ASO will have to clear more MW than is optimal or skip the marginal unit and clear a more expensive unit resulting in a higher Regulation Market Clearing Price.

21 The demand resources self schedule because SPREGO might otherwise schedule them for energy which they cannot provide.

Market Performance

Price

The weighted average regulation market clearing price for January through September, 2012, was $14.92. This is a 12.4 percent decrease from the weighted average market clearing price of $17.03 for the same period in 2011. Figure 9-3 shows the daily average Regulation Market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market. Table 9-11 shows monthly average regulation market clearing price, average marginal unit offer price, and average marginal unit LOC. All units chosen to provide regulation received the higher of the clearing price, or the unit's regulation offer plus the individual unit's real-time opportunity cost, based on actual LMP.[22]

The average offer (excluding opportunity cost) of the marginal unit for the PJM Regulation Market during January through September, 2012, was $7.60 per MWh, a decrease from the average offer in January through September 2011 of $10.43 (Table 9-11). The average opportunity cost of the marginal unit for the PJM Regulation Market in January through September 2012 was $6.18. This is a decrease from the average opportunity cost for the marginal unit during the same period of 2011 of $6.00. In the PJM Regulation Market the marginal unit opportunity cost was 42.9 percent of the RMCP. This is an decrease from the January through September, 2011, average of 63.5 percent.

Figure 9-3 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): January through September 2012 (See 2011 SOM, Figure 9-3)

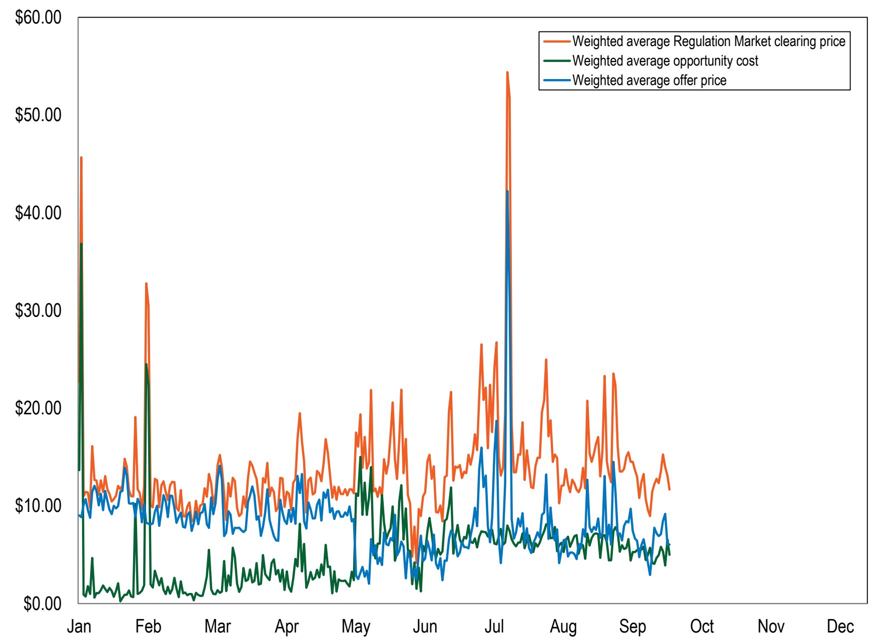


Figure 9-4 shows the level of demand for regulation by month in January through June 2012 and the corresponding level of regulation price.

22 See PJM. "Manual 28: Operating Agreement, Accounting," Revision 54, Section 4.2, "Regulation Credits" (October 1, 2012), p. 14. PJM uses estimated opportunity cost to clear the market and actual opportunity cost to compensate generators that provide regulation and synchronized reserve.

Table 9-11 PJM Regulation Market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): January through September 2012 (New Table)

Month	Weighted Average Regulation Market Clearing Price	Weighted Average Regulation Marginal Unit Offer	Weighted Average Regulation Marginal Unit LOC
Jan	$13.27	$10.58	$2.70
Feb	$11.52	$8.84	$2.68
Mar	$12.30	$8.82	$3.48
Apr	$12.71	$8.63	$4.07
May	$16.80	$6.52	$9.89
Jun	$13.83	$6.21	$6.94
Jul	$19.32	$6.60	$10.70
Aug	$15.12	$6.50	$7.37
Sep	$13.67	$5.46	$7.16

Figure 9-4 Monthly average regulation demand and price: January through September 2012 (See 2011 SOM, Figure 9-4)

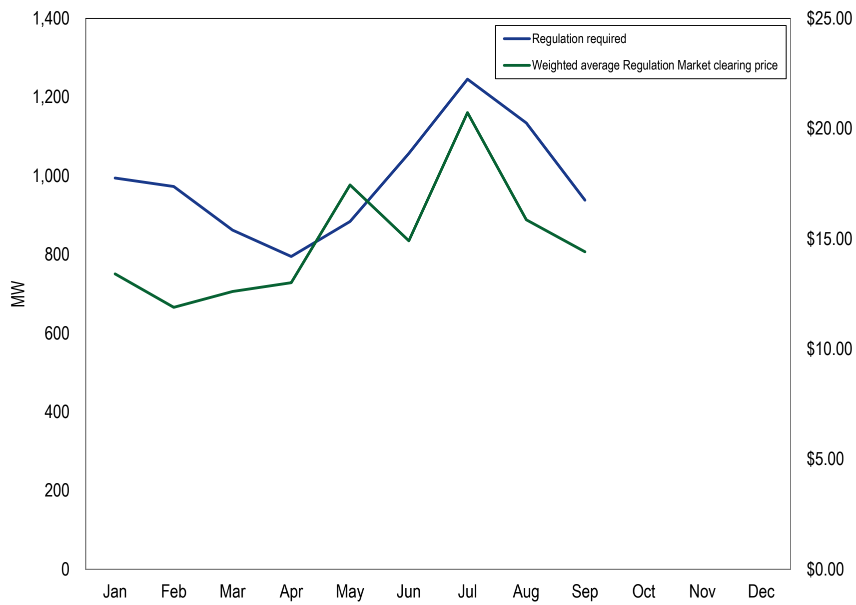
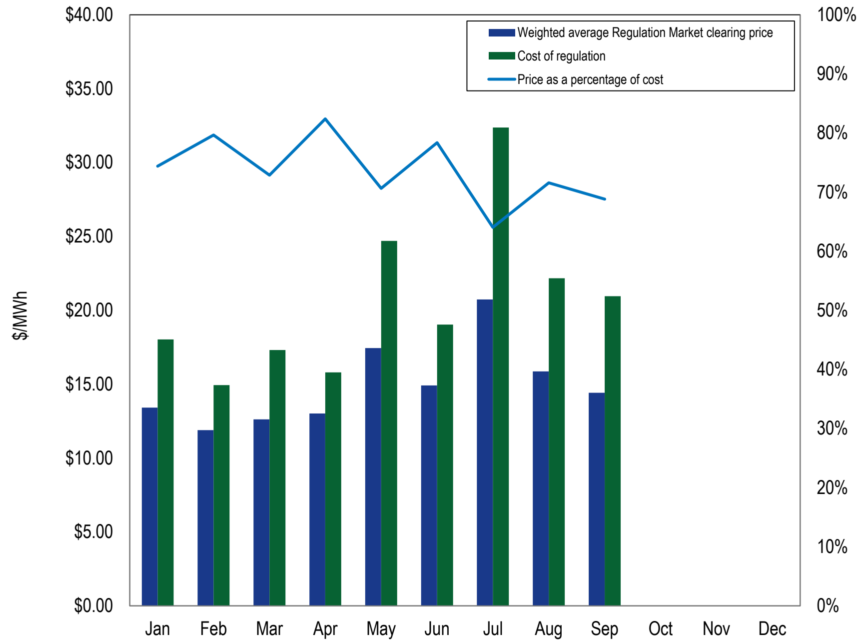


Figure 9-5 compares the regulation total cost per MWh (clearing price plus post market opportunity costs) with the regulation clearing price.

Figure 9-5 Monthly weighted, average regulation cost and price: January through September 2012 (See 2011 SOM, Figure 9-5)



Total scheduled regulation MW, total regulation charges, regulation price and regulation cost are shown in Table 9-12.

Table 9-12 Total regulation charges: January through September 2012 (See 2011 SOM, Table 9-11)

Month	Scheduled Regulation (MWh)	Total Regulation Charges	Simple Average Regulation Market Clearing Price	Weighted Average Regulation Market Price	Cost of Regulation
Jan	739,753	$13,338,201	$13.70	$13.41	$18.03
Feb	677,217	$10,108,296	$12.09	$11.89	$14.93
Mar	641,655	$11,109,763	$12.44	$12.61	$17.31
Apr	572,397	$9,038,430	$12.76	$13.01	$15.79
May	658,008	$16,248,950	$16.85	$17.44	$24.69
Jun	745,156	$14,181,461	$14.02	$14.91	$19.03
Jul	903,024	$29,228,039	$19.37	$20.73	$32.37
Aug	824,350	$18,273,264	$15.21	$15.86	$22.17
Sep	648,809	$13,593,245	$13.83	$14.41	$20.95

Table 9-13 provides a comparison of the average price and cost for PJM Regulation. The difference between the Regulation Market price and the actual cost of regulation was less in January through September 2012 than it was in the same period of 2011.

Table 9-13 Comparison of average price and cost for PJM Regulation, January through September 2006 through 2012 (See 2011 SOM, Table 9-12)

Year	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2006	$32.69	$44.98	73%
2007	$36.86	$52.91	70%
2008	$42.09	$64.43	65%
2009	$23.56	$29.87	79%
2010	$18.08	$32.07	56%
2011	$17.03	$32.71	52%
2012	$14.92	$20.58	72%

Synchronized Reserve Market

PJM operates two synchronized reserve markets. 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).

The integration of the Trans-Allegheny Line (TrAIL) project resulted in a change to the interface defining the Mid-Atlantic subzone of the RFC Synchronized Reserve Market.[23] After the implementation of TrAIL, Bedington – Black Oak became the most limiting interface. PJM reserves the right to revise the interface defining the Mid-Atlantic Subzone in accordance with operational and reliability needs.[24] From May 20, 2011, through the end of September 2011, the percent of Tier 1 synchronized reserve available west of the interface that is available in the Mid-Atlantic subzone (transfer capacity) was set to 30 percent. Since then, PJM changed the transfer capacity several times, varying from 50 percent to 15 percent at the end of 2011. From January through September 2012, the transfer capacity has remained at 15 percent.

Market Structure

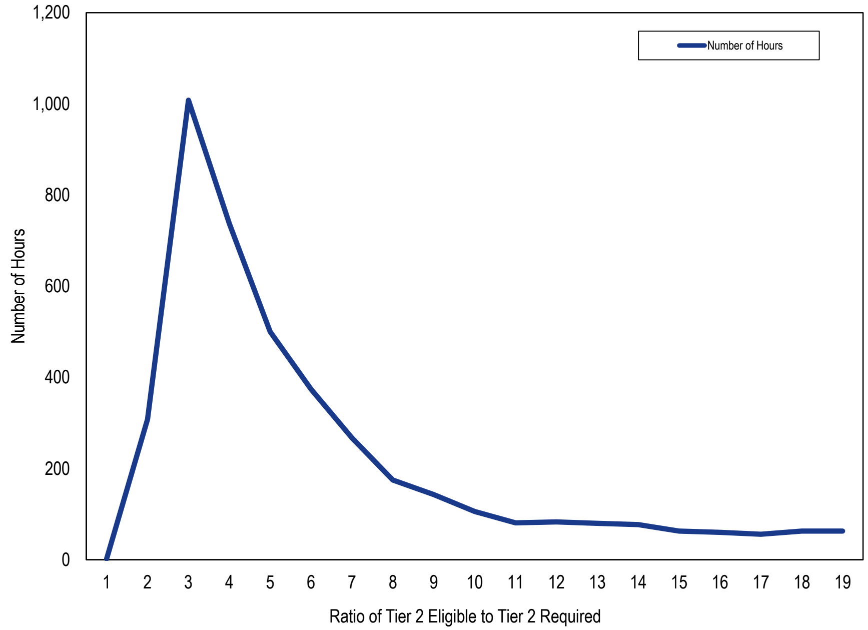
Supply

In January through September, 2012, the supply of offered and eligible synchronized reserve was both stable and adequate. The contribution of DSR to the Synchronized Reserve Market remained significant. Demand side resources are relatively low cost, and their participation lowers overall Synchronized Reserve prices. The ratio of offered and eligible synchronized reserve MW to the synchronized reserve required (1,300 MW) was 1.26 for the Mid-Atlantic Subzone.[25] This is a 15.6 percent increase from the first six months of 2011 when the ratio was 1.09. Much of the required synchronized reserve is supplied from on-line (Tier 1) synchronized reserve resources. The ratio of offered and eligible synchronized reserve to the required Tier 2 for all cleared Tier 2 hours in January through September 2012 was 4.3 for the Mid-Atlantic Subzone. This is a 27 percent increase from January through September 2011 when the ratio was 3.09. For the RFC Zone the offered and eligible excess supply ratio is determined using the administratively required level of synchronized reserve. The requirement for Tier 2 synchronized reserve is lower than the required reserve level for synchronized reserve because there

23 PJM.com "TrAIL Operational Impacts," <*http://www.pjm.com/~/media/committees-groups/committees/oc/20111018/20111018-item-08-trail-operational-impacts.ashx*> (October 2011).
24 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 52 (October 1, 2012), p. 72.
25 The Synchronized Reserve Market in the Southern Region cleared in so few hours that related data for that market are not meaningful.

is usually a significant amount of Tier 1 synchronized reserve available. (See Figure 9-6)

Figure 9-6 Ratio of Eligible Synchronized Reserve to Required Tier 2 for all cleared hours in the Mid-Atlantic Subzone: January through September 2012 (See 2011 SOM, Figure 9-6)



Demand

PJM made no changes to the default hourly required synchronized reserve requirement in January through September 2012.

In January through September, 2012, in the Mid-Atlantic Subzone, a Tier 2 synchronized reserve market was cleared in 69 percent of hours compared to 79 percent of hours for January through September 2011. In January through September, 2012, the average required Tier 2 synchronized reserve (including self-scheduled) for all cleared hours was 388 MW. In January through September, 2011, the average required Tier 2 synchronized reserve was 448 MW.

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 to ensure 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.[26]

Currently the RFC synchronized reserve requirement is the greater of the Reliability*First* Corporation's imposed minimum requirement or the system's largest contingency. The actual synchronized reserve requirement for the RFC Zone was 1,350 MW for January through September, 2012. For the Mid-Atlantic Subzone the requirement was 1,300 MW for January through September, 2012. (Table 9-14)

Table 9-14 Synchronized Reserve Market required MW, RFC Zone and Mid-Atlantic Subzone, December 2008 through September 2012 (See 2011 SOM, Table 9-16)

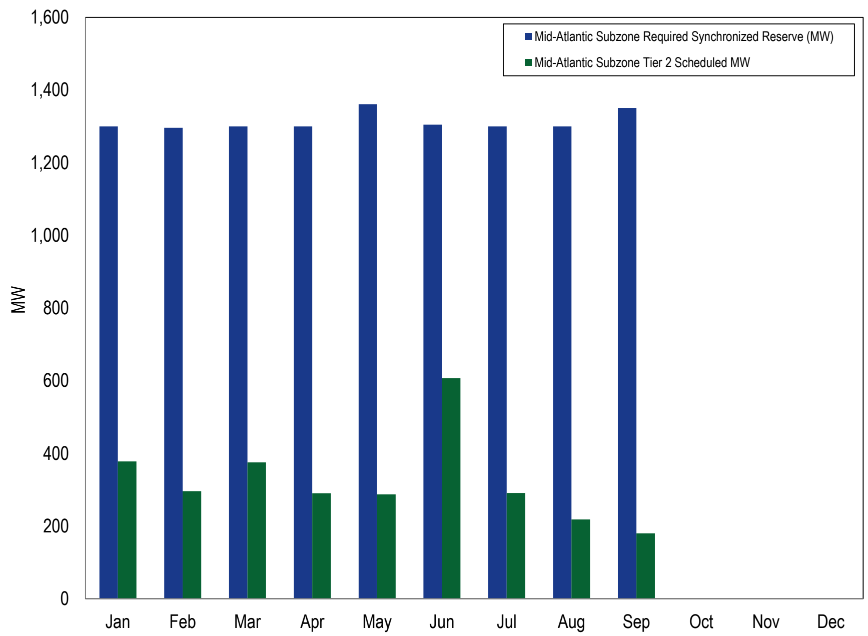
Mid-Atlantic Subzone			RFC Synchronized Reserve Zone		
From Date	To Date	Required MW	From Date	To Date	Required MW
May 10, 2008	May 8, 2010	1,150	May 10, 2008	Jan 1, 2009	1,305
May 8, 2010	Jul 13, 2010	1,200	Jan 1, 2009	Mar 15, 2010	1,320
July 13, 2010	Sep 30, 2012	1,300	Mar 15, 2010	Sep 30, 2012	1,350

Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency. The requirement in the Mid-Atlantic Subzone was raised to 1,700 MW for several hours in May and June. The requirement in the Mid-Atlantic Subzone was also raised to 1,350 MW for several hours in May. The requirement in the Mid-Atlantic Subzone was raised to 1,716 MW from September 24 through 28.

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

Figure 9-7 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during January through September 2012, for the RFC Synchronized Reserve Market.

Figure 9-7 Mid-Atlantic Synchronized Reserve Subzone monthly average synchronized reserve required vs. Tier 2 scheduled MW: January through September 2012 (See 2011 SOM, Figure 9-7)

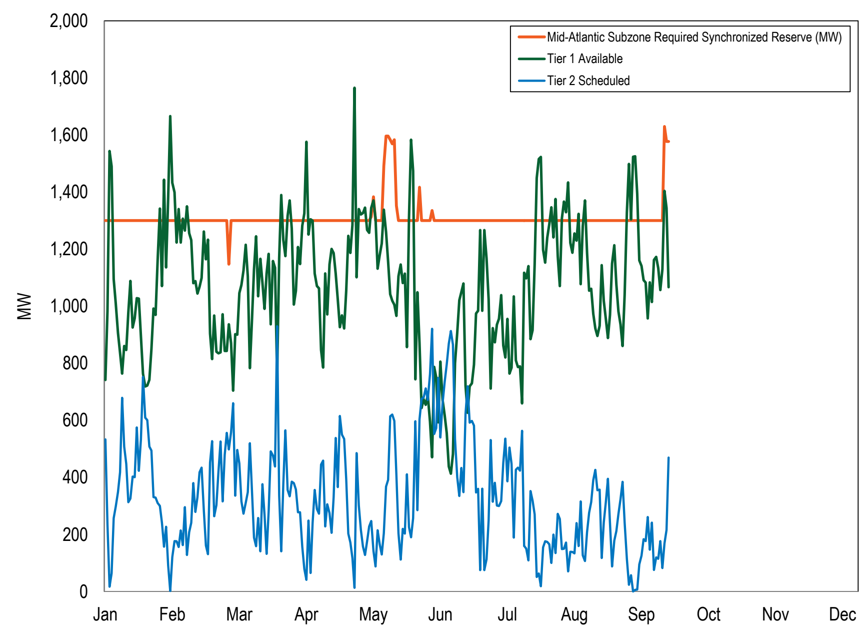


The RFC Synchronized Reserve Zone almost always has enough Tier 1 to cover its synchronized reserve requirement. Available Tier 1 in the western part of the RFC Synchronized Reserve Zone generally exceeds the total synchronized reserve requirement in the west. In January through September 2012, the RFC Synchronized Reserve Zone cleared a Tier 2 Synchronized Reserve Market in only four hours with an average SRMCP of $0.52. The Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone cleared a separate Tier 2 market in 69 percent of all hours during January through September, 2012 at a weighted SRMCP of $7.06. Figure 9-7 compares the required synchronized reserve MW to the scheduled Tier 2 MW for the Mid-Atlantic Subzone.

The actual synchronized reserve requirement for the Mid-Atlantic Subzone for January through September 2012 was usually 1,300 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.

Figure 9-8 shows the relationship among the PJM Mid-Atlantic synchronized reserve required, the estimated Tier 1 available and the amount of Tier 2 synchronized reserve needed to be purchased.

Figure 9-8 RFC Synchronized Reserve Zone, Mid-Atlantic Subzone daily average hourly synchronized reserve required, Tier 2 MW scheduled, and Tier 1 MW estimated: January through September 2012 (See 2011 SOM, Figure 9-9)



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.[27] The amount of 15 minute quick start reserve available in VACAR is sufficient to eliminate Tier 2 synchronized reserve demand for most hours. The Southern Synchronized Reserve Zone cleared a Tier 2 market for 94 hours in January through September 2012 at a weighted average clearing price of $20.47.

Market Concentration

The RFC Tier 2 Synchronized Reserve Market was more concentrated in January through September 2012 than it had been in the same period of 2011. The RFC Synchronized Reserve Market remains highly concentrated and dominated by a relatively small number of companies. The HHI for the Mid-Atlantic Subzone of the January through September 2012 RFC cleared Synchronized Reserve Market was 3202, which is defined as highly concentrated. The HHI for the Mid-Atlantic Subzone for the same period in 2011 was 2768. The largest hourly market share was 100 percent and 45 percent of all hours had a maximum market share greater than or equal to 40 percent (compared to 51 percent of all hours in January through September 2011).

In January through September, 2012, 24 percent of hours in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market failed the three pivotal supplier test. For the same time period of 2011 56 percent of hours failed the three pivotal supplier test. 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.

Table 9-15 Synchronized Reserve market monthly three pivotal supplier results: January through September 2011 and 2012 (See 2011 SOM, Table 9-9)

Month	2012 Percent of Hours Pivotal	2011 Percent of Hours Pivotal	2010 Percent of Hours Pivotal
Jan	45%	92%	64%
Feb	40%	99%	49%
Mar	38%	74%	65%
Apr	33%	83%	31%
May	15%	46%	45%
Jun	29%	14%	10%
Jul	10%	19%	23%
Aug	3%	25%	18%
Sep	4%	56%	17%

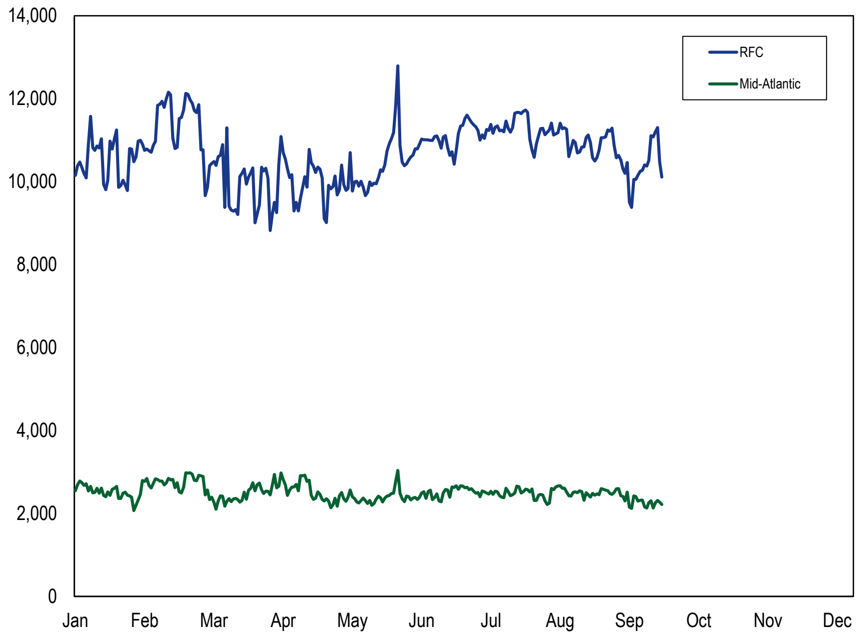
27 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 51 (August 8, 2012), p. 66.

Market Conduct

Offers

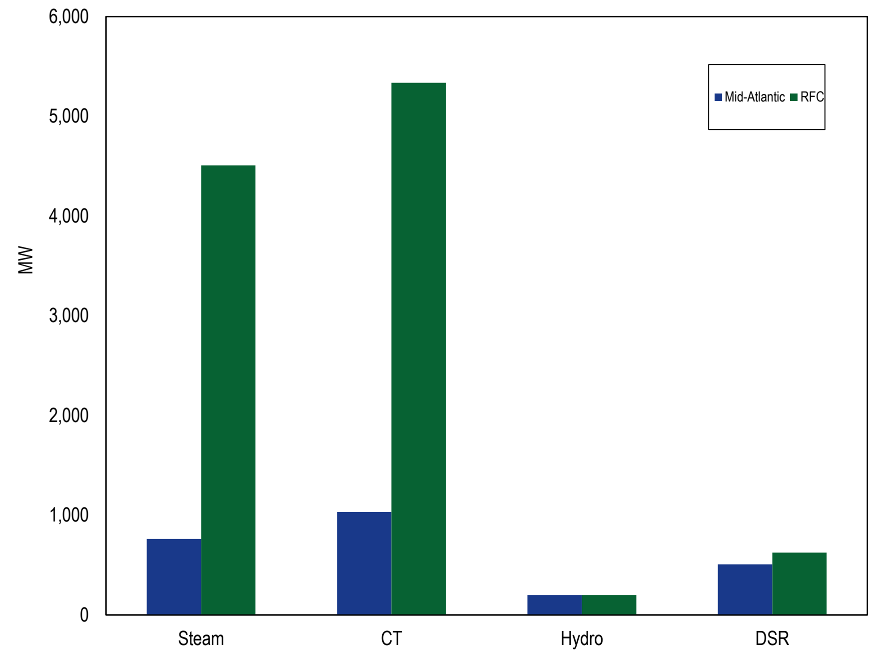
Figure 9-9 shows the daily average of hourly offered Tier 2 synchronized reserve MW.

Figure 9-9 Tier 2 synchronized reserve average hourly offer volume (MW): January through September 2012 (See 2011 SOM, Figure 9-10)



Synchronized reserve is offered by steam, CT, hydroelectric and DSR resources. Figure 9-10 shows average offer MW volume by market and unit type.

Figure 9-10 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through September 2012 (See 2011 SOM, Figure 9-11)



DSR

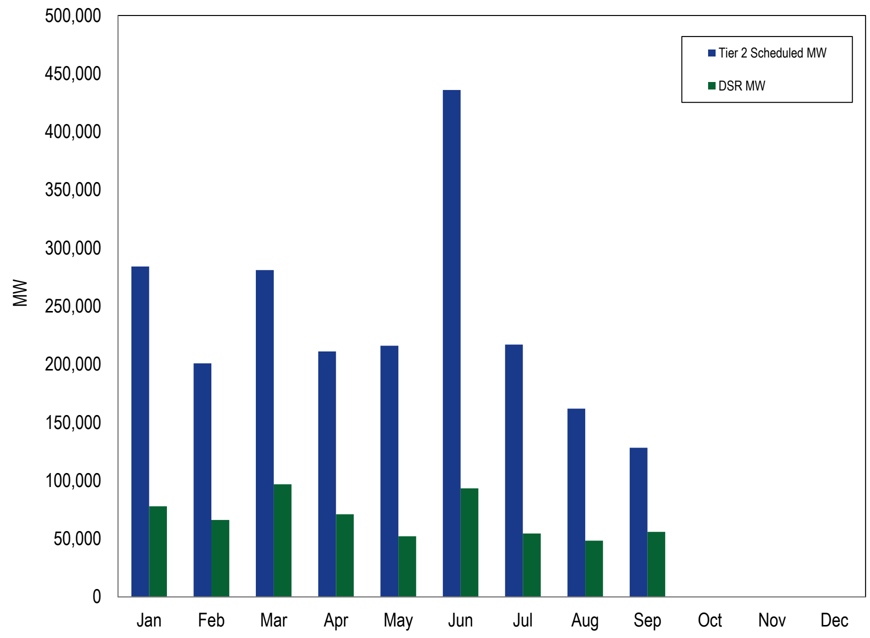
Demand-side resources were permitted to participate in the Synchronized Reserve Markets effective August, 2006. DSR has a significant impact on the Synchronized Reserve Market (Figure 9-10). In January through September 2012, DSR was 36 percent of all cleared Tier 2 synchronized reserves, compared to 21 percent for the same period in 2011. The reason is that Tier 2 demand was lower in the first nine months of 2012 than it was in the same time period of 2011 and DSR comprised a larger share of the bottom of the supply curve. In six percent of the hours in which a synchronized reserve market was cleared, all cleared MW were DSR compared to seven percent in January through September 2011. (See Table 9-16.) In the hours when all cleared MW were DSR, the simple average SRMCP was $0.97. The simple average SRMCP for all cleared hours was $4.86.

