Q1

State of the Market Report for PJM

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

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Preface

The PJM Market Monitoring Plan provides:

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

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2012 Quarterly State of the Market Report for PJM: January through March*.

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

Q1 2012 In Review

The state of the PJM markets in the first quarter 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 quarter 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 quarter 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 decreased in price in the first quarter of 2012, although the decline in gas prices was substantially larger than the decline in coal prices. PJM LMPs were substantially lower. The load-weighted average LMP was 32.7 percent lower in the first three months of 2012 than in the first three months of 2011, resulting in the lowest first quarter prices since 2002.

The results of the market dynamics in the first quarter of 2012 continued to be generally positive for new combined cycle gas units. The result of the continued decline in gas prices compared to coal prices was that the fuel cost of a new entrant combined cycle unit fell below the fuel cost of a new entrant coal plant in the first quarter of 2012. New entrant combined cycle net revenues were higher in about half the zones in the first quarter of 2012. The results of the market dynamics in the first quarter of 2012 continued to be generally negative for coal fired units. Net revenues declined for coal units in every zone in the first quarter of 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.

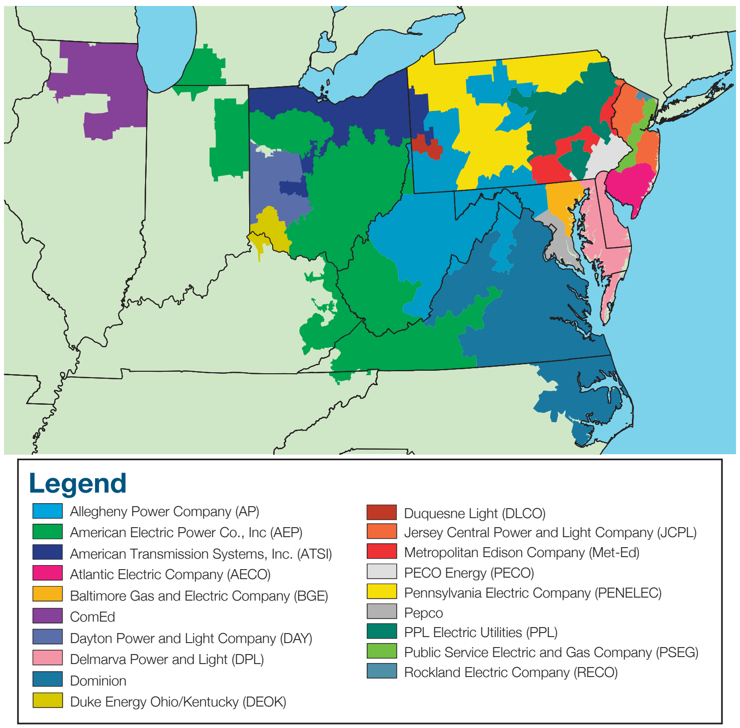
PJM Market Background

The PJM Interconnection, L.L.C. operates a centrally dispatched, competitive wholesale electric power market that, as of March 31, 2012, had installed generating capacity of 184,981 megawatts (MW) and more than 750 market buyers, sellers and traders of electricity[1] in a region including more than

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

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 three months of 2012, PJM had total billings of $6.94 billion. 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]



2 See "Company Overview." PJM.com. PJM Interconnection L.L.C. (Accessed April 13, 2012). <http://pjm.com/about-pjm/who-we-are/company-overview.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 operates the Day-Ahead Energy Market, the Real-Time Energy Market, the Reliability Pricing Model (RPM) Capacity Market, the Regulation Market, the Synchronized Reserve Markets, the Day Ahead Scheduling Reserve (DASR) Market and the Long Term, Annual and Monthly Balance of Planning Period Auction Markets in Financial Transmission Rights (FTRs).

PJM introduced energy pricing with cost-based offers and market-clearing nodal prices on April 1, 1998, and market-clearing nodal prices with market-based offers on April 1, 1999. PJM introduced the Daily Capacity Market on January 1, 1999, and the Monthly and Multimonthly Capacity Markets 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 three 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

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 2011, see the *2011 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

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.

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

Table 1-1 The Energy Market results were competitive

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 three months of 2012 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1235 with a minimum of 1107 and a maximum of 1499 in the first three 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 a number of 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 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

7 OATT Attachment M

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

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 failed the TPS 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 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 planned resource 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 a definition of DR which permits inferior products to substitute for capacity.

Table 1-3 The Regulation Market results were not competitive[11]

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 67 percent of the hours in January through March 2012.
- 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.

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.

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.

- 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.[12]
- 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

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 49 percent of the hours in January through March 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.

12 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.

Table 1-5 The Day-Ahead Scheduling Reserve Market results were competitive

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 failed the three pivotal supplier test in only a limited number of hours.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs (zero), about 12 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

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.[13] 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.[14]

13 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).

14 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.[15] The MMU has direct,

15 OATT Attachment M § IV.

confidential access to the FERC.[16] The MMU may also refer matters to the attention of State commissions.[17]

The MMU monitors market behavior for violations of FERC Market Rules.[18] 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,[19] or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies…"[20] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[21]

The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation.[22] 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[23] and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff.[24] 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. The MMU may also participate as a party or provide information or testimony in regulatory or other proceedings.

16 OATT Attachment M § IV.K.3.
17 OATT Attachment M § IV.H.
18 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.").
19 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.
20 OATT Attachment M § II(h-1).
21 OATT Attachment M § IV.C.
22 OATT Attachment M § IV.I.1.
23 *Id.*
24 *Id.*

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).[25] 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.[26]

The MMU also reviews operational parameter limits included with unit offers,[27] evaluates compliance with the requirement to offer into the energy and capacity markets,[28] evaluates the economic basis for unit retirement requests,[29] and evaluates and compares offers in the Day-Ahead and Real-Time Energy Markets.[30]

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.[31] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[32] 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.[33] The MMU also recommends changes to

25 *See* OATT Attachment M–Appendix § II.A.
26 OATT Attachment M–Appendix § II.E.
27 OATT Attachment M–Appendix § II.B.
28 OATT Attachment M–Appendix § II.C.
29 OATT Attachment M–Appendix § IV.
30 OATT Attachment M–Appendix § VII.
31 OATT Attachment M § IV.D.
32 *Id.*
33 *Id.*

the PJM Market Rules to the staff of the Commission's Office of Energy Market Regulation, State Commissions, and the PJM Board.[34] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[35]

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,"[36] 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 March*, the recommendations from the *2011 State of the Market Report for PJM* remain MMU recommendations.

The following is a new recommendation since the 2011 report.

From Section 3, "Operating Reserve":

- The MMU recommends that the reactive service make whole credits cover the entire cost of a unit providing reactive service rather than paying part of these costs through operating reserve charges. The result of paying part of the cost of reactive service through operating reserve credits 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 reserves are paid by deviations from day-ahead or real-time load plus exports depending on the allocation process rather than by zone.

Highlights

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

34 *Id.*
35 OATT Attachment M § VI.A.
36 18 CFR § 35.28(g)(3)(ii)(A); *see also* OATT Attachment M § IV.D.

Section 2, Energy Market

- Average offered supply increased by 16,249, or 10.0 percent, from 157,340 MW in the first quarter of 2011 to 173,590 MW in the first quarter of 2012. The increase in offered supply was the result of the integration of the Duke Energy Ohio/Kentucky (DEOK) transmission zone in the first quarter of 2012, the integration of the American Transmission Systems, Inc. (ATSI) transmission zone in the second quarter of 2011, and the addition of 5,008 MW of nameplate capacity to PJM in 2011. The increases in supply were partially offset by the deactivation of three units (955 MW) since January 1, 2012. (See page 18)
- In January through March 2012, coal units provided 39.9 percent, nuclear units 36.3 percent and gas units 19.0 percent of total generation. Compared to January through March 2011, generation from coal units decreased 11.6 percent, generation from nuclear units increased 8.3 percent, while generation from natural gas units increased 66.0 percent, and generation from oil units increased 54.2 percent. (See page 18)
- The PJM system peak load for the first quarter of 2012 was 122,539 MW, which was 11,880 MW, or 10.7 percent, higher than the PJM peak load for the first quarter of 2011.[37] The ATSI and DEOK transmission zones accounted for 14,019 MW in the peak hour of the first quarter of 2012. The peak load excluding the ATSI and DEOK transmission zones was 108,519 MW, a decrease of 2,139 MW from the first quarter 2011 peak load. (See page 20)
- PJM average real-time load in the first quarter of 2012 increased by 6.4 percent from the first quarter of 2011, from 81,018 MW to 86,310 MW. The PJM average real-time load in the first quarter of 2012 would have decreased by 6.5 percent from the first quarter of 2011, from 81,018 MW to 75,753 MW, if the DEOK and ATSI transmission zones were excluded. (See page 28)
- PJM average day-ahead load, including DECs and up-to congestion transactions, increased in the first quarter of 2012 by 20.7 percent from the first quarter of 2011, from 107,116 MW to 129,258 MW. PJM average

37 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).

day-ahead load would have been 9.2 percent higher in the first quarter of 2012 than in the first quarter of 2011, from 107,116 MW to 116,964 MW if the DEOK and ATSI transmission zones were excluded. (See page 30)

- PJM average real-time generation increased by 5.5 percent in the first quarter of 2012 from the first quarter of 2011, from 83,505 MW to 88,068 MW. PJM average real-time generation would have decreased 5.1 percent in the first quarter of 2012 from the first quarter of 2011, from 83,505 MW to 79,276 MW if the DEOK and ATSI transmission zones were excluded. (See page 33)
- PJM Real-Time Energy Market prices decreased in the first quarter of 2012 compared to the first quarter of 2011. The load-weighted average LMP was 32.7 percent lower in the first quarter of 2012 than in the first quarter of 2011, $31.21 per MWh versus $46.35 per MWh. (See page 37)
- PJM Day-Ahead Energy Market prices decreased in the first quarter of 2012 compared to the first quarter of 2011. The load-weighted average LMP was 33.2 percent lower in the first quarter of 2012 than in the first quarter of 2011, $31.51 per MWh versus $47.14 per MWh. (See page 40)
- Levels of offer capping for local market power remained low. In the first three months of 2012, 1.9 percent of unit hours and 1.3 percent of MW were offer capped in the Real-Time Energy Market and 0.1 percent of unit hours and 0.2 percent of MW were offer capped in the Day-Ahead Energy Market. (See page 23)
- Of the 106 units that were eligible to include a Frequently Mitigated Unit (FMU) or Associated Unit (AU) adder in their cost-based offer during the first three months of 2012, 82 (77.4 percent) qualified in all months, and 12 (11.3 percent) qualified in only one month of 2012. (See page 25)
- There were no scarcity pricing events in the first three months of 2012 under PJM's current Emergency Action based scarcity pricing rules.

Section 3, Operating Reserve

- Operating reserve charges decreased $25.9 million, or 20.7 percent, from $125.2 million in the first three months of 2011, to $99.3 million in the first three months of 2012. Day-ahead operating reserve charges decreased $10.1 million, or 35.8 percent to $18.1 million and balancing operating reserve charges decreased $15.6 million, or 16.1 percent to $96.7 million. (See page 53)
- Balancing operating reserve charges for reliability decreased by $0.8 million, or 3.5 percent compared to the first three months of 2011. Balancing operating reserve charges for deviations decreased by $24.6 million, or 42.4 percent. (See page 54)
- The reduction in balancing operating reserve charges was comprised of a decrease of $25.4 million in generator and real-time import transactions balancing operating reserve charges, an increase of $7.6 million in lost opportunity costs, an increase of $1.1 million in canceled resources and an increase of $1.1 million in charges to participants requesting resources to control local constraints. (See page 54)
- Generators and real-time transactions balancing operating reserve charges were $55.7 million, 68.6 percent of all balancing operating reserve charges. Balancing operating reserve charges were allocated 40.1 percent as reliability charges and 59.9 percent as deviation charges. Lost opportunity cost charges were $20.8 million or 25.7 percent of all balancing charges. The remaining 5.7 percent of balancing operating reserve charges were comprised of 2.9 percent canceled resources charges and 2.8 percent of local constraints control charges. (See page 54)
- 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 36.8 percent of total operating reserve credits in the first three months of 2012, compared to 50.3 percent in the first three months of 2011. (See page 64)
- The regional concentration of balancing operating reserves remained high in the first three months of 2012, although lower than the first three

months of 2011. In the first three months of 2012, 55.9 percent of all operating reserve credits were paid to resources in the top three zones, a decrease of 14.4 percent from the first three months of 2011. (See page 67)

Section 4, Capacity

- During the period January 1, through March 31, 2012, PJM installed capacity increased 6,126.6 MW or 3.4 percent from 178,854.1 MW on January 1 to 184,980.7 MW on March 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis. (See page 74)
- The 2012/2013 RPM Third Incremental Auction was run in the first quarter of 2012. In the 2012/2013 RPM Third Incremental Auction, the RTO clearing price was $2.51 per MW-day. (See page 80)
- All LDAs and the entire PJM Region failed the preliminary market structure screen (PMSS) for the 2015/2016 Delivery Year. (See page 75)
- Capacity in the RPM load management programs was 8,492.2 MW for June 1, 2012. (See page 77)
- 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 $127.05 per MW-day in 2014. (See page 81)
- Combined cycle units ran more often in January through March 2012, than in the same period in 2011, increasing from a 41.1 percent capacity factor in 2011 to a 63.0 percent capacity factor in 2012. Combined cycle units had a higher capacity factor than steam units, for which the capacity factor decreased from 51.8 percent in 2011 to 39.8 percent in January through March 2012. (See page 82)
- The average PJM equivalent demand forced outage rate (EFORd) decreased from 8.6 percent in the first three months of 2011 to 6.6 percent in the first three months of 2012. (See page 84)
- The PJM aggregate equivalent availability factor (EAF) increased from 85.8 percent in the first three months of 2011 to 86.1 percent in the first three months of 2012. The equivalent maintenance outage factor (EMOF) increased from 2.5 percent to 3.9 percent, the equivalent planned outage factor (EPOF) decreased from 6.4 percent to 5.7 percent, and the equivalent forced outage factor (EFOF) decreased from 5.3 percent to 4.3 percent. (See page 83)

Section 5, Demand Response

- In January through March 2012, the total MWh of load reduction under the Economic Load Response Program decreased by 2,089 MWh compared to the same period in 2011, from 3,272 MWh in 2011 to 1,182 MWh in 2012, a 64 percent decrease. Total payments under the Economic Program decreased by $210,002, from $240,304 in 2011 to $30,302 in 2012, an 87 percent decrease. (See page 96)
- In January through March 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 $39.8 million, or 27.6 percent, compared to the same period in 2011, from $144 million in 2011 to $104 million in 2012. (See page 99)

Section 6, Net Revenue

- Energy prices decreased by 33 percent in the first three months of 2012 compared to the first three months of 2011. Gas prices decreased by 47 percent and coal prices decreased on average by 4 percent. This combination of factors resulted in lower energy net revenues for the new entrant CC unit in approximately half the zones and lower energy net revenues for the new entrant coal CT and CP unit in all zones in 2012. (See page 103)
- Energy net revenues for the new entrant coal unit were down 87 percent from the first quarter of 2011. (See page 104)

Section 7, Environmental and Renewables

- The EPA issued the Mercury Air Toxics Rule December 16, 2011, which will require significant investments in control technology for Mercury and other pollutants, effective April 16, 2015. (See page 105)
- Generation from wind units increased from 3,647.6 GWh in January through March 2011 to 4,261.3 GWh in January through March 2012, an increase of 26.7 percent. Generation from solar units increased from 7.0 GWh in January through March 2011to 43.9 GWh in January through March 2012, an increase of 526.8 percent. (See page 113)
- At the end of 2011, the Cross-State Air Pollution Rule was subject to a stay pending further action on appeal, resulting in the reinstatement of the Clean Air Interstate Rule for 2012. (See page 105)
- Emission prices declined in January through March 2012 compared to 2011. NOx prices declined 70.3 percent in 2012 compared to 2011, and SO_2 prices declined 34.4 percent in 2012 compared to 2011. RGGI CO_2 prices increased by 3.6 percent in 2012 compared to 2011, partially as a result of the increase in the price floor for RGGI CO_2 allowances. (See page 108)
- The price of RGGI CO_2 allowances remained at or near the floor price of $1.93 during January through March 2012, and as of January 1, 2012, the state of New Jersey will no longer be participating in the RGGI program. (See page 107)
- 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. (See page 106)

Section 8, Interchange Transactions

- Real-time net imports were 800.7 GWh for the first three months of 2012. For the first three months of 2011, there were net exports of -802.0 GWh in real-time. Day-ahead net exports were -3,224.6 GWh for the first three months of 2012. For the first three months of 2011, there were net imports of 3,813.0 GWh in day-ahead. (See page 120)
- The direction of power flows was not consistent with real-time energy market price differences in 58 percent of hours at the border between PJM and MISO and in 49 percent of hours at the border between PJM and NYISO during the first three months of 2012. (See page 128)
- During the first three months of 2012, net scheduled interchange was 310 GWh and net actual interchange was 110 GWh, a difference of 200 GWh (during the first three months of 2011, net scheduled interchange was -74 GWh and net actual interchange was -211 GWh, a difference of 137 GWh). (See page 134)
- PJM initiated 6 TLRs during the first three months of 2012, a reduction from the 13 TLRs initiated during the first three months of 2011. (See page 136)
- The average daily volume of up-to congestion bids increased from 20,753 bids per day, during the first three months of 2011, to 50,305 bids per day during the first three months of 2012. A significant increase in bid volume occurred following the September 17, 2010, modification to the up-to congestion product that eliminated the requirement to procure transmission when submitting up-to congestion bids. (See page 137)
- Balancing operating reserve credits are paid to importing dispatchable transactions (also known as real-time with price) as a guarantee of the transaction price. Dispatchable transactions are made whole when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. During the first three months of 2012, there were no balancing operating reserve credits paid to dispatchable transactions, a decrease from $1.1 million for the first three 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 in three days during the first three months of 2012. (See page 144)

Section 9, Ancillary Services

- The weighted average Regulation Market clearing price, including opportunity cost, for January through March 2012 was $12.64 per MW.[38] This was an increase of $1.13, or 10 percent, from the average price for regulation in January through March 2011. The total cost of regulation decreased by $8.07 from $24.83 per MW in January through March 2011, to $16.76, or 33 percent. In January through March 2012 the weighted Regulation Market clearing price was 75 percent of the total regulation cost per MW, compared to 46 percent of the total regulation cost per MW in January through March 2011. (See page 153)
- The weighted average clearing price for Tier 2 Synchronized Reserve Market in the Mid-Atlantic Subzone was $6.06 per MW in January through March 2012, a $4.94 per MW decrease from January through March 2011.[39] The total cost of synchronized reserves per MWh in January through March 2012 was $7.76, a 59 percent decrease from the total cost of synchronized reserves ($13.19) during January through March 2011. The weighted average Synchronized Reserve Market clearing price was 78 percent of the weighted average total cost per MW of synchronized reserve in January through March 2012, down slightly from 83 percent in January through March 2011. (See page 160)
- The weighted DASR market clearing price in January through March 2012 was $0 per MW. In January through March 2011, the weighted price of DASR was $0.02 per MW. The average hourly purchased DASR increased by eight percent from 6,145 MW to 6,634 MW reflecting PJM's larger footprint with the integration of Duke on January 1, 2012. (See page 164)
- Black start zonal charges in January through March 2012 ranged from $0.02 per MW in the ATSI zone to $1.90 per MW in the AEP zone (See page 164)

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

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

Section 10, Congestion and Marginal Losses

- Total marginal loss costs decreased by $169.1 million or 42.8 percent, from $409.6 million in the first quarter of 2011 to $234.4 million in the first quarter of 2012. (See page 172)
- Total monthly marginal loss costs in the first quarter of 2012 were lower than monthly marginal loss costs in the first quarter of 2011.[40] (See page 173)
- Day-ahead marginal loss costs were $248.3 million in the first quarter of 2012 and balancing marginal loss costs were -$13.9 million in the first quarter of 2012. (See page 172)
- The marginal loss credits (loss surplus) decreased in the first quarter of 2012 to $97.7 million compared to $200.1 million in the first quarter of 2011. (See page 172)
- Congestion costs in the first three months 2012 decreased by 65.9 percent compared to congestion costs in the first three months of 2011. (See page 175)
- Monthly congestion costs in the first three months of 2012 were lower than monthly congestion costs in the first three months of 2011. (See page 176)
- Day–ahead congestion costs were $181.3 million in the first three months of 2012 and $407.3 in the first three months of 2011. (See page 176)
- Balancing congestion costs were -$58.5 million in the first three months of 2012 and -$47.4 million in the first three months of 2011. (See page 176)

Section 11, Planning

- At March 31, 2012, 83,635 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 183,000 MW in 2012 including the January 1, 2012, DEOK integration. Wind projects account for approximately 29,418 MW, 35.2 percent of the capacity in the queues, and combined-cycle projects

40 See the *2011 State of the Market Report for PJM*, Volume II, "Energy Market, Part 1," Table 2-60.

account for 38,177 MW, 45.6 percent of the capacity in the queues. (See page 190)

- A total of 955 MW of generation capacity retired in January through March 2012, and it is expected that a total of 18,825 MW will have retired from 2011 through 2019, with most of this capacity retiring by the end of 2015. Units planning to retire in 2012 make up up 6,012 MW, or 36 percent of all planned retirements. (See page 195)

Section 12, Financial Transmission Rights and Auction Revenue Rights

- On January 1, 2012, the Duke Energy Ohio and Kentucky (DEOK) Control Zone was integrated into the PJM footprint. DEOK zonal customers were eligible to participate in a direct allocation of FTRs effective from January 1, 2012 through May 31, 2012. (See page 204)
- The total cleared FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2011 to 2012 planning period increased by 22 percent from 1,681,158 MW to 2,049,614 MW compared to the first ten months of the 2010 to 2011 planning period. (See page 206)
- FTRs were paid at 83.2 percent for the first ten months of the 2011 to 2012 planning period. (See page 209)
- FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. FTRs were not profitable overall and were not profitable for either physical or financial entities in January through March 2012. Total FTR profits were -$0.8 million for physical entities and -$11.3 million for financial entities. Self scheduled FTRs were the source of $117.3 million of the FTR profits for physical entities. (See page 211)

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 three 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 95.7 percent of the total price per MWh in the first three 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.[41]
- The Operating Reserve (uplift) component is the average price per MWh of day ahead and real time operating reserve charges.[42]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[43]

41 OATT §§ 13.7, 14.5, 27A & 34.
42 OA Schedules 1 §§ 3.2.3 & 3.3.3.
43 OATT Schedule 2 and OA Schedule 1 § 3.2.3B.

- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[44]
- 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.[45]
- 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.[46]
- 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.[47]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[48]
- The Black Start component is the average cost per MWh of black start service.[49]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[50]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[51]
- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.[52]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[53]

Table 1-7 Total price per MWh by category and total revenues by category: January through March 2011 and 2012

Category	Jan-Mar 2011 $/MWh	Jan-Mar 2012 $/MWh	Percent Change Totals	Jan-Mar 2011 Percent of Total	Jan-Mar 2012 Percent of Total
Energy	$46.35	$31.21	(32.7%)	70.7%	68.6%
Capacity	$12.60	$7.51	(40.4%)	19.2%	16.5%
Transmission Service Charges	$4.32	$4.80	11.1%	6.6%	10.6%
Operating Reserves (Uplift)	$0.72	$0.49	(31.6%)	1.1%	1.1%
Reactive	$0.39	$0.48	23.8%	0.6%	1.1%
PJM Administrative Fees	$0.33	$0.36	10.4%	0.5%	0.8%
Transmission Enhancement Cost Recovery	$0.30	$0.28	(7.3%)	0.5%	0.6%
Regulation	$0.27	$0.17	(36.6%)	0.4%	0.4%
Transmssion Owner (Schedule 1A)	$0.09	$0.08	(13.6%)	0.1%	0.2%
Synchronized Reserves	$0.12	$0.03	(75.6%)	0.2%	0.1%
Black Start	$0.02	$0.02	28.8%	0.0%	0.0%
NERC/RFC	$0.02	$0.02	8.9%	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(10.9%)	0.0%	0.0%
Load Response	$0.01	$0.01	18.5%	0.0%	0.0%
Transmission Facility Charges	$0.00	$0.00	(3.2%)	0.0%	0.0%
Day Ahead Scheduling Reserve (DASR)	$0.00	$0.00	(97.6%)	0.0%	0.0%
Total	$65.56	$45.48	(30.6%)	100.0%	100.0%

44 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
45 OATT Schedule 12.
46 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
47 OATT Schedule 1A.
48 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
49 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.
50 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
51 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
52 OA Schedule 1 § 3.6.
53 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 three 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 three months of 2012.

Table 2-1 The Energy Market results were competitive

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 three months of 2012 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1235 with a minimum of 1107 and a maximum of 1499 in the first three 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 a number of 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 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 16,249, or 10.0 percent, from 157,340 MW in the first quarter of 2011 to 173,590 MW in the first quarter of 2012. The increase in offered supply was the result of the integration of the Duke Energy Ohio/Kentucky (DEOK) transmission zone in the first quarter of 2012, the integration of the American Transmission Systems, Inc. (ATSI) transmission zone in the second quarter of 2011, and the addition of 5,008 MW of nameplate capacity to PJM in 2011. The increases in supply were partially offset by the deactivation of three units (955 MW) since January 1, 2012.

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.