Table 9-16 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: January through September 2010, 2011, 2012 (See 2011 SOM, Table 9-18)

Year	Month	Average SRMCP	Average SRMCP when all cleared synchronized reserve is DSR	Percent of cleared hours all synchronized reserve is DSR
2010	Jan	$5.84	$2.03	4%
2010	Feb	$5.97	$0.10	1%
2010	Mar	$8.45	$2.01	6%
2010	Apr	$7.84	$1.86	17%
2010	May	$9.98	$1.68	15%
2010	Jun	$9.61	$0.74	9%
2010	Jul	$16.30	$0.79	7%
2010	Aug	$11.17	$0.93	12%
2010	Sep	$10.45	$1.15	12%
2011	Jan	$9.31	$0.10	0%
2011	Feb	$10.58	NA	0%
2011	Mar	$9.70	$2.04	2%
2011	Apr	$12.64	$1.84	10%
2011	May	$8.64	$1.71	14%
2011	Jun	$9.05	$1.18	10%
2011	Jul	$12.33	$0.62	6%
2011	Aug	$8.25	$0.78	7%
2011	Sep	$9.05	$1.73	15%
2012	Jan	$5.47	$1.71	11%
2012	Feb	$4.90	$1.78	24%
2012	Mar	$5.60	$1.40	6%
2012	Apr	$5.01	$0.91	4%
2012	May	$9.29	$0.54	2%
2012	Jun	$4.05	$0.43	1%
2012	Jul	$9.88	$0.10	0%
2012	Aug	$5.61	$0.60	1%
2012	Sep	$4.74	$1.23	2%

Figure 9-11 shows total cleared plus self-scheduled monthly synchronized reserve MW and cleared plus self-scheduled MW for DSR synchronized reserve.

Figure 9-11 PJM RFC Zone Tier 2 synchronized reserve scheduled MW: January through September 2012 (See 2011 SOM, Figure 9-12)



Market Performance

Price

Figure 9-12 shows the 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 the Synchronized Reserve Market Clearing Price (SRMCP).

The weighted average price for synchronized reserve in the PJM Mid-Atlantic Subzone of the RFC Synchronized Reserve Market in January through September 2012 was $7.06 while the corresponding cost of synchronized reserve was $10.96. Both price and cost are lower than for the same period in 2011, when price was $12.00 and cost was $14.21.

The RFC Synchronized Reserve requirement was satisfied by Tier 1 in all but four hours of January through June 2012. The Southern Synchronized Reserve Zone cleared a market in 94 hours of January through September 2012 with a weighted average clearing price of $20.47.

Price and Cost

A price to cost ratio close to 1.0 is an indicator of an efficient market design. In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market for January through September 2012, the price of Tier 2 synchronized reserves was 64 percent of the cost (Table 9-17 and Figure 9-12).

Figure 9-12 Comparison of Mid-Atlantic Subzone Tier 2 synchronized reserve weighted average price and cost (Dollars per MW): January through September 2012 (See 2011 SOM, Figure 9-16)

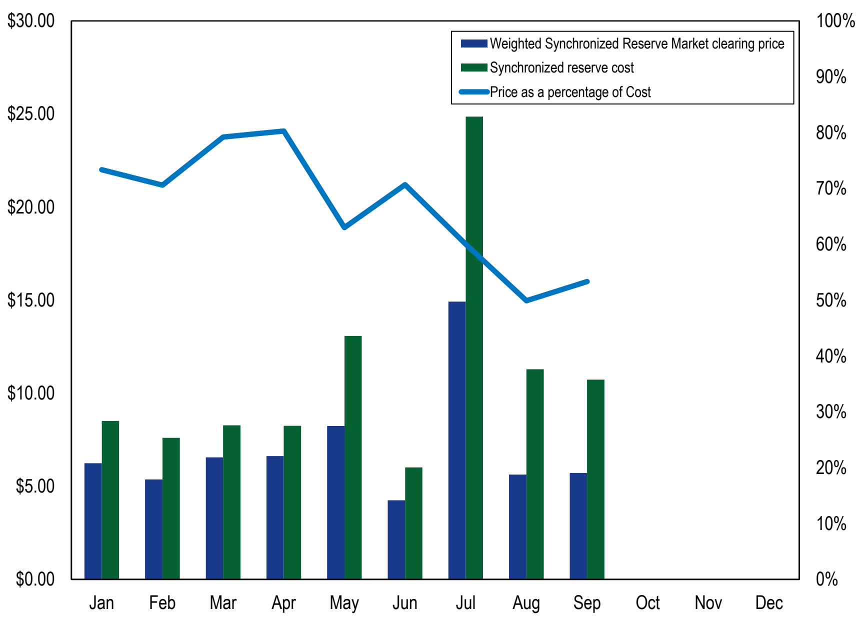


Table 9-17 shows the price and cost history of the Synchronized Reserve Market since 2005.

Table 9-17 Comparison of weighted average price and cost for PJM Synchronized Reserve, January through September, 2005 through 2012 (See 2011 SOM, Table 9-19)

Year	Weighted Synchronized Reserve Market Price	Weighted Synchronized Reserve Cost	Synchronized Reserve Price as Percent of Cost
2005 (Jan-Sep)	$12.81	$17.01	75%
2006 (Jan-Sep)	$14.40	$27.78	52%
2007 (Jan-Sep)	$18.24	$21.27	86%
2008 (Jan-Sep)	$10.87	$16.76	65%
2009 (Jan-Sep)	$6.38	$10.41	61%
2010 (Jan-Sep)	$11.51	$16.54	70%
2011 (Jan-Sep)	$12.00	$14.21	84%
2012 (Jan-Sep)	$7.06	$10.96	64%

The primary reason for the relatively low actual price to cost ratio is the difference in opportunity cost calculated using the forecast LMP and the actual LMP. In addition, the low price to cost ratio is in part a result of out of market purchases of Tier 2 synchronized reserve when PJM dispatchers need the reserves for reliability reasons. The percentage of settled Tier 2 MW that was added by PJM dispatchers from January through September 2012, after market clearance was 6.6 percent (it was 3.2 percent in January through September 2011, 5.2 percent in January through September 2010, 11.6 percent in January through September 2009, and 68.8 percent in January through September 2008).

Figure 9-13 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone: January through September 2012 (See 2011 SOM, Figure 9-14)

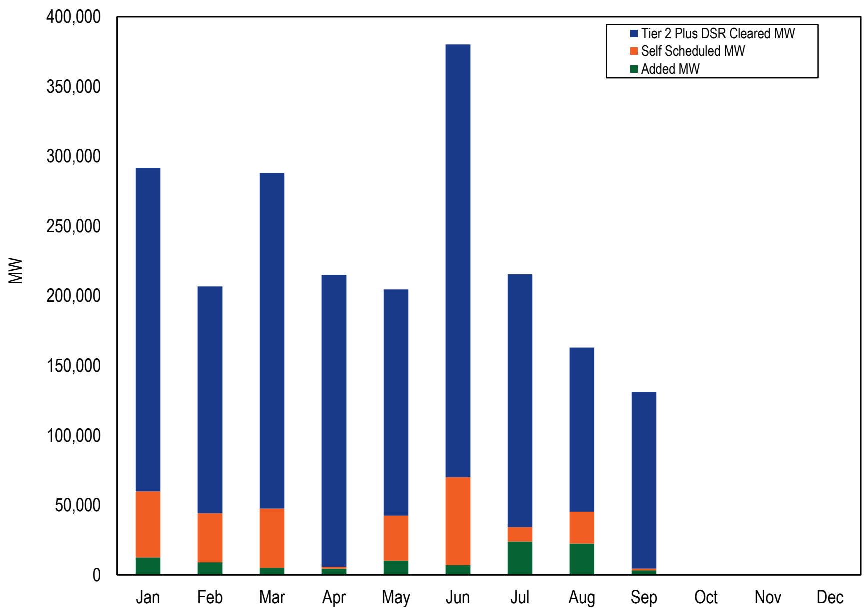
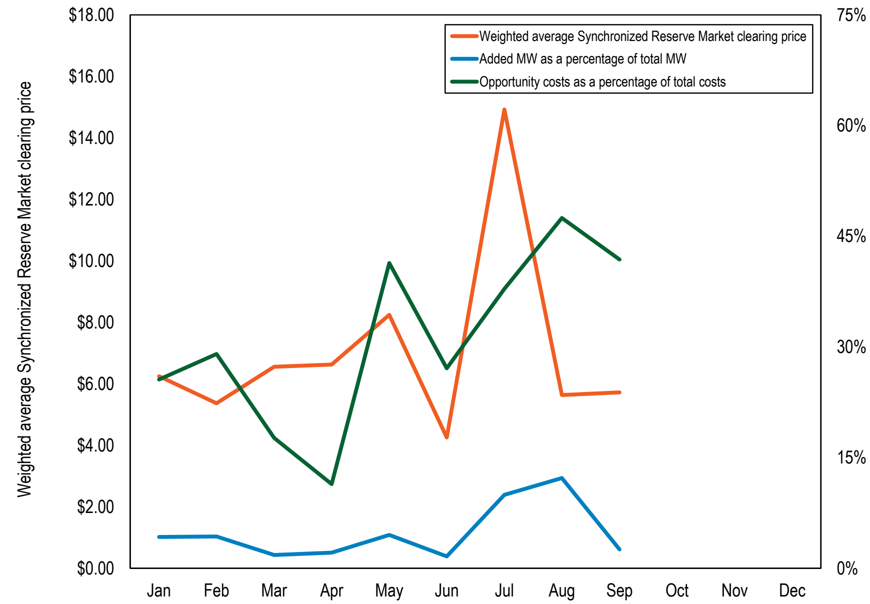


Figure 9-14 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic Subzone: January through September 2012 (See 2011 SOM, Figure 9-15)



Tier 1 bias means the manual subtraction from (or addition to) the Tier 1 estimate that the market software uses to determine how much Tier 2 MW to buy. In 2010, PJM significantly increased its use of Tier 1 bias in market solutions. By subtracting from the estimated Tier 1 MW, PJM Market Operations forces the market software to purchase more Tier 2 MW than it estimates it needs. This reduces the need for PJM Dispatch to add Tier 2 MW after market clearance but means purchasing more Tier 2 MW than are required. Tier 1 bias is used to change the Synchronized Reserve requirement (1,300 MW in the Middle Atlantic subzone) hour to hour without explicit guidelines or explicit rationale. Table 9-18 includes information on PJM's use of Tier 1 bias since 2008. The use of this bias factor appears to mean that there is a significant problem with the way Tier 1 MW are calculated or that the Tier 2 Synchronized Reserve requirement is not correct. The MMU recommends that PJM reevaluate its use of the Tier 1 bias factor and define explicit and transparent rules for calculating available Tier 1 MW and calculating required Tier 2 MW.

Table 9-18 Tier 1 bias used by PJM Dispatch January through September, 2008 through 2012 (New Table)

Year (Jan-Sep)	Total Net Tier 1 Bias (MW)	Percent of Hours with Tier 1 Bias	Average Bias (MW) of Hours with Tier 1 Bias	Added MW as a Percentage of Total Settled MW
2008 (Jan-Sep)	(92,800)	4.2%	(356)	68.8%
2009 (Jan-Sep)	(52,150)	3.1%	(258)	11.6%
2010 (Jan-Sep)	(747,745)	24.5%	(467)	5.2%
2011 (Jan-Sep)	(762,325)	28.5%	(408)	3.2%
2012 (Jan-Sep)	(599,054)	24.9%	(366)	6.6%

History of Spinning Events

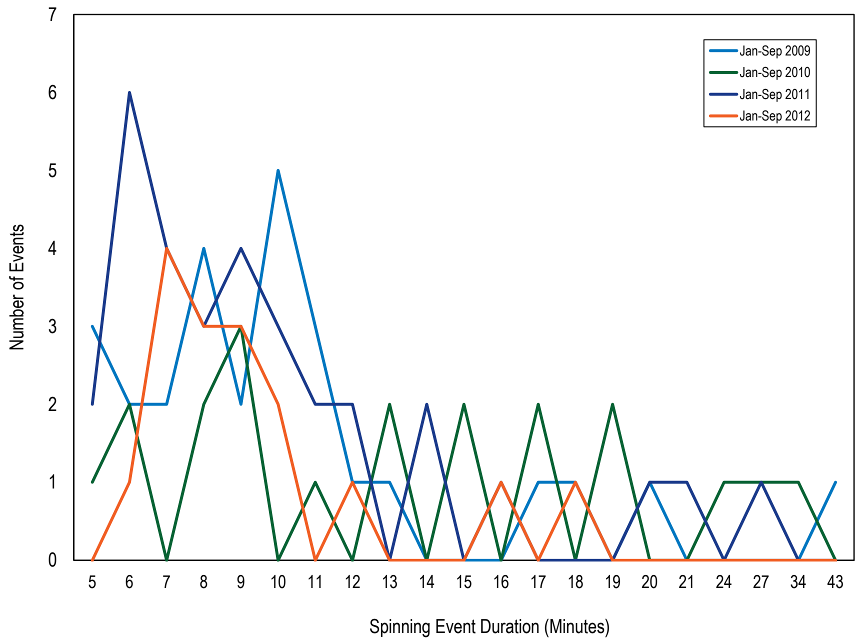
Spinning events (Table 9-19) are usually caused by a sudden generation outage or transmission disruption requiring PJM to load synchronized reserve.[28] The reserve remains loaded until system balance is recovered. From January 2009 through September 2012 PJM experienced 120 spinning events, or almost three events per month. Spinning events generally lasted between 7 minutes and 20 minutes with an average length of 11.5 minutes, although several events have lasted longer than 30 minutes.

28 See PJM. "Manual 12, Balancing Operations," Revision 25 (June 28, 2012), pp. 36-37.

Table 9-19 Spinning Events, January 2009 through September 2012 (See 2011 SOM, Table 9-20)

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-17-2009 09:37	RFC	7	FEB-18-2010 13:27	Mid-Atlantic	19	JAN-11-2011 15:10	Mid-Atlantic	6	JAN-03-2012 16:51	RFC	9
JAN-20-2009 17:33	RFC	10	MAR-18-2010 11:02	RFC	27	FEB-02-2011 01:21	RFC	5	JAN-06-2012 23:25	RFC	8
JAN-21-2009 11:52	RFC	9	MAR-23-2010 20:14	RFC	13	FEB-08-2011 22:41	Mid-Atlantic	11	JAN-23-2012 15:02	Mid-Atlantic	8
FEB-18-2009 18:38	Mid-Atlantic	10	APR-11-2010 13:12	RFC	9	FEB-09-2011 11:40	Mid-Atlantic	16	MAR-02-2012 19:54	RFC	9
FEB-19-2009 11:01	RFC	6	APR-28-2010 15:09	Mid-Atlantic	8	FEB-13-2011 15:35	Mid-Atlantic	14	MAR-08-2012 17:04	RFC	6
FEB-28-2009 06:19	RFC	5	MAY-11-2010 19:57	Mid-Atlantic	9	FEB-24-2011 11:35	Mid-Atlantic	14	MAR-19-2012 10:14	RFC	10
MAR-03-2009 05:20	Mid-Atlantic	11	MAY-15-2010 03:03	RFC	6	FEB-25-2011 14:12	RFC	10	APR-16-2012 00:20	Mid-Atlantic	9
MAR-05-2009 01:30	Mid-Atlantic	43	MAY-28-2010 04:06	Mid-Atlantic	5	MAR-30-2011 19:13	RFC	12	APR-16-2012 11:18	RFC	8
MAR-07-2009 23:22	RFC	11	JUN-15-2010 00:46	RFC	34	APR-02-2011 13:13	Mid-Atlantic	11	APR-19-2012 11:54	RFC	16
MAR-23-2009 23:40	Mid-Atlantic	10	JUN-19-2010 23:49	Mid-Atlantic	9	APR-11-2011 00:28	RFC	6	APR-20-2012 11:08	Mid-Atlantic	7
MAR-23-2009 23:42	RFCNonMA	8	JUN-24-2010 00:56	RFC	15	APR-16-2011 22:51	RFC	9	JUN-20-2012 13:35	RFC	7
MAR-24-2009 13:20	Mid-Atlantic	8	JUN-27-2010 19:33	Mid-Atlantic	15	APR-21-2011 20:02	Mid-Atlantic	6	JUN-26-2012 17:51	RFC	7
MAR-25-2009 02:29	RFC	9	JUL-07-2010 15:20	RFC	8	APR-27-2011 01:22	RFC	8	JUL-23-2012 21:45	RFC	18
MAR-26-2009 13:08	RFC	10	JUL-16-2010 20:45	Mid-Atlantic	19	MAY-02-2011 00:05	Mid-Atlantic	21	AUG-03-2012 12:44	RFC	10
MAR-26-2009 18:30	Mid-Atlantic	20	AUG-11-2010 19:09	RFC	17	MAY-12-2011 19:39	RFC	9	SEP-08-2012 04:34	RFC	12
APR-24-2009 16:43	RFC	11	AUG-13-2010 23:19	RFC	6	MAY-26-2011 17:17	Mid-Atlantic	20	SEP-27-2012 17:19	Mid-Atlantic	7
APR-26-2009 03:04	Mid-Atlantic	5	AUG-16-2010 07:08	RFC	17	MAY-27-2011 12:51	RFC	6			
MAY-03-2009 15:07	RFC	10	AUG-16-2010 19:39	Mid-Atlantic	11	MAY-29-2011 09:04	RFC	7			
MAY-17-2009 07:41	RFC	5	SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27			
MAY-21-2009 21:37	RFC	13	SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7			
JUN-18-2009 17:39	RFC	12	OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9			
JUN-30-2009 00:17	Mid-Atlantic	8	OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8			
JUL-26-2009 19:07	RFC	18	OCT-16-2010 03:25	RFCNonMA	7	JUN-26-2011 22:03	Mid-Atlantic	10			
JUL-31-2009 02:01	RFC	6	OCT-27-2010 10:35	RFC	7	JUL-10-2011 11:20	RFC	10			
AUG-15-2009 21:07	RFC	17	OCT-27-2010 12:50	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12			
SEP-08-2009 10:12	Mid-Atlantic	8	NOV-26-2010 14:24	RFC	13	AUG-02-2011 01:08	RFC	6			
SEP-29-2009 16:20	RFC	7	NOV-27-2010 11:34	RFC	8	AUG-18-2011 06:45	Mid-Atlantic	6			
OCT-01-2009 10:13	RFC	11	DEC-08-2010 01:19	RFC	11	AUG-19-2011 14:49	RFC	5			
OCT-18-2009 22:40	Mid-Atlantic	8	DEC-09-2010 20:07	RFC	5	AUG-23-2011 17:52	RFC	7			
OCT-26-2009 01:01	RFC	7	DEC-14-2010 12:02	Mid-Atlantic	24	SEP-24-2011 15:48	RFC	8			
OCT-26-2009 11:05	RFC	13	DEC-16-2010 18:40	Mid-Atlantic	20	SEP-27-2011 14:20	RFC	7			
OCT-26-2009 19:55	RFC	8	DEC-17-2010 22:09	Mid-Atlantic	6	SEP-27-2011 16:47	RFC	9			
NOV-20-2009 15:30	RFC	8	DEC-29-2010 19:01	Mid-Atlantic	15	OCT-30-2011 22:39	Mid-Atlantic	10			
DEC-09-2009 22:34	Mid-Atlantic	34				DEC-15-2011 14:35	Mid-Atlantic	8			
DEC-09-2009 22:37	RFCNonMA	31				DEC-21-2011 14:26	RFC	18			
DEC-14-2009 11:11	Mid-Atlantic	8									

Figure 9-15 Spinning events duration distribution curve, January through September 2009 to 2012 (See 2011 SOM, Figure 9-17)



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, nor the Mid-Atlantic subzone of the RFC market experienced deficits in January through September 2012.

Day Ahead Scheduling Reserve (DASR)

The Day-Ahead Scheduling Reserve Market is a market based mechanism for the procurement of supplemental, 30-minute reserves on the PJM System.[29]

29 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.

The DASR 30-minute reserve requirements are determined by the reliability region.[30] In the Reliability*First* (RFC) region, reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[31] If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

In January through September 2012, the required DASR was 7.03 percent of peak load forecast, down from 7.11 percent in 2011.[32] DASR MW purchased increased by 6.5 percent in January through September 2012 over the same period in 2011, from 43.4 million MW to 46.2 million MW.

In January through September 2012, no hours failed the three pivotal supplier test in the DASR Market. Zero hours failed the pivotal supplier test during the same period in 2011.

Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are also eligible to provide DASR, but remained insignificant. No demand side resources cleared the DASR market in January through September 2012.

Market Conduct

PJM rules allow any unit with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[33] Units that do not offer have their offers set to $0.00 per MW.

Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. However, there is a positive opportunity cost in addition to this direct marginal cost. As of September 30, 2012, fourteen percent of all units offered DASR at levels above $5 per MW. The impact on DASR prices of high offers was minor as a result of a favorable balance between supply and demand.

30 PJM. "Manual 13, Emergency Requirements," Revision 48 (April 3, 2012), pp. 11-12.
31 PJM. "Manual 10, Pre-Scheduling Operations," Revision 25 (January 1, 2010), p. 17.
32 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at Day Ahead Scheduling Reserve (DASR).
33 PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 52 (October 1, 2012), p. 122.

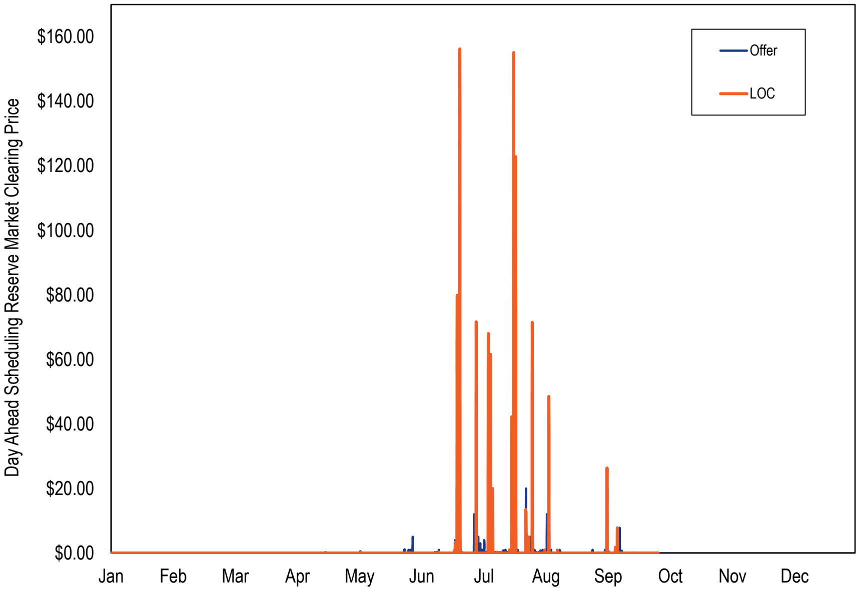
Market Performance

For 82 percent of hours in January through September 2012, DASR cleared at a price of $0.00. (Figure 9-16). For all of January through September, 2012 the weighted DASR price was $0.91, a $0.13 reduction from the weighted price during the same period in 2011.

Table 9-20 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: January through September 2011 and 2012 (See 2011 SOM, Table 9-21)

Year	Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Average Weighted Clearing Price	Total DASR Credits
2011	Jan	6,536	$0.00	$1.00	$0.03	$127,837
2011	Feb	6,180	$0.00	$1.00	$0.02	$61,682
2011	Mar	5,720	$0.00	$1.00	$0.01	$45,885
2011	Apr	5,265	$0.00	$0.05	$0.01	$24,463
2011	May	5,554	$0.00	$25.52	$0.29	$894,607
2011	Jun	7,305	$0.00	$193.97	$2.26	$9,653,815
2011	Jul	8,647	$0.00	$217.12	$4.21	$22,880,723
2011	Aug	7,787	$0.00	$61.91	$0.75	$3,577,433
2011	Sep	6,535	$0.00	$5.00	$0.07	$292,252
2012	Jan	6,944	$0.00	$0.02	$0.00	$604
2012	Feb	6,777	$0.00	$0.02	$0.00	$2,037
2012	Mar	6,180	$0.00	$0.05	$0.00	$5,031
2012	Apr	5,854	$0.00	$0.10	$0.00	$5,572
2012	May	6,491	$0.00	$5.00	$0.05	$226,881
2012	Jun	7,454	$0.00	$156.29	$2.39	$11,422,377
2012	Jul	8,811	$0.00	$155.15	$3.69	$20,723,970
2012	Aug	8,007	$0.00	$55.55	$0.51	$2,601,271
2012	Sep	6,656	$0.00	$7.80	$0.12	$540,586

Figure 9-16 Hourly components of DASR clearing price: January through September 2012 (See 2011 SOM, Figure 9-18)



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 the demonstrated ability of a generating unit to automatically remain operating when disconnected from the grid.

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of an incentive rate or for the costs associated with providing this service. PJM's goal is to charge transmission customers for black start service according to their zonal load ratio share (Table 9-21).

In January through September 2012, black start charges were $19.7 million. This is 97 percent higher than January through September 2011, when total black start service charges were $10.02 million. There was substantial zonal variation. Black start zonal charges in January through September 2012 ranged from $0.02 per MW in the ATSI zone to $1.80 per MW in the BGE zone.

The increased cost of black start is attributable to updated Schedule 6A (to the OATT) rates for all units, major refurbishments of black start resources in the BGE zone, and operating reserve charges associated with black start resources that should have been included in black start charges. The black start charges in Table 9-21 include an estimated $6.19 million of charges that were allocated to customers as operating reserve charges but that were in fact to pay for the operation of ALR black start units.[34]

Table 9-21 Black start yearly zonal charges for network transmission use: January through September 2012 (See 2011 SOM, Table 9-22)

Zone	Network Charges	Black Start Rate ($/MW)
AECO	$422,507	$0.52
AEP	$6,775,514	$1.01
AP	$146,568	$0.06
ATSI	$79,073	$0.02
BGE	$3,558,896	$1.80
ComEd	$3,332,988	$0.51
DAY	$142,060	$0.14
DEOK	$200,880	$0.13
DLCO	$32,711	$0.04
DPL	$390,945	$0.34
JCPL	$356,876	$0.20
Met-Ed	$368,772	$0.43
PECO	$929,412	$0.38
PENELEC	$323,632	$0.38
Pepco	$224,158	$0.12
PPL	$106,012	$0.05
PSEG	$2,316,319	$0.77

34 The $6.19 million is included in operating reserves. See the *2012 State of the Market Report for PJM: January through September*, Section 3, "Operating Reserves", at "Operating Reserve Charges."

Congestion and Marginal Losses

The Locational Marginal Price (LMP) is the incremental price of energy at a bus. The LMP at a bus is made up of three components: the system marginal price or energy component (SMP), the marginal loss component of LMP (MLMP), and the congestion component of LMP (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of energy, given the current dispatch, ignoring losses and congestion. Losses refer to energy lost to physical resistance in the transmission network as power is moved from generation to load. Marginal losses are the incremental change in system losses caused by changes in load and generation. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy and 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.

Congestion is neither good nor bad but is a direct measure of the extent to which there are multiple marginal generating units dispatched to serve load as a result of transmission constraints.

The components of LMP are the basis for calculating participant and location specific congestion and marginal losses.

Highlights

- Marginal loss costs decreased by $395.0 million or 34.3 percent, from $1,152.6 million in the first nine months of 2011 to $757.6 million in the first nine months of 2012 (Table 10-10).
- Day-ahead marginal loss costs decreased by $415.0 million or 34.8 percent, from $1,191.1 million in the first nine months of 2011 to $776.0 million in the first nine months of 2012 (Table 10-12).
- Balancing marginal loss costs increased by $20.0 million or 52.0 percent, from $38.5 million in the first nine months of 2011 to -$18.5 million in the first nine months of 2012 (Table 10-12).
- The marginal loss credits (loss surplus) decreased by $188.7 million or 37.6 percent, from $502.1 million in the first nine months of 2011 to $313.4 million in the first nine months of 2012. (Table 10-13).
- Congestion decreased by $449.7 million or 51.4 percent, from $874.9 million in the first nine months of 2011 to $425.2 million in the first nine months of 2012 (Table 10-15).
- Day–ahead congestion costs decreased by 460.0 million or 43.3 percent, from $1,063.2 million in the first nine months of 2011 to $603.2 million in the first nine months of 2012.
- Balancing congestion costs decreased by $10.3 million or 5.8 percent, from -$178.0 million in the first nine months of 2011 to -$188.3 million in the first nine months of 2012.

Conclusion

Marginal losses reflect the incremental power losses which result from the geographic distribution of generation and load and the physical characteristics of the transmission system interconnecting generation and load. Marginal loss costs decreased by $395.0 million or 34.3 percent, from $1,152.6 million in the first nine months of 2011 to $757.6 million in the first nine months of 2012.

Marginal loss credits are distributed to load and exports. Marginal loss credits decreased by $188.7 million or 37.6 percent, from $502.1 million in the first nine months of 2011 to $313.4 million in the first nine months of 2012.

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and

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. Dispatch within the constrained area follows merit order for the units available to relieve the constraint.

geographic distribution of generation facilities and the geographic distribution of load. Congestion costs decreased by $449.7 million or 51.4 percent, from $874.9 million in the first nine months of 2011 to $425.2 million in the first nine months of 2012. Congestion costs were significantly higher in the Day-Ahead Market than in the Real-Time Market. Congestion frequency was also significantly higher in the Day-Ahead Market than in the Real-Time Market.

ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 88.8 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2011 to 2012 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 73.8 percent of the congestion costs. FTRs were paid at 80.6 percent of the target allocation level for the 2011 to 2012 planning period, and at 79.1 percent of the target allocation level for the first four months of the 2012 to 2013 planning period.[2] Revenue adequacy, measured relative to target allocations for a planning period is not final until the end of the period.

The energy, marginal losses and congestion metrics must be interpreted carefully. The term total congestion generally refers to what is actually net congestion, which is calculated as load congestion payments less generation congestion credits. This section refers to total energy costs and total marginal loss costs in the same way. As with congestion, total energy costs are more precisely termed net energy costs and total marginal loss costs are more precisely termed net marginal loss costs.

Locational Marginal Price (LMP)

Components

Table 10-1 shows the PJM real-time, load-weighted average LMP components for the first nine months for years 2009 to 2012.[3]

2 See the *2012 Quarterly State of the Market Report for PJM: January through September*, Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-12, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2011 to 2012 and 2012 to 2013"

3 On January 1, 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. The metrics reported in this section treat DEOK as part of MISO for the first hour of January and as part of PJM for the second hour of January through September, 2012.

Table 10-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): January through September, 2009 through 2012 (See 2011 SOM, Table 10-1)

(Jan-Sep)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	$39.57	$39.49	$0.04	$0.03
2010	$49.91	$49.81	$0.06	$0.04
2011	$49.48	$49.40	$0.05	$0.03
2012	$35.02	$34.97	$0.04	$0.01

Table 10-2 shows the PJM day-ahead, load-weighted average LMP components for the first nine months of 2009 through 2012.

Table 10-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through September, 2009 through 2012 (See 2011 SOM, Table 10-2)

(Jan-Sep)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2009	$39.95	$39.50	($0.05)	($0.10)
2010	$49.12	$49.05	$0.11	($0.03)
2011	$48.34	$48.55	($0.05)	($0.16)
2012	$34.29	$34.19	$0.12	($0.02)

Zonal Components

The real-time components of LMP for each PJM control zone are presented in Table 10-3 for January through September, 2011 and 2012. The day-ahead components of LMP for each control zone are presented in Table 10-4 for January through September, 2011 and 2012.

Table 10-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): January through September, 2011 and 2012 (See 2011 SOM, Table 10-3)

	2011 (Jan-Sep)				2012 (Jan-Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$57.81	$50.11	$4.95	$2.75	$37.23	$35.88	($0.01)	$1.37
AEP	$42.97	$48.64	($3.99)	($1.68)	$32.81	$34.39	($0.82)	($0.77)
AP	$48.57	$48.99	($0.22)	($0.20)	$34.63	$34.61	$0.12	($0.10)
ATSI	$46.88	$51.24	($3.85)	($0.51)	$33.98	$34.71	($0.91)	$0.18
BGE	$58.74	$49.82	$6.62	$2.30	$40.16	$35.29	$3.28	$1.58
ComEd	$38.97	$49.12	($7.32)	($2.83)	$32.35	$35.27	($1.51)	($1.41)
DAY	$43.90	$49.40	($4.57)	($0.93)	$33.97	$34.88	($1.08)	$0.17
DEOK	NA	NA	NA	NA	$32.41	$34.95	($1.03)	($1.52)
DLCO	$43.30	$49.12	($4.15)	($1.67)	$33.44	$34.81	($0.37)	($1.01)
Dominion	$54.47	$49.83	$4.04	$0.60	$37.21	$35.29	$1.62	$0.31
DPL	$56.76	$49.95	$3.82	$2.99	$39.43	$35.40	$2.41	$1.62
JCPL	$58.09	$50.73	$4.62	$2.74	$36.95	$36.02	($0.25)	$1.17
Met-Ed	$53.64	$49.22	$3.42	$1.00	$35.56	$34.85	$0.31	$0.40
PECO	$55.19	$49.47	$3.82	$1.90	$36.34	$35.07	$0.46	$0.81
PENELEC	$48.18	$48.27	($0.46)	$0.37	$34.40	$34.22	($0.25)	$0.44
Pepco	$55.71	$49.82	$4.63	$1.26	$39.18	$35.31	$2.95	$0.92
PPL	$53.76	$48.95	$3.85	$0.96	$34.57	$34.59	($0.37)	$0.35
PSEG	$57.16	$49.71	$4.78	$2.67	$36.64	$35.31	$0.09	$1.24
RECO	$53.17	$50.88	($0.15)	$2.44	$36.88	$36.17	($0.43)	$1.15
PJM	$49.48	$49.40	$0.05	$0.03	$35.02	$34.97	$0.04	$0.01

Table 10-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through September, 2011 and 2012 (See 2011 SOM, Table 10-4)

	2011 (Jan-Sep)				2012 (Jan-Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$57.45	$49.53	$4.67	$3.25	$37.05	$34.99	$0.51	$1.54
AEP	$42.90	$48.10	($3.25)	($1.96)	$32.36	$33.84	($0.56)	($0.92)
AP	$47.66	$47.96	($0.16)	($0.15)	$34.01	$33.92	$0.16	($0.07)
ATSI	$46.14	$50.87	($3.07)	($1.66)	$33.09	$34.00	($0.78)	($0.13)
BGE	$57.10	$49.19	$5.16	$2.75	$39.53	$34.62	$3.00	$1.90
ComEd	$38.12	$48.12	($6.46)	($3.55)	$31.08	$34.41	($1.56)	($1.77)
DAY	$43.25	$48.64	($4.21)	($1.18)	$33.46	$34.30	($0.75)	($0.09)
DEOK	NA	NA	NA	NA	$31.87	$34.20	($0.59)	($1.73)
DLCO	$42.60	$48.39	($4.13)	($1.67)	$32.92	$34.13	($0.16)	($1.05)
Dominion	$53.16	$49.11	$3.35	$0.70	$36.40	$34.56	$1.35	$0.49
DPL	$56.97	$49.29	$4.20	$3.48	$38.72	$34.80	$1.85	$2.07
JCPL	$56.24	$49.45	$3.73	$3.06	$36.58	$35.01	$0.24	$1.33
Met-Ed	$52.37	$48.08	$3.28	$1.01	$34.73	$33.96	$0.26	$0.51
PECO	$55.35	$48.61	$4.33	$2.41	$35.96	$34.38	$0.60	$0.98
PENELEC	$47.41	$47.72	($0.56)	$0.24	$33.97	$33.46	($0.00)	$0.51
Pepco	$54.99	$48.72	$4.49	$1.79	$38.14	$34.28	$2.58	$1.28
PPL	$52.82	$48.27	$3.63	$0.93	$34.00	$33.86	($0.19)	$0.33
PSEG	$56.24	$48.89	$4.27	$3.09	$36.66	$34.62	$0.53	$1.51
RECO	$53.55	$49.45	$1.75	$2.35	$36.36	$35.10	$0.02	$1.24
PJM	$48.34	$48.55	($0.05)	($0.16)	$34.29	$34.19	$0.12	($0.02)

Energy Costs

Energy Accounting

The energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The energy cost is based on the day-ahead and real-time energy components of LMP (SMP). Total energy costs, analogous to total congestion costs, are equal to the load energy payments minus generation energy credits, plus explicit energy costs, incurred in both the Day-Ahead Energy Market and the balancing energy market. Total energy costs can by more accurately thought of as net energy costs.

Ignoring interchange, total generation MWh must be greater than total load MWh in every hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus in every hour, the net energy costs are negative (ignoring net interchange), with generation credits greater than load payments in every hour. These net energy costs plus net marginal loss costs plus net residual market adjustments, equal the marginal loss surplus which is distributed to load and exports.[4]

Total Energy Costs

Table 10-5 shows total energy, loss and congestion costs and total PJM billing, for the January through September period of each year from 2009 through 2012. The total energy, loss and congestion costs appear low compared to total PJM billing because these totals are actually net energy, loss and congestion costs.

4 Net residual adjustments are comprised of the known day-ahead error value minus the sum of the day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data.

Table 10-5 Total PJM costs by component (Dollars (Millions)): January through September, 2009 through 2012[5] (See 2011 SOM, Table 10-5)

(Jan-Sep)	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Charges Percent of PJM Billing
2009	($485)	$992	$544	$1,052	$19,927	5.3%
2010	($619)	$1,259	$1,139	$1,780	$26,249	6.8%
2011	($651)	$1,153	$875	$1,376	$28,836	4.8%
2012	($443)	$758	$425	$740	$22,119	3.3%

Energy costs for the first nine months for 2009 through 2012 are shown in Table 10-6 and Table 10-7. Table 10-6 shows PJM energy costs by category for the first nine months of 2009 through 2012 and Table 10-7 shows PJM energy costs by market category for the first nine months of 2009 through 2012. These energy costs are the actual total energy costs rather than the net energy costs in Table 10-5.

Table 10-6 Total PJM energy costs by category (Dollars (Millions)): January through September, 2009 through 2012 (See 2011 SOM, Table 10-6)

	Energy Costs (Millions)				
(Jan-Sep)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	$32,472.4	$32,960.8	$0.0	$3.8	($484.6)
2010	$41,562.3	$42,169.5	$0.0	($11.4)	($618.6)
2011	$38,515.2	$39,193.0	$0.0	$26.5	($651.3)
2012	$28,303.6	$28,754.0	$0.0	$7.9	($442.5)

Table 10-7 Total PJM energy costs by market category (Dollars (Millions)): January through September, 2009 through 2012 (See 2011 SOM, Table 10-7)

	Energy Costs (Millions)									
	Day Ahead				Balancing					
(Jan-Sep)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	$32,628.0	$33,162.4	$0.0	($534.4)	($155.6)	($201.6)	$0.0	$45.9	$3.8	($484.6)
2010	$41,665.6	$42,289.1	$0.0	($623.5)	($103.4)	($119.7)	$0.0	$16.3	($11.4)	($618.6)
2011	$38,908.1	$39,530.7	$0.0	($622.6)	($392.9)	($337.7)	$0.0	($55.3)	$26.5	($651.3)
2012	$28,423.3	$28,853.1	$0.0	($429.8)	($119.8)	($99.2)	$0.0	($20.6)	$7.9	($442.5)

5 The Energy Costs, Loss Costs and Congestion Costs include net inadvertent charges.

Monthly Energy Costs

Table 10-8 shows a monthly summary of energy costs by type for the first nine months of 2011 and 2012.

Table 10-8 Monthly energy costs by type (Dollars (Millions)): January through September, 2011 and 2012 (See 2011 SOM, Table 10-8)

	Energy Costs (Millions)							
	2011 (Jan-Sep)				2012 (Jan-Sep)			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($90.3)	($5.2)	$2.1	($93.3)	($48.5)	($10.1)	$2.5	($56.1)
Feb	($61.1)	($2.4)	$2.3	($61.2)	($36.0)	($9.9)	$2.4	($43.5)
Mar	($52.4)	($5.4)	$2.4	($55.4)	($30.1)	($8.6)	$1.9	($36.8)
Apr	($49.9)	($0.3)	$2.5	($47.7)	($30.7)	($2.8)	$0.7	($32.8)
May	($54.8)	($0.2)	$2.9	($52.1)	($39.4)	$0.1	($0.3)	($39.6)
Jun	($82.1)	($3.2)	$1.1	($84.2)	($57.1)	$4.0	$0.0	($53.1)
Jul	($110.0)	($16.8)	$6.7	($120.1)	($84.0)	$3.0	$0.6	($80.4)
Aug	($66.9)	($16.4)	$5.0	($78.2)	($60.3)	$2.6	$0.3	($57.4)
Sep	($55.0)	($5.5)	$1.5	($59.0)	($43.6)	$1.1	($0.2)	($42.8)
Total	($622.6)	($55.3)	$26.5	($651.3)	($429.8)	($20.6)	$7.9	($442.5)

Marginal Losses

Marginal Loss Accounting

PJM calculates marginal loss costs for each PJM member. The loss cost is based on the applicable day-ahead and real-time loss component of LMP (MLMP). Each PJM member is charged for the cost of losses on the transmission system.

Total marginal loss costs, analogous to total congestion costs, are equal to the load loss payments minus generation loss credits, plus explicit loss costs, incurred in both the Day-Ahead Energy Market and the balancing energy market. Total marginal loss costs can by more accurately thought of as net marginal loss costs.

Marginal loss costs can be both positive and negative and consequently load payments and generation credits can also be both positive and negative. The loss component of LMP is calculated with respect to the system marginal price (SMP). An increase in generation at a bus that results in an increase in losses will cause the marginal loss component of that bus to be negative. If the increase in generation at the bus results in a decrease of system losses, then the marginal loss component is positive.

Monthly marginal loss costs in the first nine months of 2012 ranged from $51.0 million in April to $143.4 million in July.

The marginal loss credits decreased by $188.8 million or 37.6 percent, from $502.1 million in the first nine months of 2011 to $313.3 million in the first nine months of 2012.

Total Marginal Loss Costs

Table 10-9 shows total marginal loss costs for the first nine months for 2009 through 2012. The total energy, loss and congestion costs appear low compared to total PJM billing because these totals are actually net energy, loss and congestion costs.

Table 10-9 Total[6] PJM Marginal Loss Costs (Dollars (Millions)): January through September, 2009 through 2012 (See 2011 SOM, Table 10-9)

(Jan-Sep)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	$992	NA	$19,927	5.0%
2010	$1,259	26.9%	$26,249	4.8%
2011	$1,153	(8.5%)	$28,836	4.0%
2012	$758	(34.3%)	$22,119	3.4%

Total marginal loss costs for the first nine months for 2009 through 2012 are shown in Table 10-10 and Table 10-11. Table 10-10 shows PJM marginal loss costs by category for the first nine months for 2009 through 2012. Table 10-11 shows PJM marginal loss costs by market category for the first nine months for 2009 through 2012.

6 Calculated values shown in Section 10, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Table 10-10 Total PJM marginal loss costs by category (Dollars (Millions)): January through September, 2009 through 2012 (See 2011 SOM, Table 10-10)

	Marginal Loss Costs (Millions)				
(Jan-Sep)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	($62.5)	($1,028.9)	$26.1	$0.0	$992.4
2010	($73.8)	($1,301.6)	$31.5	($0.0)	$1,259.3
2011	($138.8)	($1,277.7)	$13.7	$0.0	$1,152.6
2012	($17.3)	($790.0)	($15.1)	$0.0	$757.6

Table 10-11 Total PJM marginal loss costs by market category (Dollars (Millions)): January through September, 2009 through 2012 (See 2011 SOM, Table 10-11)

	Marginal Loss Costs (Millions)									
	Day Ahead				Balancing					
(Jan-Sep)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	($65.9)	($1,025.7)	$53.2	$1,013.0	$3.4	($3.1)	($27.1)	($20.6)	$0.0	$992.4
2010	($94.4)	($1,307.1)	$61.5	$1,274.2	$20.6	$5.6	($30.0)	($14.9)	($0.0)	$1,259.3
2011	($174.3)	($1,313.6)	$51.7	$1,191.1	$35.5	$36.0	($38.0)	($38.5)	$0.0	$1,152.6
2012	($42.2)	($805.6)	$12.7	$776.0	$24.9	$15.6	($27.8)	($18.5)	$0.0	$757.6

Monthly Marginal Loss Costs

Table 10-12 shows a monthly summary of marginal loss costs by type for the first nine months for 2011 and 2012.

Table 10-12 Monthly marginal loss costs by type (Dollars (Millions)): January through September, 2011 and 2012 (See 2011 SOM, Table 10-12)

	Marginal Loss Costs (Millions)							
	2011 (Jan - Sep)				2012 (Jan - Sep)			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$188.5	($2.9)	$0.0	$185.7	$100.6	($5.4)	$0.0	$95.2
Feb	$121.8	($1.8)	$0.0	$119.9	$80.4	($3.1)	$0.0	$77.2
Mar	$108.8	($4.8)	$0.0	$104.0	$67.1	($5.2)	$0.0	$61.9
Apr	$84.8	($5.6)	$0.0	$79.2	$55.4	($4.4)	$0.0	$51.0
May	$94.3	($7.0)	$0.0	$87.3	$69.6	($2.5)	($0.0)	$67.1
Jun	$129.9	($4.5)	$0.0	$125.4	$93.3	($0.8)	$0.0	$92.5
Jul	$217.4	($3.7)	$0.0	$213.7	$141.8	$1.6	$0.0	$143.4
Aug	$137.9	($3.5)	$0.0	$134.5	$96.1	$2.4	$0.0	$98.5
Sep	$107.7	($4.7)	$0.0	$102.9	$71.7	($0.9)	($0.0)	$70.8
Total	$1,191.1	($38.5)	$0.0	$1,152.6	$776.0	($18.5)	$0.0	$757.6

Marginal Loss Costs and Loss Credits

Marginal loss credits (loss surplus) are calculated by adding the total net energy costs, the total net marginal loss costs and net residual market adjustments. The total energy costs are equal to the net energy costs (generation energy credits less load energy payments plus net inadvertent energy charges plus net explicit energy costs). These total energy costs are actually net energy costs because they net generation credits and load payments. Total marginal loss costs are equal to the net marginal loss costs (generation loss credits less load loss payments plus net inadvertent loss charges plus net explicit loss costs). These total marginal loss costs are actually net marginal loss costs because they net generation credits and loss payments.

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus in every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour. These net costs plus net marginal loss costs plus net residual market adjustments equal marginal loss credits which are distributed to load and exports as marginal loss credits.

Table 10-13 shows the total net energy costs, the total net marginal loss costs collected, the net residual market adjustments and total marginal loss credits redistributed in the first nine months for 2009 through 2012.

Table 10-13 Marginal[7] loss credits (Dollars (Millions)): January through September, 2009 through 2012 (See 2011 SOM, Table 10-13)

	Loss Credit Accounting (Millions)			
(Jan-Sep)	Total Energy Costs	Total Marginal Loss Costs	Net Residual Adjustments	Loss Credits
2009	($484.6)	$992.4	$0.7	$508.5
2010	($618.6)	$1,259.3	($1.2)	$639.6
2011	($651.3)	$1,152.6	$0.7	$502.1
2012	($442.5)	$757.6	($1.7)	$313.4

7 The net residual adjustments included in the table are comprised of the known day-ahead error value minus the sum of the day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data.

Congestion

Congestion Accounting

Transmission congestion can exist in PJM's Day-Ahead and Real-Time Energy Market.[8] Total congestion costs are equal to the net congestion bill plus explicit congestion costs plus net inadvertent congestion charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

In the 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 the given period.[9]

The congestion costs associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. The congestion costs in each zone are the sum of the congestion costs 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.

Congestion costs can be both positive and negative and consequently load payments and generation credits 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.[10]

The congestion metric requires careful review when considering the significance of congestion. The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that congestion payments by load are offset by 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.

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.[11] 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.

8 When the term *congestion charges* is used in documents by PJM's Market Settlement Operations, it has the same meaning as the term *congestion costs* as used here.

9 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.

10 For an example of the congestion accounting methods used in this section, see *MMU Technical Reference for PJM Markets*, at "FTRs and ARRs."

11 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.

Generation congestion credits, when negative, measure the total congestion cost to generation in an area. Negative generation congestion credits are a cost 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 total of system marginal price and the loss component. 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 in the first nine months of 2012 were $425.2 million, which was comprised of load congestion payments of $116.8 million, negative generation credits of $359.2 million and negative explicit congestion of $50.9 million (Table 10-15).

Total Congestion

Table 10-14 shows total congestion from January through September by year from 2008 through 2012.[12]

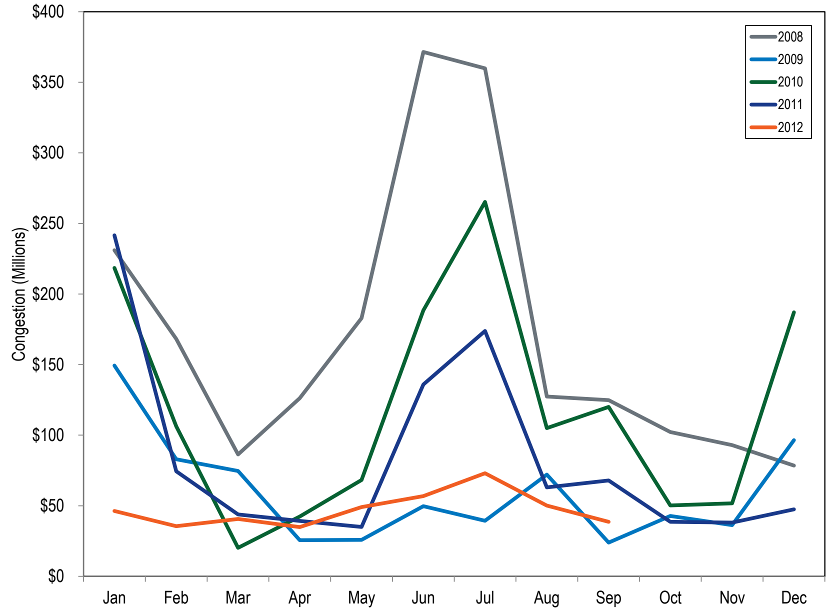
Table 10-14 Total PJM congestion (Dollars (Millions)): January through September for calendar years 2008 to 2012 (See 2011 SOM, Table 10-14)

	Congestion Costs (Millions)			
(Jan - Sep)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,778.2	NA	$26,979.0	6.6%
2009	$543.6	(69.4%)	$19,927.0	2.7%
2010	$1,134.3	108.7%	$26,249.0	4.3%
2011	$874.9	(22.9%)	$28,836.0	3.0%
2012	$425.2	(51.4%)	$22,119.0	1.9%

Figure 10-1 shows PJM monthly congestion for January 2008 through September 2012.

12 Congestion charges for 2010 reflect an updated calculation compared to the results in the *2010 State of the Market Report for PJM.*

Figure 10-1 PJM monthly congestion (Dollars (Millions)): January 2008 to September 2012 (New Figure)



Total congestion costs in Table 10-15 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO.[13]

Table 10-16 shows PJM congestion costs by category for the first nine months of 2012. The January through September 2012 PJM total congestion costs were comprised of $116.8 million in load congestion payments, $359.2 million in negative generation congestion credits, and $50.9 million in negative explicit congestion costs.

13 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) Section 6.1 <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed March 13, 2012).

Table 10-15 Total PJM congestion costs by category (Dollars (Millions)): January through September, 2011 and 2012 (See 2011 SOM, Table 10-15)

	Congestion Costs (Millions)				
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2011	$142.1	($835.5)	($102.8)	$0.0	$874.9
2012	$116.8	($359.2)	($50.9)	$0.0	$425.2

Table 10-16 Total PJM congestion costs by market category (Dollars (Millions)): January through September, 2011 and 2012 (See 2011 SOM, Table 10-16)

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2011	$68.1	($949.4)	$45.6	$1,063.2	$74.0	$113.9	($148.4)	($188.3)	$0.0	$874.9
2012	$113.1	($403.3)	$86.7	$603.2	$3.7	$44.1	($137.6)	($178.0)	$0.0	$425.2

Monthly Congestion

Table 10-17 shows that during the first nine months of 2012, monthly congestion costs ranged from $34.9 million to $73.1 million. Table 10-18 shows the congestion costs during the first nine months of 2011.

With the exception of May, monthly congestion costs in 2012 were lower than for corresponding months in 2011.

Table 10-17 Monthly PJM congestion costs (Dollars (Millions)): January through September 2012 (See 2011 SOM, Table 10-17)

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Month	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Jan	$4.0	($53.1)	$9.3	$66.3	$1.0	$5.7	($15.4)	($20.0)	$0.0	$46.3
Feb	$9.1	($38.3)	$7.4	$54.8	($3.7)	$2.7	($12.8)	($19.2)	$0.0	$35.5
Mar	$10.4	($38.5)	$10.9	$59.8	($1.6)	$3.7	($13.8)	($19.1)	$0.0	$40.7
Apr	$11.7	($43.7)	$16.5	$72.0	($3.2)	$5.2	($28.7)	($37.1)	$0.0	$34.9
May	$13.4	($37.2)	$16.7	$67.2	$0.5	($2.6)	($21.2)	($18.2)	$0.0	$49.1
Jun	$14.0	($50.9)	$4.7	$69.6	$5.4	$8.3	($9.8)	($12.7)	$0.0	$56.8
Jul	$13.9	($67.6)	$9.5	$91.0	$3.3	$7.3	($13.9)	($17.9)	$0.0	$73.1
Aug	$23.9	($30.0)	$6.9	$60.8	$5.9	$6.9	($9.6)	($10.6)	$0.0	$50.2
Sep	$12.8	($44.0)	$4.9	$61.8	($3.9)	$6.9	($12.3)	($23.1)	$0.0	$38.7
Total	$113.1	($403.3)	$86.7	$603.2	$3.7	$44.1	($137.6)	($178.0)	$0.0	$425.2

Table 10-18 Monthly PJM congestion costs (Dollars (Millions)): January through September 2011 (See 2011 SOM, Table 10-18)

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Month	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Jan	$27.0	($228.4)	$0.9	$256.4	$21.1	$15.6	($20.3)	($14.8)	$0.0	$241.6
Feb	$14.0	($77.5)	$1.0	$92.5	$5.6	$12.8	($10.9)	($18.0)	$0.0	$74.5
Mar	($2.5)	($58.8)	$2.2	$58.4	$0.2	$4.7	($10.0)	($14.6)	$0.0	$43.9
Apr	$5.0	($56.5)	$6.6	$68.0	$1.4	$6.4	($23.7)	($28.8)	$0.0	$39.2
May	$14.3	($41.5)	$8.6	$64.3	$3.0	$7.4	($24.9)	($29.3)	$0.0	$35.0
Jun	$1.8	($154.0)	$6.4	$162.3	$13.1	$22.4	($17.1)	($26.4)	$0.0	$135.9
Jul	$3.8	($184.1)	$6.5	$194.4	$21.2	$21.6	($20.2)	($20.6)	$0.0	$173.8
Aug	$4.7	($63.7)	$6.6	$75.0	($0.4)	$1.8	($9.7)	($11.9)	$0.0	$63.1
Sep	$0.0	($84.9)	$6.9	$91.9	$8.8	$21.2	($11.5)	($23.9)	$0.0	$67.9
Total	$68.1	($949.4)	$45.6	$1,063.2	$74.0	$113.9	($148.4)	($188.3)	$0.0	$874.9

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 likely exceeds the number of constrained hours and the number of congestion-event hours likely exceeds the number of hours within 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 the first nine months of 2012, there were 168,689 day-ahead, congestion-event hours compared to 102,714 day-ahead, congestion-event hours in the first nine months of 2011. In the first nine months of 2012, there were 15,254 real-time, congestion-event hours compared to 16,536 real-time, congestion-event hours in the first nine months of 2011.