- In January through March 2012, coal units provided 39.9 percent, nuclear units 36.3 percent and gas units 19.0 percent of total generation. Compared to January through March 2011, generation from coal units decreased 11.6 percent, generation from nuclear units increased 8.3 percent, while generation from natural gas units increased 66.0 percent, and generation from oil units increased 54.2 percent.
- The PJM system peak load for the first quarter of 2012 was 122,539 MW, which was 11,880 MW, or 10.7 percent, higher than the PJM peak load for the first quarter of 2011.[4] The ATSI and DEOK transmission zones accounted for 14,019 MW in the peak hour of the first quarter of 2012. The peak load excluding the ATSI and DEOK transmission zones was 108,519 MW, a decrease of 2,139 MW from the first quarter 2011 peak load.
- PJM average real-time load in the first quarter of 2012 increased by 6.4 percent from the first quarter of 2011, from 81,018 MW to 86,310 MW. The PJM average real-time load in the first quarter of 2012 would have decreased by 6.5 percent from the first quarter of 2011, from 81,018 MW to 75,753 MW, if the DEOK and ATSI transmission zones were excluded.
- PJM average day-ahead load, including DECs and up-to congestion transactions, increased in the first quarter of 2012 by 20.7 percent from the first quarter of 2011, from 107,116 MW to 129,258 MW. PJM average day-ahead load would have been 9.2 percent higher in the first quarter of 2012 than in the first quarter of 2011, from 107,116 MW to 116,964 MW if the DEOK and ATSI transmission zones were excluded.
- PJM average real-time generation increased by 5.5 percent in the first quarter of 2012 from the first quarter of 2011, from 83,505 MW to 88,068 MW. PJM average real-time generation would have decreased 5.1 percent in the first quarter of 2012 from the first quarter of 2011, from 83,505 MW to 79,276 MW if the DEOK and ATSI transmission zones were excluded.
- PJM Real-Time Energy Market prices decreased in the first quarter of 2012 compared to the first quarter of 2011. The load-weighted average LMP was 32.7 percent lower in the first quarter of 2012 than in the first quarter of 2011, $31.21 per MWh versus $46.35 per MWh.
- PJM Day-Ahead Energy Market prices decreased in the first quarter of 2012 compared to the first quarter of 2011. The load-weighted average LMP was 33.2 percent lower in the first quarter of 2012 than in the first quarter of 2011, $31.51 per MWh versus $47.14 per MWh.
- Levels of offer capping for local market power remained low. In the first three months of 2012, 1.9 percent of unit hours and 1.3 percent of MW were offer capped in the Real-Time Energy Market and 0.1 percent of unit hours and 0.2 percent of MW were offer capped in the Day-Ahead Energy Market.
- Of the 106 units that were eligible to include a Frequently Mitigated Unit (FMU) or Associated Unit (AU) adder in their cost-based offer during the first three months of 2012, 82 (77.4 percent) qualified in all months, and 12 (11.3 percent) qualified in only one month of 2012.
- There were no scarcity pricing events in the first three months of 2012 under PJM's current Emergency Action based scarcity pricing rules.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in the first three 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 in this section of the report.

Aggregate hourly supply offered increased by about 16,249 MW in the first quarter of 2012 compared to the first quarter of 2011, while aggregate peak load increased by 11,880 MW, modifying the general supply demand balance with a corresponding impact on Energy Market prices. In the Real-Time Market, average load in the first quarter of 2012 increased from the first quarter of 2011, from 81,018 MW to 86,310 MW. 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-

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).

demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load. LMP is a broader indicator of the level of competition. While PJM has experienced price spikes, these have been limited in duration and, in general, prices in PJM have been well below the marginal cost of the highest cost unit installed on the system. The significant price spikes in PJM have been directly related to supply and demand fundamentals. In PJM, prices tend to increase as the market approaches scarcity conditions as a result of generator offers and the associated shape of the aggregate supply curve. The pattern of prices within days and across months and years illustrates how prices are directly related to demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price. Energy Market results for the first three 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. 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.[5]

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 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 three months of 2012.

5 See the *2011 State of the Market Report for PJM*, Volume II, Appendix D, "Local Energy Market Structure: TPS Results" for detailed results of the TPS test.

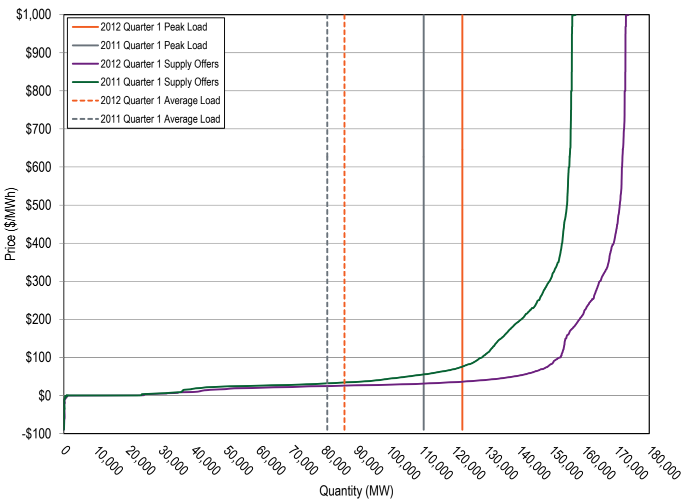
Market Structure

Supply

Average offered supply increased by 16,249, or 10.0 percent, from 157,340 MW in the first three months of 2011 to 173,590 MW in the first three months of 2012.[6] The large increase in offered supply was the result of the integration of the DEOK transmission zone in the first quarter of 2012, integration of the ATSI transmission zone in the second quarter of 2011, plus the addition of 5,008 MW of nameplate capacity to PJM in 2011. This includes five large plants (over 500 MW) that began generating in PJM in 2011. The increases in supply were partially offset by the deactivation of three units (955 MW) since January 1, 2012.

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

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



6 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.

Energy Production by Fuel Source

Compared to January through March 2011, generation from coal units decreased 11.6 percent and generation from natural gas units increased 66.0 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 25.0 percent in the first quarter of 2012 compared to the first quarter of 2011.

Table 2-2 PJM generation (By fuel source (GWh)): January through March 2011 and 2012[7] (See 2011 SOM, Table 2-2)

	Jan-Mar 2011		Jan-Mar 2012		
	GWh	Percent	GWh	Percent	Change in Output
Coal	87,871.5	47.7%	77,677.8	39.9%	(11.6%)
Standard Coal	84,742.7	46.0%	75,121.6	38.6%	(10.9%)
Waste Coal	3,128.7	1.7%	2,556.2	1.3%	(0.7%)
Nuclear	65,194.7	35.4%	70,637.4	36.3%	8.3%
Gas	22,383.0	12.2%	37,024.4	19.0%	65.4%
Natural Gas	21,945.7	11.9%	36,430.7	18.7%	66.0%
Landfill Gas	437.3	0.2%	593.6	0.3%	35.7%
Biomass Gas	0.1	0.0%	0.1	0.0%	123.5%
Hydroelectric	3,647.6	2.0%	3,357.9	1.7%	(7.9%)
Wind	3,363.8	1.8%	4,261.3	2.2%	26.7%
Waste	1,359.1	0.7%	1,249.0	0.6%	(8.1%)
Solid Waste	1,034.0	0.6%	979.3	0.5%	(5.3%)
Miscellaneous	325.1	0.2%	269.7	0.1%	(17.1%)
Oil	229.3	0.1%	353.7	0.2%	54.2%
Heavy Oil	190.1	0.1%	315.3	0.2%	65.9%
Light Oil	35.4	0.0%	37.2	0.0%	5.2%
Diesel	2.4	0.0%	1.1	0.0%	(52.7%)
Kerosene	1.5	0.0%	0.2	0.0%	(88.4%)
Jet Oil	0.0	0.0%	0.0	0.0%	(26.4%)
Solar	7.0	0.0%	43.9	0.0%	526.8%
Battery	0.1	0.0%	0.1	0.0%	(40.5%)
Total	184,056.2	100.0%	194,605.6	100.0%	5.7%

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

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

	Jan-Mar 2011		Jan-Mar 2012		
	GWh	Percent	GWh	Percent	Change in Output
Coal	87,871.5	47.7%	65,895.1	37.2%	(25.0%)
Standard Coal	84,742.7	46.0%	63,338.9	35.8%	(24.4%)
Waste Coal	3,128.7	1.7%	2,556.2	1.4%	(0.7%)
Nuclear	65,194.7	35.4%	66,012.3	37.3%	1.3%
Gas	22,383.0	12.2%	35,983.9	20.3%	60.8%
Natural Gas	21,945.7	11.9%	35,431.8	20.0%	61.5%
Landfill Gas	437.3	0.2%	552.0	0.3%	26.2%
Biomass Gas	0.1	0.0%	0.1	0.0%	123.5%
Hydroelectric	3,647.6	2.0%	3,357.9	1.9%	(7.9%)
Wind	3,363.8	1.8%	4,261.3	2.4%	26.7%
Waste	1,359.1	0.7%	1,249.0	0.7%	(8.1%)
Solid Waste	1,034.0	0.6%	979.3	0.6%	(5.3%)
Miscellaneous	325.1	0.2%	269.7	0.2%	(17.1%)
Oil	229.3	0.1%	352.9	0.2%	53.9%
Heavy Oil	190.1	0.1%	315.3	0.2%	65.9%
Light Oil	35.4	0.0%	37.1	0.0%	4.8%
Diesel	2.4	0.0%	0.4	0.0%	(82.8%)
Kerosene	1.5	0.0%	0.2	0.0%	(88.4%)
Jet Oil	0.0	0.0%	0.0	0.0%	(26.4%)
Solar	7.0	0.0%	43.9	0.0%	526.8%
Battery	0.1	0.0%	0.1	0.0%	(40.5%)
Total	184,056.2	100.0%	177,156.5	100.0%	(3.7%)

Generator Offers

Table 2-4 shows the distribution of MW generator offers by offer prices for the first quarter of 2012.

Table 2-4 Distribution[8] of MW for unit offer prices: January through March of 2012 (See 2011 SOM, Table 2-3)

	Range												
	($200) - $0		$0 - $200		$200 - $400		$400 - $600		$600 - $800		$800 - $1,000		
Unit Type	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Dispatchable	Self-Scheduled	Total
Battery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	100.0%
CC	0.0%	0.4%	62.2%	14.5%	13.3%	0.2%	1.4%	0.0%	6.7%	0.3%	1.0%	0.0%	100.0%
CT	0.0%	0.2%	37.0%	0.1%	19.2%	0.0%	9.1%	0.0%	29.1%	0.0%	5.1%	0.2%	100.0%
Diesel	0.0%	17.4%	10.2%	12.0%	49.3%	0.0%	8.7%	0.0%	1.4%	0.0%	0.9%	0.0%	100.0%
Hydrp	0.0%	96.6%	0.0%	2.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.0%	100.0%
Nuclear	0.0%	42.1%	9.2%	48.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Pumped Storage	53.5%	46.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Solar	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Steam	0.0%	1.4%	52.1%	22.1%	14.0%	9.9%	0.1%	0.0%	0.1%	0.2%	0.0%	0.1%	100.0%
Transaction	0.0%	0.0%	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	26.5%	67.2%	6.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
All Offers (by type)	1.6%	12.0%	40.1%	19.3%	12.0%	4.3%	2.2%	0.0%	7.1%	0.1%	1.3%	0.1%	100.0%
All Offers (total)		13.6%		59.4%		16.3%		2.2%		7.2%		1.4%	100.0%

Demand

The PJM system peak load for the first three months of 2012 was 122,539 MW in the HE 1900 on January 3, 2012, which was 11,880 MW, or 10.7 percent, higher than the PJM peak load for the first three months of 2011, which was 110,659 MW in the HE 800 on January 24, 2011. The ATSI and DEOK transmission zones accounted for 14,019 MW in the peak hour of the first quarter of 2012. The peak load excluding the ATSI and DEOK transmission zones was 108,519 MW, also occurring on January 3, 2012, HE 1900, a decrease of 2,139 MW from the first quarter 2011 peak load.

Table 2-5 shows the coincident first quarter peak loads for the years 2003 through 2012.

Table 2-5 Actual[9] PJM footprint peak loads: January through March of 2003 to 2012 (See 2011 SOM, Table 2-4)

(Jan - Mar)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
2003	Thu, January 23	19	54,670	NA	NA
2004	Mon, January 26	19	53,620	(1,050)	(1.9%)
2005	Tue, January 18	19	96,362	42,742	79.7%
2006	Mon, February 13	20	100,065	3,703	3.8%
2007	Mon, February 05	20	118,800	18,736	18.7%
2008	Thu, January 03	19	111,724	(7,076)	(6.0%)
2009	Fri, January 16	19	117,169	5,445	4.9%
2010	Mon, January 04	19	109,210	(7,959)	(6.8%)
2011	Mon, January 24	8	110,659	1,448	1.3%
2012 (with DEOK and ATSI)	Tue, January 03	19	122,539	11,880	10.7%
2012 (without DEOK and ATSI))	Tue, January 03	19	108,519	(2,139)	(1.9%)

8 Each range in the table is greater than the start value and less than or equal to the end value.

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

Figure 2-2 shows the first quarter peak loads for the years 2003 through 2012.

Figure 2-2 PJM[10] footprint first quarter peak loads: 2003 to 2012 (See 2011 SOM, Figure 2-2)

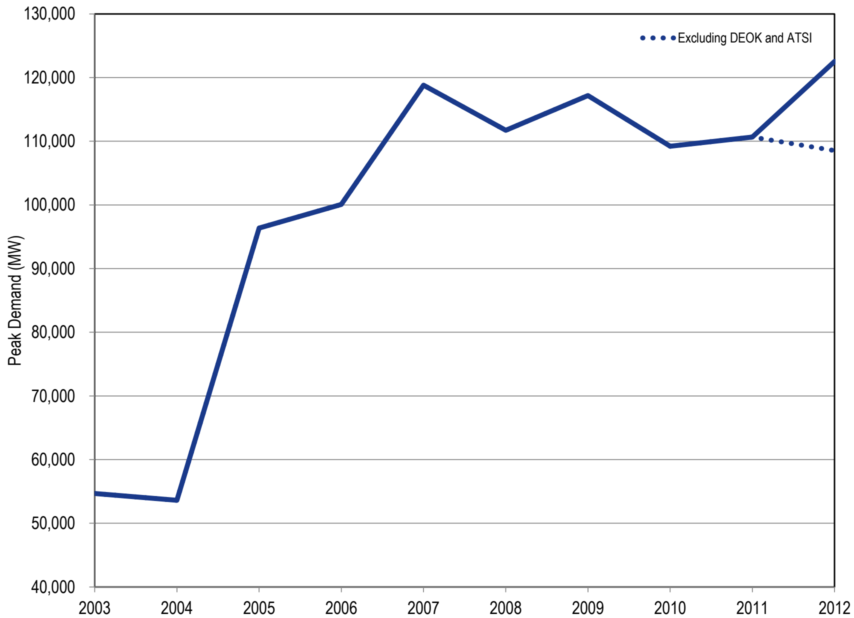
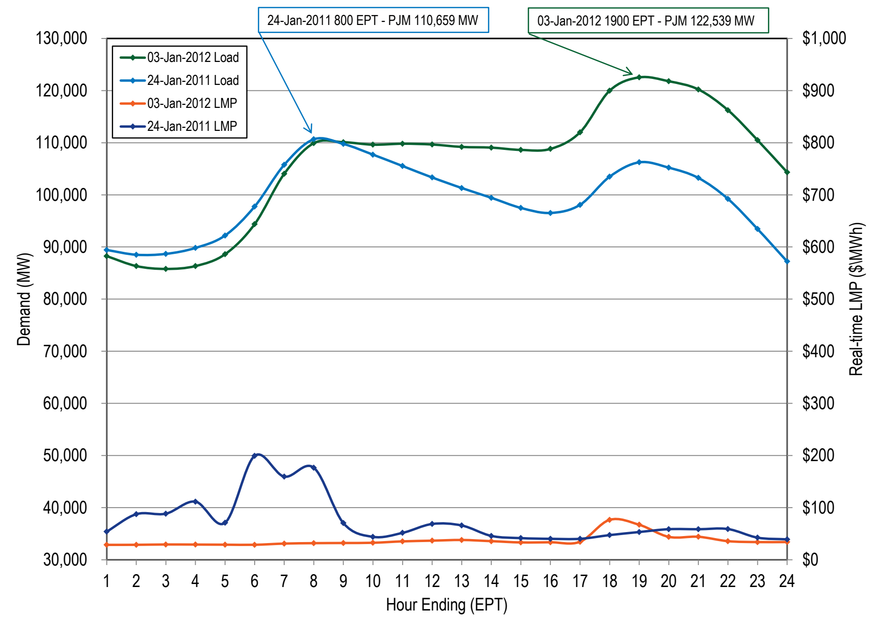


Figure 2-3 shows the peak load and LMP comparison for the first quarter of 2011 and 2012.

Figure 2-3 PJM peak-load comparison: Tuesday, January 03, 2012, and Monday, January 24, 2011 (See 2011 SOM, Figure 2-3)



Market Concentration

Analyses of supply curve segments of the PJM Energy Market for the first three months of 2012 indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.[11] 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

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

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

power and generation owners' obligations to serve load were generally effective in preventing the exercise of market power in these areas during the first three 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 2-6).

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 three months of 2012 was moderately concentrated (Table 2-6).

Table 2-6 PJM hourly Energy Market HHI: January through March 2012[12] (See 2011 SOM, Table 2-5)

	Hourly Market HHI
Average	1235
Minimum	1107
Maximum	1499
Highest market share (One hour)	28%
Average of the highest hourly market share	22%
# Hours	2,183
# Hours HHI > 1800	0
% Hours HHI > 1800	0%

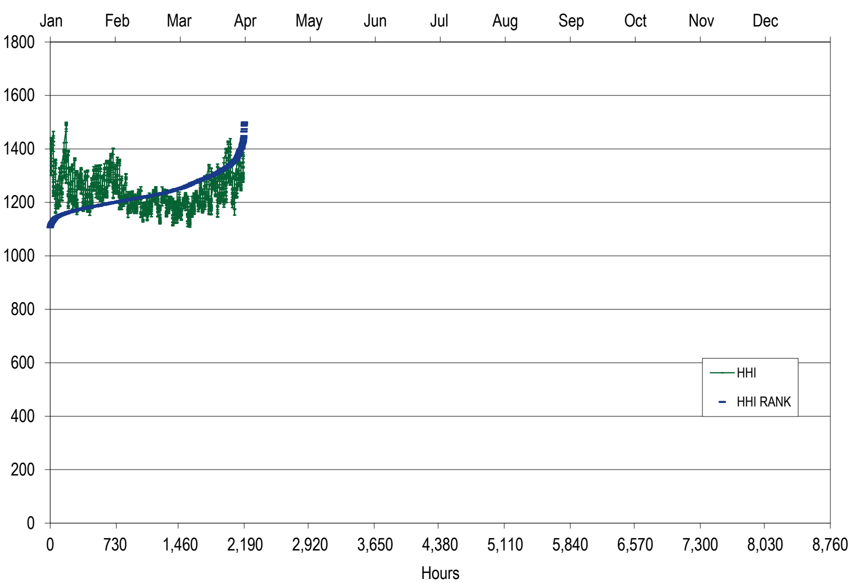
Table 2-7 includes 2012 HHI values by supply curve segment, including base, intermediate and peaking plants.

Table 2-7 PJM hourly Energy Market HHI (By supply segment): January through March 2012 (See 2011 SOM, Table 2-6)

	Minimum	Average	Maximum
Base	1110	1239	1496
Intermediate	1160	2916	7597
Peak	966	6682	10000

Figure 2-4 presents the 2012 hourly HHI values in chronological order and an HHI duration curve that shows 2012 HHI values in ascending order of magnitude.

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



12 This analysis includes all hours in the first three months of 2012, regardless of congestion.

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 2-8.

Table 2-8 Annual offer-capping statistics: 2008 through March 2012 (See 2011 SOM, Table 2-7)

	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2008	1.0%	0.2%	0.2%	0.1%
2009	0.4%	0.1%	0.1%	0.0%
2010	1.2%	0.4%	0.2%	0.1%
2011	0.9%	0.4%	0.0%	0.0%
2012 (Jan - Mar)	1.9%	1.3%	0.1%	0.2%

Table 2-9 presents data on the frequency with which units were offer capped in the first three months of 2012.

Table 2-9 Real-time offer-capped unit statistics: January through March 2012 (See 2011 SOM, Table 2-8)

	2012 Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	0	0	0	0	3	53
80% and < 90%	2	0	0	0	0	7
75% and < 80%	1	0	0	0	0	3
70% and < 75%	2	0	0	0	0	7
60% and < 70%	2	0	0	1	0	15
50% and < 60%	2	0	0	2	2	18
25% and < 50%	4	0	3	1	1	16
10% and < 25%	0	1	2	1	3	14

Table 2-9 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 three months of 2012, the AECO, AEP, AP, BGE, ComEd, DLCO, DPL, PENELEC, Pepco and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 25 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 three months of 2012.[13] The DAY, Dominion, JCPL, Met-Ed, PECO, PPL and RECO Control Zones were not affected by constraints binding for 25 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 March 31, 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 2-10 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.

13 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 2-10 Three pivotal supplier results summary for regional constraints: January through March 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	1,198	342	29%	1,028	86%
	Off Peak	560	272	49%	410	73%
AEP-DOM	Peak	257	10	4%	251	98%
	Off Peak	415	20	5%	409	99%
AP South	Peak	994	124	12%	957	96%
	Off Peak	937	236	25%	868	93%
Bedington - Black Oak	Peak	7	1	14%	7	100%
	Off Peak	NA	NA	NA	NA	NA
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	36	29	81%	16	44%
	Off Peak	9	6	67%	5	56%

Table 2-11 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 owner passing and failing for the regional 500 kV constraints.

Table 2-11 Three pivotal supplier test details for regional constraints: January through March 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	344	548	17	4	13
	Off Peak	212	406	16	7	9
AEP-DOM	Peak	226	280	8	0	7
	Off Peak	220	362	9	0	8
AP South	Peak	293	487	10	1	9
	Off Peak	257	523	11	2	9
Bedington - Black Oak	Peak	214	225	16	3	13
	Off Peak	NA	NA	NA	NA	NA
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	449	966	19	14	5
	Off Peak	227	551	14	8	6

Table 2-12 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 2-12 Summary of three pivotal supplier tests applied for regional constraints: January through March 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	1,198	21	2%	13	1%	62%
	Off Peak	560	3	1%	0	0%	0%
AEP-DOM	Peak	257	2	1%	1	0%	50%
	Off Peak	415	14	3%	12	3%	86%
AP South	Peak	994	13	1%	3	0%	23%
	Off Peak	937	8	1%	0	0%	0%
Bedington - Black Oak	Peak	7	1	14%	1	14%	100%
	Off Peak	NA	NA	NA	NA	NA	NA
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	36	0	0%	0	0%	0%
	Off Peak	9	0	0%	0	0%	0%

Frequently Mitigated Unit and Associated Unit Adders

An FMU is a frequently mitigated unit. FMUs were first provided additional compensation as a form of scarcity pricing in 2005.[14] The definition of FMUs provides for a set of graduated adders associated with increasing levels of offer capping. 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.[15] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.[16,17]

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.

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.[18]

Table 2-13 shows the number of FMUs and AUs in the first three months of 2012. For example, in March 2012, there were 25 FMUs and AUs in Tier 1, 17 FMUs and AUs in Tier 2, and 47 FMUs and AUs in Tier 3.

Table 2-13 Number of frequently mitigated units and associated units (By month): January through March, 2012 (See 2011 SOM, Table 2-26)

	FMUs and AUs			Total Eligible
	Tier 1	Tier 2	Tier 3	for Any Adder
January	26	21	52	99
February	26	22	47	95
March	25	17	47	89

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.

14 110 FERC ¶ 61,053 (2005).
15 OA, Schedule 1 § 6.4.2.
16 114 FERC ¶ 61, 076 (2006).
17 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).
18 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 March, 2012 (See 2011 SOM, Figure 2-5)

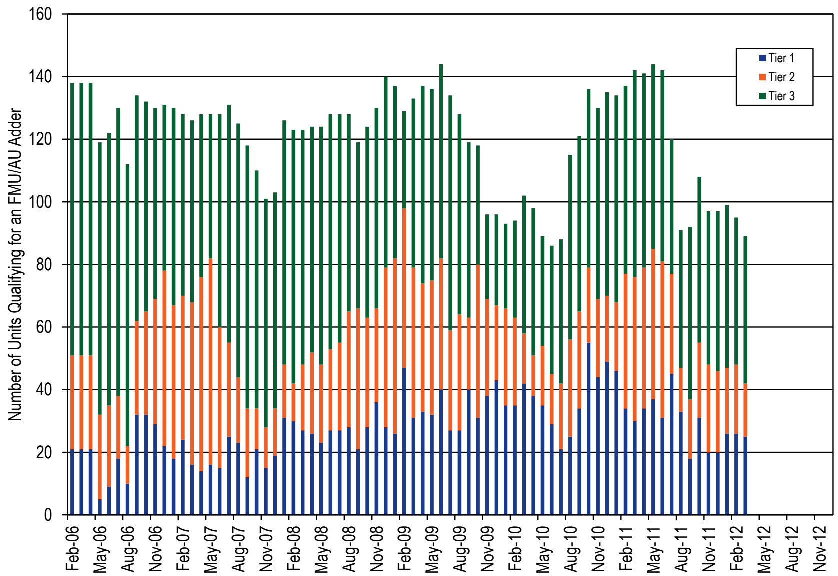


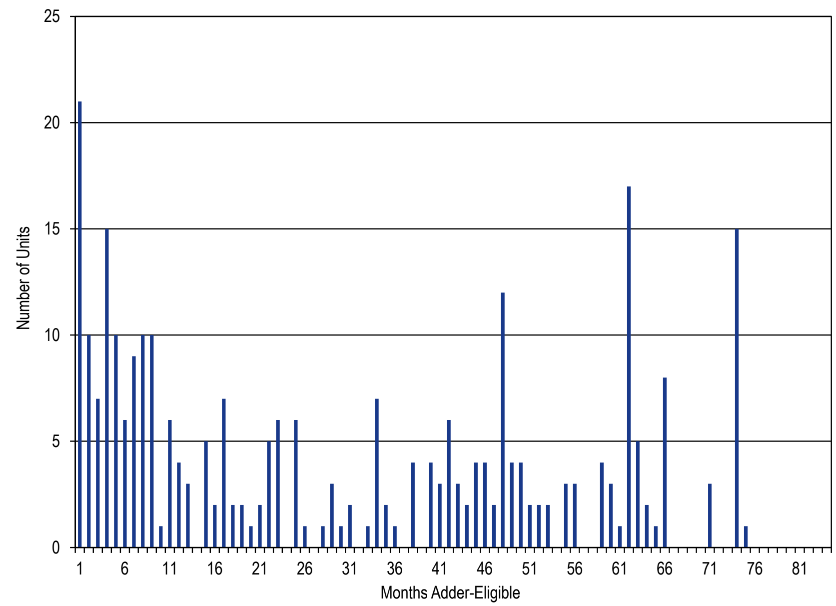
Table 2-14 shows the number of months FMUs and AUs were eligible for any adder (Tier 1, Tier 2 or Tier 3) during the first three months 2012. Of the 106 units eligible in at least one month during the first three months of 2012, 82 units (77.4 percent) were FMUs or AUs for all three months.

Table 2-14 Frequently mitigated units and associated units total months eligible: January through March, 2012 (See 2011 SOM, Table 2-27)

Months Adder-Eligible	FMU & AU Count
1	12
2	12
3	82
Total	106

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 March 31, 2012, there have been 293 unique units that have qualified for an FMU adder in at least one month. Of these 293 units, only one unit qualified for an adder in all potential months. Fifteen additional units qualified in 74 of the 75 possible months, and 124 of the 293 units (42.3 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 March, 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 quarter of 2012 increased by 6.5 percent from the first quarter of 2011, from 81,018 MW to 86,310 MW. The PJM average real-time load in the first quarter of 2012 would have decreased by 6.5 percent from the first quarter of 2011, from 81,018 MW to 75,753 MW, if the DEOK and ATSI transmission zones were excluded.

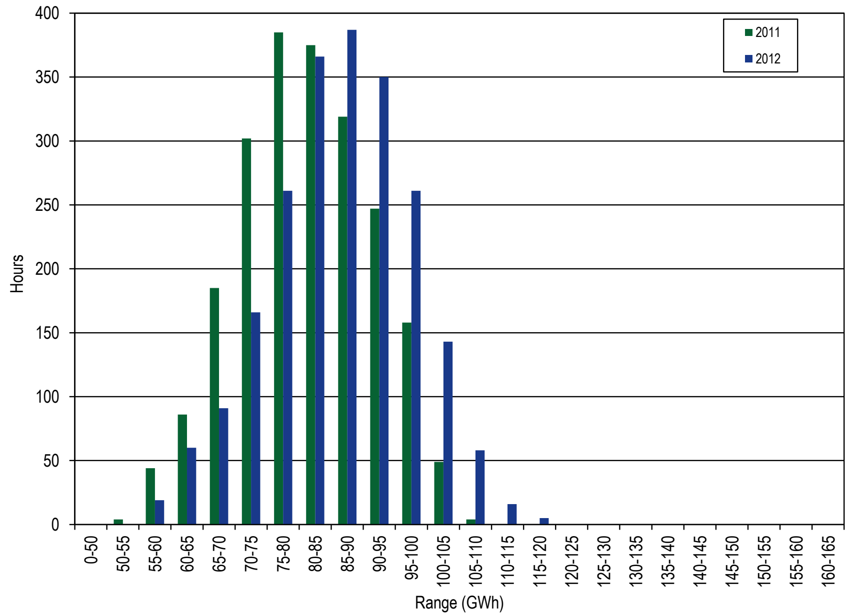
PJM average day-ahead load in the first quarter of 2012, including DECs and up-to congestion transactions, increased by 20.7 percent from the first quarter of 2011, from 107,116 MW to 129,258 MW. PJM average day-ahead load in the first quarter of 2012, including DECs and up-to congestion transactions, would have been 9.2 percent higher than in the first quarter of 2011, from 107,116 MW to 116,964 MW if the DEOK and ATSI transmission zones were excluded.

Real-Time Load

PJM Real-Time Load Duration

Figure 2-7 shows the hourly distribution of PJM real time load for the first quarter of 2011 and 2012.[19]

Figure 2-7 PJM real-time accounting load histogram: January through March for years 2011 and 2012[20] (See 2011 SOM, Figure 2-7)



PJM Real-Time, Average Load

Table 2-15 presents summary real-time load statistics for the first quarter 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.[21]

19 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.

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

21 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.*

Table 2-15 PJM real-time average hourly load: January through March for years 1998 through 2012 (See 2011 SOM, Table 2-28)

	PJM Real-Time Load (MWh)		Year-to-Year Change	
(Jan-Mar)	Average Load	Load Standard Deviation	Average Load	Load Standard Deviation
1998	28,019	3,762	NA	NA
1999	29,784	4,027	6.3%	7.0%
2000	30,367	4,624	2.0%	14.8%
2001	31,254	3,846	2.9%	(16.8%)
2002	29,968	4,083	(4.1%)	6.1%
2003	39,249	5,546	31.0%	35.8%
2004	39,549	5,761	0.8%	3.9%
2005	71,388	8,966	80.5%	55.6%
2006	80,179	8,977	12.3%	0.1%
2007	84,586	12,040	5.5%	34.1%
2008	82,235	10,184	(2.8%)	(15.4%)
2009	81,170	11,718	(1.3%)	15.1%
2010	81,121	10,694	(0.1%)	(8.7%)
2011	81,018	27,028	(0.1%)	152.7%
2012	86,310	28,501	6.5%	5.5%

PJM Real-Time, Monthly Average Load

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

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

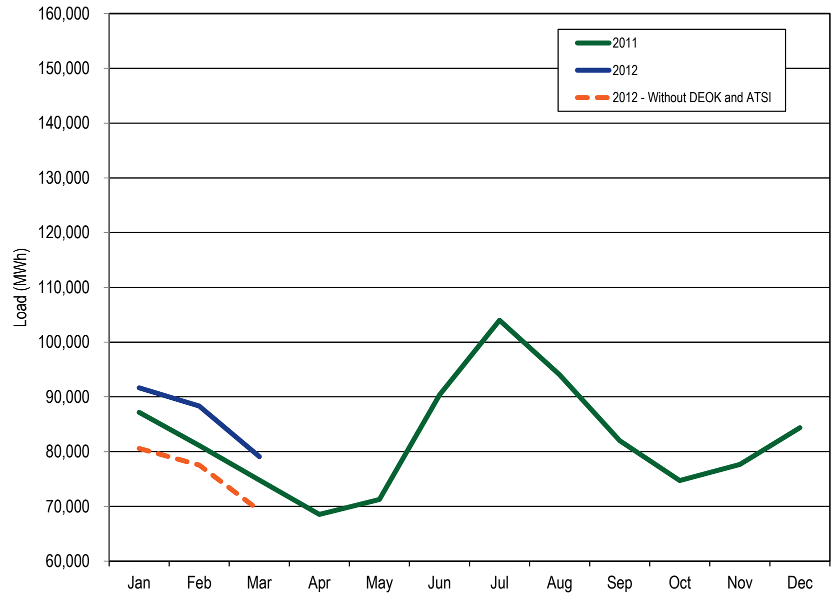


Table 2-16 shows the load weighted THI, WWP and average temperature for heating, cooling and shoulder seasons.[22]

22 The Summer THI is calculated by taking average of daily maximum THI in June, July and August. The Winter WWP is calculated by taking average of daily minimum WWP in January, February and December. Average temperature is used for the rest of months. For additional information on the calculation of these weather variables, see PJM "Manual 19: Load Forecasting and Analysis," Revision 18 (November 16, 2011), Section 3, pp. 15-16. Load weighting using real-time zonal accounting load.

Table 2-16 PJM annual Summer THI, Winter WWP and average temperature (Degrees F): cooling, heating and shoulder months of 2007 through 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	76.68	25.20	57.21
2012	NA	30.28	53.19

Day-Ahead Load

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

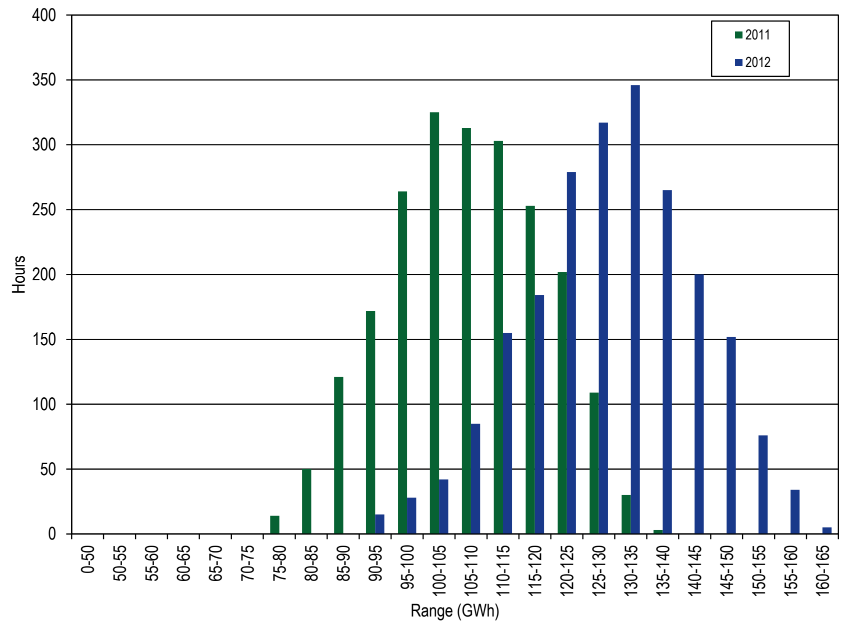
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of 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.[23] 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.[24]

PJM Day-Ahead Load Duration

Figure 2-9 shows the hourly distribution of PJM day-ahead load for the first quarter of 2011 and 2012.

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



PJM Day-Ahead, Average Load

Table 2-17 presents summary day-ahead load statistics for the first quarter of 12 year period 2001 to 2012.

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

24 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.

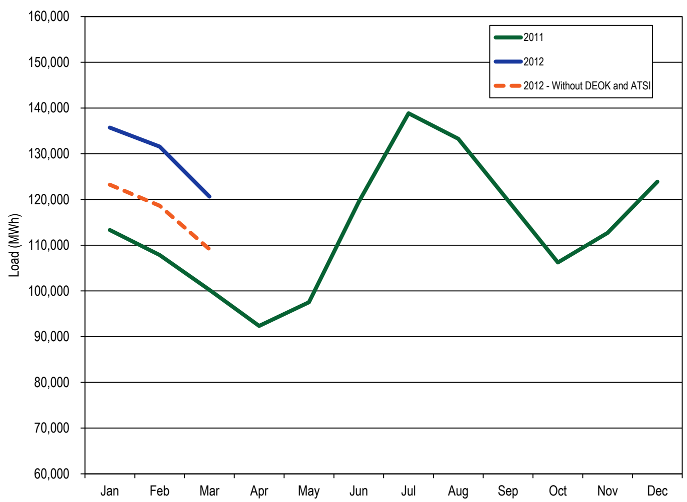
Table 2-17 PJM day-ahead average load: January through March for years 2001 through 2012 (See 2011 SOM, Table 2-31)

	PJM Day-Ahead Load (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
(Jan-Mar)	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load
2001	33,731	0	33,731	4,557	5	4,557	NA	NA	NA
2002	33,938	37	33,975	4,944	118	4,960	0.6%	11,350.0%	0.7%
2003	46,743	292	47,034	6,848	319	6,841	37.7%	686.0%	38.4%
2004	46,259	627	46,885	5,624	412	5,591	(1.0%)	114.8%	(0.3%)
2005	86,248	1,093	87,341	9,915	710	9,810	86.4%	74.5%	86.3%
2006	93,295	2,949	96,244	9,377	1,419	9,453	8.2%	169.7%	10.2%
2007	104,033	4,666	108,699	12,140	1,464	12,601	11.5%	58.3%	12.9%
2008	100,046	5,949	105,995	10,421	1,464	10,677	(3.8%)	27.5%	(2.5%)
2009	94,583	7,783	102,366	12,828	1,784	13,619	(5.5%)	30.8%	(3.4%)
2010	93,559	7,453	101,012	11,907	2,276	11,937	(1.1%)	(4.2%)	(1.3%)
2011	89,478	17,638	107,116	28,996	7,875	30,898	(4.4%)	136.7%	6.0%
2012	92,415	36,844	129,258	29,634	12,214	34,665	3.3%	108.9%	20.7%

PJM Day-Ahead, Monthly Average Load

Figure 2-10 compares the day-ahead, monthly average hourly loads of the first quarter of 2012 with those of 2011.

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



Real-Time and Day-Ahead Load

Table 2-18 presents summary statistics for the first quarter of 2011 and 2012 day-ahead and real-time loads.

Table 2-18 Cleared day-ahead and real-time load (MWh): January through March for years 2011 and 2012 (See 2011 SOM, Table 2-32)

		Day Ahead					Real Time	Average Difference	
	(Jan-Mar)	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	77,744	859	10,875	17,638	107,116	81,018	26,097	(2,415)
	2012	83,557	895	7,962	36,844	129,258	86,310	42,949	(1,857)
Median	2011	77,437	852	10,734	17,496	107,132	80,991	26,141	(2,089)
	2012	84,076	886	7,852	36,671	129,802	86,486	43,316	(1,207)
Standard Deviation	2011	9,641	189	1,894	2,654	11,890	10,273	1,617	(2,931)
	2012	10297	135	1584	4088	13163	10947	2,216	(3,457)
Peak Average	2011	83,588	950	11,877	18,130	114,546	87,187	27,359	(2,648)
	2012	90,231	963	8,501	37,274	136,970	92,965	44,005	(1,770)
Peak Median	2011	83,266	951	11,793	18,070	114,677	86,883	27,794	(2,069)
	2012	89,908	952	8,256	37,204	136,171	92,368	43,803	(1,657)
Peak Standard Deviation	2011	7,314	176	1,603	2,579	8,771	7,700	1,071	(3,111)
	2012	6764	120	1377	3967	9296	7549	1,747	(3,597)
Off-Peak Average	2011	72,472	777	9,970	17,193	100,412	75,453	24,959	(2,204)
	2012	77,485	833	7,471	36,452	122,242	80,255	41,987	(1,936)
Off-Peak Median	2011	72,228	772	9,769	17,020	99,884	74,949	24,935	(1,854)
	2012	77,190	830	7,276	36,179	122,389	79,600	42,789	(666)
Off-Peak Standard Deviation	2011	8,365	161	1,668	2,643	10,236	9,055	1,182	(3,130)
	2012	9,138	117	1,602	4,159	12,207	10,005	2,202	(3,559)

Figure 2-11 shows the first quarter 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 2-11 Day-ahead and real-time loads (Average hourly volumes): January through March of 2012 (See 2011 SOM, Figure 2-10)

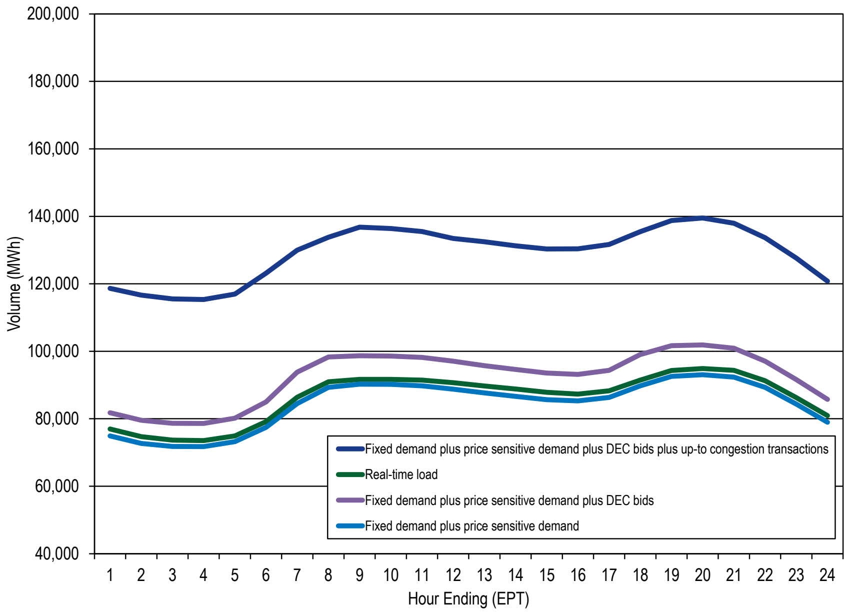
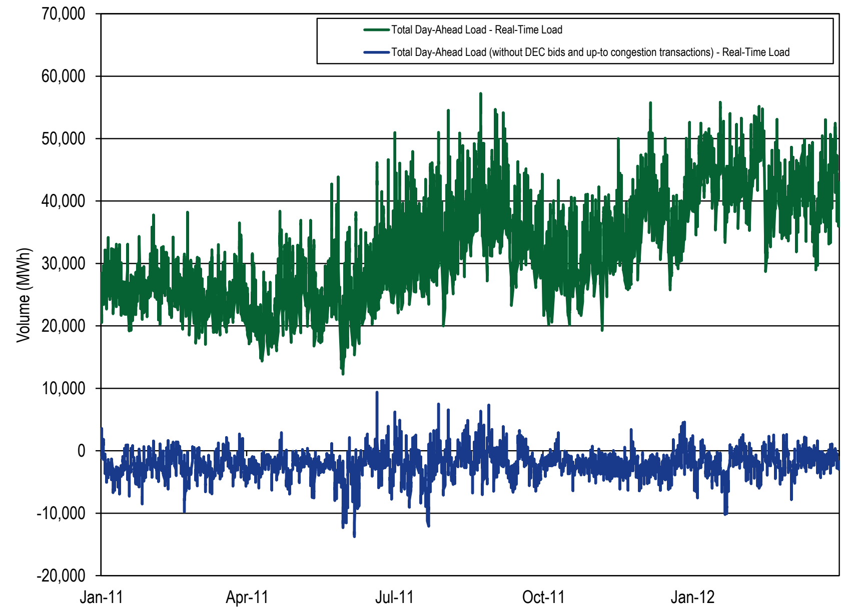


Figure 2-12 shows the difference between the day-ahead and real-time average daily loads in the first quarter of 2012 and the first quarter of 2011.

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



Real-Time and Day-Ahead Generation

PJM average real-time generation in the first quarter of 2012 increased by 5.5 percent from the first quarter of 2011, from 83,505 MW to 88,068 MW. PJM average real-time generation in the first quarter of 2012 would have decreased 5.1 percent from the first quarter of 2011, from 83,505 MW to 79,276 MW if the DEOK and ATSI transmission zones were excluded.

PJM average day-ahead generation in the first quarter of 2012, including INCs and up-to congestion transactions, increased by 19.8 percent from the first quarter of 2011, from 110,310 MW to 132,178 MW. PJM average day-ahead generation in the first quarter of 2012, including INCs and up-to congestion transactions, would have been 13.1 percent higher than in the first quarter of

2011, from 110,310 MW to 124,710 MW if the DEOK and ATSI transmission zones were excluded.

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:[25]

- **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.[26]
- **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.[27] 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 2-19 presents summary real-time generation statistics for the first quarter of the 10 year period from 2003 through 2012.

25 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."

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

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

Table 2-19 PJM real-time average hourly generation: January through March for years 2003 through 2012 (See 2011 SOM, Table 2-33)

	PJM Real-Time Generation (MWh)		Year-to-Year Change	
(Jan-Mar)	Average Generation	Generation Standard Deviation	Average Generation	Generation Standard Deviation
2003	38,731	5,187	NA	NA
2004	37,790	4,660	(2.4%)	(10.2%)
2005	74,187	8,269	96.3%	77.4%
2006	82,550	7,921	11.3%	(4.2%)
2007	86,286	10,018	4.5%	26.5%
2008	86,690	9,375	0.5%	(6.4%)
2009	81,987	11,417	(5.4%)	21.8%
2010	81,676	12,801	(0.4%)	12.1%
2011	83,505	26,470	2.2%	106.8%
2012	88,068	29,677	5.5%	12.1%

Table 2-20 presents summary day-ahead generation statistics for the first quarter of the 10 year period from 2003 to 2012.

Table 2-20 PJM day-ahead average hourly generation: January through March for years 2003 through 2012 (See 2011 SOM, Table 2-34)

	PJM Day-Ahead Generation (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
Year	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	36,855	292	37,147	4,379	319	4,337	NA	NA	NA
2004	45,964	627	46,591	4,825	412	4,794	24.7%	114.8%	25.4%
2005	87,918	1,093	89,011	9,529	710	9,434	91.3%	74.5%	91.0%
2006	94,370	2,949	97,319	8,974	1,419	9,035	7.3%	169.7%	9.3%
2007	105,433	4,666	110,099	11,438	1,464	11,938	11.7%	58.3%	13.1%
2008	103,763	5,949	109,711	10,197	1,464	10,479	(1.6%)	27.5%	(0.4%)
2009	97,097	7,783	104,880	13,093	1,784	13,895	(6.4%)	30.8%	(4.4%)
2010	94,280	7,453	101,733	14,264	2,276	13,835	(2.9%)	(4.2%)	(3.0%)
2011	92,672	17,638	110,310	29,591	7,875	31,507	(1.7%)	136.7%	8.4%
2012	95,334	36,844	132,178	31,303	12,214	36,348	2.9%	108.9%	19.8%

Table 2-21 presents summary statistics for first quarter of 2011 and 2012 for day-ahead and real-time generation.

Table 2-21 Day-ahead and real-time generation (MWh): January through March for years 2011 and 2012 (See 2011 SOM, Table 2-35)

		Day Ahead				Real Time	Average Difference	
	(Jan-Mar)	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	84,725	7,947	17,638	110,310	83,505	1,220	26,805
	2012	88,942	6,392	36,844	132,178	88,068	874	44,110
Median	2011	85,010	7,844	17,496	110,435	83,643	1,367	26,792
	2012	89,373	6,345	36,671	132,597	88,079	1,294	44,518
Standard Deviation	2011	10,911	1,134	2,654	12,200	10,116	795	2,084
	2012	11,883	773	4,088	13,701	11,177	706	2,524
Peak Average	2011	91,389	8,554	18,130	118,073	89,689	1,700	28,384
	2012	96,169	6,557	37,274	140,000	94,441	1,728	45,559
Peak Median	2011	91,319	8,412	18,070	118,178	89,381	1,938	28,797
	2012	95,687	6,497	37,204	139,084	94,019	1,668	45,065
Peak Standard Deviation	2011	7,869	1,037	2,579	8,910	7,530	339	1,380
	2012	7,975	595	3,967	9,825	8,066	-90	1,759
Off-Peak Average	2011	78,713	7,400	17,193	103,306	77,925	788	25,381
	2012	82,367	6,242	36,452	125,061	82,271	96	42,790
Off-Peak Median	2011	78,214	7,398	17,020	102,905	77,614	600	25,291
	2012	82,252	6,106	36,179	125,297	82,113	139	43,184
Off-Peak Standard Deviation	2011	9,717	920	2,643	10,397	8,825	892	1,572
	2012	11,006	879	4,159	12,823	10,435	571	2,388

Figure 2-13 shows the first quarter 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.[28]

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

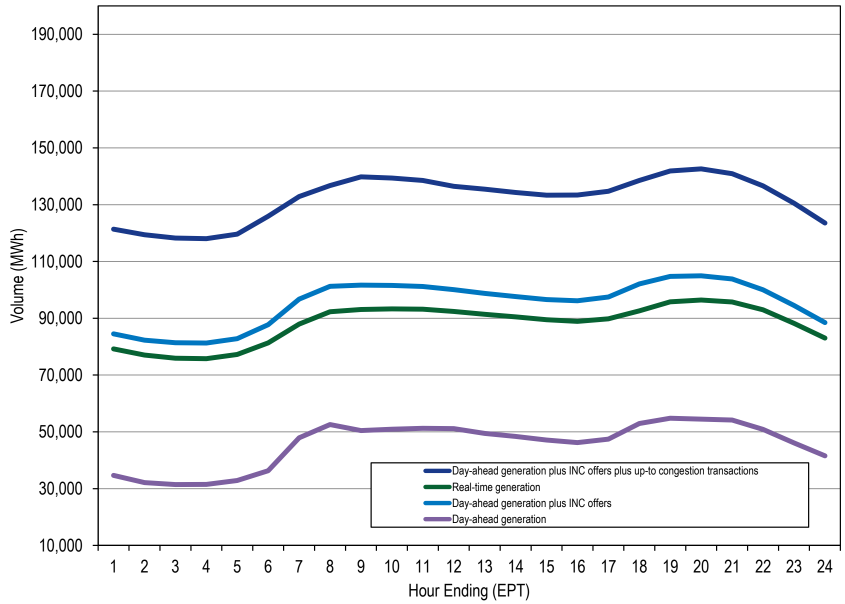
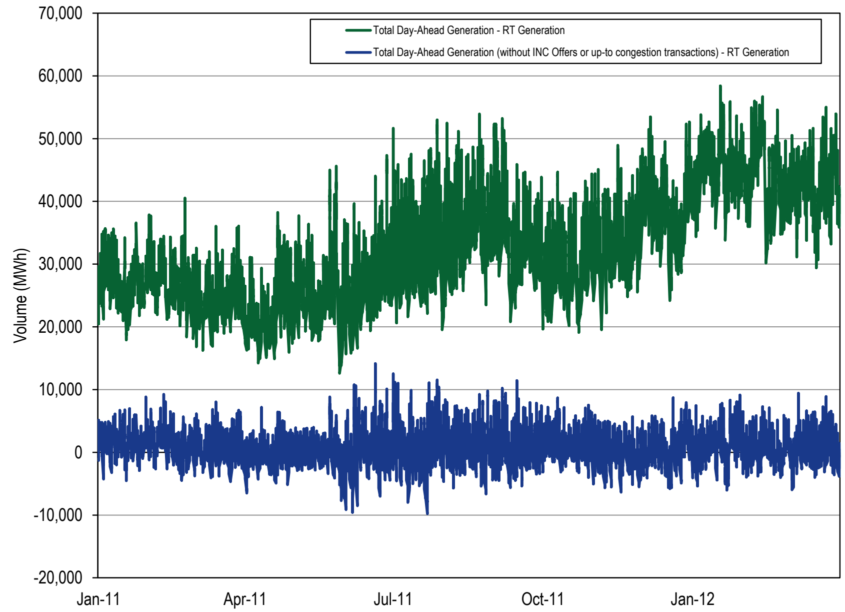


Figure 2-14 shows the difference between the day-ahead and real-time average daily generation in the first quarter of 2012 and the first quarter of 2011.