During the first nine months of 2012, for only 3.7 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. During the first nine months of 2012, for 39.9 percent of Real-Time Market facility constrained hours, the same facilities were also constrained in the Day-Ahead Market.

The AP South interface was the largest contributor to congestion costs in the first nine months of 2012. With $50.9 million in total congestion costs, it accounted for 12.0 percent of the total PJM congestion costs in the first nine months of 2012. The top five constraints in terms of congestion costs together contributed $112.5 million, or 26.5 percent, of the total PJM congestion costs in the first nine months of 2012. The top five constraints were the AP South interface, Graceton – Raphael Road transmission line, Woodstock flowgate, Belvidere – Woodstock line and Clover transformer.

Congestion by Facility Type and Voltage

In the first nine months of 2012, compared to the first nine months of 2011, day-ahead, congestion-event hours increased on the reciprocally coordinated flowgates between PJM and MISO, transmission lines and transformers while congestion frequency on internal PJM interfaces decreased. Real-time, congestion-event hours increased on the reciprocally coordinated flowgates between PJM and the MISO and transmission lines, while congestion frequency on interfaces and transformers decreased.

Day-ahead congestion costs increased on the reciprocally coordinated flowgates between PJM and MISO in the first nine months of 2012 compared to the first nine months of 2011 and decreased on PJM interfaces, transmission lines and transformers in the first nine months of 2012 compared to the first nine months of 2011. Balancing congestion costs decreased on the reciprocally coordinated flowgates between PJM and MISO and PJM interfaces and increased on transformers and transmission lines in the first nine months of 2012 compared to first nine months of 2011.

Table 10-19 provides congestion-event hour subtotals and congestion cost subtotals comparing the first nine months of 2012 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[14] For comparison, this information is presented in Table 10-20 for the first nine months of 2011.[15]

Table 10-19 Congestion summary (By facility type): January through September 2012 (See 2011 SOM, Table 10-19)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
Flowgate	($42.8)	($145.9)	$28.5	$131.5	($4.4)	$7.5	($66.6)	($78.5)	$53.0	21,819	5,355
Interface	$48.5	($51.1)	$0.0	$99.6	$12.8	$15.5	($3.3)	($6.1)	$93.6	4,451	421
Line	$66.1	($155.4)	$41.0	$262.4	($8.4)	$18.2	($54.9)	($81.5)	$180.9	101,021	7,686
Other	$9.5	($4.0)	$1.1	$14.6	($0.6)	$0.0	($0.9)	($1.5)	$13.0	3,871	428
Transformer	$29.1	($45.6)	$14.3	$89.0	$4.1	$2.7	($11.6)	($10.1)	$78.9	37,527	1,364
Unclassified	$2.8	($1.3)	$1.8	$6.0	$0.2	$0.2	($0.2)	($0.3)	$5.7	NA	NA
Total	$113.1	($403.3)	$86.7	$603.2	$3.7	$44.1	($137.6)	($178.0)	$425.2	168,689	15,254

Table 10-20 Congestion summary (By facility type): January through September 2011 (See 2011 SOM, Table 10-20)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
Flowgate	($67.9)	($132.2)	$9.5	$73.8	$7.4	$10.8	($58.1)	($61.5)	$12.2	15,070	4,226
Interface	$55.9	($375.4)	($12.4)	$418.9	$36.9	$37.1	$8.9	$8.7	$427.6	7,068	1,598
Line	$45.9	($276.0)	$25.1	$347.1	$23.5	$48.0	($59.2)	($83.7)	$263.4	58,823	7,291
Other	($1.0)	($4.5)	$0.6	$4.0	$2.1	$4.5	($0.2)	($2.7)	$1.4	622	145
Transformer	$34.5	($159.4)	$17.8	$211.7	$3.2	$13.1	($38.5)	($48.4)	$163.3	21,131	3,276
Unclassified	$0.7	($2.0)	$5.0	$7.8	$0.9	$0.3	($1.3)	($0.7)	$7.1	NA	NA
Total	$68.1	($949.4)	$45.6	$1,063.2	$74.0	$113.9	($148.4)	($188.3)	$874.9	102,714	16,536

Table 10-21 and Table 10-22 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the Day-Ahead Market, the number of hours during which the facility is also constrained in the Real-Time Market are presented in Table 10-21. In the first nine months of 2012, there were 168,689 congestion event hours in the Day-Ahead Market. Among those, only 6,196 (3.7 percent) were also constrained in the Real-Time Market. In the first nine months of 2011, among the 102,714 day-ahead congestion event hours, only 6,720 (6.5 percent) were binding in the Real-Time Market.[16]

Among the hours for which a facility is constrained in the Real-Time Market, the number of hours during which the facility is also constrained in the Day-Ahead Market are presented in Table 10-22. In the first nine months of 2012, there 15,254 congestion event hours in the Real-Time Market. Among these, 6,081 (39.9 percent) were also constrained in the Day-Ahead Market. In the first nine months of 2011, among the 16,536 real-time congestion event hours, only 6,600 (40.3 percent) were binding in the day-ahead.

14 The term flowgate refers to MISO flowgates in this section.

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 Constraints are mapped to transmission facilities. In the Day-Ahead Market, within a given hour, a single facility may be associated with multiple constraints. In such situations, the same facility accounts for more than one constraint-hour for a given hour in the Day-Ahead Market. Similarly in the Real-Time Market a facility may account for more than one constraint-hour within a given hour.

Table 10-21 Congestion Event Hours (Day Ahead against Real Time): January through September 2011 and 2012 (See 2011 SOM, Table 10-21)

	Congestion Event Hours					
	2012 (Jan - Sep)			2011 (Jan - Sep)		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	21,819	2,493	11.4%	15,070	1,861	12.3%
Interface	4,451	167	3.8%	7,068	1,018	14.4%
Line	101,021	2,682	2.7%	58,823	2,364	4.0%
Other	3,871	265	6.8%	622	2	0.3%
Transformer	37,527	589	1.6%	21,131	1,475	7.0%
Total	168,689	6,196	3.7%	102,714	6,720	6.5%

Table 10-22 Congestion Event Hours (Real Time against Day Ahead): January through September 2011 and 2012 (See 2011 SOM, Table 10-22)

	Congestion Event Hours					
	2012 (Jan - Sep)			2011 (Jan - Sep)		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	5,355	2,569	48.0%	4,226	1,867	44.2%
Interface	421	165	39.2%	1,598	1,017	63.6%
Line	7,686	2,554	33.2%	7,291	2,329	31.9%
Other	428	229	53.5%	145	2	1.4%
Transformer	1,364	564	41.3%	3,276	1,445	44.1%
Total	15,254	6,081	39.9%	16,536	6,660	40.3%

Table 10-23 shows congestion costs by facility voltage class for the first nine months of 2012. In comparison to the first nine months of 2011 (shown in Table 10-24), congestion costs decreased across 765 kV, 500kV, 345 kV and 230kV in the first nine months of 2012.

Table 10-23 Congestion summary (By facility voltage): January through September 2012 (See 2011 SOM, Table 10-23)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	($0.1)	($2.8)	$2.6	$5.3	$0.2	($0.1)	($0.1)	$0.1	$5.4	2,256	89
500	$51.6	($59.8)	$1.9	$113.3	$14.1	$15.2	($5.8)	($6.9)	$106.4	8,040	686
345	($33.5)	($103.3)	$14.1	$84.0	$1.0	$6.1	($30.1)	($35.2)	$48.9	22,915	2,231
230	$62.8	($61.0)	$12.4	$136.1	$5.6	$5.9	($22.0)	($22.2)	$113.9	25,368	3,276
161	($11.4)	($17.9)	$4.5	$11.1	($0.8)	$1.5	($9.7)	($11.9)	($0.8)	3,012	1,189
138	($2.3)	($159.3)	$46.5	$203.4	($6.8)	$11.5	($69.1)	($87.3)	$116.1	87,865	6,281
115	$21.1	($2.2)	$2.6	$25.9	($0.4)	$1.5	($1.1)	($3.0)	$22.9	13,130	738
69	$22.0	$4.4	$0.3	$18.0	($9.5)	$2.3	$0.5	($11.3)	$6.6	6,091	762
34	($0.0)	($0.0)	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	0	2
12	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	12	0
Unclassified	$2.8	($1.4)	$1.9	$6.1	$0.2	$0.2	($0.2)	($0.3)	$5.8	NA	NA
Total	$113.1	($403.3)	$86.7	$603.2	$3.7	$44.1	($137.6)	($178.0)	$425.2	168,689	15,254

Table 10-24 Congestion summary (By facility voltage): January through September 2011 (See 2011 SOM, Table 10-24)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	$0.8	($8.7)	$2.0	$11.5	$2.8	$2.0	($2.4)	($1.6)	$9.9	830	139
500	$90.7	($440.7)	($7.5)	$523.8	$41.3	$45.6	($9.0)	($13.3)	$510.5	14,985	3,339
345	($64.9)	($184.5)	$10.7	$130.3	$7.4	$20.5	($54.0)	($67.1)	$63.2	17,547	2,704
230	($8.1)	($162.1)	$11.4	$165.4	$18.5	$19.0	($32.5)	($32.9)	$132.4	17,050	2,600
161	($8.5)	($13.1)	$4.4	$9.0	($1.0)	$3.5	($13.1)	($17.5)	($8.5)	1,098	651
138	$35.0	($122.7)	$16.7	$174.4	$4.3	$14.4	($35.0)	($45.0)	$129.4	36,790	5,830
115	$9.1	($14.5)	$3.0	$26.6	$1.8	$6.7	($1.2)	($6.1)	$20.5	7,789	738
69	$13.4	($1.2)	($0.2)	$14.4	($2.0)	$2.0	$0.0	($4.0)	$10.4	6,599	530
34	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	5
14	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	7	0
12	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	17	0
Unclassified	$0.7	($2.0)	$5.0	$7.8	$0.9	$0.3	($1.3)	($0.7)	$7.1	NA	NA
Total	$68.1	($949.4)	$45.6	$1,063.2	$74.0	$113.9	($148.4)	($188.3)	$874.9	102,697	16,536

Constraint Duration

Table 10-25 lists constraints in the first nine months of 2011 and 2012 that were most frequently in effect and Table 10-26 shows the constraints which experienced the largest change in congestion-event hours from the first nine months of 2011 to the first nine months of 2012.

Table 10-25 Top 25 constraints with frequent occurrence: January through September 2011 and 2012 (See 2011 SOM, Table 10-25)

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2011	2012	Change	2011	2012	Change	2011	2012	Change	2011	2012	Change
1	Sporn	Transformer	0	11,131	11,131	0	0	0	0%	127%	127%	0%	0%	0%
2	Oak Grove - Galesburg	Flowgate	1,098	3,012	1,914	651	1,182	531	13%	34%	22%	7%	13%	6%
3	Kammer	Transformer	260	3,285	3,025	47	13	(34)	3%	37%	34%	1%	0%	(0%)
4	Graceton - Raphael Road	Line	218	2,478	2,260	103	693	590	2%	28%	26%	1%	8%	7%
5	Monticello - East Winamac	Flowgate	482	2,544	2,062	120	567	447	6%	29%	23%	1%	6%	5%
6	Linden - VFT	Line	1,813	3,007	1,194	0	0	0	21%	34%	14%	0%	0%	0%
7	Huntingdon - Huntingdon1	Line	0	2,786	2,786	0	0	0	0%	32%	32%	0%	0%	0%
8	Cumberland - Bush	Flowgate	914	2,053	1,139	159	313	154	10%	23%	13%	2%	4%	2%
9	Big Sandy - Grangston	Line	29	2,218	2,189	0	0	0	0%	25%	25%	0%	0%	0%
10	Crete - St Johns Tap	Flowgate	2,763	1,910	(853)	640	277	(363)	32%	22%	(10%)	7%	3%	(4%)
11	Rockwell - Crosby	Line	0	2,050	2,050	0	0	0	0%	23%	23%	0%	0%	0%
12	Clover	Transformer	1,193	1,564	371	460	441	(19)	14%	18%	4%	5%	5%	(0%)
13	Howard - Shelby	Line	196	1,991	1,795	0	0	0	2%	23%	20%	0%	0%	0%
14	Dixon - Stillman Valley	Line	125	1,854	1,729	60	81	21	1%	21%	20%	1%	1%	0%
15	AP South	Interface	3,334	1,725	(1,609)	861	157	(704)	38%	20%	(18%)	10%	2%	(8%)
16	Taylor - Grenshaw	Line	0	1,831	1,831	0	0	0	0%	21%	21%	0%	0%	0%
17	Nelson - Cordova	Line	425	1,563	1,138	84	253	169	5%	18%	13%	1%	3%	2%
18	Belmont	Transformer	3,838	1,737	(2,101)	497	60	(437)	44%	20%	(24%)	6%	1%	(5%)
19	Conesville	Transformer	0	1,750	1,750	0	0	0	0%	20%	20%	0%	0%	0%
20	Wolfcreek	Transformer	2,148	1,611	(537)	226	49	(177)	25%	18%	(6%)	3%	1%	(2%)
21	Conesville	Transformer	0	1,594	1,594	0	0	0	0%	18%	18%	0%	0%	0%
22	Hillsdale - New Milford	Line	0	1,331	1,331	4	259	255	0%	15%	15%	0%	3%	3%
23	Bellefonte - Grangston	Line	12	1,577	1,565	0	0	0	0%	18%	18%	0%	0%	0%
24	Danville - East Danville	Line	3,297	1,570	(1,727)	321	6	(315)	38%	18%	(20%)	4%	0%	(4%)
25	Bayway - Federal Square	Line	777	1,503	726	15	48	33	9%	17%	8%	0%	1%	0%

Table 10-26 Top 25 constraints with largest year-to-year change in occurrence: January through September 2011 and 2012 (See 2011 SOM, Table 10-26)

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2011	2012	Change	2011	2012	Change	2011	2012	Change	2011	2012	Change
1	Sporn	Transformer	0	11,131	11,131	0	0	0	0%	127%	127%	0%	0%	0%
2	South Mahwah - Waldwick	Line	4,628	88	(4,540)	473	0	(473)	53%	1%	(52%)	5%	0%	(5%)
3	Kammer	Transformer	260	3,285	3,025	47	13	(34)	3%	37%	34%	1%	0%	(0%)
4	Graceton - Raphael Road	Line	218	2,478	2,260	103	693	590	2%	28%	26%	1%	8%	7%
5	Huntingdon - Huntingdon1	Line	0	2,786	2,786	0	0	0	0%	32%	32%	0%	0%	0%
6	Belmont	Transformer	3,838	1,737	(2,101)	497	60	(437)	44%	20%	(24%)	6%	1%	(5%)
7	Monticello - East Winamac	Flowgate	482	2,544	2,062	120	567	447	6%	29%	23%	1%	6%	5%
8	Oak Grove - Galesburg	Flowgate	1,098	3,012	1,914	651	1,182	531	13%	34%	22%	7%	13%	6%
9	AP South	Interface	3,334	1,725	(1,609)	861	157	(704)	38%	20%	(18%)	10%	2%	(8%)
10	Fairview	Transformer	2,248	0	(2,248)	0	0	0	26%	0%	(26%)	0%	0%	0%
11	Big Sandy - Grangston	Line	29	2,218	2,189	0	0	0	0%	25%	25%	0%	0%	0%
12	Cox's Corner - Marlton	Line	2,618	468	(2,150)	0	0	0	30%	5%	(25%)	0%	0%	0%
13	Rockwell - Crosby	Line	0	2,050	2,050	0	0	0	0%	23%	23%	0%	0%	0%
14	Danville - East Danville	Line	3,297	1,570	(1,727)	321	6	(315)	38%	18%	(20%)	4%	0%	(4%)
15	Michigan City - Laporte	Flowgate	2,323	866	(1,457)	571	40	(531)	27%	10%	(17%)	7%	0%	(6%)
16	Electric Jct - Nelson	Line	2,303	621	(1,682)	158	5	(153)	26%	7%	(19%)	2%	0%	(2%)
17	Taylor - Grenshaw	Line	0	1,831	1,831	0	0	0	0%	21%	21%	0%	0%	0%
18	Howard - Shelby	Line	196	1,991	1,795	0	0	0	2%	23%	20%	0%	0%	0%
19	Dixon - Stillman Valley	Line	125	1,854	1,729	60	81	21	1%	21%	20%	1%	1%	0%
20	Conesville	Transformer	0	1,750	1,750	0	0	0	0%	20%	20%	0%	0%	0%
21	East Frankfort - Crete	Line	1,403	1	(1,402)	313	0	(313)	16%	0%	(16%)	4%	0%	(4%)
22	Wylie Ridge	Transformer	1,882	572	(1,310)	357	4	(353)	21%	7%	(15%)	4%	0%	(4%)
23	Pinehill - Stratford	Line	1,888	288	(1,600)	0	0	0	22%	3%	(18%)	0%	0%	0%
24	Conesville	Transformer	0	1,594	1,594	0	0	0	0%	18%	18%	0%	0%	0%
25	Hillsdale - New Milford	Line	0	1,331	1,331	4	259	255	0%	15%	15%	0%	3%	3%

Constraint Costs

Table 10-27 and Table 10-28 present the top constraints affecting congestion costs by facility for the periods January through September 2012 and 2011.

Table 10-27 Top 25 constraints affecting PJM congestion costs (By facility): January through September 2012 (See 2011 SOM, Table 10-27)

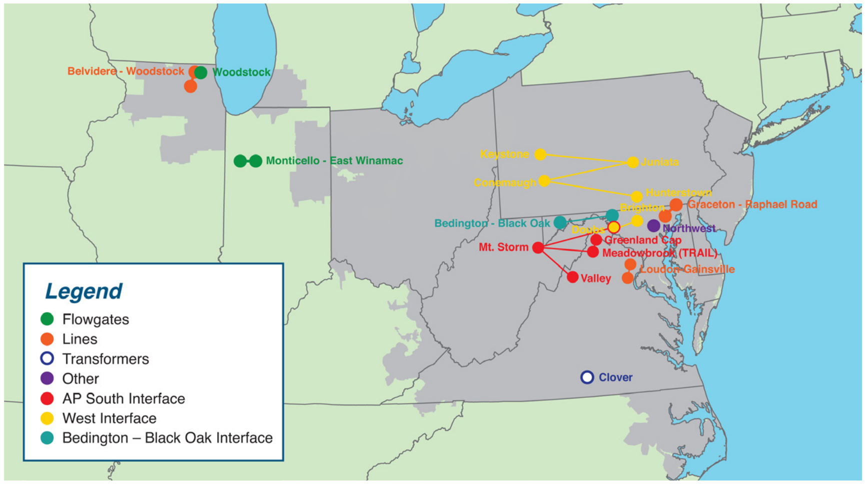
				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2012 (Jan - Sep)
1	AP South	Interface	500	$36.0	($14.0)	$1.3	$51.3	$7.1	$4.6	($2.9)	($0.4)	$50.9	12%
2	Graceton - Raphael Road	Line	BGE	$25.1	($7.8)	($1.6)	$31.3	$0.8	($1.1)	$0.2	$2.1	$33.4	8%
3	Woodstock	Flowgate	MISO	($7.0)	($30.2)	$6.8	$30.0	$0.0	$0.0	$0.0	$0.0	$30.0	7%
4	Belvidere - Woodstock	Line	ComEd	($0.2)	($4.7)	$0.9	$5.4	($2.4)	$3.2	($16.8)	($22.5)	($17.1)	(4%)
5	Clover	Transformer	Dominion	$9.4	($7.5)	$6.7	$23.6	$0.9	$0.7	($8.4)	($8.2)	$15.3	4%
6	West	Interface	500	($0.6)	($17.4)	($2.2)	$14.5	$1.2	$1.2	$0.5	$0.4	$15.0	4%
7	Monticello - East Winamac	Flowgate	MISO	($0.2)	($18.9)	$11.1	$29.8	$0.4	$2.0	($15.4)	($16.9)	$12.9	3%
8	Bedington - Black Oak	Interface	500	$9.0	($4.0)	($0.0)	$13.0	$1.0	$1.1	($0.7)	($0.8)	$12.1	3%
9	Loudoun - Gainsville	Line	Dominion	$0.4	($11.0)	($1.2)	$10.2	$0.6	$0.9	$0.2	($0.1)	$10.0	2%
10	Northwest	Other	BGE	$7.8	($2.4)	$0.4	$10.6	($0.7)	($0.1)	($0.8)	($1.5)	$9.1	2%
11	Nelson - Cordova	Line	ComEd	($16.6)	($29.5)	$5.8	$18.7	($0.9)	$1.6	($7.5)	($10.0)	$8.7	2%
12	Hunterstown	Transformer	Met-Ed	$3.4	($4.2)	$0.2	$7.8	$0.1	$0.0	($0.0)	$0.0	$7.8	2%
13	Pleasant Valley - Belvidere	Line	ComEd	($2.2)	($8.0)	$1.8	$7.6	$0.1	$0.1	($0.8)	($0.7)	$6.9	2%
14	Kammer	Transformer	AEP	($3.0)	($11.2)	($1.3)	$6.9	($0.2)	$0.1	$0.2	($0.0)	$6.9	2%
15	Unclassified	Unclassified	Unclassified	$2.8	($1.3)	$1.8	$6.0	$0.2	$0.2	($0.2)	($0.3)	$5.7	1%
16	AEP-DOM	Interface	500	$6.0	($2.0)	$0.9	$9.0	$1.0	$4.2	($0.5)	($3.7)	$5.2	1%
17	Crescent	Transformer	DLCO	$0.9	($4.3)	($0.2)	$5.1	$0.2	$0.2	($0.1)	$0.0	$5.1	1%
18	Belmont	Transformer	AP	$0.6	($5.5)	$0.6	$6.6	($0.4)	$0.8	($0.4)	($1.5)	$5.0	1%
19	Plymouth Meeting - Whitpain	Line	PECO	$0.8	($3.9)	($0.1)	$4.6	$0.3	$0.7	$0.5	$0.0	$4.7	1%
20	Electric Jct - Nelson	Line	ComEd	($1.3)	($4.2)	$1.7	$4.6	$0.0	$0.0	($0.0)	($0.0)	$4.6	1%
21	Silver Lake - Pleasant Valley	Line	ComEd	($2.8)	($6.0)	$1.3	$4.5	$0.0	$0.0	$0.0	$0.0	$4.5	1%
22	Buxmont - Whitpain	Line	PPL	($1.1)	($6.9)	($1.5)	$4.3	$0.0	$0.0	$0.0	$0.0	$4.3	1%
23	East	Interface	500	($2.6)	($7.9)	($0.6)	$4.7	$0.1	$0.5	($0.1)	($0.5)	$4.2	1%
24	5004/5005 Interface	Interface	500	$0.1	($4.0)	$0.4	$4.5	$2.4	$3.2	$0.5	($0.4)	$4.2	1%
25	Kenova - Tri State	Line	AEP	$0.4	($3.4)	($0.1)	$3.8	($0.0)	$0.1	$0.1	$0.0	$3.8	1%

Table 10-28 Top 25 constraints affecting PJM congestion costs (By facility): January through September 2011 (See 2011 SOM, Table 10-28)

				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2011 (Jan - Sep)
1	AP South	Interface	500	$87.4	($133.0)	($1.4)	$219.0	$17.9	$15.8	$1.9	$4.0	$223.1	25%
2	5004/5005 Interface	Interface	500	($24.7)	($96.7)	($4.7)	$67.4	$16.2	$18.3	$7.4	$5.2	$72.6	8%
3	West	Interface	500	($19.3)	($82.1)	($5.2)	$57.6	$0.2	$0.1	$0.1	$0.3	$57.8	7%
4	Belmont	Transformer	AP	$7.9	($48.7)	($2.3)	$54.3	($3.5)	($3.2)	($1.6)	($1.8)	$52.5	6%
5	AEP-DOM	Interface	500	$13.3	($19.3)	$2.0	$34.6	$1.9	$1.5	($0.3)	$0.1	$34.7	4%
6	Electric Jct - Nelson	Line	ComEd	($9.9)	($40.6)	$6.8	$37.6	$0.4	$3.7	($7.7)	($11.0)	$26.6	3%
7	Bedington - Black Oak	Interface	500	$10.6	($14.3)	($2.0)	$22.9	$0.2	$0.1	$0.0	$0.1	$23.1	3%
8	Crete - St Johns Tap	Flowgate	MISO	($27.7)	($53.3)	($4.0)	$21.7	$5.3	$4.4	($2.1)	($1.2)	$20.5	2%
9	Clover	Transformer	Dominion	$0.4	($21.3)	$4.5	$26.2	$2.8	$3.5	($7.6)	($8.3)	$17.9	2%
10	Dickerson - Quince Orchard	Line	Pepco	($9.4)	($28.8)	($1.7)	$17.7	$4.6	$7.4	$2.7	($0.2)	$17.5	2%
11	East	Interface	500	($10.1)	($27.5)	($1.1)	$16.2	$0.2	$1.3	$0.1	($1.0)	$15.3	2%
12	Susquehanna	Transformer	PPL	($2.9)	($17.4)	($0.1)	$14.4	$0.0	$0.0	$0.0	$0.0	$14.4	2%
13	Wylie Ridge	Transformer	AP	$15.3	$3.6	$1.8	$13.6	$2.2	$1.2	($2.5)	($1.5)	$12.1	1%
14	East Frankfort - Crete	Line	ComEd	($9.2)	($21.9)	($1.3)	$11.4	$0.6	$0.7	($0.5)	($0.6)	$10.8	1%
15	Brues - West Bellaire	Line	AEP	$19.5	$4.9	$0.6	$15.2	($1.9)	$1.7	($1.3)	($4.9)	$10.4	1%
16	Waldwick	Transformer	PSEG	($0.5)	($2.3)	$2.1	$3.8	$0.1	$1.3	($12.5)	($13.8)	($10.0)	(1%)
17	Plymouth Meeting - Whitpain	Line	PECO	($0.9)	($10.8)	($0.0)	$9.9	$0.2	$0.2	($0.1)	($0.2)	$9.7	1%
18	Cloverdale	Transformer	AEP	$0.5	($7.5)	$1.6	$9.6	$0.7	$0.6	($0.1)	($0.0)	$9.6	1%
19	Oak Grove - Galesburg	Flowgate	MISO	($8.5)	($13.1)	$4.4	$9.0	($1.0)	$3.5	($13.1)	($17.5)	($8.5)	(1%)
20	Bunsonville - Eugene	Flowgate	MISO	($8.3)	($14.6)	$1.5	$7.7	$0.0	$0.0	$0.0	$0.0	$7.7	1%
21	Unclassified	Unclassified	Unclassified	$0.7	($2.0)	$5.0	$7.8	$0.9	$0.3	($1.3)	($0.7)	$7.1	1%
22	Pleasant Valley - Belvidere	Line	ComEd	($6.5)	($17.0)	$1.7	$12.3	($0.6)	$2.1	($3.0)	($5.7)	$6.5	1%
23	Cloverdale - Lexington	Line	500	$4.8	($2.9)	$1.2	$9.0	$3.3	$2.1	($3.8)	($2.7)	$6.3	1%
24	Gore - Hampshire	Line	AP	$0.0	($6.3)	($0.3)	$6.1	$0.0	$0.0	$0.0	$0.0	$6.1	1%
25	Danville - East Danville	Line	AEP	$25.1	$16.4	($2.7)	$5.9	$1.7	$1.2	($0.7)	($0.2)	$5.7	1%

Figure 10-2 shows the locations of the top 10 constraints affecting PJM congestion costs in the first nine months of 2012.