Figure 2-14 Difference between day-ahead and real-time generation (Average daily volumes): January 2011 through March 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.[29]

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

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

29 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 32.1 percent and 30.1 percent lower than in the first quarter of 2011 due to the decrease in gas prices coupled with warmer more stable winter weather.

PJM Real-Time Energy Market prices decreased in the first three months of 2012 compared to the first three months of 2011. The system average LMP was 32.1 percent lower in the first three months of 2012 than in the first three months of 2011, $30.38 per MWh versus $44.76 per MWh. The load-weighted average LMP was 32.7 percent lower in the first three months of 2012 than in the first three months of 2011, $31.21 per MWh versus $46.35 per MWh.

PJM Day-Ahead Energy Market prices decreased in the first three months of 2012 compared to the first three months of 2011. The system average LMP was 30.1 percent lower in the first three months of 2012 than in the first three months of 2011, $31.86 per MWh versus $45.60 per MWh. The load-weighted average LMP was 33.2 percent lower in the first three months of 2012 than in the first three months of 2011, $31.51 per MWh versus $47.14 per MWh.[30]

Real-Time LMP

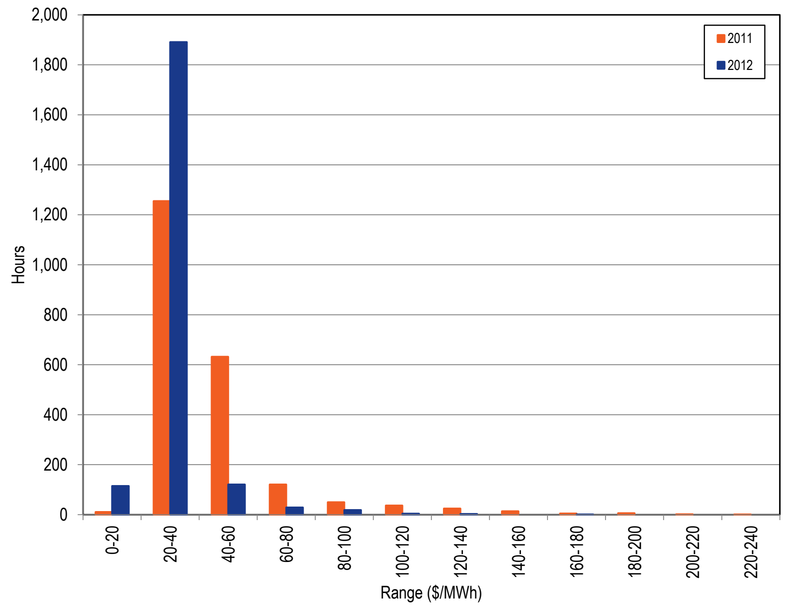
Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[31] This section discusses the real-time average LMP and the real-time load weighted average LMP. Average LMP is the simple, unweighted average LMP.

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 2-15 shows the number of hours that PJM real-time average LMP for the first quarter of 2011 and 2012 were within a defined range.

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



30 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".

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

PJM Real-Time, Average LMP

Table 2-22 shows the PJM real-time, annual, average LMP for the first quarter of the 15-year period 1998 to 2012.[32]

Table 2-22 PJM real-time, average LMP (Dollars per MWh): January through March, 1998 through 2012 (See 2011 SOM, Table 2-36)

	Real-Time LMP			Year-to-Year Change		
(Jan-Mar)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$17.51	$15.30	$7.84	NA	NA	NA
1999	$18.79	$16.56	$7.29	7.3%	8.3%	(7.0%)
2000	$23.66	$17.73	$16.22	25.9%	7.0%	122.4%
2001	$33.77	$26.01	$20.79	42.8%	46.8%	28.2%
2002	$22.23	$19.22	$9.61	(34.2%)	(26.1%)	(53.8%)
2003	$49.57	$43.08	$30.54	123.0%	124.2%	217.9%
2004	$46.37	$41.04	$24.07	(6.5%)	(4.8%)	(21.2%)
2005	$46.51	$40.62	$22.07	0.3%	(1.0%)	(8.3%)
2006	$52.98	$46.15	$23.29	13.9%	13.6%	5.5%
2007	$55.34	$47.15	$33.29	4.5%	2.2%	43.0%
2008	$66.75	$57.05	$35.54	20.6%	21.0%	6.8%
2009	$47.29	$40.56	$21.99	(29.2%)	(28.9%)	(38.1%)
2010	$44.13	$37.82	$21.87	(6.7%)	(6.8%)	(0.6%)
2011	$44.76	$38.14	$23.10	1.4%	0.8%	5.6%
2012	$30.38	$28.82	$11.63	(32.1%)	(24.4%)	(49.7%)

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 2-23 shows the PJM real-time, load-weighted, average LMP for the first quarter of the 15-year period 1998 to 2012.

32 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.

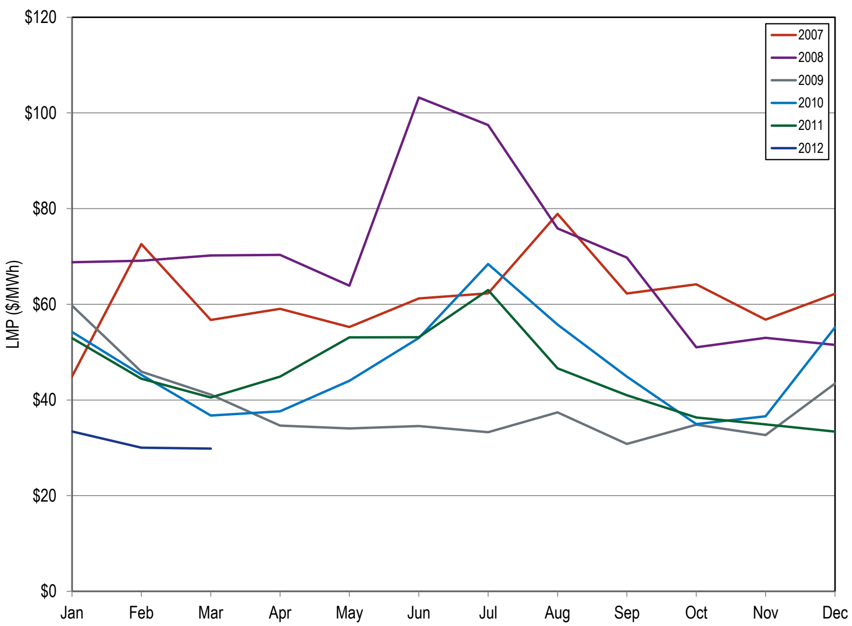
Table 2-23 PJM real-time, load-weighted, average LMP (Dollars per MWh): January through March, 1998 through 2012 (See 2011 SOM, Table 2-37)

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Mar)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$18.13	$15.80	$8.14	NA	NA	NA
1999	$19.38	$16.90	$7.66	6.9%	7.0%	(5.9%)
2000	$25.10	$18.25	$17.22	29.5%	8.0%	124.9%
2001	$35.16	$27.38	$21.52	40.1%	50.0%	25.0%
2002	$23.01	$19.89	$9.93	(34.6%)	(27.4%)	(53.8%)
2003	$51.93	$46.12	$30.99	125.6%	131.9%	211.9%
2004	$48.77	$43.22	$24.62	(6.1%)	(6.3%)	(20.6%)
2005	$48.37	$42.20	$22.62	(0.8%)	(2.4%)	(8.1%)
2006	$54.43	$47.62	$23.69	12.5%	12.9%	4.7%
2007	$58.07	$50.60	$34.44	6.7%	6.3%	45.4%
2008	$69.35	$60.11	$36.56	19.4%	18.8%	6.2%
2009	$49.60	$42.23	$23.38	(28.5%)	(29.8%)	(36.1%)
2010	$45.92	$39.01	$22.99	(7.4%)	(7.6%)	(1.7%)
2011	$46.35	$39.11	$24.26	0.9%	0.3%	5.5%
2012	$31.21	$29.25	$12.02	(32.7%)	(25.2%)	(50.5%)

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

Figure 2-16 shows the PJM real-time, monthly, load-weighted LMP from 2007 through the first quarter of 2012.

Figure 2-16 PJM real-time, monthly, load-weighted, average LMP: 2007 through March 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 quarter of 2012. Comparing prices on March 31, 2012 to prices on December 31, 2011, the price of Northern Appalachian coal was 7.3 percent lower; the price of Central Appalachian coal was 14.4 percent lower; the price of Powder River Basin coal was 12.1 percent lower; the price of eastern natural gas was 37.7 percent lower; and the price of western natural gas was 38.8 percent lower. Figure 2-17 shows spot average fuel prices for 2011 and 2012.[33]

Figure 2-17 Spot average fuel price comparison: 2011 and January through March 2012 (See 2011 SOM, Figure 2-17)

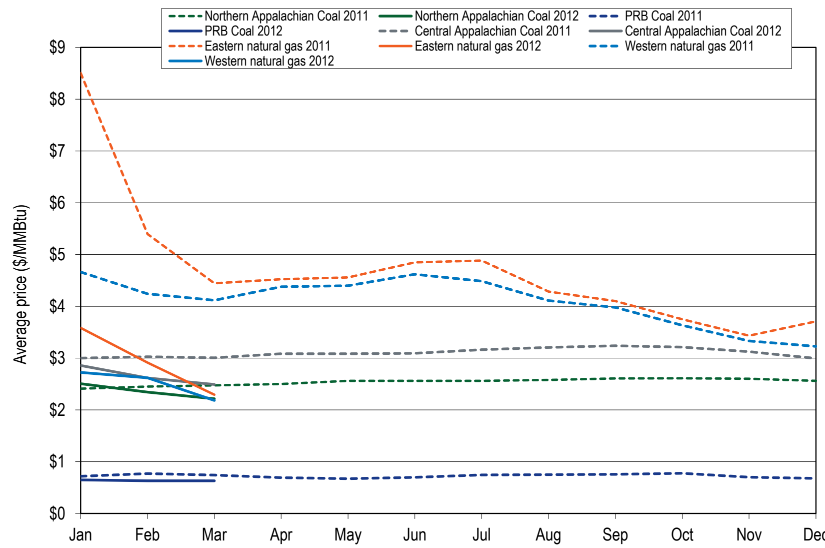


Figure 2-12 shows the spot average cost of generation, comparing the fuel cost of a coal plant, combined cycle, and combustion turbine in dollars per MWh. On average, the fuel cost of a new entrant combined cycle unit was lower than the fuel cost of a new entrant coal plant in the first three months of 2012.

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

Figure 2-18 Spot average fuel cost of generation of CP, CT, and CC: 2011 and January through March 2012 (New Figure)

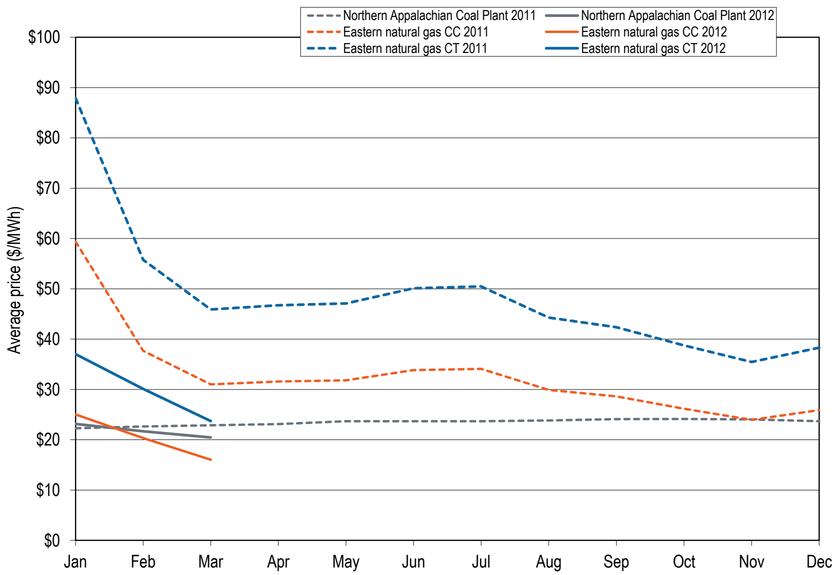
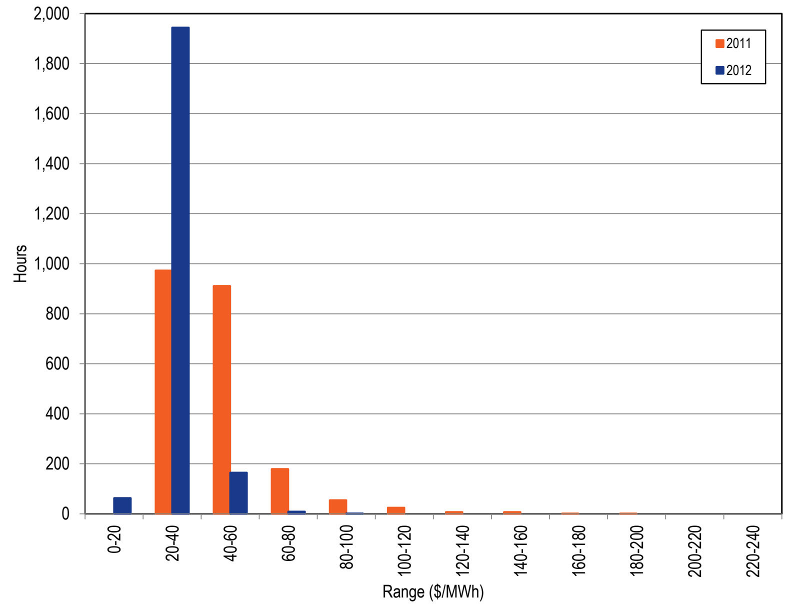


Figure 2-19 Price histogram for the PJM Day-Ahead Energy Market: January through March, 2011 and 2012 (See 2011 SOM, Figure 2-18)



Day-Ahead LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[34] This section discusses the day-ahead average LMP and the day-ahead load weighted average LMP. Average LMP is the simple, unweighted average LMP.

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 2-19 shows the hourly distribution of PJM day-ahead average LMP for the first quarter of 2011 and 2012.

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

PJM Day-Ahead, Average LMP

Table 2-24 shows the PJM day-ahead, average LMP for the first quarter of the 12 year period 2001 to 2012.

Table 2-24 PJM day-ahead, average LMP (Dollars per MWh): January through March, 2001 through 2012 (See 2011 SOM, Table 2-40)

	Day-Ahead LMP			Year-to-Year Change		
(Jan-Mar)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.45	$32.72	$16.39	NA	NA	NA
2002	$22.43	$20.59	$7.56	(38.5%)	(37.1%)	(53.9%)
2003	$51.20	$46.06	$25.65	128.2%	123.7%	239.3%
2004	$45.84	$43.01	$18.85	(10.5%)	(6.6%)	(26.5%)
2005	$45.14	$41.56	$16.19	(1.5%)	(3.4%)	(14.1%)
2006	$51.23	$48.53	$14.16	13.5%	16.8%	(12.6%)
2007	$52.76	$49.43	$22.59	3.0%	1.9%	59.5%
2008	$66.10	$62.57	$23.90	25.3%	26.6%	5.8%
2009	$47.41	$43.43	$16.85	(28.3%)	(30.6%)	(29.5%)
2010	$46.13	$41.99	$15.93	(2.7%)	(3.3%)	(5.5%)
2011	$45.60	$41.10	$16.82	(1.2%)	(2.1%)	5.6%
2012	$31.86	$30.56	$6.49	(30.1%)	(25.6%)	(61.4%)

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 2-25 shows the PJM day-ahead, load-weighted, average LMP for the first quarter of the 12-year period 2001 to 2012.

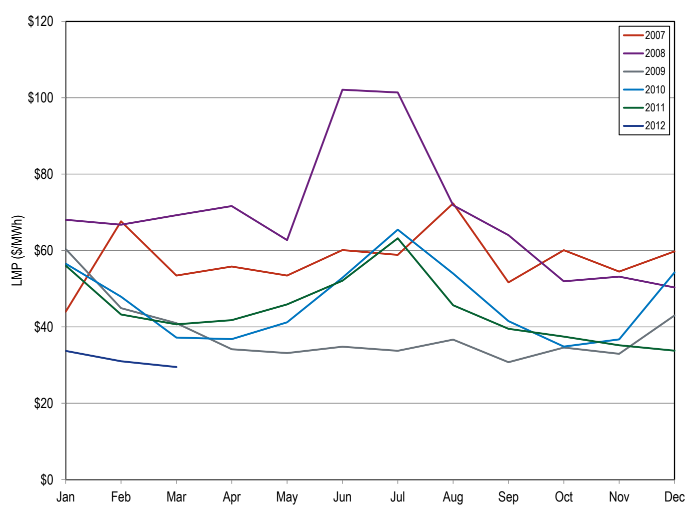
Table 2-25 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through March, 2001 through 2012 (See 2011 SOM, Table 2-41)

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Mar)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$37.70	$34.55	$16.66	NA	NA	NA
2002	$23.17	$21.18	$7.76	(38.5%)	(38.7%)	(53.4%)
2003	$53.16	$48.69	$25.75	129.5%	129.9%	231.7%
2004	$47.75	$45.02	$19.19	(10.2%)	(7.5%)	(25.4%)
2005	$46.54	$42.88	$16.46	(2.5%)	(4.8%)	(14.2%)
2006	$52.40	$49.51	$14.29	12.6%	15.5%	(13.2%)
2007	$54.87	$51.89	$23.16	4.7%	4.8%	62.0%
2008	$68.00	$64.70	$24.35	23.9%	24.7%	5.1%
2009	$49.44	$44.85	$17.54	(27.3%)	(30.7%)	(28.0%)
2010	$47.77	$43.62	$16.52	(3.4%)	(2.7%)	(5.8%)
2011	$47.14	$42.49	$17.73	(1.3%)	(2.6%)	7.3%
2012	$31.51	$30.44	$6.83	(33.2%)	(28.3%)	(61.5%)

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

Figure 2-20 shows the PJM day-ahead, monthly, load-weighted LMP from 2007 through the first quarter of 2012.

Figure 2-20 Day-ahead, monthly, load-weighted, average LMP: 2007 through March of 2012 (See 2011 SOM, Figure 2-19)



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.

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.[35] Table 2-26 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 2-27 shows the average volume of up-to congestion transactions per hour and the average total MW values of all bids per hour.

Table 2-26 Hourly average volume of cleared and submitted INCs, DECs by month: 2011 through March of 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	Annual	6,393	10,107	92	464	7,955	11,419	110	434

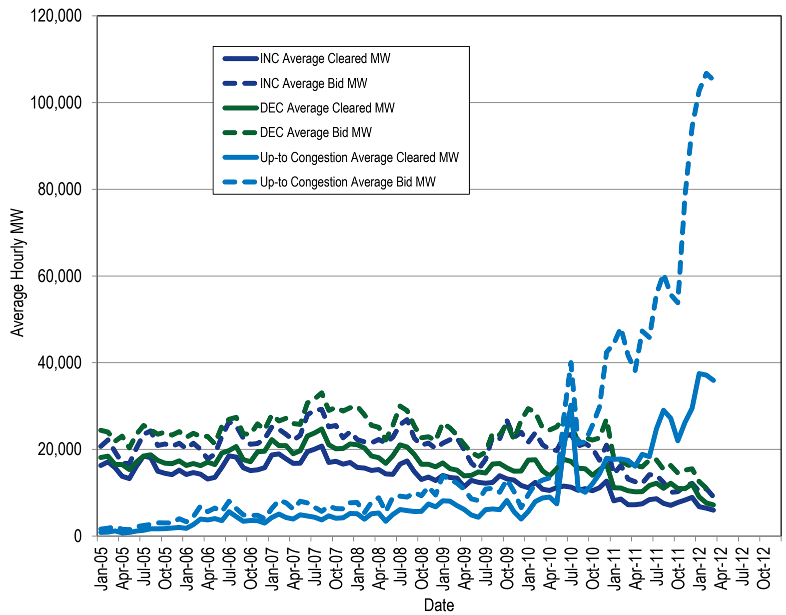
Table 2-27 Hourly average of cleared and submitted up-to congestion bids by month: 2011 through March of 2012 (See 2011 SOM, Table 2-44)

		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	Annual	36,841	104,908	833	2,096

35 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.

Figure 2-21 shows the hourly volume of bid and cleared INC, DEC and up-to congestion bids by month.

Figure 2-21 Hourly volume of bid and cleared INC, DEC and Up-to Congestion bids (MW) by month: January, 2005 through March, 2012 (See 2011 SOM, Figure 2-20)



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 2-28 shows the total increment offers and decrement bids by the type of parent organization: financial or physical. Table 2-29 shows the total up-to congestion transactions by the type of parent organization: financial or physical.

Table 2-28 PJM INC and DEC bids by type of parent organization (MW): January through March, 2011 and 2012 (See 2011 SOM, Table 2-46)

	2011 (Jan-Mar)		2012 (Jan-Mar)	
Category	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	35,013,405	51.1%	17,564,197	37.4%
Physical	33,470,237	48.9%	29,408,939	62.6%
Total	68,483,641	100.0%	46,973,136	100.0%

Table 2-29 PJM up-to congestion transactions by type of parent organization (MW): January through March, 2011 and 2012 (See 2011 SOM, Table 2-47)

	2011 (Jan-Mar)		2012 (Jan-Mar)	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	36,721,026	96.8%	76,787,244	95.1%
Physical	1,355,931	3.2%	3,931,378	4.9%
Total	38,076,956	100.0%	80,718,623	100.0%

Table 2-30 shows increment offers and decrement bids bid by top ten locations.

Table 2-30 PJM virtual offers and bids by top ten locations (MW): January through March, 2011 and 2012 (See 2011 SOM, Table 2-48)

2011 (Jan-Mar)					2012 (Jan-Mar)				
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	6,426,945	6,902,555	13,329,499	WESTERN HUB	HUB	7,688,302	8,954,480	16,642,782
N ILLINOIS HUB	HUB	2,625,577	4,527,187	7,152,764	AEP-DAYTON HUB	HUB	1,311,830	1,322,353	2,634,183
AEP-DAYTON HUB	HUB	1,480,675	1,641,866	3,122,541	SOUTHIMP	INTERFACE	2,362,472	0	2,362,472
SOUTHIMP	INTERFACE	1,731,983	0	1,731,983	N ILLINOIS HUB	HUB	797,387	1,217,638	2,015,025
MISO	INTERFACE	68,374	1,244,714	1,313,088	PECO	ZONE	569,142	1,413,636	1,982,778
PECO	ZONE	296,203	999,453	1,295,655	PPL	ZONE	109,230	1,461,786	1,571,016
PPL	ZONE	104,239	993,763	1,098,001	MISO	INTERFACE	68,763	1,325,083	1,393,845
IMO	INTERFACE	808,906	85,891	894,798	IMO	INTERFACE	1,095,465	7,054	1,102,519
COMED	ZONE	680,972	165,165	846,137	PSEG	ZONE	211,672	342,435	554,108
BGE	ZONE	48,094	762,176	810,270	BGE	ZONE	53,894	446,806	500,700
		14,271,967	17,322,770	31,594,736			14,268,157	16,491,270	30,759,427
PJM total		31,347,701	37,135,940	68,483,641			22,025,564	24,947,572	46,973,136
Top ten total as percent of PJM total		45.5%	46.6%	46.1%			64.8%	66.1%	65.5%

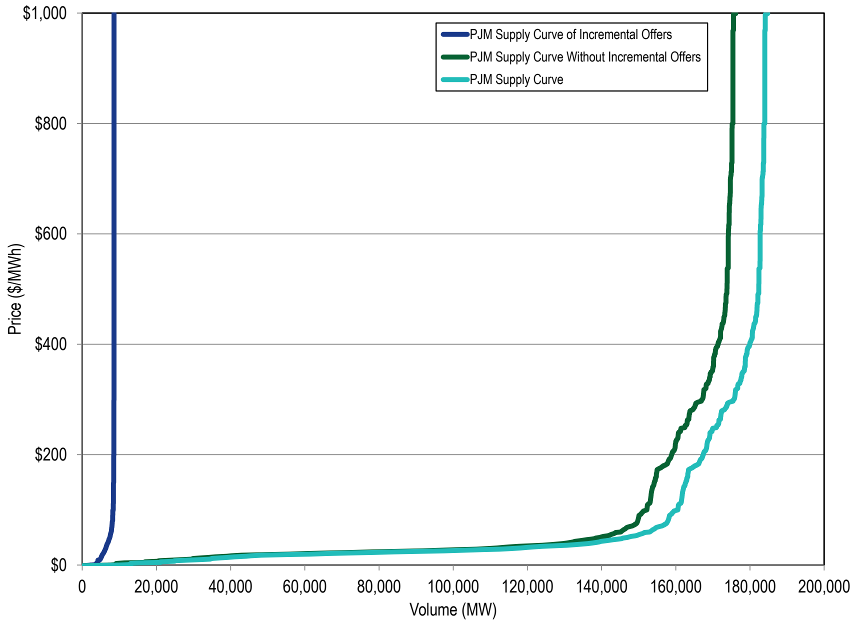
Table 2-31 shows up-to congestion transactions by import, export and wheel for the top ten locations.

Table 2-31 PJM cleared up-to congestion import, export and wheel bids by top ten source and sink pairs (MW): January through March, 2011 and 2012 (See 2011 SOM, Table 2-49)

2011 (Jan-Mar)														
Imports					Exports					Wheels				
Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	112 WILTON	EHVAGG	1,071,503	WESTERN HUB	HUB	MISO	INTERFACE	851,201	NORTHWEST	INTERFACE	SOUTHWEST	AGGREGATE	133,090
MISO	INTERFACE	N ILLINOIS HUB	HUB	932,389	23 COLLINS	EHVAGG	MISO	INTERFACE	841,950	NORTHWEST	INTERFACE	MISO	INTERFACE	90,509
NORTHWEST	INTERFACE	ZION 1	AGGREGATE	750,284	BEAV DUQ UNIT1	AGGREGATE	MICHFE	AGGREGATE	649,505	NYIS	INTERFACE	MICHFE	AGGREGATE	60,290
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	486,580	21 KINCA ATR24304	AGGREGATE	SOUTHWEST	AGGREGATE	579,542	SOUTHWEST	AGGREGATE	OVEC	INTERFACE	55,425
NORTHWEST	INTERFACE	BRAIDWOOD 1	AGGREGATE	448,342	21 KINCA ATR24304	AGGREGATE	OVEC	INTERFACE	455,450	NCMPAIMP	INTERFACE	OVEC	INTERFACE	49,289
OVEC	INTERFACE	STUART 1	AGGREGATE	401,442	COOK	EHVAGG	OVEC	INTERFACE	338,754	MISO	INTERFACE	NIPSCO	INTERFACE	49,248
OVEC	INTERFACE	CONESVILLE 6	AGGREGATE	374,351	QUAD CITIES 2	AGGREGATE	MISO	INTERFACE	288,843	SOUTHEAST	AGGREGATE	CPLEEXP	INTERFACE	46,200
NORTHWEST	INTERFACE	112 WILTON	EHVAGG	333,682	STUART 1	AGGREGATE	OVEC	INTERFACE	260,156	NIPSCO	INTERFACE	OVEC	INTERFACE	41,081
NYIS	INTERFACE	MARION	AGGREGATE	289,556	SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	208,808	NIPSCO	INTERFACE	MISO	INTERFACE	35,408
NYIS	INTERFACE	PSEG	ZONE	277,926	21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	202,774	SOUTHEAST	AGGREGATE	IMO	INTERFACE	24,194
Top ten total				5,366,053					4,676,983					584,733
PJM total				21,828,666					15,408,100					840,190
Top ten total as percent of PJM total				24.6%					30.4%					69.6%
2012 (Jan-Mar)														
Imports					Exports					Wheels				
Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW	Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	112 WILTON	EHVAGG	3,950,243	ROCKPORT	EHVAGG	OVEC	INTERFACE	1,653,313	MISO	INTERFACE	NORTHWEST	INTERFACE	50,943
OVEC	INTERFACE	CONESVILLE 4	AGGREGATE	1,372,477	ROCKPORT	EHVAGG	SOUTHWEST	AGGREGATE	1,079,308	NIPSCO	INTERFACE	NORTHWEST	INTERFACE	18,738
OVEC	INTERFACE	DEOK	ZONE	1,064,356	23 COLLINS	EHVAGG	MISO	INTERFACE	931,276	SOUTHWEST	AGGREGATE	OVEC	INTERFACE	13,961
OVEC	INTERFACE	CONESVILLE 5	AGGREGATE	752,791	167 PLANO	EHVAGG	MISO	INTERFACE	757,345	NORTHWEST	INTERFACE	MISO	INTERFACE	13,833
MISO	INTERFACE	N ILLINOIS HUB	HUB	724,225	SPORN 3	AGGREGATE	OVEC	INTERFACE	646,956	SOUTHEAST	AGGREGATE	SOUTHWEST	AGGREGATE	11,601
OVEC	INTERFACE	CONESVILLE 6	AGGREGATE	701,270	WESTERN HUB	HUB	MISO	INTERFACE	633,292	SOUTHWEST	AGGREGATE	SOUTHEXP	INTERFACE	10,572
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	616,066	SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	570,882	OVEC	INTERFACE	SOUTHEXP	INTERFACE	9,346
MISO	INTERFACE	POWERTON 5	AGGREGATE	615,189	ROCKPORT	EHVAGG	MISO	INTERFACE	544,717	NYIS	INTERFACE	NEPTUNE	INTERFACE	8,786
NYIS	INTERFACE	HUDSON BC	AGGREGATE	523,487	QUAD CITIES 1	AGGREGATE	NORTHWEST	INTERFACE	536,568	NORTHWEST	INTERFACE	SOUTHEXP	INTERFACE	8,593
MISO	INTERFACE	COOK	EHVAGG	418,931	SPORN 5	AGGREGATE	OVEC	INTERFACE	530,900	NIPSCO	INTERFACE	IMO	INTERFACE	7,855
Top ten total				10,739,036					7,884,555					154,227
PJM total				39,854,574					40,363,681					227,583
Top ten total as percent of PJM total				26.9%					19.5%					67.8%

Figure 2-22 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 2-22 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 2-23). There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis (Figure 2-24).

As Table 2-32 shows, day-ahead and real-time prices were relatively close, on average, in the first quarter of 2011 and 2012.

Table 2-32 Day-ahead and real-time average LMP (Dollars per MWh): January through March, 2011 and 2012[36] (See 2011 SOM, Table 2-50)

	2011 (Jan - Mar)				2012 (Jan - Mar)			
	Day Ahead	Real Time	Difference	Difference as Percent of Real Time	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$45.60	$44.76	($0.84)	(1.9%)	$30.82	$30.38	($0.43)	(1.4%)
Median	$41.10	$38.14	($2.96)	(7.8%)	$30.04	$28.82	($1.22)	(4.2%)
Standard deviation	$16.82	$23.10	$6.27	27.2%	$6.63	$11.63	$5.00	43.0%
Peak average	$50.24	$49.26	($0.98)	(2.0%)	$33.78	$33.75	($0.03)	(0.1%)
Peak median	$45.77	$42.16	($3.61)	(8.6%)	$32.08	$30.65	($1.43)	(4.7%)
Peak standard deviation	$16.21	$23.06	$6.86	29.7%	$6.30	$12.05	$5.75	47.7%
Off peak average	$41.41	$40.70	($0.71)	(1.7%)	$28.19	$27.41	($0.79)	(2.9%)
Off peak median	$36.85	$34.85	($2.00)	(5.7%)	$27.75	$26.75	($1.00)	(3.7%)
Off peak standard deviation	$16.27	$22.37	$6.10	27.3%	$5.76	$10.38	$4.62	44.5%

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 2-33 shows the difference between the Real-Time and the Day-Ahead Energy Market Prices for the first quarter of 2001 to 2012.

Table 2-33 Day-ahead and real-time average LMP (Dollars per MWh): January through March, 2001 through 2012 (See 2011 SOM, Table 2-51)

(Jan - Mar)	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2001	$36.45	$33.77	($2.68)	(7.3%)
2002	$22.43	$22.23	($0.20)	(0.9%)
2003	$51.20	$49.57	($1.63)	(3.2%)
2004	$45.84	$46.37	$0.52	1.1%
2005	$45.14	$46.51	$1.37	3.0%
2006	$51.23	$52.98	$1.75	3.4%
2007	$52.76	$55.34	$2.58	4.9%
2008	$66.10	$66.75	$0.65	1.0%
2009	$47.41	$47.29	($0.12)	(0.2%)
2010	$46.13	$44.13	($2.00)	(4.3%)
2011	$45.60	$44.76	($0.84)	(1.8%)
2012	$30.82	$30.38	($0.43)	(1.4%)

Table 2-34 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 quarter of years 2007 through 2012.

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

Table 2-34 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): January through March, 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%	0	0.00%	0	0.00%
($150) to ($100)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.05%	0	0.00%
($100) to ($50)	14	0.65%	21	0.96%	1	0.05%	5	0.23%	17	0.83%	2	0.09%
($50) to $0	1,214	56.88%	1,309	60.93%	1,347	62.44%	1,569	72.90%	1,464	68.64%	1,566	71.83%
$0 to $50	847	96.11%	740	94.82%	788	98.93%	547	98.24%	619	97.31%	601	99.36%
$50 to $100	73	99.49%	97	99.27%	21	99.91%	33	99.77%	51	99.68%	12	99.91%
$100 to $150	7	99.81%	14	99.91%	2	100.00%	1	99.81%	6	99.95%	2	100.00%
$150 to $200	0	99.81%	1	99.95%	0	100.00%	4	100.00%	1	100.00%	0	100.00%
$200 to $250	1	99.86%	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$250 to $300	1	99.91%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$300 to $350	2	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$350 to $400	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$400 to $450	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
$450 to $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%

Figure 2-23 shows the hourly differences between day-ahead and real-time load-weighted hourly LMP in the first quarter of 2012.

Figure 2-23 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: January through March, 2012 (See 2011 SOM, Figure 2-22)

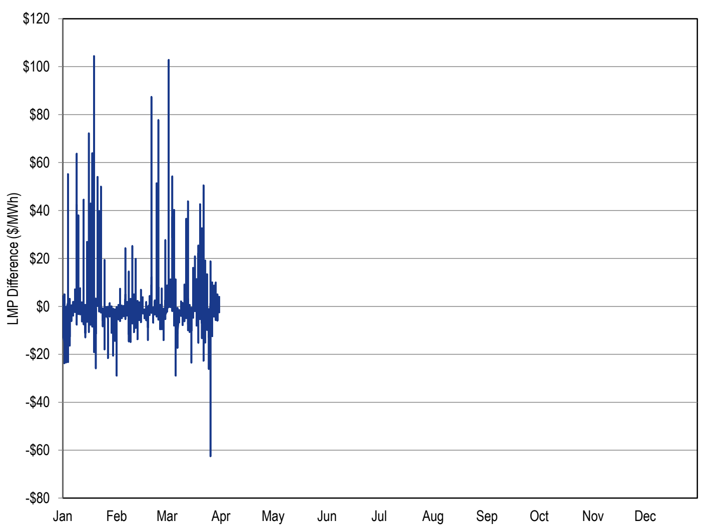
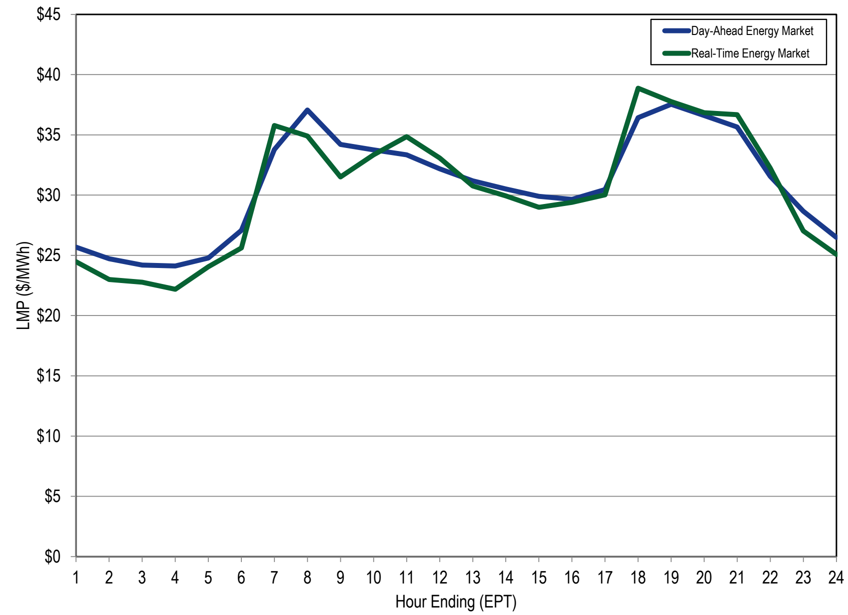


Figure 2-24 shows the monthly average differences between the day-ahead and real-time LMP in the first quarter of 2012.

Figure 2-24 Monthly average of real-time minus day-ahead LMP: January through March, 2012 (See 2011 SOM, Figure 2-23)

Figure 2-25 shows day-ahead and real-time LMP on an average hourly basis.

Figure 2-25 PJM system hourly average LMP: January through March, 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 2-35 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, 10.2 percent of real-time load was supplied by bilateral contracts, 23.3 percent by spot market purchase and 66.5 percent by self-supply. Compared with 2011, reliance on bilateral contracts decreased 01.3 percentage points, reliance on spot supply decreased by 3.3 percentage points and reliance on self-supply increased by 3.6 percentage points.

Table 2-35 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%						
May	11.1%	25.7%	63.3%						
Jun	10.5%	25.4%	64.1%						
Jul	9.5%	24.7%	65.8%						
Aug	10.3%	24.6%	65.1%						
Sep	10.9%	26.7%	62.4%						
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%	10.2%	23.3%	66.5%	(0.3%)	(3.3%)	3.6%

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 2-36 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, 7.2 percent of day-ahead load was supplied by bilateral contracts, 22.7 percent by spot market purchases, and 70.1 percent by self-supply. Compared with 2011, reliance on bilateral contracts increased by 1.4 percentage points, reliance on spot supply decreased by 1.7 percentage points, and reliance on self-supply increased by 0.3 percentage points.

Table 2-36 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%	7.1%	22.4%	70.5%	2.4%	(1.3%)	(1.1%)
Feb	5.4%	23.7%	70.9%	7.3%	21.3%	71.4%	1.9%	(2.4%)	0.5%
Mar	5.8%	24.3%	70.0%	7.3%	24.4%	68.2%	1.6%	0.2%	(1.7%)
Apr	6.1%	23.8%	70.1%						
May	6.0%	24.0%	70.0%						
Jun	6.0%	25.3%	68.8%						
Jul	5.5%	23.4%	71.2%						
Aug	5.7%	24.1%	70.1%						
Sep	5.8%	25.2%	69.0%						
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%	7.2%	22.7%	70.1%	1.4%	(1.7%)	0.3%

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 $25.9 million, or 20.7 percent, from $125.2 million in the first three months of 2011, to $99.3 million in the first three months of 2012. Day-ahead operating reserve charges decreased $10.1 million, or 35.8 percent to $18.1 million and balancing operating reserve charges decreased $15.6 million, or 16.1 percent to $96.7 million.
- Balancing operating reserve charges for reliability decreased by $0.8 million, or 3.5 percent compared to the first three months of 2011. Balancing operating reserve charges for deviations decreased by $24.6 million, or 42.4 percent.
- The reduction in balancing operating reserve charges was comprised of a decrease of $25.4 million in generator and real-time import transactions balancing operating reserve charges, an increase of $7.6 million in lost opportunity costs, an increase of $1.1 million in canceled resources and an increase of $1.1 million in charges to participants requesting resources to control local constraints.
- Generators and real-time transactions balancing operating reserve charges were $55.7 million, 68.6 percent of all balancing operating reserve charges. Balancing operating reserve charges were allocated 40.1 percent as reliability charges and 59.9 percent as deviation charges. Lost opportunity cost charges were $20.8 million or 25.7 percent of all balancing charges. The remaining 5.7 percent of balancing operating reserve charges were comprised of 2.9 percent canceled resources charges and 2.8 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 36.8 percent of total operating reserve credits in the first three months of 2012, compared to 50.3 percent in the first three months of 2011.
- The regional concentration of operating reserves remained high in the first three months of 2012, although lower than the first three months of 2011. In the first three months of 2012, 55.9 percent of all operating reserve credits were paid to resources in the top three zones, a decrease of 14.4 percent from the first three months of 2011.

Recommendations

- The MMU recommends that the reactive service make whole credits cover the entire cost of a unit providing reactive service rather than paying part of these costs through operating reserve charges. The result of paying part of the cost of reactive service through operating reserve credits 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 reserves are paid by deviations from day-ahead or real-time load plus exports depending on the allocation process rather than by zone.

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

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.

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 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, startup and no-load offers.

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.

Operating Reserves 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, startup and no-load offers.

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)

Deviations		
Day-Ahead		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 three months of 2011 and 2012.[2] Total operating reserve charges decreased by 20.7 percent in the first three months of 2012 compared to the first three months of 2011, to a total of $99.3 million.

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

	2011	2012	Change	Percentage Change
Total Operating Reserve Charges	$125,194,704	$99,250,805	($25,943,899)	(20.7%)
Operating Reserve as a Percent of Total PJM Billing	1.3%	1.4%	0.1%	9.5%
Day-Ahead Rate ($/MWh)	0.143	0.088	(0.055)	(38.3%)
Balancing RTO Deviation Rate ($/MWh)	1.270	0.767	(0.503)	(39.6%)
Balancing RTO Reliability Rate ($/MWh)	0.093	0.021	(0.072)	(77.6%)

Total operating reserve charges in the first three months of 2012 were $99.3 million, down from the total of $125.2 million in the first three months of 2011. Table 3-4 compares monthly operating reserve charges by category for calendar years 2011 and 2012. The decrease of 20.7 percent in the first three months of 2012 is comprised of a 35.8 percent decrease in day-ahead operating reserve charges, an 88.7 percent decrease in synchronous condensing charges and a 16.1 percent decrease in balancing operating reserve charges.

The reduction in day-ahead operating reserve credits was primarily a result of a lower spread between the total energy offer of units receiving day-ahead operating reserve credits and the LMP at the units' buses.

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 transmission constraints. In the first three months of 2012, generation and transactions charges decreased by $25.4 million or 31.3 percent, lost opportunity cost charges increased by $7.6 million or 57.4 percent, canceled resources charges increased by $1.1 million or 92.9 percent and charges for local constraints control increased by $1.1 million or 96.8 percent.

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 April 10, 2012.

3 The total operating reserve charges in Table 3-3 are $3.2 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 reports is published.

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

	2011 Charges				2012 Charges			
	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	$27,177,428	$35,504,364
Feb	$8,940,203	$139,287	$26,607,792	$35,687,282	$5,858,308	$18,592	$24,532,362	$30,409,262
Mar	$6,837,719	$66,032	$23,030,108	$29,933,859	$3,894,926	$1,648	$29,440,606	$33,337,180
Apr	$4,405,102	$13,011	$18,762,006	$23,180,118				
May	$7,064,934	$39,417	$46,178,207	$53,282,558				
Jun	$8,303,391	$9,056	$62,118,948	$70,431,396				
Jul	$4,993,311	$238,127	$106,596,647	$111,828,085				
Aug	$8,360,392	$104,982	$55,142,158	$63,607,531				
Sep	$6,249,240	$40,878	$36,617,421	$42,907,539				
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	$28,151,021	$315,414	$96,728,269	$125,194,704	$18,064,808	$35,603	$81,150,395	$99,250,805
Share of Charges	22.5%	0.3%	77.3%	100.0%	18.2%	0.0%	81.8%	100.0%

Table 3-5 Monthly balancing operating reserve charges by category: January through March 2012 (See 2011 SOM, Table 3-8)

	Generation and Transactions	Lost Opportunity Cost	Canceled Resources	Local Constraints Control	Total
Jan	$20,300,434	$5,449,229	$772,882	$654,882	$27,177,428
Feb	$18,581,149	$4,632,856	$517,612	$800,744	$24,532,362
Mar	$16,820,894	$10,763,338	$1,034,994	$821,380	$29,440,606
Apr					
May					
Jun					
Jul					
Aug					
Sep					
Oct					
Nov					
Dec					
Total	$55,702,477	$20,845,424	$2,325,489	$2,277,006	$81,150,395
Share of Charges	68.6%	25.7%	2.9%	2.8%	100.0%

Table 3-6 shows the amount and percentages of regional balancing charge allocations for the first three months of 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 three months of 2012, balancing operating reserve charges, excluding lost opportunity costs, canceled resources and local constraints control categories, decreased by $25.4 million compared to the first three months of 2011. Balancing operating reserve charges for reliability decreased by $0.8 million or 3.5 percent and balancing operating reserve charges for deviations decreased by $24.6 million or 42.4 percent. Reliability charges in the Western Region increased by $13.4 million compared to the first three months of 2011, as a result of payments to units providing blackstart and voltage support in the AEP Control Zone. The remaining two reliability categories decreased by $14.2 million. The decrease in balancing operating reserve charges was mainly a result of a lower spread between the units' energy offer and the real-time LMP. The total real-time generation receiving balancing operating reserve credits increased by 3.2 percent.

Table 3-6 Regional balancing charges allocation: January through March 2012[4] (See 2011 SOM, Table 3-9)

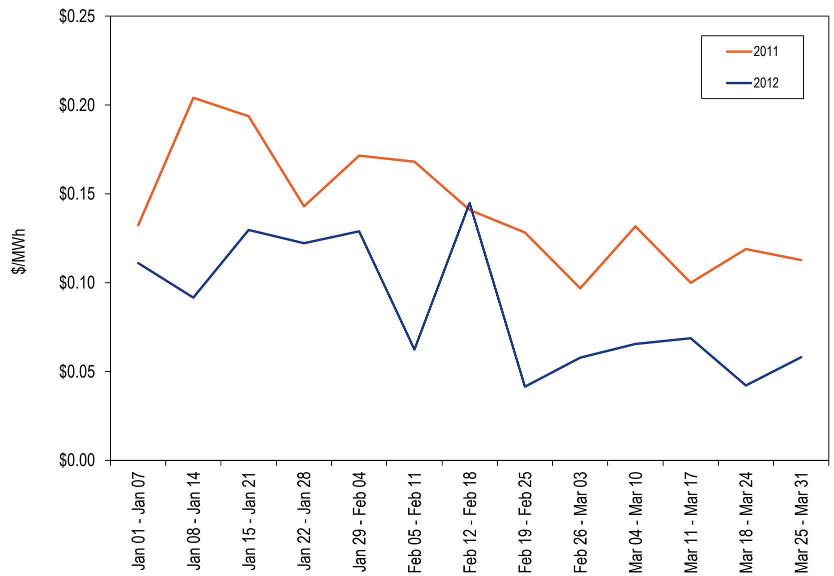
Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$3,947,480	5.0%	$88,579	0.1%	$17,552,181	22.3%	$21,588,240	27.4%
	Real-Time Exports	$109,794	0.1%	$2,265	0.0%	$611,789	0.8%	$723,847	0.9%
	Total	$4,057,274	5.1%	$90,844	0.1%	$18,163,969	23.0%	$22,312,087	28.3%
Deviation Charges	Demand	$15,162,154	19.2%	$3,574,276	4.5%	$437,614	0.6%	$19,174,044	24.3%
	Supply	$5,740,759	7.3%	$1,326,944	1.7%	$172,663	0.2%	$7,240,366	9.2%
	Generator	$5,672,684	7.2%	$988,200	1.3%	$315,096	0.4%	$6,975,980	8.8%
	Total	$26,575,597	33.7%	$5,889,420	7.5%	$925,373	1.2%	$33,390,390	42.3%
Lost Opportunity Cost and Canceled Resources Charges	Demand	$12,545,609	15.9%	$0	0.0%	$0	0.0%	$12,545,609	15.9%
	Supply	$5,458,363	6.9%	$0	0.0%	$0	0.0%	$5,458,363	6.9%
	Generator	$5,166,940	6.6%	$0	0.0%	$0	0.0%	$5,166,940	6.6%
	Total	$23,170,912	29.4%	$0	0.0%	$0	0.0%	$23,170,912	29.4%
Total Balancing Charges		$53,803,783	68.2%	$5,980,264	7.6%	$19,089,342	24.2%	$78,873,389	100%

Operating Reserve Rates

Under the operating reserve 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 three months of 2011 and 2012. The average rate in the first three months of 2012 was $0.0882 per MWh, $0.0548 per MWh lower than the average of the first three months of 2011. The highest rate occurred on February 1, when the rate reached $0.2171 per MWh, 39.7 percent lower than the $0.3603 reached on January 14, 2011.

Figure 3-1 Weekly weighted average day-ahead operating reserve rate ($/MWh): January through March 2012 (See 2011 SOM, Figure 3-1)



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.

The top chart in Figure 3-2 shows the RTO and the regional reliability rates for the first three months of 2012. The average daily RTO reliability rate was $0.0208 per MWh. The highest RTO reliability rate of 2012 occurred on January 16, when the rate reached $0.2506 per MWh. Reliability rates in the Western Region have been high primarily because of the use of certain units in the AEP Control Zone to provide black start and voltage support.

The center chart in Figure 3-2 shows the RTO and the regional deviation rates for the first three months of 2012. The average daily RTO deviation rate was $0.7672 per MWh. The largest daily rate occurred on January 4, when the RTO deviation rate reached $2.6654 per MWh.

The bottom chart in Figure 3-2 shows the daily lost opportunity cost rate and the daily canceled resources rate. The lost opportunity rate averaged $0.6018 per MWh. The highest lost opportunity cost rate occurred on March 5, when it reached $3.6135 per MWh. The canceled resources rate averaged $0.0671 per MWh and credits were paid during 52.7 percent of all the days in the first three months of 2012. Spikes in the lost opportunity cost charge rate are often caused by credits paid to combustion turbines with long start-up and notification time. Combustion turbines with long start-up and notification time are generally not dispatched in real time because their availability is outside the PJM dispatcher window. The lost opportunity cost eligibility rule has been modified to address this issue.

Figure 3-2 Daily balancing operating reserve rates ($/MWh): January through March 2012 (See 2011 SOM, Figure 3-2)

Table 3-7 shows the rates for each region in each category. RTO deviation charges and lost opportunity cost charges accounted for 58.4 percent of all balancing operating reserve charges in the first three months of 2012.

Table 3-7 Balancing operating reserve rates ($/MWh): Calendar year 2012 (See 2011 SOM, Table 3-10)

	Reliability ($/MWh)	Deviations ($/MWh)	Lost Opportunity Cost ($/MWh)	Canceled Resources ($/MWh)
RTO	0.021	0.767	0.602	0.067
East	0.001	0.302	NA	NA
West	0.176	0.062	NA	NA

Table 3-8 shows the operating reserve cost of a 1 MW transaction during the first three months of 2012. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $1.8063 per MWh with a maximum rate of $6.4533 per MWh, a minimum rate of $0.4698 per MWh and a standard deviation of $0.8854 per MWh. The rates in the table include all operating reserve charges including RTO deviation charges.

Table 3-8 Operating reserve rates statistics ($/MWh): January through March 2012 (See 2011 SOM, Table 3-11)

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	6.395	1.719	0.330	0.897
	DEC	6.453	1.806	0.470	0.885
	DA Load	0.217	0.087	0.010	0.050
	RT Load	0.251	0.021	0.000	0.043
	Deviation	6.395	1.719	0.330	0.897
West	INC	4.749	1.480	0.330	0.750
	DEC	4.803	1.568	0.409	0.741
	DA Load	0.217	0.087	0.010	0.050
	RT Load	0.354	0.200	0.057	0.065
	Deviation	4.749	1.480	0.330	0.750

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 3-9 shows monthly real-time deviations for demand, supply and generator categories for 2011 and the first three 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 three months of 2012 compared to the first three months of 2011 by 6,924,284 MWh or 16.7 percent. Demand deviations decreased by 21.3 percent, supply deviations decreased by 10.4 percent, and generator deviations decreased by 9.5 percent. In the first three months of 2012 compared to the first three months of 2011, the share of total deviations in the demand category decreased by 3.3 percentage points, the share of supply deviations increased by 1.6 percentage points, and the share of generator deviations increased by 1.8 percentage points.