Figure 10-2 Location of the top 10 constraints affecting PJM congestion costs: January through September 2012[17] (New Figure)



Congestion-Event Summary for MISO Flowgates

PJM and MISO 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.[18] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[19] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch. Table 10-29 and Table 10-30 show the MISO flowgates which PJM and/or MISO took dispatch action to control during the first nine months of 2012 and 2011 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 MISO flowgates affecting PJM and MISO dispatch are presented by constraint, in descending order of the absolute value of total congestion costs. Among MISO flowgates in the first nine months of 2012, the Woodstock flowgate made the most significant contribution to positive congestion while the Breed - Wheatland flowgate made the most significant contribution to negative congestion.

17 The term flowgate refers to MISO reciprocal coordinated flowgates in this section.
18 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed March 13, 2012).
19 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008), Section 2.2.24 <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed March 13, 2012).

Table 10-29 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through September 2012 (See 2011 SOM, Table 10-29)

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Woodstock	($7.0)	($30.2)	$6.8	$30.0	$0.0	$0.0	$0.0	$0.0	$30.0	1,073	567
2	Monticello - East Winamac	($0.2)	($18.9)	$11.1	$29.8	$0.4	$2.0	($15.4)	($16.9)	$12.9	2,544	567
3	Palisades - Roosevelt	($0.8)	($5.1)	($0.6)	$3.7	$0.1	$0.3	($0.2)	($0.4)	$3.3	739	209
4	Crete - St Johns Tap	($4.9)	($15.5)	($1.3)	$9.3	$0.3	$0.9	($5.7)	($6.3)	$3.0	1,910	277
5	Breed - Wheatland	($1.3)	($8.2)	($0.1)	$6.9	$0.3	$0.3	($9.6)	($9.6)	($2.8)	1,252	276
6	Miami Fort - Hebron	($1.4)	($4.2)	($0.2)	$2.6	($0.1)	($0.0)	$0.1	$0.0	$2.6	685	76
7	Benton Harbor - Palisades	($0.4)	($3.5)	($0.8)	$2.4	$0.1	$0.3	($0.2)	($0.4)	$2.0	506	71
8	Rising	($0.3)	($0.3)	$0.0	$0.1	($0.4)	$0.2	($1.1)	($1.6)	($1.5)	48	114
9	Prairie State - W Mt. Vernon	($1.8)	($2.8)	$0.5	$1.5	($0.0)	$0.0	($0.2)	($0.2)	$1.3	495	186
10	Cumberland - Bush	($1.2)	($5.5)	$6.2	$10.5	$0.4	$1.2	($10.9)	($11.7)	($1.2)	2,053	313
11	Edwards - Kewanee	($0.2)	($0.9)	$0.5	$1.1	$0.0	($0.1)	($0.2)	($0.1)	$1.0	224	59
12	Rantoul - Rantoul Jct	($2.3)	($4.8)	$0.3	$2.8	($0.2)	($0.1)	($1.7)	($1.9)	$0.9	1,051	315
13	Oak Grove - Galesburg	($11.4)	($17.9)	$4.5	$11.1	($0.8)	$1.5	($9.6)	($11.8)	($0.7)	3,012	1,182
14	Pana North	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.7)	($0.7)	($0.7)	0	12
15	Bunsonville - Eugene	($0.7)	($1.1)	$0.2	$0.7	$0.0	($0.1)	($0.1)	($0.0)	$0.7	236	42
16	Dunes Acres - Michigan City	($0.2)	($0.3)	$0.1	$0.2	($0.2)	($0.0)	($0.7)	($0.9)	($0.7)	180	11
17	Bush - Lafayette	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1	($0.6)	($0.7)	($0.7)	0	23
18	Michigan City - Laporte	($0.8)	($2.3)	($0.3)	$1.1	($0.3)	($0.1)	($0.3)	($0.5)	$0.6	866	40
19	Brokaw - Gibson	($0.5)	($0.9)	$0.2	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	160	0
20	Sheffield - Marktown	($1.1)	($2.1)	$0.2	$1.2	$0.2	$0.5	($0.3)	($0.7)	$0.5	1,055	0

Table 10-30 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through September 2011 (See 2011 SOM, Table 10-30)

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Crete - St Johns Tap	($27.7)	($53.3)	($4.0)	$21.7	$5.3	$4.4	($2.1)	($1.2)	$20.5	2,763	640
2	Oak Grove - Galesburg	($8.5)	($13.1)	$4.4	$9.0	($1.0)	$3.5	($13.1)	($17.5)	($8.5)	1,098	651
3	Bunsonville - Eugene	($8.3)	($14.6)	$1.5	$7.7	$0.0	$0.0	$0.0	$0.0	$7.7	1,794	0
4	Lakeview - Pleasant Prairie	($0.1)	($0.2)	$0.2	$0.3	($0.2)	($0.1)	($5.7)	($5.8)	($5.5)	24	294
5	Pleasant Prairie - Zion	($1.2)	($2.3)	$2.0	$3.1	($0.1)	($0.5)	($7.9)	($7.5)	($4.4)	839	210
6	Michigan City - Laporte	($9.1)	($14.4)	$2.2	$7.5	($1.4)	($1.1)	($3.2)	($3.6)	$3.9	2,323	571
7	Cook - Palisades	($0.9)	($3.9)	$0.2	$3.2	$0.0	$0.0	($0.2)	($0.2)	$3.0	419	9
8	Benton Harbor - Palisades	($0.2)	($1.0)	$0.2	$1.0	$1.1	$1.1	($2.7)	($2.8)	($1.8)	67	120
9	Nucor - Whitestown	$0.0	$0.0	$0.0	$0.0	$0.2	$0.5	($1.5)	($1.8)	($1.8)	0	49
10	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($1.6)	($1.7)	($1.7)	0	76
11	Rising	($5.2)	($8.1)	($0.1)	$2.8	$0.0	$1.1	($3.3)	($4.4)	($1.6)	947	172
12	Rantoul Jct - Sidney	($1.0)	($2.0)	$0.1	$1.1	$0.5	$0.0	($0.2)	$0.3	$1.3	62	113
13	Rantoul - Rantoul Jct	($1.8)	($3.1)	$0.3	$1.6	$0.1	$0.1	($0.4)	($0.4)	$1.2	289	129
14	Burr Oak	$1.0	($0.2)	$0.0	$1.2	$0.3	($0.0)	($0.4)	($0.1)	$1.2	147	27
15	Kenosha - Lakeview	$0.3	($2.4)	$0.8	$3.6	($0.3)	($0.6)	($5.0)	($4.7)	($1.1)	986	349
16	Pierce - Foster	$0.0	$0.0	$0.0	$0.0	$0.4	$0.2	($1.2)	($1.0)	($1.0)	0	16
17	Cooper South	$0.0	$0.0	$0.0	$0.0	$0.0	$0.2	($0.6)	($0.8)	($0.8)	0	16
18	Cumberland - Bush	($0.4)	($2.8)	$0.8	$3.1	$0.2	$0.3	($2.4)	($2.4)	$0.7	914	159
19	Breed - Wheatland	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.7)	($0.6)	($0.6)	0	27
20	Miami Fort	($0.1)	($0.7)	$0.0	$0.6	$0.0	$0.0	($0.0)	($0.0)	$0.6	96	5

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 10-31 and Table 10-32 show the 500 kV constraints impacting congestion costs in PJM for the first nine months of 2012 and 2011 respectively. 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.

Table 10-31 Regional constraints summary (By facility): January through September 2012 (See 2011 SOM, Table 10-31)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$36.0	($14.0)	$1.3	$51.3	$7.1	$4.6	($2.9)	($0.4)	$50.9	1,725	17
2	West	Interface	500	($0.6)	($17.4)	($2.2)	$14.5	$1.2	$1.2	$0.5	$0.4	$15.0	369	17
3	Bedington - Black Oak	Interface	500	$9.0	($4.0)	($0.0)	$13.0	$1.0	$1.1	($0.7)	($0.8)	$12.1	412	54
4	AEP-DOM	Interface	500	$6.0	($2.0)	$0.9	$9.0	$1.0	$4.2	($0.5)	($3.7)	$5.2	1,299	59
5	East	Interface	500	($2.6)	($7.9)	($0.6)	$4.7	$0.1	$0.5	($0.1)	($0.5)	$4.2	190	5
6	5004/5005 Interface	Interface	500	$0.1	($4.0)	$0.4	$4.5	$2.4	$3.2	$0.5	($0.4)	$4.2	160	121
7	Doubs - Mount Storm	Line	500	$1.3	($1.1)	$0.1	$2.5	$0.0	$0.0	$0.0	$0.0	$2.5	80	0
8	Central	Interface	500	($0.8)	($1.4)	$0.1	$0.8	$0.0	$0.0	($0.0)	($0.0)	$0.8	184	2
9	Cloverdale - Lexington	Line	500	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.8)	($0.8)	($0.7)	7	61
10	Nagel	Line	500	$0.1	($0.0)	($0.0)	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	30	0
11	AEP - DOM	Interface	500	$0.0	($0.0)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	41	0
12	Mount Storm - Pruntytown	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	0	2
13	Kammer	Transformer	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	19
14	Branchburg - Elroy	Line	500	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0
15	Burches Hill - Chalk Point	Line	500	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0

Table 10-32 Regional constraints summary (By facility): January through September 2011 (See 2011 SOM, Table 10-32)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$87.4	($133.0)	($1.4)	$219.0	$17.9	$15.8	$1.9	$4.0	$223.1	3,334	861
2	5004/5005 Interface	Interface	500	($24.7)	($96.7)	($4.7)	$67.4	$16.2	$18.3	$7.4	$5.2	$72.6	684	439
3	West	Interface	500	($19.3)	($82.1)	($5.2)	$57.6	$0.2	$0.1	$0.1	$0.3	$57.8	798	19
4	AEP-DOM	Interface	500	$13.3	($19.3)	$2.0	$34.6	$1.9	$1.5	($0.3)	$0.1	$34.7	1,269	172
5	Bedington - Black Oak	Interface	500	$10.6	($14.3)	($2.0)	$22.9	$0.2	$0.1	$0.0	$0.1	$23.1	624	7
6	East	Interface	500	($10.1)	($27.5)	($1.1)	$16.2	$0.2	$1.3	$0.1	($1.0)	$15.3	295	22
7	Cloverdale - Lexington	Line	500	$4.8	($2.9)	$1.2	$9.0	$3.3	$2.1	($3.8)	($2.7)	$6.3	589	427
8	Central	Interface	500	($1.3)	($2.4)	($0.1)	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	64	0
9	Mount Storm - Pruntytown	Line	500	$0.1	($0.2)	$0.0	$0.3	$0.2	$0.0	($0.1)	$0.0	$0.3	29	38
10	Doubs - Mount Storm	Line	500	$0.0	($0.3)	($0.0)	$0.3	($0.0)	$0.0	($0.0)	($0.0)	$0.3	9	4
11	Harrison - Pruntytown	Line	500	$0.0	($0.1)	$0.0	$0.1	($0.0)	($0.0)	$0.0	$0.0	$0.1	10	4
12	Dominion East	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.3	$0.1	($0.2)	$0.0	$0.0	0	38
13	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	0	9

Generation and Transmission Planning

Highlights

- At September 30, 2012, 75,869 MW of capacity were in generation request queues to be in service through 2018, compared to an average installed capacity of 185,000 MW in 2012 including the January 1, 2012, DEOK integration. Wind projects account for 26,495 MW, 34.9 percent of the capacity in the queues, and combined-cycle projects account for 38,806 MW, 51.1 percent of the capacity in the queues.
- A total of 6,722 MW of generation capacity retired between January and October 1, 2012, and it is expected that a total of 19,142.8 MW will have retired from 2011 through 2019, with most of this capacity retiring by the end of 2015. Units that have retired through October 1, 2012, make up 35 percent of all retirements currently expected to occur from 2012 through 2019.

Planned Generation and Retirements

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 investors' perception of the incentives provided by the combination of revenues from the PJM Energy, Capacity and Ancillary Service Markets. At September 30, 2012, 75,869 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 185,000 MW in 2012 including the January 1, 2012, DEOK integration. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000 (Table 11-1).[1] Overall, 1,898 MW of nameplate capacity were added in PJM between January and September 2012 (excluding the integration of the DEOK zone).

1 The capacity additions are new MW by year, including full nameplate capacity of solar and wind facilities and are not net of retirements or deratings.

Table 11-1 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through September 30, 2012[2] (See 2011 SOM, Table 11-1)

	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
2010	2,097
2011	5,008
January-September 2012	1,898

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 until Queue T, when new queues began to open annually. Queue Y will be active through January 31, 2013.

Capacity in generation request queues for the seven year period beginning in 2012 and ending in 2018 decreased by 14,856 MW from 90,725 MW in 2011 to 75,869 MW in 2012, or 16.4 percent (Table 11-2).[3] Queued capacity scheduled for service in 2012 decreased from 27,184 MW to 14,924 MW, or 45.1 percent. Queued capacity scheduled for service in 2013 decreased from 13,051 MW to 9,144 MW, or 29.9 percent. The 75,869 MW includes generation with scheduled in-service dates in 2012 and units still active in the queue with in-service dates scheduled before 2012, listed at nameplate capacity, although these units are not yet in service.

2 The capacity described in this table refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.
3 See the *2011 State of the Market Report for PJM*: Volume II, Section 11, pp. 286-288, for the queues in 2011.

Table 11-2 Queue comparison (MW): September 30, 2012 vs. December 31, 2011 (See 2011 SOM, Table 11-3)

	MW in the Queue 2011	MW in the Queue 2012	Year-to-Year Change (MW)	Year-to-Year Change
2012	27,184	14,924	(12,260)	(45.1%)
2013	13,051	9,144	(3,908)	(29.9%)
2014	17,036	11,212	(5,824)	(34.2%)
2015	19,251	24,198	4,947	25.7%
2016	9,288	8,858	(430)	(4.6%)
2017	1,720	5,939	4,219	245.3%
2018	3,194	1,594	(1,600)	(50.1%)
Total	90,725	75,869	(14,856)	(16.4%)

Table 11-3 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.[4]

Table 11-3 Capacity in PJM queues (MW): At September 30, 2012[5, 6] (See 2011 SOM, Table 11-4)

Queue	Active	In-Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,103	0	17,347	25,450
B Expired 31-Jan-99	0	4,646	0	14,957	19,602
C Expired 31-Jul-99	0	531	0	3,471	4,002
D Expired 31-Jan-00	0	851	0	7,182	8,033
E Expired 31-Jul-00	0	795	0	8,022	8,817
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	0	1,116	525	17,409	19,050
H Expired 31-Jan-02	0	703	0	8,422	9,124
I Expired 31-Jul-02	0	103	0	3,728	3,831
J Expired 31-Jan-03	0	40	0	846	886
K Expired 31-Jul-03	0	218	80	2,345	2,643
L Expired 31-Jan-04	0	257	0	4,034	4,290
M Expired 31-Jul-04	0	505	422	3,556	4,482
N Expired 31-Jan-05	0	2,279	38	8,090	10,407
O Expired 31-Jul-05	10	1,491	1,025	5,066	7,592
P Expired 31-Jan-06	413	2,915	455	4,908	8,690
Q Expired 31-Jul-06	120	2,038	2,914	9,462	14,534
R Expired 31-Jan-07	1,866	1,216	778	18,894	22,755
S Expired 31-Jul-07	1,778	3,243	652	11,469	17,142
T Expired 31-Jan-08	7,802	1,197	821	17,726	27,546
U Expired 31-Jan-09	4,684	256	541	27,876	33,357
V Expired 31-Jan-10	5,692	227	1,658	9,426	17,004
W Expired 31-Jan-11	9,338	245	1,111	13,565	24,259
X Expired 31-Jan-12	21,922	47	312	8,674	30,955
Y Expires 31-Jan-13	10,903	0	8	730	11,642
Total	64,528	33,073	11,341	230,297	339,239

Data presented in Table 11-4 show that through the first nine months of 2012, 38.5 percent of total in-service capacity from all the queues was from Queues A and B and an additional 6.5 percent was from Queues C, D and E.[7] As of September 30, 2012, 31.8 percent of the capacity in Queues A and B has been placed in service, and 9.7 percent of all queued capacity has been placed in service.

4 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.

5 The *2012 Quarterly State of the Market Report for PJM: January through September* contains all projects in the queue including reratings of existing generating units and energy only resources.
6 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.
7 The data for Queue Y include projects through September 30, 2012.

The data presented in Table 11-4 show that for successful projects there is an average time of 812 days between entering a queue and the in-service date, an increase of 30 days since the third quarter of 2011. The data also show that for withdrawn projects, there is an average time of 529 days between entering a queue and completion or exiting. For each status, there is substantial variability around the average results.

Table 11-4 Average project queue times (days): At September 30, 2012 (See 2011 SOM, Table 11-5)

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	886	629	0	2,801
In-Service	812	714	0	3,964
Suspended	2,198	818	704	3,849
Under Construction	1,344	804	0	5,083
Withdrawn	529	550	0	3,186

Table 11-5 shows queued capacity that was planned to be in service by September 30, 2012. This indicates there is a substantial amount of queued capacity that is not yet under construction that should already be in service based on the original queue date.

Table 11-5 Active capacity queued to be in service prior to October 1, 2012 (New table)

	MW
2007	87.0
2008	362.0
2009	344.4
2010	2,417.5
2011	4,325.4
2012	1,387.6
Total	8,923.9

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. At September 30, 2012, 75,869 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 185,000 MW in 2012 including the January 1, 2012, DEOK integration. Wind projects account for 26,495 MW, 34.9 percent of the capacity in the queues, and combined-cycle projects account for 38,806 MW, 51.1 percent of the capacity in the queues. On September 30, 2012, there were 38,806 MW of capacity from combined cycle units in the queue, compared to 34,788 MW in 2011, an increase of 11.6 percent.

Table 11-6 shows the projects under construction or active as of September 30, 2012, by unit type and control zone. Most of the steam projects (92.5 percent of the MW) and most of the wind projects (93.3 percent of the MW) are outside the Eastern MAAC (EMAAC)[8] and Southwestern MAAC (SWMAAC)[9] locational deliverability areas (LDAs).[10] Of the total capacity additions, only 14,571 MW, or 19.2 percent, are projected to be in EMAAC, while 4,201 MW or 5.5 percent are projected to be constructed in SWMAAC. Of total capacity additions, 28,348 MW, or 37.4 percent of capacity, is being added inside MAAC zones. Overall, 75.3 percent of capacity is being added outside EMAAC and SWMAAC, and 62.6 percent of capacity is being added outside MAAC zones.

Wind projects account for 26,495 MW of capacity or 34.9 percent of the capacity in the queues and combined-cycle projects account for 38,806 MW of capacity or 51.1 percent of the capacity in the queues.[11] Wind projects account for 3,468 MW of capacity in MAAC LDAs, or 12.2 percent. While there are no wind projects in the SWMAAC LDA, in the EMAAC LDA wind projects account for 1,769 MW of capacity, or 12.1 percent.

8 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG Control Zones.
9 SWMAAC consists of the BGE and Pepco Control Zones.
10 See the *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.
11 Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent of installed capacity until actual generation data are available. Beginning with Queue U, PJM derates wind resources to 13 percent of installed capacity. PJM derates solar resources to 38 percent of installed capacity. Based on the derating of 26,495 MW of wind resources and 2,675 MW of solar resources, the 75,869 MW currently active in the queue would be reduced to 51,159 MW.

Table 11-6 Capacity additions in active or under-construction queues by control zone (MW): At September 30, 2012 (See 2011 SOM, Table 11-6)

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	2,737	63	9	0	0	519	138	0	1,419	4,885
AEP	4,370	0	70	70	0	118	183	8	10,878	15,697
AP	984	0	13	75	0	202	869	0	826	2,970
ATSI	4,692	40	10	0	30	65	135	0	849	5,820
BGE	678	256	0	0	0	2	0	0	0	936
ComEd	1,080	444	95	23	607	65	600	46	9,010	11,970
DAY	0	0	2	112	0	23	12	0	845	994
DEOK	20	0	0	0	0	0	0	0	0	20
DLCO	40	0	0	5	91	0	0	0	0	136
Dominion	6,676	535	0	0	1,594	120	370	0	619	9,914
DPL	1,221	1	4	0	0	276	22	27	330	1,881
JCPL	2,770	47	30	0	0	942	0	0	0	3,788
Met-Ed	1,818	0	18	0	58	3	0	0	0	1,897
PECO	48	7	8	0	470	10	0	5	0	547
PENELEC	879	43	224	0	0	32	106	0	1,215	2,499
Pepco	3,245	0	20	0	0	0	0	0	0	3,265
PPL	4,476	11	2	3	100	84	0	20	485	5,180
PSEG	3,073	77	9	0	50	215	24	2	20	3,469
Total	38,806	1,525	513	288	3,000	2,675	2,459	108	26,495	75,869

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 are replaced by units burning natural gas. (Table 11-7)

Table 11-7 Capacity additions in active or under-construction queues by LDA (MW): At September 30, 2012[12] (See 2011 SOM, Table 11-7)

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
EMAAC	9,848	195	60	0	520	1,961	184	34	1,769	14,571
SWMAAC	3,923	256	20	0	0	2	0	0	0	4,201
WMAAC	7,173	55	244	3	158	119	106	20	1,699	9,576
Non-MAAC	17,862	1,019	190	285	2,322	593	2,169	54	23,027	47,521
Total	38,806	1,525	513	288	3,000	2,675	2,459	108	26,495	75,869

Table 11-8 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 11-6) 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. The western part of the PJM footprint is also likely to see a shift to more natural gas-fired capacity due to changes in environmental regulations and natural gas costs, but likely will maintain a larger amount of coal steam capacity than eastern zones.

12 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.

Table 11-8 Existing PJM capacity: At September 30, 2012[13] (By zone and unit type (MW)) (See 2011 SOM, Table 11-8)

	CC	CT	Diesel	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	164	701	21	0	0	40	1,087	0	8	2,020
AEP	4,900	3,682	60	1,072	2,071	0	21,677	0	1,553	35,015
AP	1,129	1,215	34	80	0	16	7,372	27	799	10,672
ATSI	685	1,661	71	0	2,134	0	6,540	0	0	11,091
BGE	0	835	11	0	1,714	0	3,007	0	0	5,567
ComEd	1,763	7,257	94	0	10,438	0	5,417	0	2,254	27,223
DAY	0	1,369	48	0	0	1	4,368	0	0	5,785
DEOK	0	842	0	0	0	0	2,671	0	0	3,513
DLCO	244	15	0	6	1,777	0	784	0	0	2,826
Dominion	4,030	3,762	174	3,589	3,581	3	8,320	0	0	23,457
DPL	1,125	1,822	96	0	0	0	1,800	3	0	4,847
External	974	990	0	66	439	0	5,728	0	185	8,382
JCPL	1,693	1,232	27	400	615	25	15	0	0	4,005
Met-Ed	2,051	408	41	20	805	0	844	0	0	4,168
PECO	3,209	836	6	1,642	4,541	3	1,145	1	0	11,383
PENELEC	0	344	46	513	0	0	6,831	0	750	8,483
Pepco	230	1,092	12	0	0	0	3,649	0	0	4,983
PPL	1,793	618	49	582	2,520	0	5,537	0	220	11,317
PSEG	3,091	2,838	12	5	3,493	98	2,040	0	0	11,577
Total	27,080	31,516	800	7,974	34,127	185	88,830	31	5,769	196,312

Table 11-9 shows the age of PJM generators by unit type.

Table 11-9 PJM capacity (MW) by age: at September 30, 2012 (See 2011 SOM Table 11-9)

Age (years)	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 11	18,982	9,255	445	11	0	185	2,496	31	5,734	37,140
11 to 20	6,062	13,070	106	48	0	0	3,261	0	34	22,582
21 to 30	1,594	1,663	56	3,448	15,409	0	8,504	0	0	30,674
31 to 40	244	3,106	43	105	16,353	0	28,696	0	0	48,547
41 to 50	198	4,421	135	2,915	2,365	0	29,492	0	0	39,526
51 to 60	0	0	15	379	0	0	13,682	0	0	14,076
61 to 70	0	0	0	0	0	0	2,526	0	0	2,526
71 to 80	0	0	0	280	0	0	95	0	0	375
81 to 90	0	0	0	549	0	0	79	0	0	628
91 to 100	0	0	0	155	0	0	0	0	0	155
101 and over	0	0	0	84	0	0	0	0	0	84
Total	27,080	31,516	800	7,974	34,127	185	88,830	31	5,769	196,312

13 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Table 11-10 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 generation.

Without the planned coal-fired capability in EMAAC, new gas-fired capability would represent 69.8 percent of all new capability in EMAAC and 86.3 percent when the derating of wind and solar capacity is reflected.

A planned addition of 1,640 MW of nuclear capacity to Calvert Cliffs in SWMAAC was withdrawn from the queue. Without the planned nuclear capability in SWMAAC, new gas-fired capability represents 99.4 percent of all new capability in the SWMAAC. In 2018, this would mean that CC and CT generators would comprise 55.1 percent of total capability in SWMAAC.

In Non-MAAC zones, if older units retire, a substantial amount of coal-fired generation would be replaced by wind generation if the units in the generation queues are constructed.[14] In these zones, 87.9 percent of all generation 40 years or older is steam (primarily coal). With the retirement of these units in 2018, wind farms would comprise 19.7 percent of total capacity in Non-MAAC zones, if all queued capacity is built.