Real-time load, real-time exports, and deviations in each region are shown in Table 3-10. RTO deviations are defined as the sum of eastern and western deviations, plus deviations from hubs that span multiple regions.

Table 3-9 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	2,780,753	12,617,743
Feb	7,196,554	2,809,384	2,680,742	12,686,680	5,894,539	2,380,558	2,310,547	10,585,644
Mar	7,510,358	2,467,175	2,730,454	12,707,988	6,041,789	2,776,433	2,616,098	11,434,320
Apr	6,623,238	2,027,200	2,662,761	11,313,199				
May	7,144,854	2,381,825	2,902,093	12,428,772				
Jun	9,845,466	2,558,697	2,996,041	15,400,204				
Jul	10,160,922	2,690,836	3,306,340	16,158,098				
Aug	8,566,032	2,057,281	2,907,427	13,530,739				
Sep	8,829,765	2,198,858	2,561,534	13,590,157				
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	24,505,143	8,537,968	8,518,879	41,561,991	19,276,997	7,653,312	7,707,398	34,637,707
Share of Deviations	59.0%	20.5%	20.5%	100.0%	55.7%	22.1%	22.3%	100.0%

Table 3-10 Regional charges determinants (MWh): January through March 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	188,414,264	6,264,066	194,678,331	19,276,997	7,653,312	7,707,398	34,637,707
East	88,335,848	2,908,310	91,244,158	11,851,856	4,441,592	3,237,459	19,530,908
West	100,078,417	3,355,756	103,434,173	7,341,579	3,193,434	4,469,939	15,004,951

Operating Reserve Credits by Category

Figure 3-3 shows that 81.8 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 increased 4.5 percent from the 77.3 percent for the first three months of 2011.

Figure 3-3 Operating reserve credits: January through March 2012 (See 2011 SOM, Figure 3-3)

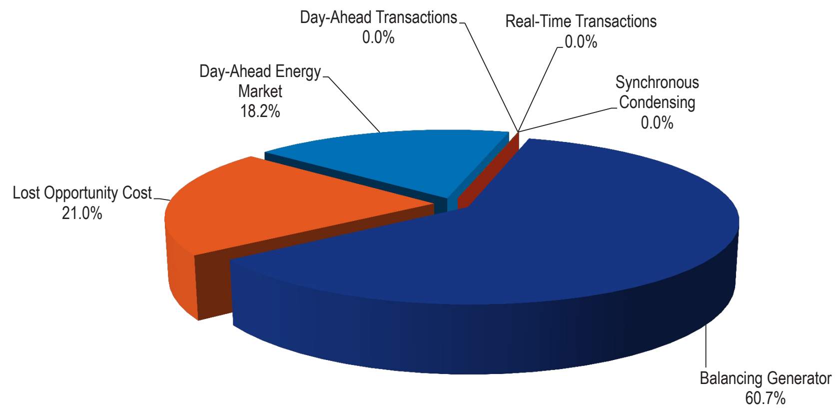


Table 3-11 shows the monthly totals for each credit category for the first three months of 2012.

Table 3-11 Credits by month (By operating reserve market): January through March 2012 (See 2011 SOM, Table 3-12)

	Day-Ahead Generator	Day-Ahead Transactions	Synchronous Condensing	Balancing Generator	Balancing Transactions	Lost Opportunity Cost	Total
Jan	$8,311,573	$0	$15,362	$21,718,168	$10,031	$5,449,229	$35,504,365
Feb	$5,858,308	$0	$18,592	$19,896,576	$2,929	$4,632,856	$30,409,262
Mar	$3,894,705	$220	$1,648	$18,658,434	$18,833	$10,763,337	$33,337,179
Apr							
May							
Jun							
Jul							
Aug							
Sep							
Oct							
Nov							
Dec							
Total	$18,064,587	$220	$35,603	$60,273,178	$31,794	$20,845,423	$99,250,805
Share of Credits	18.2%	0.0%	0.0%	60.7%	0.0%	21.0%	100.0%

Characteristics of Credits

Types of Units

Table 3-12 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 3-12 Credits by unit types (By operating reserve market): January through March 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%	0.0%	0.0%	0.0%	0.0%	$0
Combined Cycle	41.8%	0.0%	53.7%	4.5%	0.0%	0.0%	$18,362,490
Combustion Turbine	5.4%	0.1%	31.7%	62.5%	0.0%	0.3%	$29,546,459
Diesel	0.3%	0.0%	26.0%	73.6%	0.0%	0.0%	$1,486,228
Hydro	0.0%	0.0%	88.9%	0.0%	11.1%	0.0%	$219,411
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	$0
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	$0
Steam - Coal	18.8%	0.0%	75.8%	0.6%	0.0%	4.8%	$45,847,391
Steam - Others	11.6%	0.0%	76.3%	12.0%	0.0%	0.0%	$1,467,265
Wind	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%	$2,289,547

Table 3-13 shows the distribution of credits for each type of operating reserves received by each unit type (each column sums to 100 percent). Combined cycle units and conventional steam units fueled by coal received 90.2 percent of the day-ahead generator credits. Combustion turbines received 100.0 percent of the synchronous condensing credits. Combustion turbines and diesels received 93.8 percent of the lost opportunity cost credits. Wind units received 98.5 percent of the canceled resources credits.

Wind Unit Credits

PJM calculates credits for scheduled resources that are canceled by PJM before coming on line. PJM credits each participant for cancellations based on actual costs incurred and submitted in writing to PJM. The cancellation credit equals the actual costs incurred, capped at the appropriate start-up cost as specified in the generating resource's offer. The total cancellation credits are allocated to RTO demand, supply and generator deviations on a daily basis.

PJM categorizes lost opportunity costs credits paid to wind units as canceled resources credits. Canceled resources credits should reflect the actual cost of starting a unit. None of the wind units that received canceled resources credits submitted start-up costs. This categorization does not have any impact on the allocation of the charges since both are allocated to RTO demand, supply and generator deviations. However these credits appear to have been misclassified.

Credits paid to wind units continued to increase in the first three months of 2012. In the first three months of 2012 the total was $2.3 million higher than the $0.9 million paid in the first three months of 2011. A total of 11 wind farms were paid credits under the canceled resources category of the operating reserve rules. Table 3-14 shows the monthly canceled resources credits paid to wind farms.

Table 3-13 Credits by operating reserve market (By unit type): January through March 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	42.5%	0.0%	17.7%	4.0%	0.0%	0.0%
Combustion Turbine	8.9%	100.0%	16.8%	88.6%	0.5%	3.7%
Diesel	0.0%	0.0%	0.7%	5.2%	0.0%	0.0%
Hydro	0.0%	0.0%	0.4%	0.0%	1.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	47.7%	0.0%	62.4%	1.4%	0.0%	96.3%
Steam - Others	0.9%	0.0%	2.0%	0.8%	0.0%	0.0%
Wind	0.0%	0.0%	0.0%	0.0%	98.5%	0.0%
Total	$18,064,587	$35,603	$55,670,684	$20,845,423	$2,325,489	$2,277,006

Table 3-14 Canceled resources credits paid to wind units: January through March 2012 (See 2011 SOM, Table 3-15)

	Wind Units Canceled Resources Credits	Annual Share
Jan	$741,979	32.4%
Feb	$517,612	22.6%
Mar	$1,029,884	45.0%
Apr		
May		
Jun		
Jul		
Aug		
Sep		
Oct		
Nov		
Dec		
Total	$2,289,475	100.0%

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

Economic and Noneconomic Generation

Economic generation includes units producing energy at an offer price less than or equal to the LMP at the unit. Noneconomic generation includes units that are producing energy but at an offer price higher than the LMP at the unit. Balancing generator operating reserve credits are paid on a segmented basis for each period defined by the day ahead schedule or minimum run time.

The MMU analyzed the hours for which a unit received balancing generator operating reserve credits to determine which units are economic and noneconomic. Each hour was first determined to be economic or noneconomic based solely on the unit's hourly energy offer. The hourly energy offer does not include the hourly no-load cost or any applicable startup cost. A unit could be economic for every hour during a segment, but still receive balancing generator operating reserve credits because LMP revenue did not cover the additional startup and hourly no-load costs.

Table 3-15 shows the number of economic and noneconomic hours for each unit type. For example, of the 7,071 hours in which combined cycle units were paid balancing generator operating reserve credits, the LMP at the unit's bus was higher than its real-time energy offer in 2,244 hours, or 31.7 percent of those hours. Diesel engines had the highest proportion of economic hours with 37.3 percent.

Table 3-15 Economic vs. noneconomic hours: January through March 2012 (See 2011 SOM, Table 3-16)

Unit Type	Economic Hours	Economic Hours Percentage	Noneconomic Hours	Noneconomic Hours Percentage	Total Hours
Combined Cycle	2,244	31.7%	4,827	68.3%	7,071
Combustion Turbine	519	20.5%	2,007	79.5%	2,526
Diesel	357	37.3%	599	62.7%	956
Hydro	0	0.0%	48	100.0%	48
Steam - Coal	5,277	18.0%	24,047	82.0%	29,324
Steam - Others	233	32.9%	476	67.1%	709
Total	8,630	21.2%	32,004	78.8%	40,634

Geography of Balancing Charges and Credits

Table 3-16 shows the geography of charges and credits in the first three 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 AECO Control Zone paid 0.8 percent of all operating reserve charges, and resources were paid 0.9 percent of all operating reserve credits. The AECO Control Zone received more operating reserve credits than charges paid. The JCPL Control Zone paid more operating reserve charges than credits received. Table 3-16 also shows that 82.0 percent of all charges were allocated in control zones, 5.8 percent in hubs and 12.3 percent in interfaces.

Table 3-16 Geography of Balancing Charges and Credits: January through March 2012[5] (New Table)

					Shares			
Location		Charges	Credits	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$780,582	$890,864	$110,282	0.8%	0.9%	0.0%	0.3%
	AEP	$14,807,680	$22,362,594	$7,554,914	15.3%	23.1%	0.0%	18.6%
	AP - DLCO	$8,451,336	$9,386,073	$934,737	8.7%	9.7%	0.0%	2.3%
	ATSI	$6,462,160	$8,806,019	$2,343,858	6.7%	9.1%	0.0%	5.8%
	BGE - Pepco	$6,633,539	$18,635,413	$12,001,874	6.8%	19.2%	0.0%	29.6%
	ComEd - External	$12,203,924	$4,060,193	($8,143,731)	12.6%	4.2%	20.1%	0.0%
	DAY - DEOK	$5,013,092	$277,367	($4,735,725)	5.2%	0.3%	11.7%	0.0%
	Dominion	$5,778,360	$6,395,868	$617,508	6.0%	6.6%	0.0%	1.5%
	DPL	$2,115,778	$3,935,900	$1,820,122	2.2%	4.1%	0.0%	4.5%
	JCPL	$1,895,733	$361,940	($1,533,793)	2.0%	0.4%	3.8%	0.0%
	Met-Ed	$1,467,375	$255,698	($1,211,676)	1.5%	0.3%	3.0%	0.0%
	PECO	$3,636,698	$198,138	($3,438,560)	3.8%	0.2%	8.5%	0.0%
	PENELEC	$2,160,540	$1,549,991	($610,549)	2.2%	1.6%	1.5%	0.0%
	PPL	$3,988,845	$685,035	($3,303,809)	4.1%	0.7%	8.2%	0.0%
	PSEG	$3,967,380	$19,105,090	$15,137,710	4.1%	19.7%	0.0%	37.4%
	RECO	$112,885	$0	($112,885)	0.1%	0.0%	0.3%	0.0%
	All Zones	$79,475,907	$96,906,182	$17,430,275	82.0%	100.0%	57.0%	100.0%
Hubs	AEP - Dayton	$444,475	$0	($444,475)	0.5%	0.0%	1.1%	0.0%
	Dominion	$140,897	$0	($140,897)	0.1%	0.0%	0.3%	0.0%
	Eastern	$206,028	$0	($206,028)	0.2%	0.0%	0.5%	0.0%
	New Jersey	$124,311	$0	($124,311)	0.1%	0.0%	0.3%	0.0%
	Ohio	$26,077	$0	($26,077)	0.0%	0.0%	0.1%	0.0%
	Western Interface	$12,754	$0	($12,754)	0.0%	0.0%	0.0%	0.0%
	Western	$4,622,901	$0	($4,622,901)	4.8%	0.0%	11.4%	0.0%
	All Hubs	$5,577,443	$0	($5,577,443)	5.8%	0.0%	13.8%	0.0%
Interfaces	IMO	$1,583,243	$0	($1,583,243)	1.6%	0.0%	3.9%	0.0%
	Linden	$277,560	$0	($277,560)	0.3%	0.0%	0.7%	0.0%
	MISO	$2,696,864	$0	($2,696,864)	2.8%	0.0%	6.7%	0.0%
	Neptune	$287,777	$0	($287,777)	0.3%	0.0%	0.7%	0.0%
	NIPSCO	$5,861	$0	($5,861)	0.0%	0.0%	0.0%	0.0%
	Northwest	$37,888	$0	($37,888)	0.0%	0.0%	0.1%	0.0%
	NYIS	$928,082	$0	($928,082)	1.0%	0.0%	2.3%	0.0%
	OVEC	$239,603	$0	($239,603)	0.2%	0.0%	0.6%	0.0%
	South Exp	$1,570,408	$0	($1,570,408)	1.6%	0.0%	3.9%	0.0%
	South Imp	$4,257,561	$0	($4,257,561)	4.4%	0.0%	10.5%	0.0%
	All Interfaces	$11,884,847	$32,014	($11,852,833)	12.3%	0.0%	29.3%	0.0%
	Total	$96,938,196	$96,938,196	$0	100.0%	100.0%	100.0%	100.0%

5 Zonal information in each zonal table has been aggregated to ensure that market sensitive data is not revealed.

Table 3-17 and Table 3-18 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 3-17 shows that on average, 10.1 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 44.5 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 3-17 Monthly balancing operating reserve charges and credits to generators (Eastern Region): January through March 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	$1,152,259	$234,342	$561,494	$1,948,095	$13,988,700
Feb	$703,873	$284,761	$434,163	$1,422,796	$9,546,059
Mar	$614,429	$469,097	$1,170,534	$2,254,060	$11,548,489
Apr					
May					
Jun					
Jul					
Aug					
Sep					
Oct					
Nov					
Dec					
East Generators Total	$2,470,561	$988,200	$2,166,190	$5,624,951	$35,083,248
PJM Total Charges	$26,575,597	$5,889,420	$23,170,912	$55,635,929	$78,841,596
Share	9.3%	16.8%	9.3%	10.1%	44.5%

Table 3-18 also shows that generators in the Western Region paid 12.9 percent of balancing generator charges including lost opportunity cost and canceled resources charges while these generators received 55.5 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 3-18 Monthly balancing operating reserve charges and credits to generators (Western Region): January through March 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	$1,299,689	$32,410	$787,093	$2,119,192	$12,523,816
Feb	$1,085,106	$282,686	$706,392	$2,074,185	$14,180,627
Mar	$817,328	$0	$1,507,265	$2,324,592	$17,044,912
Apr					
May					
Jun					
Jul					
Aug					
Sep					
Oct					
Nov					
Dec					
West Generators Total	$3,202,123	$315,096	$3,000,750	$6,517,969	$43,749,354
PJM Total	$26,575,597	$925,373	$23,170,912	$50,671,882	$78,841,596
Share	12.0%	34.1%	13.0%	12.9%	55.5%

Table 3-19 shows that on average in the first three months of 2012, generator charges were 12.5 percent of all operating reserve charges, excluding local constraints control charges which are allocated to the requesting transmission owner, 1.3 percent lower than 2011. Generators received 99.97 percent of all operating reserve credits, while the remaining 0.03 percent were credits paid to import transactions.

Table 3-19 Percentage of unit credits and charges of total credit and charges: January through March 2012 (See 2011 SOM, Table 3-19)

	Generators Share of Total Operating Reserve Charges	Generators Share of Total Operating Reserve Credits
Jan	11.7%	100.0%
Feb	11.8%	100.0%
Mar	14.1%	99.9%
Apr		
May		
Jun		
Jul		
Aug		
Sep		
Oct		
Nov		
Dec		
Average	12.5%	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 three months of 2012, 32.2 percent of payments for demand reduction offers were covered by operating reserve credits while the remaining 67.8 percent was paid through the economic load response program as shown in Table 3-20.

Table 3-20 Day-ahead and balancing operating reserve for load response credits: Calendar year 2009 through March 2012 (See 2011 SOM, Table 3-20)

	Economic Program Load Response Credits	Operating Reserves for Load Response Credits	Proportion Covered by the Economic Load Program	Proportion Covered by Operating Reserve Credits
2009	$1,389,136	$287,402	82.9%	17.1%
2010	$3,088,049	$363,469	89.5%	10.5%
2011	$2,052,996	$154,589	93.0%	7.0%
2012	$30,302	$14,379	67.8%	32.2%

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 three months of 2012 were $23.1 million, about 3.7 times higher than the $4.9 million in the first three months of 2011. Table 3-21 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 three months of 2012, seven units ran a combined

2,455 hours out of merit in order to support the area's voltage. The top three zones accounted for 68.9 percent of the total reactive costs, a decrease of 15.1 percent from the 2011 share. The top three control zones were JCPL, ATSI and Pepco.

Table 3-21 Monthly reactive service credits: January through March 2012 (See 2011 SOM, Table 3-21)

	Reactive Service Credits	Percent of Total Reactive Service Credits
Jan	$2,920,441	12.6%
Feb	$13,108,018	56.7%
Mar	$7,077,227	30.6%
Apr		
May		
Jun		
Jul		
Aug		
Sep		
Oct		
Nov		
Dec		
Total	$23,105,685	100.0%

Table 3-22 shows the distribution of credits for each category of reactive service credit received by each unit type (each column sums to 100 percent). Credits received by combustion turbines decreased from 51.5 percent in 2011 to 10.6 percent in the first three months of 2012. Combined cycles and coal steam turbines credits share increased from 43.5 percent to 86.2 percent in the first three months of 2012.

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

Unit Type	Reactive Service Credits	Reactive Service Lost Opportunity Cost Credits	Reactive Service Synchronous Condensing Credits	Total Reactive Credits
Battery	0.0%	0.0%	0.0%	0.0%
Combined Cycle	33.9%	0.1%	0.0%	32.8%
Combustion Turbine	10.6%	0.4%	100.0%	10.6%
Diesel	1.8%	0.0%	0.0%	1.8%
Hydro	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%
Steam - Coal	52.2%	96.8%	0.0%	53.4%
Steam - Others	1.4%	2.6%	0.0%	1.4%
Wind	0.0%	0.0%	0.0%	0.0%
Total	$22,330,909	$706,638	$68,139	$23,105,685

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 three months of 2012 compared to the first three months of 2011. Table 3-23 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 36.8 percent of total operating reserve credits in the first three months of 2012, compared to 50.3 percent in the first three months of 2011. The top 20 units received 54.1 percent of total operating reserve credits in the first three months of 2012.

Table 3-23 Top 10 operating reserve revenue units (By percent of total system): Calendar years 2001 through March 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	36.8%	0.7%

Table 3-16 shows the distribution of operating reserve credits to units by zone. The AEP Control Zone had the largest share of credits with 23.1 percent, the PSEG Control Zone had the second highest with 19.7 percent, and the BGE and Pepco Control Zones combined had the third highest with a 19.2 percent share.

Table 3-24 shows the credits received by the top 10 units and top 10 organizations in each of the operating reserves categories. The share of the top 10 units in three of the categories: day-ahead generator, canceled resources and reactive services, was above 80.0 percent. The share of the top 10 units in all categories was above 90.0 percent.

Table 3-24 Top 10 units and organizations operating reserve credits: January through March 2012 (New Table)

	Top 10 units		Top 10 organizations	
Category	Credits	Credits Share	Credits	Credits Share
Total Operating Reserves	$36,544,135	36.8%	$91,993,962	92.7%
Day-Ahead Generator	$14,981,699	82.9%	$17,671,004	97.8%
Synchronous Condensing	$28,373	79.7%	$35,603	100.0%
Balancing Generator	$26,669,609	47.9%	$53,797,252	96.6%
Canceled Resources	$1,882,277	80.9%	$2,291,523	98.5%
Lost Opportunity Cost	$10,948,236	52.5%	$20,312,532	97.4%
Reactive Services	$18,649,307	80.7%	$21,954,096	95.0%

Concentration of Operating Reserves Credits

In the first three months of 2012, concentration in all operating reserve credits categories was high.[6] Operating reserves HHI was calculated based on each organization's daily credits for each category. Table 3-25 shows the average HHI for each category. Day-ahead operating reserve HHI was 4553. Balancing operating reserve HHI averaged 3209. Lost opportunity cost HHI was 4831.

Table 3-25 Daily Operating Reserve Credits HHI: January through March 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	4553	10000	10000	3209	10000	4831	4933	1944
Minimum	2249	10000	10000	1829	10000	1485	968	915
Maximum	9814	10000	10000	5379	10000	10000	10000	4209
Highest market share (One day)	99.1%	100.0%	100.0%	71.0%	100.0%	100.0%	100.0%	61.5%
Highest market share (All days)	42.2%	50.0%	98.8%	34.8%	100.0%	48.0%	40.5%	22.6%
Numbers of Days	91	1	5	91	26	91	48	91
Days with HHI > 1,800	91	1	5	91	26	88	40	50
% of Days with HHI > 1,800	100.0%	100.0%	100.0%	100.0%	100.0%	96.7%	83.3%	54.9%
Days with HHI = 10,000	0	1	5	0	26	1	10	0
% of Days with HHI = 10,000	0.0%	100.0%	100.0%	0.0%	100.0%	1.1%	20.8%	0.0%

Table 3-26 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In the first three months of 2012, 48.6 percent of all credits paid to these units were allocated to deviations while the remaining 51.4 percent were paid for reliability reasons.

Table 3-26 Identification of balancing operating reserve credits received by the top 10 units by category and region: January through March 2012 (See 2011 SOM, Table 3-35)

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits	$1,598,935	$0	$12,106,242	$11,383,434	$1,580,998	$0	$26,669,609
Share	6.0%	0.0%	45.4%	42.7%	5.9%	0.0%	100.0%

Lost Opportunity Cost Credits

In the first three months of 2012, total operating reserve credits decreased by 20.7 percent. In spite of the overall decrease in operating reserve credits, lost opportunity cost credits increased by 57.4 percent. In the first three months of 2012 lost opportunity cost credits increased by $7.6 million compared to the first three months of 2011.

Balancing operating reserve lost opportunity cost credits are paid to units under two scenarios. If a combustion turbine is scheduled to operate in the day-ahead market but 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 the lost opportunity cost based on the desired output.

Units in PJM receive lost opportunity cost credits when they are scheduled in day-ahead and not called in real-time. Table 3-27 shows the generation scheduled in day-ahead and requested by PJM to run in real-time, which did not receive lost opportunity cost credits, and the generation scheduled in day-ahead and not requested by PJM to run in real-time which did receive lost opportunity cost credits. In the first three months of 2012, 73.6 percent of the day-ahead scheduled generation was not requested by PJM in real-time. This percentage increased 23.2 percent from 2011.

6 See the *2012 Quarterly State of the Market Report for PJM: January through March*, Section 2, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

Table 3-27 Reduced/Suspended Day-Ahead Scheduled Generation receiving lost opportunity cost credits (MWh): Calendar year 2009 through March 2012 (See 2011 SOM, Table 3-37)

	Day-Ahead Scheduled Generation Requested in Real-Time	Day-Ahead Scheduled Generation Not Requested in Real-Time	Percentage of Day-Ahead Generation Not Called in Real-Time
2009	4,077,730	1,621,867	28.5%
2010	5,285,833	3,444,165	39.5%
2011	4,648,666	4,713,960	50.3%
2012	716,016	1,994,880	73.6%

Table 3-28 shows the distribution by zone of the generation not called in real time. In the first three months of 2012, the AP, ATSI and Dominion Control Zones combined had 76.2 percent of all the generation not called in real-time receiving lost opportunity cost credits.

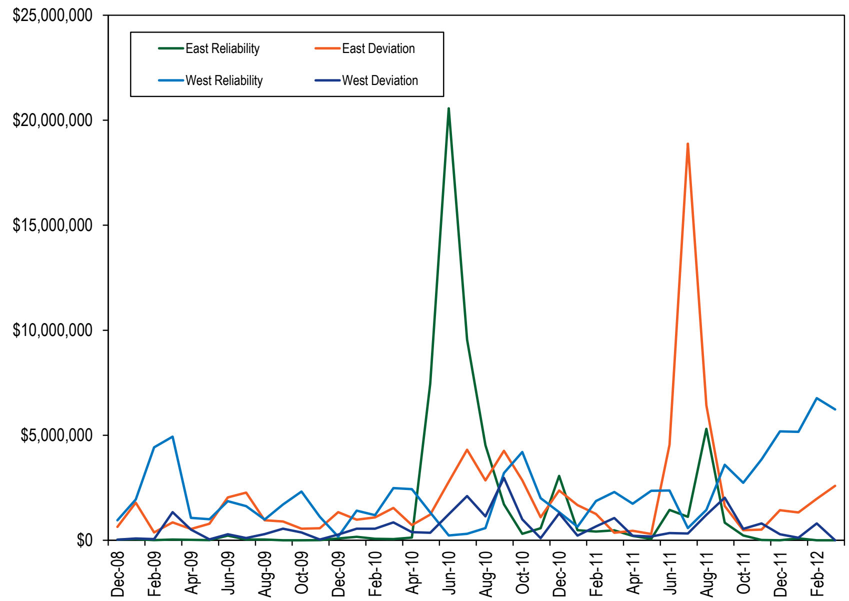
Table 3-28 Reduced/Suspended Day-Ahead Scheduled Generation receiving lost opportunity cost credits by zone (MWh): January through March 2012 (See 2011 SOM, Table 3-38)

Zone	Day-Ahead Scheduled Generation Requested in Real-Time	Day-Ahead Scheduled Generation Not Requested in Real-Time	Share of Day-Ahead Generation Not Called in Real-Time
AECO - JCPL - PSEG - PECO	20,393	50,006	2.5%
AEP - DAY - DEOK	56,329	89,122	4.5%
AP - DLCO	4,522	581,706	29.2%
ATSI - PENELEC	77,877	529,280	26.5%
BGE - DPL - Dominion - Pepco	544,257	480,158	24.1%
ComEd - External	10,702	259,050	13.0%
Met-Ed - PPL	1,936	5,560	0.3%
Total	716,016	1,994,880	100.0%

Regional Credits Allocation

Figure 3-4 shows the regional reliability and regional deviation credits since the introduction of the new operating reserve rules in December 2008. The figure shows the impact of the regional allocation of balancing operating reserve credits during events that only affect a specific region. High east reliability credits during the summer of 2010 were due to transmission maintenance on a 230kV line, while high east deviations credits during the summer of 2011 were the result of high load levels during the peak months. The increase in west reliability credits was the result of credits paid to units providing blackstart and voltage support in the AEP Control Zone.

Figure 3-4 Monthly regional reliability and deviations credits: December 2008 through March 2012[7] (See 2011 SOM, Figure 3-5)



One of the purposes of the operating reserve rules implemented on December 1, 2008, was to allocate reliability charges to those requiring additional resources to maintain system reliability, defined to be real-time load and exports. In the first three months of 2012, the rule change had a significant impact on the categorization and corresponding allocation of balancing operating reserve charges. In the first three months of 2012, $22.3 million of reliability charges were allocated to participants serving real-time load and exports, which would have been charged to deviations under the prior rules.

7 Credits in this figure do not include additional balancing operating reserve credits, such as lost opportunity cost, canceled resources or resources controlling local constraints control.

Table 3-6 and Table 3-29 show how reliability credits were allocated across the RTO, Eastern and Western Regions.

Figure 3-5 Monthly balancing operating reserve categories: January through March 2012 (See 2011 SOM, Figure 3-6)

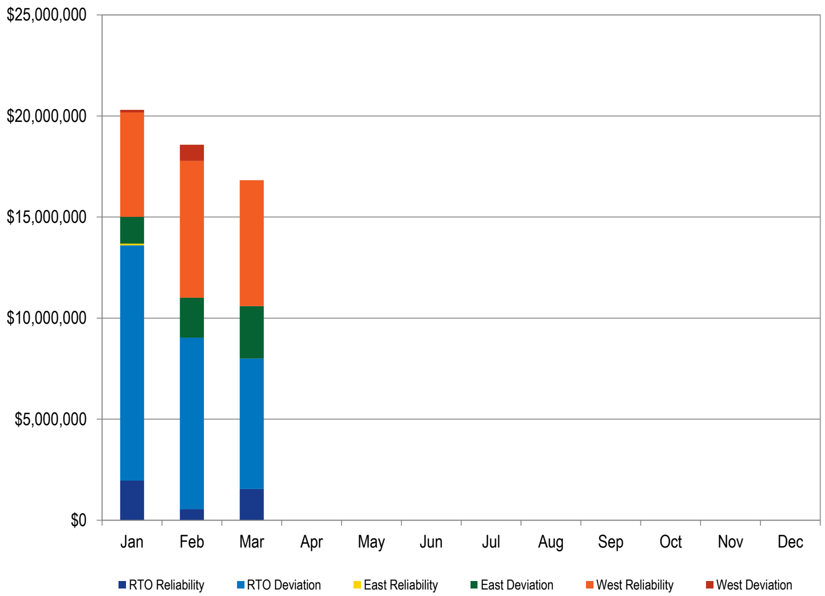


Table 3-29 Monthly balancing operating reserve categories: January through March 2012 (See 2011 SOM, Table 3-39)

Month	RTO Reliability Credits	East Reliability Credits	West Reliability Credits	RTO Deviation Credits	East Deviation Credits	West Deviation Credits
Jan	$1,960,777	$90,844	$5,165,990	$11,636,173	$1,323,039	$123,612
Feb	$549,422	$0	$6,769,404	$8,485,052	$1,975,509	$801,761
Mar	$1,547,075	$0	$6,228,575	$6,454,372	$2,590,872	$0
Apr						
May						
Jun						
Jul						
Aug						
Sep						
Oct						
Nov						
Dec						
Total	$4,057,274	$90,844	$18,163,969	$26,575,597	$5,889,420	$925,373

Con-Ed – PSEG Wheeling Contracts Support

It appears that certain units located near the boundary between New Jersey and New York City have been operated to support the wheeling contracts between Con-Ed and PSEG.[8] These units are often run out of merit and received substantial balancing operating reserves credits. The MMU recommends that this issue be addressed by PJM in order to determine if the cost of running these units is being allocated properly.

AEP Blackstart and Voltage Support Units

Certain units located in the AEP zone are relied on for their blackstart capability and for voltage support on a regular basis even during periods when the units are not economic. The relevant blackstart units provide blackstart service under the ALR option, which means that the units must be running even if not economic. Units providing blackstart 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

8 See the *2011 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions" at "Con Edison and PSE&G Wheeling Contracts" for a description of the contracts.

are run out of merit to comply with blackstart requirements or voltage support in order to correctly assign the associated charges.

Credits categorized as reliability paid to units in the Western Region increased considerably in the first three months of 2012 compared to the first three months of 2011 because of these units used in the AEP Control Zone for blackstart 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 three months of 2012, 49.5 percent of all up-to congestion transactions were profitable.[9]

In order to address the reaction of participants using up-to congestion transactions to an allocation of operating reserves charges and the associated impact on profitability, the MMU calculated the up-to congestion transactions that would have remained if operating reserves 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 reserves charges as actually occurred when no operating reserves charges were paid. If up-to congestion transactions were allocated operating reserves charges, it would be reasonable to expect that some transactions would not be made if such charges were assigned. The result is that only 30.4 percent of all up-to congestion transactions would have been made if such transactions had to pay operating reserves charges and the proportional distribution of profitable and unprofitable transactions remained the same. Even with this reduction in the level of up-to congestion transactions, the contribution to total operating reserves charges and the impact on other participants who pay those charges would have been significant.

Table 3-30 shows the impact that including the identified 30.4 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 three months of 2012. For example, the RTO deviations rate would have been reduced by 57.9 percent.

Table 3-30 Up-to Congestion Transactions Impact on the Operating Reserve Rates: January through March 2012 (See 2011 SOM, Table 3-44)

	Current Rates ($/MWh)	Rates Including Up-To Congestion Transactions ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.088	0.079	(0.009)	(10.4%)
RTO Deviations	0.767	0.3232	(0.4440)	(57.9%)
East Deviations	0.302	0.1835	(0.1181)	(39.20%)
West Deviations	0.062	0.019	(0.0432)	(70.0%)
Lost Opportunity Cost	0.602	0.2535	(0.3483)	(57.9%)
Canceled Resources	0.067	0.028	(0.0389)	(57.9%)

Reactive Service Credits and Operating Reserve Credits

Credits to resources providing reactive services are separate from operating reserve credits.[10] Under the rules providing for credits for reactive service, units are not assured recovery of the entire offer including start up and no load as they are under the operating reserves 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 reserves are paid by deviations from day-ahead or real-time load plus exports depending on the allocation process rather than by zone.

9 An up-to congestion transaction position equals its market value (difference between the day-ahead and real-time value) net of PJM and MMU administrative charges.

10 OA Schedule 1 § 3.2.3B(f).

In the first three months of 2012, units providing reactive services were paid $7.9 million in balancing operating reserve credits in order to cover their total energy offer. Of these credits, 92.8 percent were paid by deviations in the RTO Region, 6.5 percent by real-time load and real-time exports in the RTO Region and the remaining 0.7 percent by real-time load and real-time exports in the Western Region.

Table 3-31 shows the impact of these credits in each of the balancing operating reserve categories.

Table 3-31 Impact of credits paid to units providing reactive services on the balancing operating reserve rates ($/MWh): January through March 2012 (New Table)

		Balancing Operating Reserve Rates ($/MWh)		Impact	
Category	Region	Without Credits to Units Providing Reactive Services	Current	($/MWh)	Percentage
Reliability	RTO	0.018	0.021	0.003	14.6%
	East	0.001	0.001	0.000	0.0%
	West	0.175	0.176	0.001	0.3%
Deviation	RTO	0.555	0.767	0.213	38.3%
	East	0.302	0.302	0.000	0.0%
	West	0.062	0.062	0.000	0.0%

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 meet their obligations in the capacity market by constructing generation and offering it into the capacity market, by entering into bilateral contracts, by developing demand-side resources and Energy Efficiency (EE) resources and offering them into the capacity market, or by constructing transmission upgrades and offering them into the capacity market.

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

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: 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.[1]
- 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 failed the TPS which is conducted at the time of the auction.[2]
- 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 planned resource 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 a definition of DR which permits inferior products to substitute for capacity.

Highlights

- During the period January 1, through March 31, 2012, PJM installed capacity increased 6,126.6 MW or 3.4 percent from 178,854.1 MW on January 1 to 184,980.7 MW on March 31. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- The 2012/2013 RPM Third Incremental Auction was run in the first quarter of 2012. In the 2012/2013 RPM Third Incremental Auction, the RTO clearing price was $2.51 per MW-day.
- All LDAs and the entire PJM Region failed the preliminary market structure screen (PMSS) for the 2015/2016 Delivery Year.

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

2 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 8,492.2 MW for June 1, 2012.
- 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 $127.05 per MW-day in 2014.
- Combined cycle units ran more often in January through March 2012, than in the same period in 2011, increasing from a 41.1 percent capacity factor in 2011 to a 63.0 percent capacity factor in 2012. Combined cycle units had a higher capacity factor than steam units, for which the capacity factor decreased from 51.8 percent in 2011 to 39.8 percent in January through March 2012.
- The average PJM equivalent demand forced outage rate (EFORd) decreased from 8.6 percent in the first three months of 2011 to 6.6 percent in the first three months of 2012.
- The PJM aggregate equivalent availability factor (EAF) increased from 85.8 percent in the first three months of 2011 to 86.1 percent in the first three months of 2012. The equivalent maintenance outage factor (EMOF) increased from 2.5 percent to 3.9 percent, the equivalent planned outage factor (EPOF) decreased from 6.4 percent to 5.7 percent, and the equivalent forced outage factor (EFOF) decreased from 5.3 percent to 4.3 percent.

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 Capacity Market is the result of a regulatory/administrative decision to require a specified level of reliability and the related decision to require all load serving entities to purchase a share of the capacity required to provide that reliability. It is important to keep these basic facts in mind when designing and evaluating capacity markets. The Capacity Market is unlikely ever to approach the economist's view of a competitive market structure in the absence of a substantial and unlikely structural change that results in much more diversity of ownership.

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 three 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 three 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.[3,4,5,6] In 2011 and 2012, the MMU prepared a number of RPM-related reports and testimony, shown in Table 4-2.

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

3 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).
4 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)
5 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).
6 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).

Installed Capacity

On January 1, 2012, PJM installed capacity was 178,854.1 MW (Table 4-3).[7] Over the next three months, unit retirements, facility reratings plus import and export shifts resulted in PJM installed capacity of 184,980.7 MW on March 31, 2012, an increase of 6,126.6 MW or 3.4 percent over the January 1 level.[8,9]

Table 4-3 PJM installed capacity (By fuel source): January 1, January 31, February 29, and March 31, 2012 (See the 2011 SOM, Table 4-3)

	1-Jan-12		31-Jan-12		29-Feb-12		31-Mar-12	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	75,190.4	42.0%	80,212.1	43.3%	79,749.1	43.1%	79,749.1	43.1%
Gas	50,529.3	28.3%	51,788.5	27.9%	51,774.8	28.0%	51,774.8	28.0%
Hydroelectric	8,047.0	4.5%	8,047.0	4.3%	8,047.0	4.4%	8,047.0	4.4%
Nuclear	32,492.6	18.2%	32,492.6	17.5%	32,492.6	17.6%	32,534.6	17.6%
Oil	11,217.3	6.3%	11,495.2	6.2%	11,494.7	6.2%	11,494.7	6.2%
Solar	15.3	0.0%	15.3	0.0%	15.3	0.0%	15.3	0.0%
Solid waste	705.1	0.4%	705.1	0.4%	705.1	0.4%	705.1	0.4%
Wind	657.1	0.4%	660.1	0.4%	660.1	0.4%	660.1	0.4%
Total	178,854.1	100.0%	185,415.9	100.0%	184,938.7	100.0%	184,980.7	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.[10]

Market Structure

Supply

Offered MW in the 2012/2013 RPM Third Incremental Auction totaled 5,569.4 MW. Effective with the 2012/2013 delivery year, PJM sell offers and buys bids are submitted in RPM Incremental Auctions as a result of changes in the RTO and LDA reliability requirements and the procurement of the Short-Term Resource Procurement Target. PJM sell offers for the RTO in the 2012/2013 RPM Third Incremental Auction were 2,729.8 MW.

Demand

Participant buy bids in the 2012/2013 RPM Third Incremental Auction totaled 7,459.2 MW. Participant buy bids are submitted to cover short positions due to deratings and EFORd increases or because participants wanted to purchase additional capacity. PJM buy bids for the RTO in the 2012/2013 RPM Third Incremental Auction were 11.6 MW.

Market Concentration

Preliminary Market Structure Screen

Under the terms of the PJM Open Access Transmission Tariff (OATT), the MMU is required to apply the preliminary market structure screen (PMSS) prior to RPM Base Residual Auctions. The results of the PMSS are applicable for all RPM Auctions for the given delivery year. The purpose of the PMSS is to determine whether additional data are needed from owners of capacity resources in the defined areas in order to permit the application of market structure tests defined in the Tariff.

7 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.

8 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.

9 Wind-based resources accounted for 660.1 MW of installed capacity in PJM on March 31, 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 in place of the 87 percent reduction. There are additional wind resources not reflected in this total because they are energy only resources and do not participate in the PJM Capacity Market.

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

Table 4-4 Preliminary market structure screen results: 2011/2012 through 2015/2016 RPM Auctions (See the 2011 SOM, Table 4-7)

RPM Markets	Highest Market Share	HHI	Pivotal Suppliers	Pass/Fail
2011/2012				
RTO	18.0%	855	1	Fail
2012/2013				
RTO	17.4%	853	1	Fail
MAAC	17.6%	1071	1	Fail
EMAAC	32.8%	2057	1	Fail
SWMAAC	50.7%	4338	1	Fail
PSEG	84.3%	7188	1	Fail
PSEG North	90.9%	8287	1	Fail
DPL South	55.0%	3828	1	Fail
2013/2014				
RTO	14.4%	812	1	Fail
MAAC	18.1%	1101	1	Fail
EMAAC	33.0%	1992	1	Fail
SWMAAC	50.9%	4790	1	Fail
PSEG	89.7%	8069	1	Fail
PSEG North	89.5%	8056	1	Fail
DPL South	55.8%	3887	1	Fail
JCPL	28.5%	1731	1	Fail
Pepco	94.5%	8947	1	Fail
2014/2015				
RTO	15.0%	800	1	Fail
MAAC	17.6%	1038	1	Fail
EMAAC	33.1%	1966	1	Fail
SWMAAC	49.4%	4733	1	Fail
PSEG	89.4%	8027	1	Fail
PSEG North	88.2%	7825	1	Fail
DPL South	56.5%	3796	1	Fail
Pepco	94.5%	8955	1	Fail
2015/2016				
RTO	14.3%	763	1	Fail
MAAC	17.5%	1114	1	Fail
EMAAC	32.6%	1904	1	Fail
SWMAAC	51.9%	4745	1	Fail
DPL South	49.2%	3257	1	Fail
PSEG	89.4%	8020	1	Fail
PSEG North	88.0%	7794	1	Fail
Pepco	94.1%	8876	1	Fail
ATSI	75.5%	5881	1	Fail

An LDA or the RTO Region fails the PMSS if any one of the following three screens is failed: the market share of any capacity resource owner exceeds 20 percent; the HHI for all capacity resource owners is 1800 or higher; or there are not more than three jointly pivotal suppliers. As shown in Table 4-4, all defined markets failed the preliminary market structure screen (PMSS) for the 2015/2016 Delivery Year.[11] As a result, all capacity market sellers owning or controlling any generation capacity resource located in the entire PJM Region shall be required to provide the information specified in Section 6.7(b) of Attachment DD of the PJM Open Access Transmission Tariff (OATT).

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 2012/2013 Third Incremental Auction.[12] 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.[13,14,15]

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

11 See "Preliminary Market Structure Screen Results for 2015/2016 RPM Base Residual Auction" (February 7, 2012) <http://www.monitoringanalytics.com/reports/Reports/2012/PMSS_Results_20152016_20120207.pdf>.
12 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.
13 See OATT Attachment DD § 6.5.
14 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.
15 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: 2011/2012 through 2014/2015 RPM Auctions[16] (See the 2011 SOM, Table 4-8)

RPM Markets	$RSI_{1\ 1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2011/2012 BRA				
RTO	0.85	0.63	76	76
2011/2012 First Incremental Auction				
RTO	0.86	0.62	30	30
2011/2012 ATSI FRR Integration Auction				
RTO	0.18	0.07	21	21
2011/2012 Third Incremental Auction				
RTO	0.54	0.41	52	52
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 Inremental 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
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

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

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.[17]

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 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 another reason 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 decreased by 1,196.1 MW from 9,688.3 MW on June 1, 2011 to 8,492.2 MW on June 1, 2012. Table 4-7 shows RPM commitments for DR and EE resources as the result of RPM Auctions prior to adjustments for replacement transactions along with certified ILR.

17 OATT Attachment DD § 5.6.6(b).

Table 4-6 RPM load management statistics by LDA: June 1, 2010 to June 1, 2014[18,19,20] (See the 2011 SOM, Table 4-10)

								UCAP (MW)
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco
DR cleared	962.9	918.5		520.8	14.9			
DR net replacements	(516.3)	(480.9)		(112.7)	(14.9)			
ILR	8,236.4	3,113.7		655.2	97.2			
RPM load management @ 01-Jun-10	8,683.0	3,551.3		1,063.3	97.2			
DR cleared	1,826.6							
EE cleared	76.4							
DR net replacements	(1,247.5)							
EE net replacements	0.2							
ILR	9,032.6							
RPM load management @ 01-Jun-11	9,688.3							
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	(892.6)	(592.8)	(88.5)	(345.2)	0.0	(5.5)	(4.8)	
EE net replacements	(22.2)	(22.2)	(6.0)	(16.2)	0.0	0.0	0.0	
RPM load management @ 01-Jun-12	8,492.2	4,832.2	1,925.4	1,593.1	71.0	528.2	100.9	
DR cleared	9,802.4	6,005.2	2,588.4	1,650.3	146.1	1,183.8	534.8	547.8
EE cleared	748.6	204.5	55.2	113.5	2.0	25.8	9.2	36.7
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	10,551.0	6,209.7	2,643.6	1,763.8	148.1	1,209.6	544.0	584.5
DR cleared	14,118.4	7,236.8	2,866.8	2,234.4	220.9	964.2	443.3	893.1
EE cleared	822.1	199.6	20.9	161.3	5.0	4.8	0.0	42.9
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	14,940.5	7,436.4	2,887.7	2,395.7	225.9	969.0	443.3	936.0

18 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.

19 For 2010/2011, DPL zonal ILR MW are allocated to the DPL South LDA using the sub-zonal load ratio share (57.72 percent for DPL South).

20 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 2014/2015[21,22,23] (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	8,429.8	8,740.9	643.4	666.1	0.0	0.0
2013/2014	9,487.2	9,802.4	726.3	748.6	0.0	0.0
2014/2015	13,663.8	14,118.4	796.9	822.1	0.0	0.0

Table 4-8 RPM load management statistics: June 1, 2007 to June 1, 2014[24,25] (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)
1-Jun-07	1,708.1	1,763.9	0.0	0.0	0.0	0.0	1,708.1	1,763.9
1-Jun-08	4,029.4	4,167.5	(38.7)	(40.0)	0.0	0.0	3,990.7	4,127.5
1-Jun-09	7,138.3	7,374.4	(459.5)	(474.7)	0.0	0.0	6,678.8	6,899.7
1-Jun-10	8,892.2	9,199.3	(499.1)	(516.3)	0.0	0.0	8,393.1	8,683.0
1-Jun-11	10,570.7	10,935.6	(1,205.8)	(1,247.5)	0.2	0.2	9,365.1	9,688.3
1-Jun-12	9,073.2	9,407.0	(860.8)	(892.6)	(21.4)	(22.2)	8,191.0	8,492.2
1-Jun-13	10,213.5	10,551.0	0.0	0.0	0.0	0.0	10,213.5	10,551.0
1-Jun-14	14,460.7	14,940.5	0.0	0.0	0.0	0.0	14,460.7	14,940.5

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.[26,27,28]

21 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.

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

23 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.

24 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.

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

26 See OATT Attachment DD § 6.5.

27 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.

28 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: 2012/2013 RPM Auctions (See the 2011 SOM, Table 4-14)

	2012/2013 Base Residual Auction		2012/2013 ATSI Integration Auction		2012/2013 First Incremental Auction		2012/2013 Second Incremental Auction		2012/2013 Third Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	465	41.0%	117	67.6%	92	56.8%	80	42.6%	35	11.7%
ACR data input (APIR)	118	10.4%	12	6.9%	14	8.6%	8	4.3%	2	0.7%
ACR data input (non-APIR)	2	0.2%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Opportunity cost input	8	0.7%	2	1.2%	2	1.2%	0	0.0%	0	0.0%
Default ACR and opportunity cost	14	1.2%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	26	15.0%	NA	NA	NA	NA	130	43.6%
Uncapped planned uprate and default ACR	NA	NA	NA	NA	NA	NA	3	1.6%	0	0.0%
Uncapped planned uprate and opportunity cost	NA	NA	NA	NA	NA	NA	0	0.0%	0	0.0%
Uncapped planned uprate and price taker	NA	NA	NA	NA	NA	NA	2	1.1%	2	0.7%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA	NA	NA	NA	NA	1	0.3%
Uncapped planned generation resources	11	1.0%	0	0.0%	17	10.5%	12	6.4%	10	3.4%
Price takers	515	45.5%	16	9.2%	37	22.8%	83	44.1%	118	39.6%
Total Generation Capacity Resources offered	1,133	100.0%	173	100.0%	162	100.0%	188	100.0%	298	100.0%

2012/2013 RPM Third Incremental Auction

As shown in Table 4-9, 298 generation resources submitted offers in the 2012/2013 Third Incremental Auction. Unit-specific offer caps were calculated for two resources (0.7 percent of all generation resources). The MMU calculated offer caps for 37 resources (12.4 percent), of which 35 were based on the technology specific default (proxy) ACR values. Of the 298 generation resources, 131 resources elected offer cap option of 1.1 times the BRA clearing price (44.0 percent), 10 planned generation resources had uncapped offers (3.4 percent), two resources had uncapped planned uprates along with price taker status (0.7 percent), one resource had an uncapped planned uprate along with the 1.1 times the BRA clearing price option for the existing portion (0.3 percent), while the remaining 118 resources were price takers (39.6 percent), of which the offers for 111 resources were zero and the offers for seven resources were set to zero because no data were submitted.

Market Performance[29]

In the 2012/2013 RPM Third Incremental Auction, participant sell offers were 5,569.4 MW, while participant buy bids were 7,459.2 MW. Cleared participant sell offers in the RTO were 2,403.5 MW, while cleared participant buy bids were 4,382.8 MW. Released capacity by PJM were 1,990.9 MW, while procured capacity by PJM were 11.6 MW. As shown in Table 4-10, the RTO clearing price in the 2012/2013 RPM Third Incremental Auction was $2.51 per MW-day.

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 $135.16 per MW-day in 2011 and then declined to $127.05 per MW-day in 2014. Figure 4-1 presents cleared MW weighted average capacity market prices on a calendar year basis for the entire history of the PJM capacity markets.

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

Cleared capacity resources across the entire RTO will receive a total of $2.2 million based on the unforced MW cleared and the prices in the 2012/2013 RPM Third Incremental Auction.

Table 4-11 shows RPM revenue by resource type for all RPM Auctions held to date with over $500 million for new/reactivated resources based on the unforced MW cleared and the resource clearing prices.