14 Non-MAAC zones consist of the AEP, AP, ATSI, ComEd, DAY, DEOK, DLCO, and Dominion Control Zones.

Table 11-10 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2018[15] (See 2011 SOM, Table 11-10)

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	Combined Cycle	198	2.4%	9,282	27.4%	9,848	18,932	46.5%
	Combustion Turbine	2,229	27.0%	7,429	22.0%	195	5,395	13.2%
	Diesel	51	0.6%	162	0.5%	60	171	0.4%
	Hydroelectric	2,042	24.7%	2,047	6.1%	0	620	1.5%
	Nuclear	615	7.4%	8,648	25.6%	520	8,554	21.0%
	Solar	0	0.0%	165	0.5%	1,961	2,126	5.2%
	Steam	3,135	37.9%	6,087	18.0%	184	3,136	7.7%
	Storage	0	0.0%	4	0.0%	34	38	0.1%
	Wind	0	0.0%	8	0.0%	1,769	1,777	4.4%
	EMAAC Total	8,269	100.0%	33,831	100.0%	14,571	40,748	100.0%
SWMAAC	Combined Cycle	0	0.0%	230	2.2%	3,923	4,153	39.5%
	Combustion Turbine	542	12.8%	1,927	18.3%	256	1,640	15.6%
	Diesel	0	0.0%	23	0.2%	20	43	0.4%
	Nuclear	0	0.0%	1,714	16.2%	0	1,714	16.3%
	Solar	0	0.0%	0	0.0%	2	2	0.0%
	Steam	3,702	87.2%	6,656	63.1%	0	2,954	28.1%
	SWMAAC Total	4,244	100.0%	10,549	100.0%	4,201	10,506	100.0%
WMAAC	Combined Cycle	0	0.0%	3,843	16.0%	7,173	11,016	77.5%
	Combustion Turbine	559	6.1%	1,369	5.7%	55	865	6.1%
	Diesel	46	0.5%	136	0.6%	244	333	2.3%
	Hydroelectric	887	9.7%	1,114	4.6%	3	1,117	7.9%
	Nuclear	0	0.0%	3,325	13.9%	158	3,483	24.5%
	Solar	0	0.0%	0	0.0%	119	119	0.8%
	Steam	7,702	83.8%	13,211	55.1%	106	5,616	39.5%
	Storage	0	0.0%	0	0.0%	20	20	0.1%
	Wind	0	0.0%	970	4.0%	1,699	2,669	18.8%
	WMAAC Total	9,194	100.0%	23,968	100.0%	9,576	14,222	100.0%
Non-MAAC	Combined Cycle	0	0.0%	13,724	10.7%	17,862	31,587	22.4%
	Combustion Turbine	1,092	3.1%	20,792	16.2%	1,019	20,719	14.7%
	Diesel	53	0.1%	480	0.4%	190	617	0.4%
	Hydroelectric	1,433	4.0%	4,814	3.8%	285	5,098	3.6%
	Nuclear	1,751	4.9%	20,440	16.0%	2,322	21,011	14.9%
	Solar	0	0.0%	20	0.0%	593	613	0.4%
	Steam	31,336	87.9%	62,876	49.1%	2,169	33,710	23.9%
	Storage	0	0.0%	27	0.0%	54	82	0.1%
	Wind	0	0.0%	4,791	3.7%	23,027	27,818	19.7%
	Non-MAAC Total	35,663	100.0%	127,964	100.0%	47,521	141,254	100.0%
All Areas	Total	57,369		196,312		75,869	206,730	

15 Percentages shown in Table 11-10 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Planned Deactivations

As shown in Table 11-11, 11,098.5 MW are planning to deactivate by the end of calendar year 2019. Units planning to retire in 2012 make up 189.9 MW, or 2 percent of all planned retirements. Of deactivations in 2012, 1,458 MW, or 21.5 percent, are located in the ATSI zone. Overall, 3,951.1 MW, or 35.6 percent of all retirements, are expected in the AEP zone. Figure 11-1 shows plant retirements throughout the PJM footprint, with retirements in nearly every PJM state. A total of 1,322.3 MW retired in 2011, and a total of 6,722 MW retired between January and October 1, 2012. It is expected that a total of 19,142.8 MW will have retired by 2019, with most of this capacity retiring by the end of 2015.

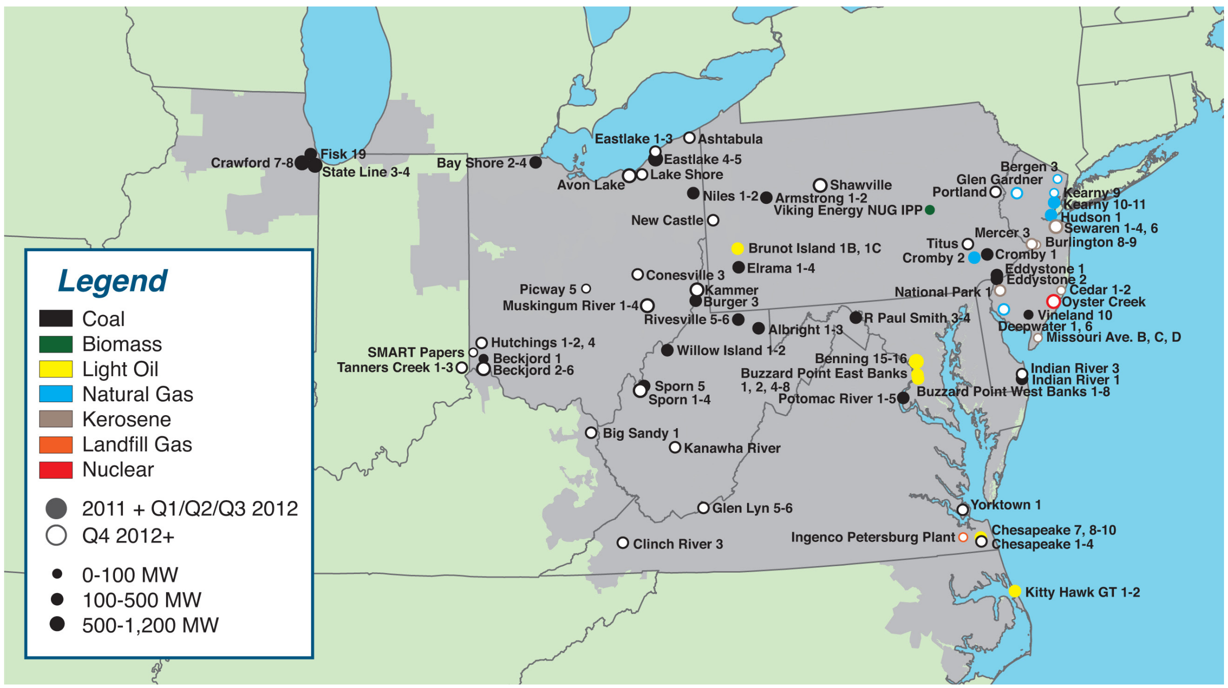
Table 11-11 Summary of PJM unit retirements (MW): Calendar year 2011 through 2019 (See 2011 SOM, Table 11-11)

	MW
Retirements 2011	1,322.3
Retirements 2012	6,722.0
Planned Retirements 2012	189.9
Planned Retirements Post-2012	10,908.6
Total	19,142.8

Table 11-12 Planned deactivations of PJM units in calendar year 2012 as of October 1, 2012[16] (See 2011 SOM, Table 11-12)

Unit	Zone	MW	Projected Deactivation Date
SMART Paper	DEOK	24.9	10-Aug-12
Conesville 3	AEP	165.0	31-Dec-12
Total		189.9	

Figure 11-1 Unit retirements in PJM Calendar year 2011 through 2019 (See 2011 SOM, Figure 11-1)



16 See "Pending Deactivation Requests," <http://pjm.com/planning/generation-retirements/~/media/planning/gen-retire/pending-deactivation-requests.ashx> (Accessed October 5, 2012).

Table 11-13 Planned deactivations of PJM units after calendar year 2012, as of October 1, 2012 (See 2011 SOM, Table 11-13)

Unit	Zone	MW	Projected Deactivation Date
Ingenco Petersburg Plant	Dominion	2.9	31-May-13
Hutchings 4	DAY	61.9	01-Jun-13
Burlington 9	PSEG	184.0	01-Jun-13
Indian River 3	DPL	169.7	31-Dec-13
Chesapeake 1-2	Dominion	222.0	31-Dec-14
Yorktown 1	Dominion	159.0	31-Dec-14
Portland	Met-Ed	401.0	07-Jan-15
Beckjord 2-6	DEOK	1,024.0	01-Apr-15
Avon Lake	ATSI	732.0	16-Apr-15
New Castle	ATSI	330.5	16-Apr-15
Titus	Met-Ed	243.0	16-Apr-15
Shawville	PENELEC	597.0	16-Apr-15
Glen Gardner	JCPL	160.0	01-May-15
Kearny 9	PSEG	21.0	01-May-15
Cedar 1-2	AECO	67.7	31-May-15
Deepwater 1, 6	AECO	158.0	31-May-15
Missouri Ave B, C, D	AECO	60.0	31-May-15
Big Sandy 2	AEP	278.0	01-Jun-15
Clinch River 3	AEP	230.0	01-Jun-15
Glen Lyn 5-6	AEP	325.0	01-Jun-15
Kammer	AEP	600.0	01-Jun-15
Kanawha River	AEP	400.0	01-Jun-15
Muskingum River 1-4	AEP	790.0	01-Jun-15
Picway 5	AEP	95.0	01-Jun-15
Sporn	AEP	580.0	01-Jun-15
Tanners Creek 1-3	AEP	488.1	01-Jun-15
Ashtabula	ATSI	210.0	01-Jun-15
Eastlake 1-3	ATSI	327.0	01-Jun-15
Lake Shore	ATSI	190.0	01-Jun-15
Hutchings 1-2	DAY	97.3	01-Jun-15
Bergen 3	PSEG	21.0	01-Jun-15
Burlington 8	PSEG	21.0	01-Jun-15
Mercer 3	PSEG	115.0	01-Jun-15
National Park 1	PSEG	21.0	01-Jun-15
Sewaren 1-4, 6	PSEG	558.0	01-Jun-15
Chesapeake 3-4	Dominion	354.0	31-Dec-15
Oyster Creek	JCPL	614.5	31-Dec-19
Total		10,908.6	

Table 11-14 HEDD Units in PJM as of October 1, 2012[17] (See 2011 SOM, Table 11-14)

Unit	Zone	MW
Carlls Corner 1-2	AECO	72.6
Cedar Station 1-3	AECO	66.0
Cumberland 1	AECO	92.0
Mickleton 1	AECO	72.0
Middle Street 1-3	AECO	75.3
Missouri Ave. B,C,D	AECO	60.0
Sherman Ave.	AECO	92.0
Vineland West CT	AECO	26.0
Forked River 1-2	JCPL	65.0
Gilbert 4-7, 9, C1-C4	JCPL	446.0
Glen Gardner A1-A4, B1-B4	JCPL	160.0
Lakewood 1-2	JCPL	316.1
Parlin NUG	JCPL	114.0
Sayreville C1-C4	JCPL	224.0
South River NUG	JCPL	299.0
Werner C1-C4	JCPL	212.0
Bayonne	PSEG	118.5
Bergen 3	PSEG	21.0
Burlington 111-114, 121-124, 91-94, 8	PSEG	557.0
Camden	PSEG	145.0
Eagle Point 1-2	PSEG	127.1
Edison 11-14, 21-24, 31-34	PSEG	504.0
Elmwood	PSEG	67.0
Essex 101-104, 111-114, 121,124	PSEG	536.0
Kearny 9-11, 121-124	PSEG	446.0
Linden 1-2	PSEG	1,230.0
Mercer 3	PSEG	115.0
National Park	PSEG	21.0
Newark Bay	PSEG	120.2
Pedricktown	PSEG	120.3
Salem 3	PSEG	38.4
Sewaren 6	PSEG	105.0
Total		6,663.5

Actual Generation Deactivations in 2012

Table 11-15 shows unit deactivations for 2012.[18] A total of 6,722 MW retired in January through October 1, 2012, including 2,320 MW from FirstEnergy Corp, or 34.5 percent of all retirements. The retirements included 5,718.0 MW

17 See "Current New Jersey Turbines that are HEDD Units," <*http://www.state.nj.us/dep/workgroups/docs/apcrule_20110909turbinelist.pdf*> (Accessed October 1, 2012).
18 "*PJM Generator Deactivations*," PJM.com <*http://pjm.com/planning/generation-retirements/gr-summaries.aspx*> (October 5, 2012).

of coal steam generation, 788.0 MW of light oil generation, 250.0 MW of natural gas generation, and 16.0 MW of wood waste generation. Of retirements in 2012, 1,458.0 MW, or 21.5 percent, were in the ATSI zone

Table 11-15 Unit deactivations: January through October 1, 2012 (See 2011 SOM, Table 11-15)

Company	Unit Name	ICAP	Primary Fuel	Zone Name	Age (Years)	Retirement Date
American Electric Power Company, Inc.	Sporn 5	440.0	Coal	AEP	51	Feb 13, 2012
Edison International	State Line 3	197.0	Coal	ComEd	56	Mar 25, 2012
Edison International	State Line 4	318.0	Coal	ComEd	51	Mar 25, 2012
GDF Suez	Viking Energy NUG	16.0	Wood Waste	PPL	24	Mar 31, 2012
Duke Energy Corporation	Walter C Beckjord 1	94.0	Coal	DEOK	59	May 01, 2012
Pepco Holdings, Inc.	Buzzard Point East Banks 1, 2, 4-8	112.0	Light Oil	Pepco	44	May 31, 2012
Pepco Holdings, Inc.	Buzzard Point West Banks 1-9	128.0	Light Oil	Pepco	44	May 31, 2012
Exelon Corporation	Eddystone 2	309.0	Coal	PECO	51	May 31, 2012
GenOn Energy, Inc.	Niles 2	108.0	Coal	ATSI	58	Jun 01, 2012
GenOn Energy, Inc.	Elrama 1	93.0	Coal	DLCO	60	Jun 01, 2012
GenOn Energy, Inc.	Elrama 2	93.0	Coal	DLCO	59	Jun 01, 2012
GenOn Energy, Inc.	Elrama 3	103.0	Coal	DLCO	57	Jun 01, 2012
Public Service Enterprise Group Incorporated	Kearny 10	122.0	Natural Gas	PSEG	42	Jun 01, 2012
Public Service Enterprise Group Incorporated	Kearny 11	128.0	Natural Gas	PSEG	42	Jun 01, 2012
Pepco Holdings, Inc.	Benning 15	275.0	Light Oil	Pepco	44	Jul 17, 2012
Pepco Holdings, Inc.	Benning 16	273.0	Light Oil	Pepco	40	Jul 17, 2012
Edison International	Crawford 8	319.0	Coal	ComEd	51	Aug 24, 2012
Edison International	Crawford 7	213.0	Coal	ComEd	54	Aug 28, 2012
Edison International	Fisk Street 19	326.0	Coal	ComEd	53	Aug 30, 2012
FirstEnergy Corp	Albright 1	73.0	Coal	APS	59	Sep 01, 2012
FirstEnergy Corp	Albright 2	73.0	Coal	APS	59	Sep 01, 2012
FirstEnergy Corp	Albright 3	137.0	Coal	APS	57	Sep 01, 2012
FirstEnergy Corp	Armstrong 1	172.0	Coal	APS	54	Sep 01, 2012
FirstEnergy Corp	Armstrong 2	171.0	Coal	APS	55	Sep 01, 2012
FirstEnergy Corp	R Paul Smith 3	28.0	Coal	APS	64	Sep 01, 2012
FirstEnergy Corp	R Paul Smith 4	87.0	Coal	APS	53	Sep 01, 2012
FirstEnergy Corp	Rivesville 5	35.0	Coal	APS	69	Sep 01, 2012
FirstEnergy Corp	Rivesville 6	86.0	Coal	APS	61	Sep 01, 2012
FirstEnergy Corp	Willow Island 1	53.0	Coal	APS	63	Sep 01, 2012
FirstEnergy Corp	Willow Island 2	164.0	Coal	APS	51	Sep 01, 2012
FirstEnergy Corp	Bay Shore 2	120.0	Coal	ATSI	53	Sep 01, 2012
FirstEnergy Corp	Bay Shore 3	119.0	Coal	ATSI	49	Sep 01, 2012
FirstEnergy Corp	Bay Shore 4	180.0	Coal	ATSI	44	Sep 01, 2012
FirstEnergy Corp	Eastlake 4	225.0	Coal	ATSI	56	Sep 01, 2012
FirstEnergy Corp	Eastlake 5	597.0	Coal	ATSI	40	Sep 01, 2012
City of Vineland	Howard Down 10	23.0	Coal	AECO	42	Sep 01, 2012
GenOn Energy, Inc.	Niles 1	109.0	Coal	ATSI	58	Oct 01, 2012
GenOn Energy, Inc.	Elrama 4	171.0	Coal	DLCO	51	Oct 01, 2012
GenOn Energy, Inc.	Potomac River 1	88.0	Coal	Pepco	63	Oct 01, 2012
GenOn Energy, Inc.	Potomac River 2	88.0	Coal	Pepco	62	Oct 01, 2012
GenOn Energy, Inc.	Potomac River 3	102.0	Coal	Pepco	58	Oct 01, 2012
GenOn Energy, Inc.	Potomac River 4	102.0	Coal	Pepco	56	Oct 01, 2012
GenOn Energy, Inc.	Potomac River 5	102.0	Coal	Pepco	55	Oct 01, 2012

Updates on Key Backbone Facilities

PJM continually implements baseline upgrade projects to eliminate violations of reliability criteria. The backbone projects are implemented to reinforce the Extra High Voltage (EHV) parts of the PJM transmission system. The reinforcement of the EHV subsystems helps to eliminate major reliability criteria violations and reduces congestion. The current backbone projects are: Mount Storm – Doubs; Jacks Mountain; Mid-Atlantic Power Pathway (MAPP); Potomac – Appalachian Transmission Highline (PATH); and Susquehanna – Roseland.

In August, 2012, the PJM Board of Managers cancelled the Potomac-Appalachian Transmission Highline (PATH) and Mid-Atlantic Power Pathway (MAPP) projects based on recommendations from Transmission Expansion Advisory Committee (TEAC). The decision to cancel the projects was also based on the reductions in load growth and increases in demand response.[19]

On October 1, 2012, the Susquehanna – Roseland project received final approval from the National Park Service (NPS) for the project to be constructed on the route selected by PSEG and PPL.[20]

19 See PJM.com. "Potomac – Appalachian Transmission Highline (PATH) <*http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/path.aspx*>. (Accessed November 1, 2012)

20 See PSEG.com. "Susquehanna-Roseland line receives final federal approval" <*http://www.pseg.com/info/media/newsreleases/2012/2012-10-02.jsp*>. (Accessed November 1, 2012)

Financial Transmission and Auction Revenue Rights

In an LMP market, the lowest cost generation is dispatched to meet the load, subject to the ability of the transmission system to deliver that energy. When the lowest cost generation is remote from load centers, the physical transmission system permits that lowest cost generation to be delivered to load. This was true prior to the introduction of LMP markets and continues to be true in LMP markets. Prior to the introduction of LMP markets, contracts based on the physical rights associated with the transmission system were the mechanism used to provide for the delivery of low cost generation to load. Firm transmission customers who paid for the transmission system through rates were the beneficiaries of the system.

After the introduction of LMP markets, financial transmission rights permitted the loads which pay for the transmission system to continue to receive those benefits in the form of revenues which offset congestion to the extent permitted by the transmission system.[1] Financial transmission rights and the associated revenues were directly provided to loads in recognition of the fact that loads pay for the transmission system which permits low cost generation to be delivered to load and which creates the funds available to offset congestion costs in an LMP market.[2]

In PJM, Financial Transmission Rights (FTRs) were part of the market design, and FTRs were available to network service and long-term, firm, point-to-point transmission service customers as an offset to congestion costs, from the inception of locational marginal pricing (LMP) on April 1, 1998.[3]

Effective June 1, 2003, PJM replaced the allocation of FTRs with an allocation of Auction Revenue Rights (ARRs) and an associated Annual FTR Auction.[4, 5] Since then, all PJM members have been eligible to purchase FTRs in auctions. On June 1, 2007, PJM implemented marginal losses in the calculation of LMP.

1 *See* 81 FERC ¶ 61,257, at 62,241 (1997).
2 *See Id.* at 62, 259–62,260 & n. 123.
3 *Id.*
4 102 FERC ¶ 61,276 (2003).
5 87 FERC ¶ 61,054 (1999).

Since then, FTRs have been valued based on the difference in congestion prices rather than the difference in LMPs. FTR funding has been based on both day ahead and balancing congestion revenues from its initial design.

PJM created the split between ARRs and FTRs in order to both continue to provide the appropriate protection against congestion for load, and to permit any excess transmission capacity on the system to be made available to those market participants who wished to use FTRs to speculate or to hedge positions. This separation substantively changed the definition of FTRs. FTRs no longer represent the rights of load to the congestion offset associated with the physical transmission system, but instead represent the potential offset to congestion costs associated with the excess capability of the transmission system to deliver energy over and above that assigned to ARRs.

The *2012 Quarterly State of the Market Report for PJM: January through September* focuses on the Monthly Balance of Planning Period FTR Auctions during the 2012 to 2013 planning period, which covers June 1, 2012, through September 30, 2013.

Table 12-1 The FTR Auction Markets results were competitive (See 2011 SOM, Table 12-1)

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	Competitive	Effective

- The market structure was evaluated as competitive because the FTR auction is voluntary and the ownership positions resulted from the distribution of ARRs and voluntary participation.
- Participant behavior was evaluated as competitive because there was no evidence of anti-competitive behavior.
- Performance was evaluated as competitive because it reflected the interaction between participant demand behavior and FTR supply, limited by PJM's analysis of system feasibility.

- Market design was evaluated as effective because the market design provides a wide range of options for market participants to acquire FTRs and a competitive auction mechanism.

Highlights

- The total cleared FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2012 to 2013 planning period decreased by 15.2 percent from 1,067,015 MW to 904,797 MW compared to the first four months of the 2011 to 2012 planning period.
- FTRs were paid at 79.1 percent for the first four months of the 2012 to 2013 planning period.
- FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. FTRs were not profitable overall for physical entities but were profitable for financial entities in the period from January through September 2012. Total FTR profits were -$3.3 million for physical entities and $77.2 million for financial entities. Self-scheduled FTRs were the source of $134.0 million of the FTR profits for physical entities.

Conclusion

The annual ARR allocation provides firm transmission service customers with the financial equivalent of physically firm transmission service, without requiring physical transmission rights that are difficult to define and enforce. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service. With the creation of ARRs, FTRs no longer serve their original function of providing firm transmission customers with the financial equivalent of physically firm transmission service. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy.

Financial Transmission Rights

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, subject to revenue adequacy. 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, 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 is a cap on what FTR holders can receive. Revenues above that level are used to fund FTRs which received less than their target allocations.

FTR funding is not on a path specific basis or on a time specific basis. There are cross subsidies paid to equalize payments across paths and across time periods within a planning period. All paths receive the same proportional level of target revenue. FTR auction revenues and excess revenues are 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 for 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.

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. Revenues to fund FTRs come from both day-ahead congestion

6 For additional information on marginal losses, see the *2011 State of the Market Report for PJM*, Volume II, Section 10, "Congestion and Marginal Losses," at "Marginal Losses."

charges on the transmission system and balancing congestion charges. 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 in the Annual FTR Auction.

There are two types of FTR 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.

PJM operates an Annual FTR Auction for all participants. In addition PJM conducts Monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period, which allows participants to buy and sell 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. FTR options are not available in the Long Term FTR Auction. A secondary bilateral market is also administered by PJM to allow participants to buy and sell existing FTRs. FTRs can also be exchanged bilaterally outside PJM markets.

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, and only in the Annual FTR Auction.

As one of the measures to address FTR funding, effective August 5, 2011, PJM does not allow FTR buy bids to clear with a price of zero unless there is at least one constraint in the auction which affects the FTR path.

Market Structure

Any PJM member can participate in the Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions.

Supply and Demand

Monthly Balance of Planning Period FTR Auctions

The residual capability of the PJM transmission system after the Long Term and Annual FTR Auctions are concluded is offered in the Monthly Balance of Planning Period FTR Auctions. These are single-round monthly auctions that allow any transmission service customer or PJM member 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 planning period. FTRs in the auctions include obligations and options and 24-hour, on peak or off peak products.[7]

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 bilateral market system.

7 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 39.

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.

Credit Issues

Default

In June 2012 PJM processed $38 million of billing adjustments associated with marginal loss surplus allocations. These billing adjustments required participants to repay refunds which had been previously ordered by FERC and subsequently reversed by FERC. Five of the companies required to repay the allocation defaulted based on inadequate collateral and fifteen defaulted on payment of their billing adjustments, totaling $28.3 million in defaults. One company cured its payment default. Default Allocation Assessments were included in the next monthly bill for non-defaulting members to cover the unpaid billing adjustments. Twenty five additional members defaulted on $96,000 of their payment obligations resulting from these billed Default Allocation Assessments.

In addition, unrelated to the marginal loss surplus billing adjustments, eighteen participants defaulted during the first three quarters of 2012 from nineteen default events. The average of these defaults was $401,467, with seven based on inadequate collateral and twelve based on nonpayment. Six of these defaults were cured as of the last report with a remaining default average of $49,412.[8] All of the defaulting participants were financial companies. These defaults were not necessarily related to FTR positions.

As reported in a filing to FERC on April 23, 2012, PJM terminated RTP Controls, Inc's membership due to a credit default effective March 9, 2012.[9] RTP Controls was declared in default three times within a twelve month period, and in accordance with sections 15.1.6(c) and 4.1(c) of the Operating Agreement its membership was terminated and its forward market positions liquidated.

Patterns of Ownership

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.

For the Monthly Balance of Planning Period Auctions of January through September 2012, financial entities purchased 81.6 percent of prevailing flow and 86.6 percent of counter flow FTRs for 2012. Financial entities owned 61.6 percent of all prevailing and counter flow FTRs, including 53.3 percent of all prevailing flow FTRs and 79.9 percent of all counter flow FTRs.

Table 12-2 presents the Monthly Balance of Planning Period FTR Auction market cleared FTRs for January through September 2012 by trade type, organization type and FTR direction.

Table 12-2 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through September 2012 (See 2011 SOM, Table 12-6)

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	18.4%	13.4%	16.2%
	Financial	81.6%	86.6%	83.8%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	24.2%	7.5%	18.8%
	Financial	75.8%	92.5%	81.2%
	Total	100.0%	100.0%	100.0%

8 Email to Members Committee, "PJM Settlement Member Credit Exposure and Default Disclosure Report – September 2012," October 11, 2012.
9 Burlew, James. Letter to Honorable Kimberly D. Bose. April 23, 2012.

Table 12-3 presents the daily FTR net position ownership for January through September 2012 by FTR direction.

Table 12-3 Daily FTR net position ownership by FTR direction: January through September 2012 (See 2011 SOM, Table 12-7)

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	46.7%	20.1%	38.4%
Financial	53.3%	79.9%	61.6%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

In the Monthly Balance of Planning Period FTR Auctions for the first four months (June through September, 2012) of the 2012 to 2013 planning period, total participant FTR sell offers were 2,217,996 MW, down from 2,527,945 MW for the same period during the 2011 to 2012 planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2012 to 2013 (June 2012 through September 2012) planning period increased 15.6 percent from 7,977,007 MW, during the same time period of the prior planning period, to 9,223,203 MW. For the first four months of the 2012 to 2013 planning period, FTR auctions cleared 904,797 MW (9.8 percent) of FTR buy bids and 283,924 MW (12.8 percent) of sell offers.

Table 12-4 provides the Monthly Balance of Planning Period FTR market volume for the first nine months of 2012, the entire 2011 to 2012 planning period and the first four months of the 2012 to 2013 planning period.

Table 12-4 Monthly Balance of Planning Period FTR Auction market volume: January through September 2012 (See 2011 SOM, Table 12-11)

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-12	Obligations	Buy bids	185,712	1,024,729	146,344	14.3%	878,385	85.7%
		Sell offers	75,415	421,756	48,770	11.6%	372,986	88.4%
	Options	Buy bids	2,721	215,626	1,680	0.8%	213,946	99.2%
		Sell offers	5,615	45,756	10,572	23.1%	35,184	76.9%
Feb-12	Obligations	Buy bids	207,775	1,039,918	147,207	14.2%	892,711	85.8%
		Sell offers	80,631	375,855	47,609	12.7%	328,246	87.3%
	Options	Buy bids	2,247	194,423	2,620	1.3%	191,804	98.7%
		Sell offers	5,299	42,130	8,241	19.6%	33,889	80.4%
Mar-12	Obligations	Buy bids	197,115	893,900	156,694	17.5%	737,206	82.5%
		Sell offers	77,440	400,030	50,162	12.5%	349,868	87.5%
	Options	Buy bids	3,463	232,307	5,079	2.2%	227,228	97.8%
		Sell offers	5,869	60,228	11,952	19.8%	48,276	80.2%
Apr-12	Obligations	Buy bids	142,073	662,487	128,791	19.4%	533,695	80.6%
		Sell offers	55,915	306,492	49,050	16.0%	257,442	84.0%
	Options	Buy bids	4,259	133,298	2,427	1.8%	130,871	98.2%
		Sell offers	3,767	40,214	9,597	23.9%	30,617	76.1%
May-12	Obligations	Buy bids	89,626	464,275	93,721	20.2%	370,554	79.8%
		Sell offers	27,827	156,483	42,051	26.9%	114,432	73.1%
	Options	Buy bids	539	6,220	921	14.8%	5,299	85.2%
		Sell offers	2,017	18,909	10,402	55.0%	8,507	45.0%
Jun-12	Obligations	Buy bids	231,094	1,308,800	200,836	15.3%	1,107,963	84.7%
		Sell offers	88,406	418,825	33,562	8.0%	385,262	92.0%
	Options	Buy bids	20,190	1,314,332	8,527	0.6%	1,305,806	99.4%
		Sell offers	19,390	163,948	35,669	21.8%	128,279	78.2%
Jul-12	Obligations	Buy bids	268,379	1,355,612	244,325	18.0%	1,111,287	82.0%
		Sell offers	103,032	444,140	43,815	9.9%	400,325	90.1%
	Options	Buy bids	20,083	1,379,657	7,624	0.6%	1,372,033	99.4%
		Sell offers	15,896	113,139	25,438	22.5%	87,701	77.5%
Aug-12	Obligations	Buy bids	240,490	1,320,134	219,428	16.6%	1,100,706	83.4%
		Sell offers	108,381	395,062	49,382	12.5%	345,680	87.5%
	Options	Buy bids	4,582	98,115	7,004	7.1%	91,112	92.9%
		Sell offers	17,553	114,076	25,357	22.2%	88,719	77.8%
Sep-12	Obligations	Buy bids	232,215	1,308,752	206,467	15.8%	1,102,286	84.2%
		Sell offers	127,461	456,861	43,445	9.5%	413,416	90.5%
	Options	Buy bids	14,767	1,137,801	10,587	0.9%	1,127,214	99.1%
		Sell offers	17,728	111,945	27,256	24.3%	84,688	75.7%
2011/2012*	Obligations	Buy bids	2,787,546	15,084,909	2,216,646	14.7%	12,868,263	85.3%
		Sell offers	1,078,612	5,164,979	551,669	10.7%	4,613,310	89.3%
	Options	Buy bids	40,237	2,549,347	58,829	2.3%	2,490,519	97.7%
		Sell offers	99,695	687,656	164,180	23.9%	523,476	76.1%
2012/2013**	Obligations	Buy bids	972,178	5,293,298	871,056	16.5%	4,422,242	83.5%
		Sell offers	427,280	1,714,888	170,204	9.9%	1,544,684	90.1%
	Options	Buy bids	59,622	3,929,905	33,741	0.9%	3,896,164	99.1%
		Sell offers	70,567	503,107	113,720	22.6%	389,388	77.4%

* Shows Twelve Months for 2011/2012; ** Shows four months ended 30-Sep-12 for 2012/2013

Table 12-5 presents the buy-bid, bid and cleared volume of the Monthly Balance of Planning Period FTR Auction, and the effective periods for the volume.

Table 12-5 Monthly Balance of Planning Period FTR Auction buy-bid, bid and cleared volume (MW per period): January through September 2012 (See 2011 SOM, Table 12-12)

Monthly Auction	MW Type	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-12	Bid	649,775	210,717	168,284				211,578	1,240,355
	Cleared	110,546	15,316	8,624				13,537	148,024
Feb-12	Bid	651,268	240,292	189,159				153,622	1,234,341
	Cleared	103,278	20,608	15,634				10,307	149,827
Mar-12	Bid	570,266	266,873	208,586				80,482	1,126,207
	Cleared	117,447	22,710	16,217				5,400	161,773
Apr-12	Bid	579,513	216,271						795,784
	Cleared	115,408	15,810						131,218
May-12	Bid	470,495							470,495
	Cleared	94,642							94,642
Jun-12	Bid	708,790	372,480	348,955	92,103	365,680	369,416	365,707	2,623,132
	Cleared	104,967	20,127	16,731	9,850	22,471	17,552	17,664	209,363
Jul-12	Bid	810,399	393,948	356,419		397,111	396,290	381,102	2,735,269
	Cleared	130,965	26,218	17,256		25,812	27,939	23,759	251,949
Aug-12	Bid	650,279	166,379	162,525		121,561	163,558	153,946	1,418,249
	Cleared	130,706	20,892	20,608		11,719	22,169	20,337	226,432
Sep-12	Bid	794,152	384,866	356,543		120,840	400,055	390,097	2,446,553
	Cleared	120,426	26,470	19,959		8,747	21,376	20,076	217,053

Figure 12-1 shows the cleared auction volume as a percent of the total FTR cleared volume by calendar months for June 2004 through September 2012. FTR volume is shown by the calendar month that it is effective, with Long Term and Annual FTR auction volume contributing a constant amount to each calendar month in its effective planning period.

Figure 12-1 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through September 2012 (See 2011 SOM, Figure 12-2)

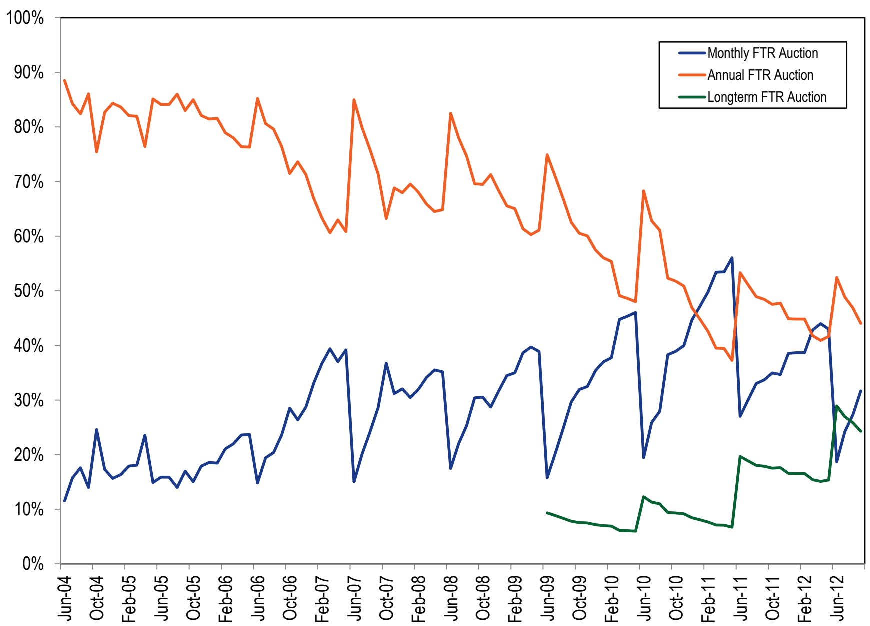


Table 12-6 provides the Secondary bilateral FTR market volume for the entire 2011 to 2012 planning period and the first four months of the 2012 to 2013 planning period.

Table 12-6 Secondary bilateral FTR market volume: Planning periods 2011 to 2012 and 2012 to 2013[10] (See 2011 SOM, Table 12-13)

Planning Period	Hedge Type	Class Type	Volume (MW)
2011/2012	Obligation	24-Hour	239
		On Peak	11,925
		Off Peak	4,268
		Total	16,431
	Option	24-Hour	0
		On Peak	8,965
		Off Peak	6,330
		Total	15,296
2012/2013*	Obligation	24-Hour	90
		On Peak	18
		Off Peak	0
		Total	107
	Option	24-Hour	0
		On Peak	0
		Off Peak	0
		Total	0

* Shows four months ended 30-Sep-2012

Figure 12-2 shows the historic FTR bid, cleared and net bid volume from June 2003 through September 2012 for Long Term, Annual and Monthly Balance of Planning Period Auctions. Cleared volume represents the volume of FTRs buy and sell offers that were accepted. The net bid volume includes the total buy, sell and self-scheduled offers in a given auction, counting sell offers as a negative volume. The bid volume is the total of all bid and self-scheduled offers in a given auction whether or not they cleared, excluding sell offers.

10 The 2012 to 2013 planning period covers bilateral FTRs that are effective for any time between June 1, 2012 through September 30, 2012, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

Figure 12-2 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through September 2012 (See 2011 SOM, Figure 12-3)

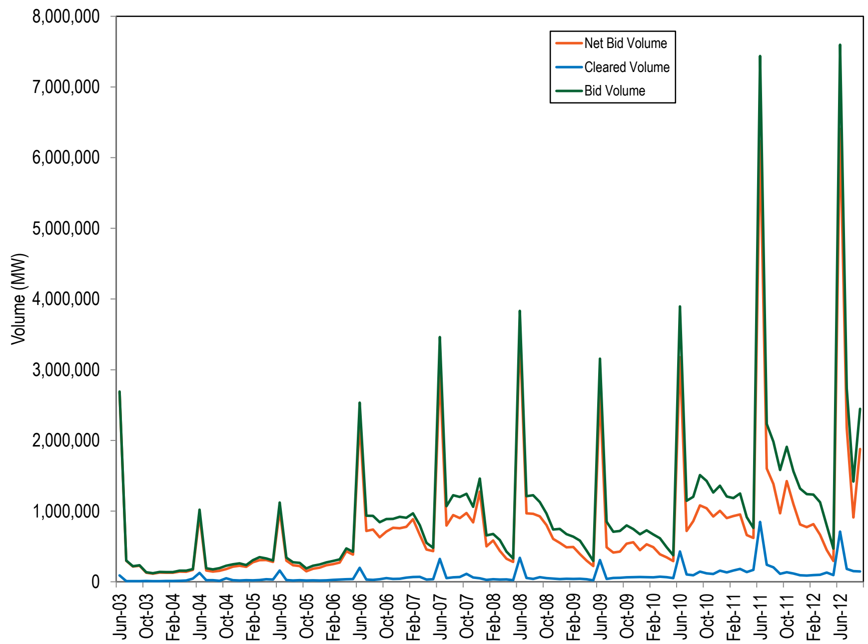
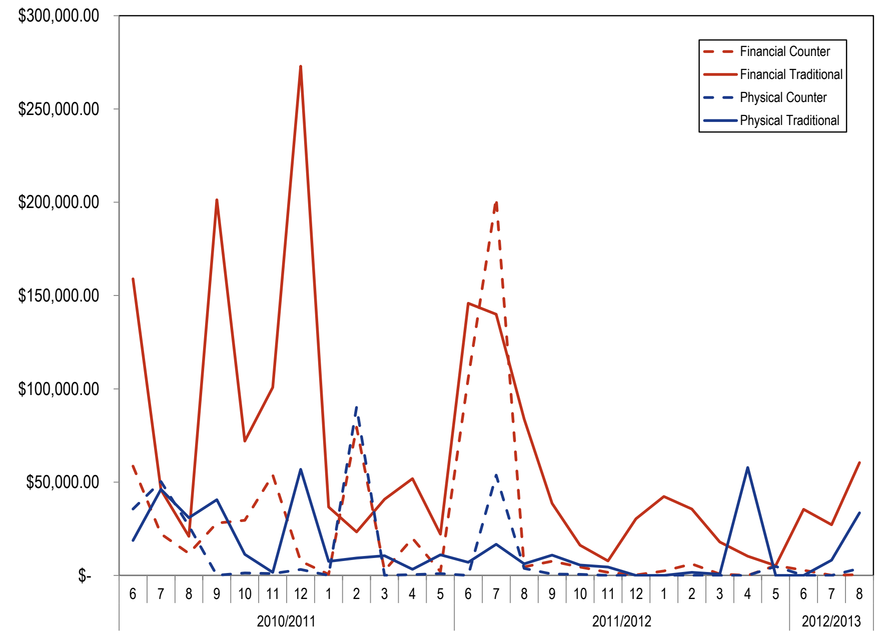


Figure 12-3 Monthly FTR Forfeitures for physical and financial participants: June 2010 through August 2012 (New Figure)



FTR Forfeitures

An FTR holder may be subject to forfeiture of any profits if it meets the criteria defined in Section 6 of Attachment M of the PJM Open Access Transmission Tariff (OATT).

Figure 12-3 shows the FTR forfeitures for both counter flow FTRs and prevailing flow FTRs for physical and financial companies from June 2010 through August 2012.

Price

The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2012 to 2013 planning period was $0.11, down from $0.13 per MW in the first four months of the 2011 to 2012 planning period.

Table 12-7 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2012 through September 2012.

Table 12-7 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MW): January through September 2012 (See 2011 SOM, Table 12-16)

Monthly Auction	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-12	$0.10	$0.14	$0.04				$0.13	$0.11
Feb-12	$0.10	$0.09	$0.11				$0.16	$0.11
Mar-12	$0.06	$0.13	$0.11				$0.01	$0.07
Apr-12	$0.08	$0.15						$0.08
May-12	$0.11							$0.11
Jun-12	$0.11	$0.20	$0.16	$0.30	$0.10	$0.17	$0.10	$0.14
Jul-12	$0.09	$0.11	$0.03		$0.09	$0.12	$0.08	$0.09
Aug-12	$0.10	$0.09	$0.09		$0.08	$0.19	$0.10	$0.11
Sep-12	$0.08	$0.15	$0.11		$0.06	$0.18	$0.13	$0.11

Revenue

Monthly Balance of Planning Period FTR Auction Revenue

The Monthly Balance of Planning Period FTR Auctions generated $11.9 million in net revenue for all FTRs for the first four months of the 2012 to 2013 planning period, down from $17.0 million for the same time period in the 2011 to 2012 planning period.

Table 12-8 shows Monthly Balance of Planning Period FTR Auction revenue data by trade type, hedge type and class type for January through September 2012.

Table 12-8 Monthly Balance of Planning Period FTR Auction revenue: January through September 2012 (See 2011 SOM, Table 12-20)

			Class Type			
Monthly Auction	Hedge Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-12	Obligations	Buy bids	$524,730	$3,220,163	$2,694,130	$6,439,023
		Sell offers	$273,645	$2,111,566	$1,753,975	$4,139,186
	Options	Buy bids	$47,640	$250,066	$185,282	$482,989
		Sell offers	$3,520	$1,158,143	$803,885	$1,965,548
Feb-12	Obligations	Buy bids	$738,466	$3,603,048	$2,051,190	$6,392,705
		Sell offers	$157,900	$3,038,310	$1,577,337	$4,773,546
	Options	Buy bids	$0	$289,791	$229,111	$518,902
		Sell offers	$0	$648,876	$439,093	$1,087,969
Mar-12	Obligations	Buy bids	$52,294	$2,878,603	$1,411,063	$4,341,960
		Sell offers	$205,654	$1,869,094	$670,898	$2,745,647
	Options	Buy bids	$9,004	$170,196	$109,643	$288,843
		Sell offers	$0	$613,978	$496,981	$1,110,960
Apr-12	Obligations	Buy bids	($103,515)	$2,497,186	$1,518,273	$3,911,943
		Sell offers	$261,819	$1,380,449	$742,304	$2,384,572
	Options	Buy bids	$0	$66,944	$50,134	$117,078
		Sell offers	$0	$455,585	$380,110	$835,695
May-12	Obligations	Buy bids	$331,445	$1,959,349	$1,414,983	$3,705,777
		Sell offers	$20,537	$1,196,092	$767,455	$1,984,084
	Options	Buy bids	$0	$22,067	$12,390	$34,458
		Sell offers	$4,435	$569,872	$486,239	$1,060,545
Jun-12	Obligations	Buy bids	$1,675,452	$10,781,405	$4,151,710	$16,608,567
		Sell offers	$374,681	$6,390,257	$1,919,494	$8,684,433
	Options	Buy bids	$64,800	$685,972	$578,673	$1,329,445
		Sell offers	$0	$3,780,497	$2,069,955	$5,850,452
Jul-12	Obligations	Buy bids	($859,311)	$9,916,659	$3,550,156	$12,607,505
		Sell offers	($849,209)	$6,099,746	$1,367,013	$6,617,550
	Options	Buy bids	$0	$736,304	$502,081	$1,238,385
		Sell offers	$0	$2,857,593	$1,792,063	$4,649,656
Aug-12	Obligations	Buy bids	$48,011	$8,111,495	$4,740,753	$12,900,258
		Sell offers	$32,573	$4,002,172	$1,840,346	$5,875,091
	Options	Buy bids	$965	$752,557	$296,514	$1,050,035
		Sell offers	$5,087	$2,340,565	$1,958,938	$4,304,590
Sep-12	Obligations	Buy bids	($608,953)	$8,762,531	$4,088,277	$12,241,856
		Sell offers	$436,202	$4,077,427	$1,414,673	$5,928,301
	Options	Buy bids	$1,436	$650,310	$336,001	$987,746
		Sell offers	$0	$3,190,050	$1,947,586	$5,137,636
2011/2012*	Obligations	Buy bids	$11,022,879	$70,675,860	$43,198,742	$124,897,481
		Sell offers	$4,694,451	$44,380,545	$26,582,133	$75,657,129
	Options	Buy bids	$117,492	$4,428,304	$3,191,765	$7,737,562
		Sell offers	$14,172	$18,614,021	$12,092,649	$30,720,842
	Total		$6,431,748	$12,109,598	$7,715,726	$26,257,072
2012/2013**	Obligations	Buy bids	$255,199	$37,572,091	$16,530,896	$54,358,186
		Sell offers	($5,753)	$20,569,601	$6,541,526	$27,105,375
	Options	Buy bids	$67,200	$2,825,143	$1,713,269	$4,605,612
		Sell offers	$5,087	$12,168,706	$7,768,541	$19,942,334
	Total		$323,064	$7,658,927	$3,934,098	$11,916,089

* Shows Twelve Months for 2011/2012; ** Shows four months ended 30-Sep-2012 for 2012/2013

Figure 12-4 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 four months of the 2012 to 2013 planning period.

Figure 12-4 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2012 to 2013 through September 30, 2012 (See 2011 SOM, Figure 12-11)

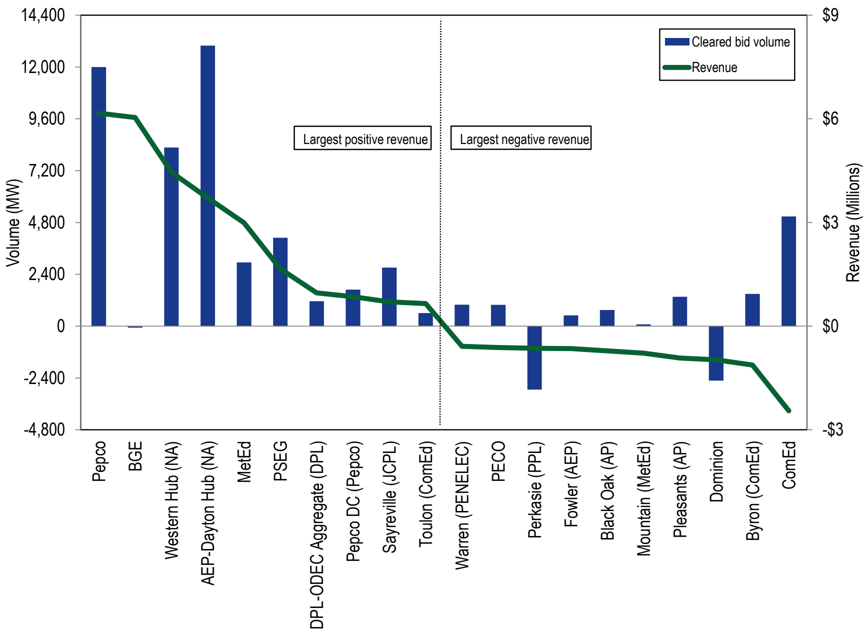
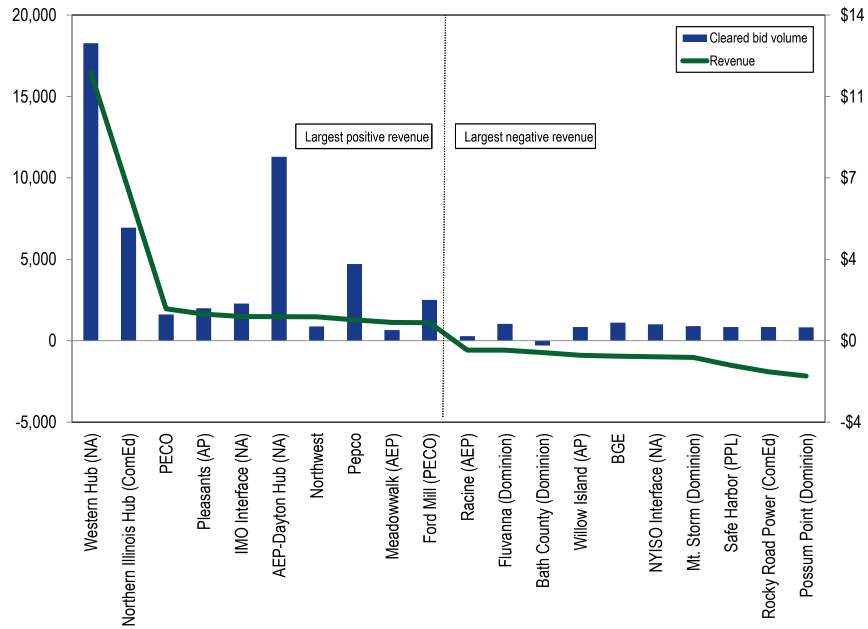


Figure 12-5 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Monthly Balance of Planning Period FTR Auctions during the first four months of the 2012 to 2013 planning period.

Figure 12-5 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2012 to 2013 through September 30, 2012 (See 2011 SOM, Figure 12-12)



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 generators receive, excluding losses, positive congestion revenue exists and is available to cover the target allocations of FTR holders. The load MW exceed the generation MW in constrained areas because part of the load is served by imports using transmission capability into the constrained areas. That is why load, which pays for the transmission capability, receives ARRs to offset congestion in the constrained areas based on that transmission capability. 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 constrained areas receives the congestion price and all load in constrained areas pays the congestion price. As a result, load congestion payments are greater than the congestion-related payments to generation.[11] 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 an offset against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion to the target allocations across specific paths for which FTRs were available and purchased. The adequacy of FTRs as an offset against congestion compares FTR revenues to total congestion on the system as a measure of the extent to which FTRs offset the actual, total congestion across all paths paid by market participants, regardless of the availability or purchase of FTRs.

FTRs are paid each month from congestion revenues, both day ahead and balancing, 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 2011 to 2012 planning period, FTRs were not fully funded and thus an uplift charge was collected.

FTR revenues are primarily comprised of hourly congestion revenue, from the day ahead and balancing markets, 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 12-9 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO whose operating limits are respected by PJM.[12] 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 no reimbursement ofcongestion charges to Con Edison in the 2012 to 2013 planning period through September 30, 2012.[13, 14]

If hourly congestion revenues are negative at the end of the month, charges are allocated as Day-Ahead Operating Reserves charges. When the congestion dollars collected from load are less than the congestion dollars paid to generation, this is included in Day-Ahead Operating Reserve charges. For the current planning period, $27,896 of charges have been included. This type of adjustment is infrequent, occurring only three times in the 2010 to 2011 planning period, never in the 2011 to 2012 planning period and once in the first four months of the 2012 to 2013 planning period.

FTRs were paid at 79.1 percent of the target allocation level for the first four months of the 2012 to 2013 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $222.5 million of FTR revenues during the first four months of the 2012 to 2013 planning period, and $799.4 million during the 2011 to 2012 planning period. For the first four months of the 2012 to 2013 planning period, the sink and source with the highest positive FTR target allocations were Northern Illinois Hub and Byron. Similarly, the sink and source with the largest negative FTR target allocations were Quad Cities and Kammer.

11 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," *MMU Technical Reference for PJM Markets*, at "Financial Transmission and Auction Revenue Rights."

12 See "Joint Operating Agreement between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008), Section 6.1 <http://www.pjm.com/~/Media/documents/agreements/joa-complete.ashx>. (Accessed March 13, 2012)

13 111 FERC ¶ 61,228 (2005).

14 See the *2010 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," at "Con Edison and PSE&G Wheeling Contracts" and Appendix E, "Interchange Transactions" at Table D-2, "Con Edison and PSE&G wheel settlements data: Calendar year 2010."

Table 12-9 presents the PJM FTR revenue detail for all of the 2011 to 2012 planning period and the first four months of the 2012 to 2013 planning period.

Table 12-9 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2011 to 2012 and 2012 to 2013 (See 2011 SOM, Table 12-21)

Accounting Element	2011/2012	2012/2013**
ARR information:		
ARR target allocations	$982.9	$196.0
FTR auction revenue	$1,091.8	$215.9
ARR excess	$108.9	$19.9
FTR targets:		
FTR target allocations	$992.8	$281.6
Adjustments		
Adjustments to FTR target allocations	($1.1)	($0.2)
Total FTR targets	$991.7	$281.4
FTR revenues:		
ARR excess	$108.9	$19.9
Competing uses	$0.1	$0.1
Congestion:		
Net Negative Congestion (enter as negative)	($64.5)	($21.8)
Hourly congestion revenue	$835.5	$241.7
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($79.6)	($17.4)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	(0.2)	$0.0
Adjustments:		
Excess revenues carried forward into future months	$0.0	$0.0
Excess revenues distributed back to previous months	$0.0	$0.0
Other adjustments to FTR revenues	($0.8)	($0.0)
Total FTR revenues	$799.4	$222.5
Excess revenues distributed to other months	$0.0	$0.0
Net Negative Congestion charged to DA Operating Reserves	$0.0	$0.0
Excess revenues distributed to CEPSW for end-of-year distribution	$0.0	$0.0
Excess revenues distributed to FTR holders	$0.0	$0.0
Total FTR congestion credits	$799.4	$222.5
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$799.6	$222.5
Remaining deficiency	$192.3	$58.9

** Shows four month ended 30-Sep-12

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 compensate FTR holders fully for congestion on those specific paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations. Table 12-10 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.

The total row in Table 12-10 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 distributed back from later months.

Table 12-10 Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2011 to 2012 and 2012 to 2013 (See 2011 SOM, Table 12-22)

Period	FTR Revenues (with adjustments)	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Monthly Credits Excess/Deficiency (with adjustments)
Jun-11	$134.6	$154.6	86.9%	$134.6	87.1%	($20.0)
Jul-11	$178.2	$181.4	97.8%	$178.2	98.3%	($3.1)
Aug-11	$70.6	$73.4	96.2%	$70.6	96.2%	($2.8)
Sep-11	$69.4	$88.3	78.6%	$69.4	78.7%	($18.8)
Oct-11	$37.5	$52.3	73.0%	$37.5	71.7%	($14.8)
Nov-11	$32.8	$57.1	57.4%	$32.8	57.4%	($24.4)
Dec-11	$46.4	$64.8	71.6%	$46.4	71.6%	($18.4)
Jan-12	$49.4	$61.8	79.8%	$49.4	80.0%	($12.4)
Feb-12	$38.4	$57.4	66.8%	$38.4	66.8%	($19.0)
Mar-12	$48.3	$57.8	84.2%	$48.3	83.6%	($9.5)
Apr-12	$40.6	$73.6	55.3%	$40.6	55.2%	($32.9)
May-12	$53.1	$69.3	76.7%	$53.1	76.6%	($16.2)
Summary for Planning Period 2011 to 2012						
Total	$799.4	$991.7		$799.4	80.6%	($192.3)
Jun-12	$58.5	$62.9	92.9%	$58.5	92.9%	($4.5)
Jul-12	$71.3	$80.1	88.9%	$71.3	88.9%	($8.9)
Aug-12	$54.1	$55.6	97.1%	$54.1	97.3%	($1.5)
Sep-12	$38.7	$82.8	46.7%	$38.7	46.8%	($44.1)
Summary for Planning Period 2012 to 2013						
Total	$222.5	$281.5		$222.5	79.1%	($58.9)

Figure 12-6 shows the original FTR payout ratio with adjustments by month, excluding excess revenue distribution, for January 2004 through September 2012. The months with payout ratios above 100 percent are overfunded and the months with payout ratios under 100 percent are underfunded. Figure 12-6 also shows the payout ratio after distributing excess revenue across months within the planning period. If there are excess revenues in a given month, the excess is distributed to other months within the planning period that were revenue deficient. The payout ratios for months in the 2012 to 2013 planning period may change if excess revenue is collected in the remainder of the planning period.

Figure 12-6 FTR payout ratio with adjustments by month, excluding and including excess revenue distribution: January 2004 to September 2012 (See 2011 SOM, Figure 12-13)

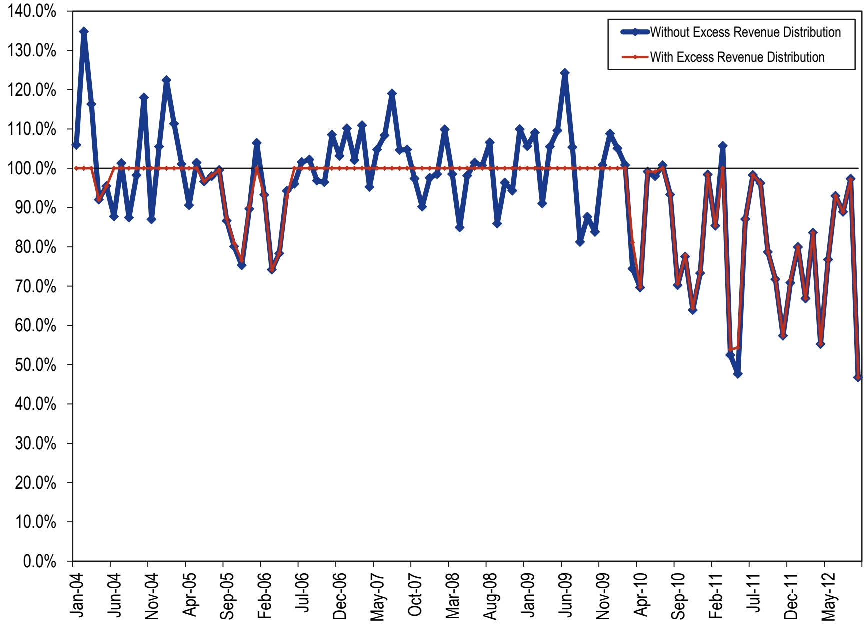


Table 12-11 shows the FTR payout ratio by planning period from the 2003/2004 planning period forward.

Table 12-11 FTR payout ratio by planning period (See 2011 SOM, Table 12-23)

Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011	85.0%
2011/2012	80.6%
2012/2013*	79.1%

*2012/2013 Through 30-Sep-12

Figure 12-7 shows the ten largest positive and negative FTR target allocations, summed by sink, for the 2012 to 2013 planning period through September 30, 2012.

Figure 12-7 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2012 to 2013 through September 30, 2012 (See 2011 SOM, Figure 12-14)

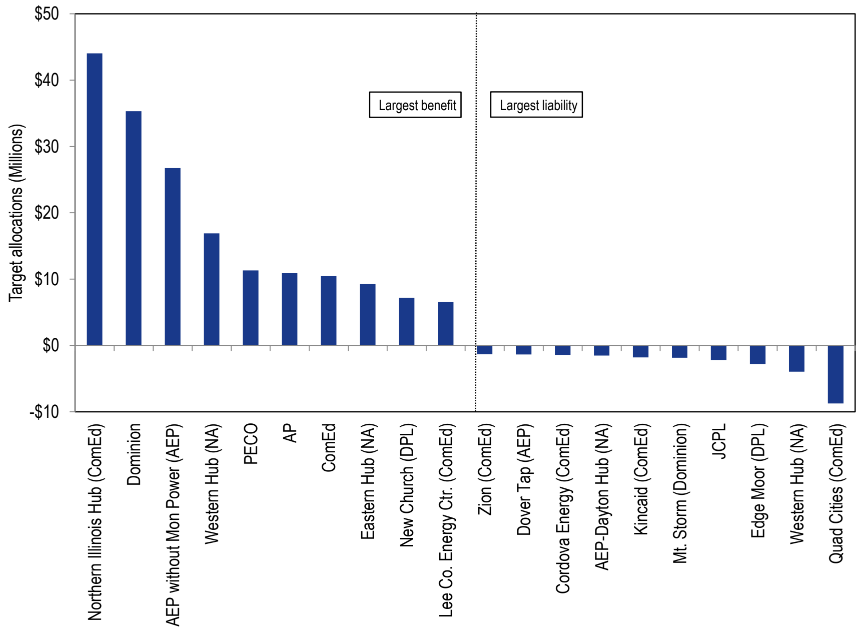


Figure 12-8 shows the ten largest positive and negative FTR target allocations, summed by source, for the 2012 to 2013 planning period through September 30, 2012.

Figure 12-8 Ten largest positive and negative FTR target allocations summed by source: Planning period 2012 to 2013 through September 30, 2012 (See 2011 SOM, Figure 12-15)

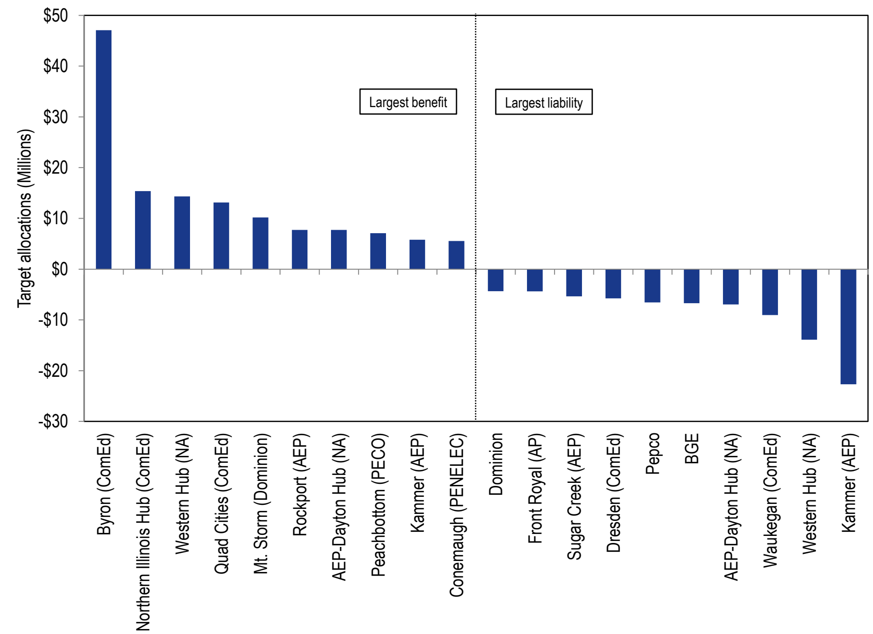
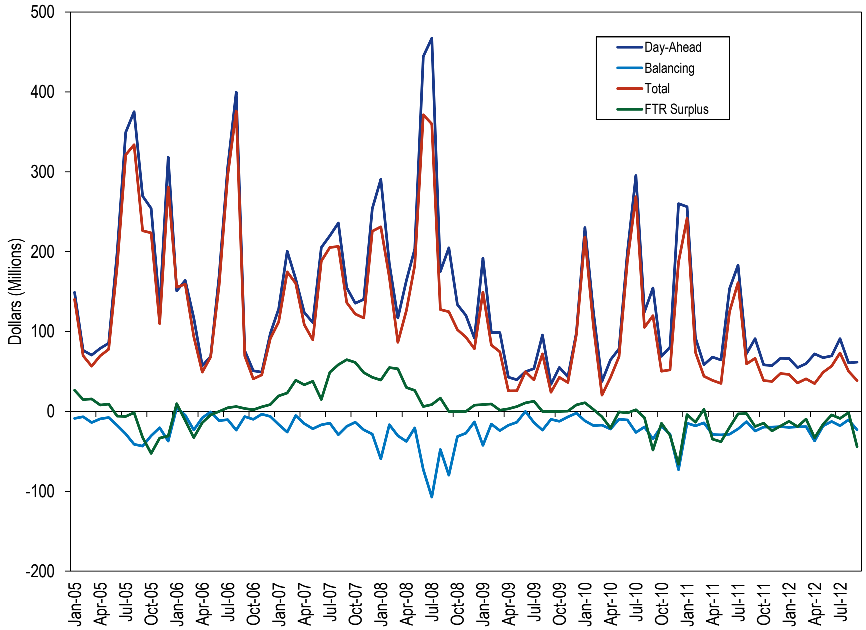


Figure 12-9 shows the FTR surplus, collected day-ahead, balancing and total congestion payments from January 2005 through September 2012.

Figure 12-9 FTR Surplus and the collected Day-Ahead, Balancing and Total congestion: January 2005 through September 2012 (New Figure)



Profitability

FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. For a prevailing flow FTR, the FTR credits are the revenue that an FTR holder receives, after adjusting by the FTR payout ratio for the planning period, and the auction price is the cost. For a counter flow FTR, the auction price is the revenue that an FTR holder receives and the FTR credits are the cost to the FTR holder. The cost of self-scheduled FTRs is zero. ARR holders that self-schedule FTRs purchase the FTRs in the Annual FTR Auction, but ARR holders receive offsetting ARR credits that equal the purchase price of the FTRs. Table 12-12 lists FTR profits by organization type and FTR direction for the 2012 calendar year. FTR profits are the sum of the daily FTR credits, including self-scheduled FTRs, minus the daily FTR auction costs for each FTR held by an organization. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source in the Day-Ahead Energy Market. The FTR credits do not include after the fact adjustments. The daily FTR auction costs are the product of the FTR MW and the auction price divided by the time period of the FTR in days, but self-scheduled FTRs have zero cost. FTRs were not profitable overall for physical entities, with -$3.3 million in profits for physical entities, of which $134.0 million was from self-scheduled FTRs. FTRs were profitable for financial entities, providing $77.2 million in profits primarily from counter flow FTRs.

Table 12-12 shows FTR profits by organization from January through September 2012.

Table 12-12 FTR profits by organization type and FTR direction: January through September 2012 (See 2011 SOM, Table 12-24)

	FTR Direction				
Organization Type	Prevailing Flow	Self Scheduled Prevailing Flow	Counter Flow	Self Scheduled Counter Flow	All
Physical	($189,991,190)	$132,206,121	$52,735,192	$1,786,344	($3,263,534)
Financial	($53,881,538)	NA	$131,117,667	NA	$77,236,130
Total	($243,872,728)	$132,206,121	$183,852,859	$1,786,344	$73,972,596

Table 12-13 lists the monthly FTR profits in the 2012 calendar year by organization type.

Table 12-13 Monthly FTR profits by organization type: January through September 2012 (See 2011 SOM, Table 12-25)

	Organization Type			
Month	Physical	Self Scheduled FTRs	Financial	Total
Jan	($21,202,380)	$14,779,795	$3,981,524	($2,441,061)
Feb	($23,137,563)	$13,247,875	$7,491,849	($2,397,839)
Mar	($24,189,367)	$12,778,994	$4,873,661	($6,536,712)
Apr	($17,314,923)	$11,004,118	$11,848,177	$5,537,372
May	($22,911,625)	$11,306,839	$13,000,958	$1,396,172
Jun	($10,579,634)	$16,612,605	$9,064,486	$15,097,457
Jul	($183,123)	$19,259,505	$7,964,676	$27,041,058
Aug	($13,862,467)	$17,507,831	$3,868,376	$7,513,740
Sep	($3,874,915)	$17,494,902	$15,142,422	$28,762,409
Total	($137,255,998)	$133,992,464	$77,236,130	$73,972,596

Auction Revenue Rights

ARRs are financial instruments that entitle the holder to receive revenues or to pay charges based on nodal price differences determined in the Annual FTR Auction.[15] 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 and expected revenues. 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 and expected revenues including both day-ahead and balancing congestion.

ARRs are available only as obligations (not options) and 24-hour products. 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 price difference between sink and source, with a negative difference resulting in a liability for the holder. The ARR target allocation represents the revenue that an ARR holder should receive. 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 greater than the sum of all ARR target allocations, ARRs are fully funded. If these revenues are less than the sum of all ARR target allocations, available revenue is proportionally allocated among all ARR holders.

When a new control zone is integrated into PJM, firm transmission customers in that control zone may 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 not eligible for directly allocated FTRs. Network Service Users and Firm Transmission Customers cannot choose to receive both an FTR allocation and an ARR allocation. This selection applies to the participant's entire portfolio of ARRs that sink into the new control zone. During this transitional period, the directly allocated FTRs are reallocated as load shifts between LSEs within the transmission zone.

Effective August 1, 2012 PJM began offering monthly residual ARRs, as ordered by FERC in Docket No. EL12-50-000. These residual ARRs will provide ARRs to eligible participants when a transmission outage was modeled in the Annual ARR Allocation, but the transmission facility becomes available during the year. Residual ARRs are determined the month before the effective date, are only available on paths prorated in Stage 1 of the Annual ARR Allocation, and are allocated automatically to participants. Residual ARRs are effective for single, whole months and cannot be self scheduled. ARR target allocations are based on the clearing prices from FTR obligations in the effective monthly auction, may not exceed zonal Network Service Peak Load or Firm Transmission Reservation Levels, and are up to the prorated ARR MW as allocated in the Annual ARR Allocation.

15 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.

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 through the 2010 to 2011 planning period, all eligible market participants were allocated ARRs. For the 2011 to 2012 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the ATSI control zone. For the 2011 to 2012 planning period eligible participants in the DEOK zone could request incremental FTRs valid from January 1, 2012 through May 31, 2012.

Table 12-14 shows the Residual ARRs automatically allocated to eligible participants, along with the target allocations from the effective month.

Table 12-14 Residual ARR allocation volume and target allocation (New Table)

Month	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
Aug-12	4,508.2	2,460.5	54.6%	$1,026,836
Sep-12	4,696.3	2,343.1	49.9%	$1,003,031

ARR Reassignment for Retail Load Switching

Current PJM rules provide that when load switches between 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.[16] 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 offset to 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 selfscheduled 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 ARR for the receiving LSE compared to the total value held by the original ARR holder.

There were 22,543 MW of ARRs associated with approximately $226,900 of revenue that were reassigned in the first four months of the 2012 to 2013 planning period. There were 41,770 MW of ARRs associated with approximately $758,900 of revenue that were reassigned for the full twelve months of the 2011 to 2012 planning period.

16 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 28.

Table 12-15 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2011 and September 2012.

Table 12-15 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2011, through September 30, 2012 (See 2011 SOM, Table 12-29)

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2011/2012 (12 months)	2012/2013 (4 months)*	2011/2012 (12 months)	2012/2013 (4 months)*
AECO	563	287	$4.8	$1.5
AEP	6,341	2,249	$119.0	$27.9
AP	5,516	2,660	$319.4	$63.2
ATSI	3,321	2,246	$13.3	$4.1
BGE	2,745	1,278	$45.9	$15.2
ComEd	3,804	4,225	$59.1	$60.7
DAY	463	260	$0.6	$0.4
DEOK	NA	1,116	NA	$0.6
DLCO	2,964	1,120	$10.4	$8.0
DPL	1,957	917	$15.4	$5.1
Dominion	1	0	$0.0	$0.0
JCPL	1,332	715	$10.1	$2.8
Met-Ed	1,273	515	$20.9	$3.6
PECO	1,994	784	$21.9	$5.0
PENELEC	1,116	420	$21.2	$3.8
PPL	3,565	1,290	$38.1	$7.9
PSEG	2,325	1,201	$31.2	$8.4
Pepco	2,489	1,261	$27.4	$8.6
RECO	73	33	$0.0	$0.0
Total	41,770	22,543	$758.9	$226.9

* Through 30-Sep-2012

Market Performance

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

As with FTRs, revenue adequacy for ARRs must be distinguished from the adequacy of ARRs as an offset to congestion. Revenue adequacy is a narrower concept that compares the revenues available to ARR holders to the value of ARRs as determined in the Annual FTR Auction. ARRs have been revenue adequate for every auction to date. ARRs that are self scheduled as FTRs have the same revenue adequacy characteristics as all other FTRs.

The adequacy of ARRs as an offset to congestion compares ARR revenues to total congestion sinking in the participant's load zone as a measure of the extent to which ARRs offset market participants' actual, total congestion into their zone. ARRs that are self scheduled as FTRs provide the same offset to congestion as all other FTRs.

ARR holders will receive $565.4 million in credits from the Annual FTR Auction during the 2012 to 2013 planning period, with an average hourly ARR credit of $0.63 per MW. During the comparable 2011 to 2012 planning period, ARR holders received $947.3 million in ARR credits, with an average hourly ARR credit of $1.06 per MW.

Table 12-16 lists ARR target allocations and net revenue sources from the Annual and Monthly Balance of Planning Period FTR Auctions for the 2011 to 2012 and the 2012 to 2013 (through September 30, 2012) planning periods.

Table 12-16 ARR revenue adequacy (Dollars (Millions)): Planning periods 2011 to 2012 and 2012 to 2013 (See 2011 SOM, Table 12-33)

	2011/2012	2012/2013
Total FTR auction net revenue	$1,055.9	$614.8
Annual FTR Auction net revenue	$1,029.6	$602.9
Monthly Balance of Planning Period FTR Auction net revenue*	$26.3	$11.9
ARR target allocations	$947.3	$565.4
ARR credits	$947.3	$565.4
Surplus auction revenue	$108.6	$49.4
ARR payout ratio	100%	100%
FTR payout ratio*	80.6%	79.1%

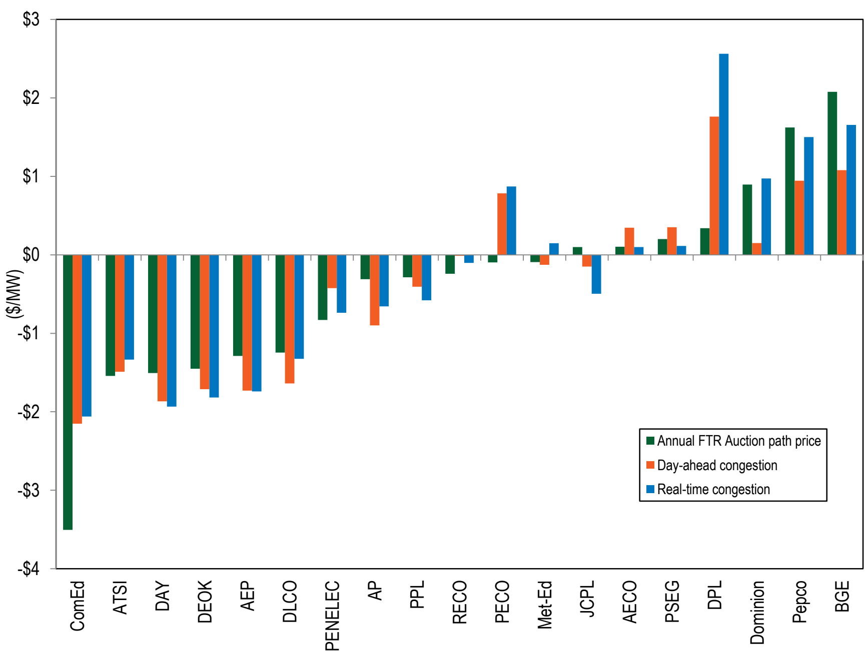
* Shows twelve months for 2011/2012 four months for 2012/2013.

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 12-10 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone for the 2012 to 2013 planning period through September 30, 2012. The day-ahead and real-time congestion are based on the difference between zonal congestion prices and Western Hub congestion prices.

Figure 12-10 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2012 to 2013 through September 30, 2012 (See 2011 SOM, Figure 12-16)



Effectiveness of ARRs as an Offset to Congestion

One measure of the effectiveness of ARRs as an offset to congestion is a comparison of the revenue received by the holders of ARRs and the congestion paid by the holders of ARRs in both the Day-Ahead Energy Market and the Balancing Energy Market. The revenue which serves as an offset for ARR holders comes from the FTR auctions while the revenue for FTR holders is provided by the congestion payments from the Day-Ahead Energy Market and the Balancing Energy Market. During the first four months of the 2012 to 2013 planning period, the total revenues received by holders of all ARRs and FTRs offset 73.8 percent of the total congestion costs within PJM.

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 12-17. ARRs and self-scheduled FTRs that sink at an aggregate are assigned to a control zone if applicable.[17] 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 ARR 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 cleared price 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 may be less than the target allocation. The FTR payout ratio was 79.1 percent of the target allocation for the 2012 to 2013 planning period through September 30, 2012.

17 For Table 12-17 through Table 12-19, aggregates are separated into their individual bus components and each bus is assigned to a control zone. The "External" Control Zone includes all aggregate sinks that are external to PJM or buses that cannot otherwise be assigned to a specific control zone.

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.

Table 12-17 ARR and self-scheduled FTR congestion offset (in millions) by control zone: Planning period 2012 to 2013 through September 30, 2012[18] (See 2011 SOM, Table 12-34)

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Offset
AECO	$5.9	$0.0	$5.9	$5.8	$0.1	>100%
AEP	$25.1	$20.6	$45.7	$33.3	$17.9	>100%
APS	$41.8	$8.1	$49.9	$4.8	$47.2	>100%
ATSI	$4.1	$0.1	$4.2	($1.0)	$5.2	>100%
BGE	$30.2	$0.2	$30.4	$3.9	$26.6	>100%
ComEd	$101.9	$0.0	$101.9	($27.2)	$129.1	>100%
DAY	$1.5	$0.6	$2.1	($1.3)	$3.6	>100%
DEOK	$1.1	($0.1)	$1.0	$3.8	($2.7)	27.6%
DLCO	$5.9	$0.3	$6.3	($0.3)	$6.6	>100%
Dominion	$4.8	$24.7	$29.5	$11.2	$24.9	>100%
DPL	$11.6	$0.9	$12.5	$22.2	($9.5)	56.1%
External	$5.9	($0.0)	$5.9	$2.8	$3.0	>100%
JCPL	$8.9	($0.0)	$8.9	$6.7	$2.2	>100%
Met-Ed	$8.6	$0.1	$8.7	$3.5	$5.2	>100%
PECO	$16.9	$2.4	$19.3	$4.6	$15.4	>100%
PENELEC	$6.9	$2.3	$9.2	$7.4	$2.4	>100%
Pepco	$24.8	$0.5	$25.3	$20.1	$5.2	>100%
PPL	$16.0	$0.4	$16.5	$4.0	$12.6	>100%
PSEG	$26.2	$1.6	$27.8	$2.2	$26.1	>100%
RECO	$0.0	$0.0	$0.0	$0.6	($0.6)	0.3%
Total	$348.0	$62.9	$410.9	$107.2	$329.1	>100%

Effectiveness of ARRs and FTRs as an Offset to Congestion

Table 12-18 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 2012 to 2013 planning period through September 30, 2012. This compares the total offset 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 cleared price of the ARR path from the Annual FTR Auction. In Table 12-18 ARR credits are calculated as if no ARR MW are self-scheduled to show the maximum available offset. The FTR Credits column represents the total FTR target allocation for FTRs that sink in each control zone from the applicable FTRs from the Long Term FTR Auction, 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 79.1 percent of the target allocation for the 2012 to 2013 planning period through September 30, 2012. The FTR Auction Revenue column shows the amount paid for FTRs that sink in each control zone from the applicable FTRs from the Long Term FTR Auction, 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.[19] The last column shows the difference between the total ARR and FTR hedge and the congestion cost for each control zone.

18 The "External" zone was labeled as "PJM" in previous State of the Market Reports. The name was changed to "External" to clarify that this component of congestion is accrued on energy flows between external buses and PJM interfaces.

19 The total zonal congestion numbers were calculated as of October 24, 2012 and may change as a result of continued PJM billing updates.

Table 12-18 ARR and FTR congestion offset (in millions) by control zone: Planning period 2012 to 2013 through September 30, 2012 (See 2011 SOM, Table 12-35)

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
AECO	$5.9	$0.2	$5.8	$0.4	$3.9	($3.6)	8.9%
AEP	$110.0	$32.3	$122.2	$20.1	$43.4	($23.4)	46.2%
APS	$78.2	$9.0	$41.3	$45.9	$23.5	$22.4	>100%
ATSI	$4.3	$6.0	($0.1)	$10.4	$1.2	$9.2	>100%
BGE	$31.5	$8.8	$41.6	($1.3)	$10.7	($11.9)	0.0%
ComEd	$121.5	$51.8	$83.0	$90.2	$58.5	$31.8	>100%
DAY	$3.8	$1.9	$5.6	$0.2	$3.6	($3.4)	5.8%
DEOK	$1.4	$3.5	$4.2	$0.7	($0.6)	$1.3	>100%
DLCO	$7.2	$0.5	$7.4	$0.3	$0.8	($0.5)	34.2%
Dominion	$79.3	$38.0	$110.9	$6.3	$30.1	($23.7)	21.1%
DPL	$12.4	$16.9	$18.6	$10.7	$13.5	($2.7)	79.6%
External	$8.0	($1.5)	$2.4	$4.1	($13.7)	$17.8	>100%
JCPL	$9.2	$0.6	$20.2	($10.3)	$4.6	($14.9)	0.0%
Met-Ed	$9.0	$2.6	$14.9	($3.4)	$1.9	($5.3)	0.0%
PECO	$20.1	$16.5	$18.3	$18.3	$5.6	$12.7	>100%
PENELEC	$11.8	$12.4	$32.9	($8.7)	$14.0	($22.7)	0.0%
Pepco	$27.1	$12.1	$75.9	($36.8)	$10.7	($47.5)	0.0%
PPL	$18.7	($0.1)	$10.8	$7.9	$4.0	$3.8	>100%
PSEG	$24.0	$8.7	$27.9	$4.8	$2.4	$2.4	>100%
RECO	$0.0	($0.1)	($1.6)	$1.5	$0.7	$0.8	>100%
Total	$583.5	$220.1	$642.2	$161.4	$218.8	($57.4)	73.8%

Table 12-19 shows the total offset due to ARRs and FTRs for the entire 2011 to 2012 planning period and the first four months of the 2012 to 2013 planning period.

Table 12-19 ARR and FTR congestion hedging (in millions): Planning periods 2011 to 2012 and 2012 to 2013 through September 30, 2012[20] (See 2011 SOM, Table 12-36)

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
2011/2012	$982.9	$794.3	$1,092.4	$684.8	$771.2	($86.4)	88.8%
2012/2013*	$583.5	$220.1	$642.2	$161.4	$218.8	($57.4)	73.8%

* Shows four months ended 30-Sep-12

20 The FTR credits do not include after-the-fact adjustments. For the 2012 to 2013 planning period, the ARR credits were the total credits allocated to all ARR holders for the first four months (June 2012 through September 2013) 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 four months of this planning period and the portion of Annual FTR Auction revenue distributed to the first four months.