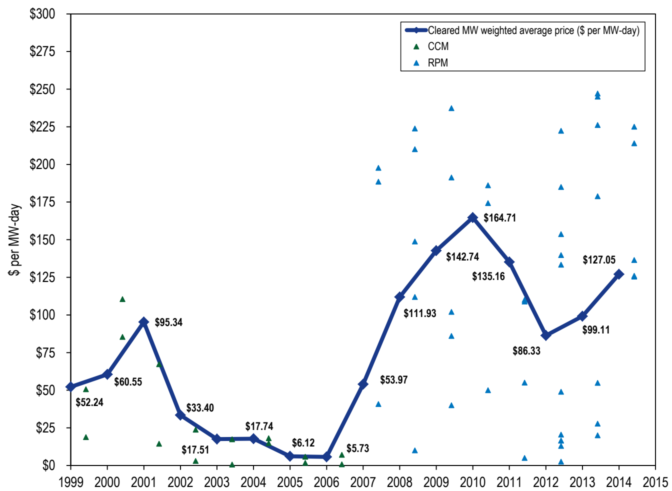
Table 4-10 Capacity prices: 2007/2008 through 2014/2015 RPM Auctions (See the 2011 SOM, Table 4-21)

		RPM Clearing Price ($ per MW-day)							
	Product Type	RTO	MAAC	APS	EMAAC	SWMAAC	DPL South	PSEG North	Pepco
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
2011/2012 Third Incremental Auction		$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
2012/2013 First Incremental Auction		$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$16.46
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$13.01
2012/2013 Third Incremental Auction		$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
2013/2014 First Incremental Auction		$20.00	$20.00	$20.00	$178.85	$54.82	$178.85	$178.85	$54.82
2014/2015 BRA	Limited	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47
2014/2015 BRA	Extended Summer	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$225.00	$136.50
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$225.00	$136.50

Table 4-11 RPM revenue by type: 2007/2008 through 2014/2015[30,31] (See the 2011 SOM, Table 4-22)

Type	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	Total
Demand Resources	$5,537,085	$35,349,116	$65,762,003	$60,235,796	$55,795,785	$264,387,898	$551,453,434	$666,313,051	$1,704,834,167
Energy Efficiency Resources	$0	$0	$0	$0	$139,812	$11,408,552	$20,680,368	$38,571,074	$70,799,806
Imports	$22,225,980	$60,918,903	$56,517,793	$106,046,871	$185,421,273	$13,260,822	$31,191,272	$178,063,746	$653,646,660
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	$1,736,326,997	$1,827,519,210	$14,122,252,257
Coal new/reactivated	$0	$0	$1,854,781	$3,168,069	$28,330,047	$7,414,940	$12,493,918	$56,917,305	$110,179,060
Gas existing	$1,514,681,896	$1,951,345,311	$2,329,209,917	$2,632,336,161	$1,607,317,731	$1,117,382,927	$1,894,356,673	$2,003,810,846	$15,050,441,462
Gas new/reactivated	$3,472,667	$9,751,112	$30,168,831	$58,065,964	$98,448,693	$76,633,409	$166,414,514	$184,029,455	$626,984,645
Hydroelectric existing	$209,490,444	$287,850,403	$364,742,517	$442,429,815	$278,529,660	$179,117,975	$308,742,213	$328,877,767	$2,399,780,793
Hydroelectric new/reactivated	$0	$0	$0	$0	$0	$11,397	$17,520	$6,591,114	$6,620,031
Nuclear existing	$996,085,233	$1,322,601,837	$1,517,723,628	$1,799,258,125	$1,079,386,338	$762,719,551	$1,346,024,263	$1,459,911,217	$10,283,710,191
Nuclear new/reactivated	$0	$0	$0	$0	$0	$0	$0	$0	$0
Oil existing	$448,034,948	$532,432,515	$663,370,167	$623,141,070	$368,084,004	$385,988,279	$620,740,652	$433,317,895	$4,075,109,531
Oil new/reactivated	$0	$4,837,523	$5,676,582	$4,339,539	$967,887	$2,772,987	$5,669,955	$3,896,120	$28,160,593
Solid waste existing	$29,956,764	$33,843,188	$41,243,412	$40,731,606	$25,636,836	$26,840,670	$43,613,120	$34,529,047	$276,394,643
Solid waste new/reactivated	$0	$0	$523,739	$413,503	$261,690	$469,608	$2,411,690	$1,190,758	$5,270,987
Solar existing	$0	$0	$0	$0	$0	$0	$0	$0	$0
Solar new/reactivated	$0	$0	$0	$0	$66,978	$1,246,337	$2,521,159	$2,371,155	$6,205,629
Wind existing	$430,065	$1,180,153	$2,011,156	$1,819,413	$1,072,929	$812,644	$1,372,110	$1,491,563	$10,190,033
Wind new/reactivated	$0	$2,917,048	$6,836,827	$15,232,177	$9,919,881	$5,052,036	$12,898,748	$30,987,962	$83,844,678
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	$6,756,928,604	$7,258,389,284	$49,514,425,166

Figure 4-1 History of capacity prices: Calendar year 1999 through 2014[32] (See the 2011 SOM, Figure 4-1)



30 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.

31 The results for the ATSI Integrations Auctions are not included in this table.

32 1999-2006 capacity prices are CCM combined market, weighted average prices. The 2007 capacity price is a combined CCM/RPM weighted average price. The 2008-2014 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 4-12 RPM cost to load: 2011/2012 through 2014/2015 RPM Auctions[33,34,35] (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	$16.73	65,495.4	$399,981,901
MAAC	$133.31	30,107.9	$1,464,999,689
EMAAC	$142.94	19,954.6	$1,041,085,667
DPL	$171.13	4,523.9	$282,576,598
PSEG	$157.60	11,645.3	$669,874,086
2013/2014			
RTO	$27.86	84,109.2	$855,248,034
MAAC	$227.11	15,244.6	$1,263,706,654
EMAAC	$245.32	37,751.5	$3,380,397,528
SWMAAC	$226.15	8,281.8	$683,618,413
Pepco	$239.36	7,861.0	$686,795,004
2014/2015			
RTO	$125.94	84,581.3	$3,888,042,879
MAAC	$135.25	52,277.4	$2,580,741,594
DPL	$142.99	4,615.4	$240,881,412
PSEG	$164.00	12,208.7	$730,811,202

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).[36]

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output 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 March 2012, nuclear units had a capacity factor of 96.3 percent. Combined cycle units ran more often in January through March 2012 than in the same period in 2011, going from a 41.1 percent capacity factor in 2011 to a 63.0 percent capacity factor in 2012. Combined cycle units had a higher capacity factor than steam units, for which the capacity factor decreased from 51.8 percent in 2011 to 39.8 percent in January through March 2012. Due to inexpensive natural gas, this trend may continue, as efficient combined cycle units replace coal steam units in the PJM footprint.

Table 4-13 PJM capacity factor (By unit type (GWh)); January through March 2011 and 2012[37,38] (See the 2011 SOM, Table 4-24)

	Jan-Mar 2011		Jan-Mar 2012	
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
Battery	0.1	5.1%	0.1	0.1%
Combined Cycle	21,045.3	41.1%	35,691.6	63.0%
Combustion Turbine	500.5	0.8%	557.1	0.8%
Diesel	183.4	17.6%	214.5	19.1%
Diesel (Landfill gas)	168.7	40.2%	277.7	52.6%
Nuclear	65,194.7	95.9%	70,637.4	96.3%
Pumped Storage Hydro	1,652.5	13.9%	1,227.8	10.2%
Run of River Hydro	1,995.2	39.4%	2,130.1	40.4%
Solar	7.0	9.2%	43.9	13.8%
Steam	89,295.8	51.8%	79,543.8	39.8%
Wind	3,363.8	36.0%	4,261.3	37.3%
Total	183,407.0	48.6%	194,585.3	45.6%

33 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM Base Residual Auction results.
34 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.
35 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 2012/2013, 2013/2014, and 2014/2015 Net Load Prices are not finalized. The 2012/2013, 2013/2014, and 2014/2015 Obligation MW are not finalized.

36 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.
37 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.
38 The capacity factor for solar units in 2011 contains a significantly smaller sample of units than 2012.

Generator Performance Factors

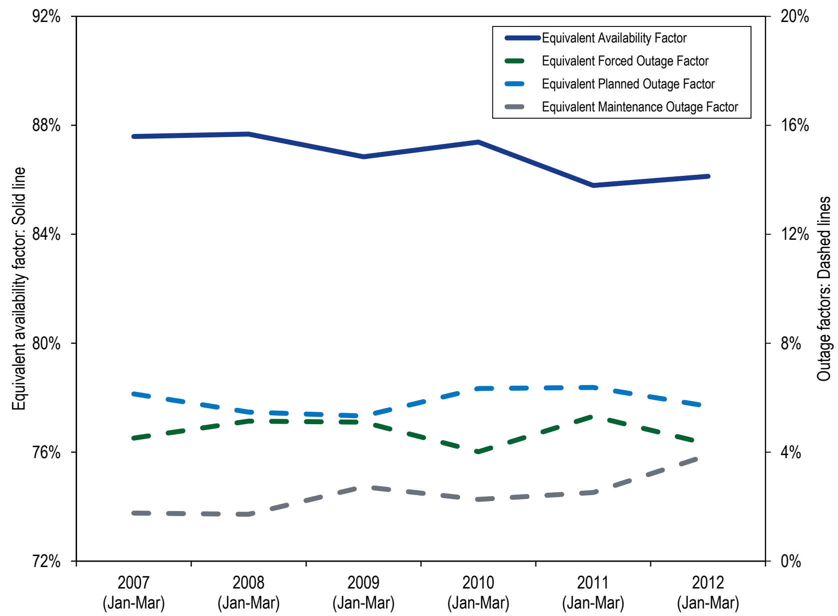
Generator performance factors are based on a defined period, usually a year, and are directly comparable.[39] Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage 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 85.8 percent in January through March 2011 to 86.1 percent in 2012. The EMOF increased from 2.5 percent to 3.9 percent, the EPOF decreased from 6.4 percent to 5.7 percent, and the EFOF decreased from 5.3 percent to 4.3 percent (Figure 4-2).[40]

39 Data from all PJM capacity resources for the years 2007 through 2012 were analyzed.

40 Data are for the three months ending March 31 as downloaded from the PJM GADS database on April 28, 2012. Annual EFORd data presented in state of the market reports may be revised based on data submitted after the publication of the reports as generation owners may submit corrections at any time with permission from PJM GADS administrators.

Figure 4-2 PJM equivalent outage and availability factors: Calendar years 2007 to 2012 (See the 2011 SOM, Figure 4-2)



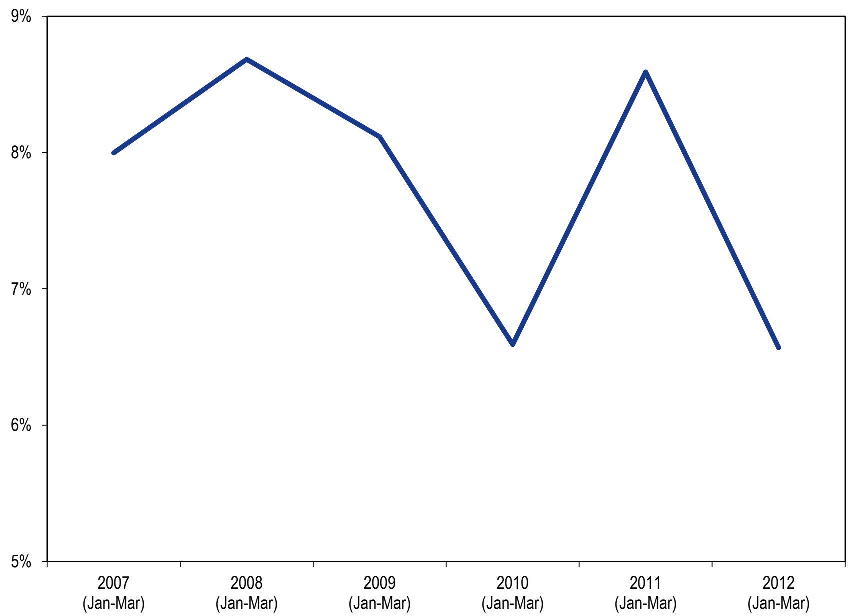
Generator Forced Outage Rates

The equivalent demand forced outage rate (EFORd) (generally referred to as the forced outage rate) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd is calculated using historical performance data. PJM systemwide EFORd is a capacity-weighted average of individual unit EFORd. Unforced capacity in the PJM Capacity Market for any individual generating unit is equal to one minus the EFORd adjusted to exclude Outside Management Control (OMC) events multiplied by the unit's net dependable summer capability.[41] The PJM Capacity Market creates an incentive to minimize the forced outage rate because the amount of capacity resources available to sell from a unit (unforced capacity) is inversely related to the forced outage rate.

41 EFORd adjusted to exclude Outside Management Control (OMC) events is defined as XEFORd.

EFORd calculations use historical data, including equivalent forced outage hours,[42] service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[43] The average PJM EFORd decreased from 8.6 percent in the three months January through March 2011 to 6.6 percent in the three months January through March 2012. Figure 4-3 shows the average January through March EFORd since 2007 for all units in PJM.

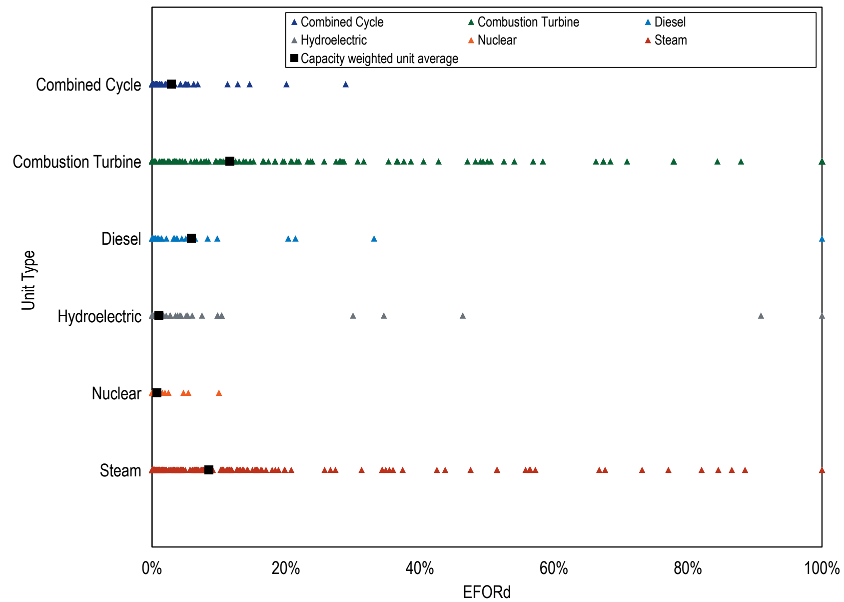
Figure 4-3 Trends in the PJM equivalent demand forced outage rate (EFORd): January through March 2007 to 2012 (See the 2011 SOM, Figure 4-3)



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



42 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.
43 See "Manual 22: Generator Resource Performance Indices," Revision 16 (November 16, 2011), Equations 2 through 5.

Components of EFORd

Table 4-14 PJM EFORd data for different unit types: January through March 2007 to 2012 (See the 2011 SOM, Table 4-25)

	2007 (Jan-Mar)	2008 (Jan-Mar)	2009 (Jan-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)	2012 (Jan-Mar)
Combined Cycle	6.3%	4.8%	4.9%	2.9%	3.4%	1.9%
Combustion Turbine	20.6%	16.2%	12.8%	11.6%	11.4%	9.4%
Diesel	9.1%	10.1%	8.2%	5.9%	5.0%	2.6%
Hydroelectric	1.9%	2.9%	1.9%	1.0%	2.1%	1.0%
Nuclear	0.4%	1.5%	3.8%	0.7%	1.6%	0.9%
Steam	7.9%	10.4%	9.5%	8.5%	12.1%	9.3%
Total	8.0%	8.7%	8.1%	6.6%	8.6%	6.6%

Table 4-15 shows the contribution of each unit type to the system EFORd, calculated as the total forced MW for the unit type divided by the total capacity of the system.[44] Forced MW for a unit type is the EFORd multiplied by the generator's net dependable summer capability.

Table 4-15 Contribution to EFORd for specific unit types (Percentage points): January through March 2007 to 2012[45] (See the 2011 SOM, Table 4-26)

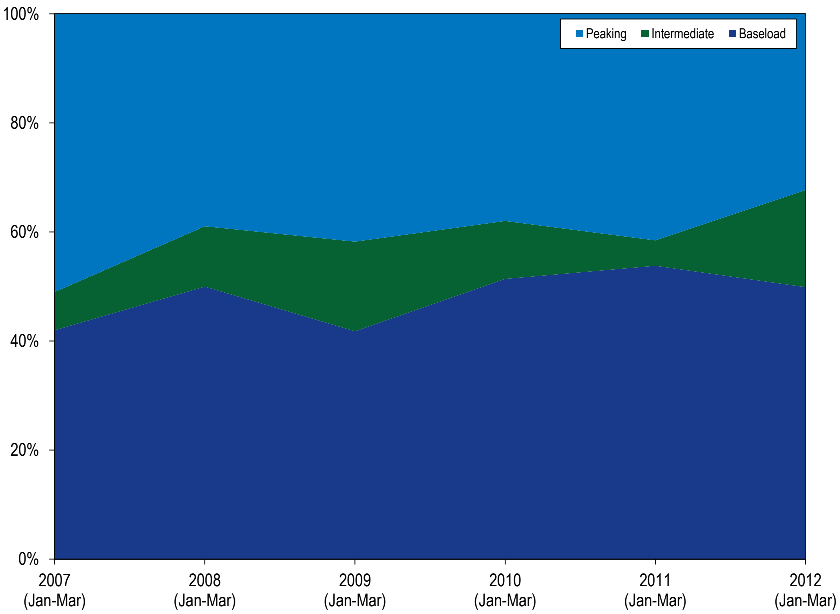
	2007 (Jan-Mar)	2008 (Jan-Mar)	2009 (Jan-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)	2012 (Jan-Mar)
Combined Cycle	0.7	0.5	0.5	0.3	0.4	0.2
Combustion Turbine	3.3	2.5	2.0	1.9	1.9	1.5
Diesel	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	0.1	0.1	0.1	0.0	0.1	0.0
Nuclear	0.1	0.3	0.7	0.1	0.3	0.2
Steam	3.8	5.2	4.7	4.2	5.9	4.6
Total	8.0	8.7	8.1	6.6	8.6	6.6

Steam units continue to be the largest contributor to overall PJM EFORd.

Duty Cycle and EFORd

In addition to disaggregating system EFORd by unit type, units were categorized by actual duty cycles as baseload, intermediate or peaking to determine the relationship between type of operation and forced outage rates.[46] Figure 4-5 shows the contribution of unit types to system average EFORd.

Figure 4-5 Contribution to EFORd by duty cycle: January through March 2007 to 2012 (See the 2011 SOM, Figure 4-5)



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

44 The generating unit types are: combined cycle, combustion turbine, diesel, hydroelectric, nuclear and steam. For all tables, run of river and pumped storage hydroelectric are combined into a single hydroelectric category.

45 Calculated values presented in Section 4, "Capacity Market" at "Generator Performance" are based on unrounded, underlying data and may differ from those derived from the rounded values shown in the tables.

46 Duty cycle is the time the unit is generating divided by the time the unit is available to generate. A baseload unit is defined here as a unit that generates during 50 percent or more of its available hours. An intermediate unit is defined here as a unit that generates during from 10 percent to 50 percent of its available hours. A peaking unit is defined here as a unit that generates during less than 10 percent of its available hours.

47 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.

For the three months January through March 2012, PJM EFOF was 4.3 percent. This means there was 4.3 percent lost availability because of forced outages. Table 4-16 shows that forced outages for boiler tube leaks, at 18.9 percent of the systemwide EFOF, were the largest single contributor to EFOF.

Table 4-16 Contribution to EFOF by unit type by cause: January through March 2012 (See the 2011 SOM, Table 4-27)

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	2.4%	0.0%	0.0%	0.0%	0.0%	21.7%	18.9%
Boiler Piping System	1.5%	0.0%	0.0%	0.0%	0.0%	10.6%	9.2%
Economic	0.6%	1.6%	1.6%	0.2%	0.0%	9.8%	8.6%
Electrical	3.2%	15.2%	0.5%	8.6%	30.4%	4.6%	6.1%
High Pressure Turbine	0.0%	0.0%	0.0%	0.0%	0.0%	6.7%	5.8%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	6.0%	5.2%
Feedwater System	9.9%	0.0%	0.0%	0.0%	5.6%	5.0%	4.9%
Reserve Shutdown	0.0%	17.5%	4.2%	11.9%	0.0%	4.0%	4.6%
Boiler Fuel Supply from Bunkers to Boiler	0.2%	0.0%	0.0%	0.0%	0.0%	5.0%	4.4%
Precipitators	0.0%	0.0%	0.0%	0.0%	0.0%	3.1%	2.7%
Miscellaneous (Generator)	10.0%	7.5%	0.9%	15.3%	0.0%	1.9%	2.5%
Other Operating Environmental Limitations	0.0%	0.0%	0.0%	0.0%	1.1%	2.8%	2.5%
Slag and Ash Removal	0.0%	0.0%	0.0%	0.0%	0.0%	2.3%	2.0%
Valves	3.9%	0.0%	0.0%	0.0%	0.0%	2.1%	1.9%
Boiler Tube Fireside Slagging or Fouling	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%	1.8%
Controls	8.4%	1.8%	0.0%	1.8%	17.5%	0.9%	1.8%
Cooling System	0.1%	0.0%	4.0%	12.5%	19.8%	0.7%	1.3%
Fuel, Ignition and Combustion Systems	9.6%	13.9%	0.0%	0.0%	0.0%	0.0%	1.1%
Miscellaneous (Steam Turbine)	2.6%	0.0%	0.0%	0.0%	1.4%	1.0%	1.0%
All Other Causes	47.6%	42.6%	88.7%	49.6%	24.2%	9.8%	13.8%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 4-17 shows the categories which are included in the economic category.[48] Lack of fuel that is considered Outside Management Control accounted for 97.9 percent of all economic reasons while lack of fuel that was not Outside Management Control accounted for only 2.0 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”[49]. 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.

48 The classification and definitions of these outages are defined by NERC GADS.
49 The classification and definitions of these outages are defined by NERC GADS.

Table 4-17 Contributions to Economic Outages: January through March 2012 (See the 2011 SOM, Table 4-28)

	Contribution to Economic Reasons
Lack of fuel (OMC)	97.9%
Lack of fuel (Non-OMC)	2.0%
Ground water or other water supply problems	0.0%
Lack of water (Hydro)	0.0%
Other economic problems	0.0%
Total	100.0%

Table 4-18 Contribution to EFOF by unit type: January through March 2012 (See the 2011 SOM, Table 4-29)

	EFOF	Contribution to EFOF
Combined Cycle	1.6%	3.0%
Combustion Turbine	2.2%	6.0%
Diesel	3.8%	0.1%
Hydroelectric	0.7%	0.7%
Nuclear	0.7%	3.5%
Steam	6.7%	86.7%
Total	4.0%	100.0%

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages to be deemed Outside Management Control (OMC).[50] 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.”

50 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/2009_GADS_DRI_Complete_SetVersion_010111.pdf>.

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.[51] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, fuel quality issues (i.e., codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered per the NERC directive.

All outages, including OMC outages, are included in the EFORd that is used for planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market. This modified EFORd is termed the XEFORd. Table 4-19 shows OMC forced outages by cause code. OMC forced outages account for 10.6 percent of all forced outages. The largest contributor to OMC outages, lack of fuel, is the cause of 79.7 percent of OMC outages and 8.4 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." Of the OMC lack of fuel outages in 2012, 79.5 percent of the outages were submitted by units operated by a single owner.

It is questionable whether the OMC outages defined as lack of fuel should be identified as OMC and 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 transparent set of rules governing the designation of outages as OMC and post those guidelines. The MMU also recommends that PJM consider eliminating lack of fuel as an acceptable basis for an OMC outage.

Table 4-19 OMC Outages: January through March 2012 (See the 2011 SOM, Table 4-30)

OMC Cause Code	% of OMC Forced Outages	% of all Forced Outages
Lack of fuel	79.7%	8.4%
Other switchyard equipment external	6.1%	0.6%
Switchyard circuit breakers external	5.4%	0.6%
Transmission line	4.4%	0.5%
Transmission equipment beyond the 1st substation	2.3%	0.2%
Tornados	0.6%	0.1%
Flood	0.5%	0.1%
Transmission system problems other than catastrophes	0.4%	0.0%
Transmission equipment at the 1st substation	0.2%	0.0%
Switchyard transformers and associated cooling systems external	0.2%	0.0%
Lightning	0.1%	0.0%
Switchyard system protection devices external	0.1%	0.0%
Lack of water (hydro)	0.0%	0.0%
Storms (ice, snow, etc)	0.0%	0.0%
Total	100.0%	10.6%

Table 4-20 shows the impact of OMC outages on EFORd for 2012. The difference is especially noticeable for steam units and combustion turbine units. For steam units, the OMC outage reason that resulted in the highest total MW loss in 2012 was lack of fuel. Combustion turbine units have natural gas fuel curtailment outages that were also classified as OMC. If companies' natural gas fuel supply is curtailed because of pipeline issues, the event can be deemed OMC. However, natural gas curtailments caused by lack of firm transportation contracts or arbitraging transportation reservations should not be classified as OMC. In 2012, steam XEFORd was 1.2 percentage points less than EFORd, which translates into a 1,004 MW difference in unforced capacity.

51 For a list of these cause codes, see the *MMU Technical Reference for PJM Markets*, at "Generator Performance: NERC OMC Outage Cause Codes."

Table 4-20 PJM EFORd vs. XEFORd: January through March 2012 (See the 2011 SOM, Table 4-31)

	EFORd	XEFORd	Difference
Combined Cycle	1.9%	1.8%	0.1%
Combustion Turbine	9.4%	6.3%	3.1%
Diesel	2.6%	1.4%	1.2%
Hydroelectric	1.0%	1.0%	0.1%
Nuclear	0.9%	0.9%	0.0%
Steam	9.3%	8.2%	1.2%
Total	6.6%	5.5%	1.1%

Components of EFORp

The equivalent forced outage rate during peak hours (EFORp) is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate during the peak hours of the day in the peak months of January, February, June, July and August. EFORp is calculated using historical performance data and is designed to measure if a unit would have run had the unit not been forced out. Like XEFORd, EFORp excludes OMC outages. PJM systemwide EFORp is a capacity-weighted average of individual unit EFORp.

Table 4-21 shows the contribution of each unit type to the system EFORp, calculated as the total forced MW for the unit type divided by the total capacity of the system. Forced MW for a unit type is the EFORp multiplied by the generator's net dependable summer capability.

Table 4-21 Contribution to EFORp by unit type (Percentage points): January through March 2011 to 2012 (See the 2011 SOM, Table 4-32)

	2011 (Jan-Mar)	2012 (Jan-Mar)
Combined Cycle	0.2	0.1
Combustion Turbine	0.4	0.1
Diesel	0.0	0.0
Hydroelectric	0.1	0.1
Nuclear	0.4	0.2
Steam	3.5	1.6
Total	4.7	2.1

Table 4-22 PJM EFORp data by unit type: January through March 2011 to 2012 (See the 2011 SOM, Table 4-33)

	2011 (Jan-Mar)	2012 (Jan-Mar)
Combined Cycle	2.1%	0.8%
Combustion Turbine	2.6%	0.9%
Diesel	1.7%	0.5%
Hydroelectric	2.0%	1.4%
Nuclear	2.3%	0.8%
Steam	7.2%	3.3%
Total	4.7%	2.1%

EFORd, XEFORd and EFORp

EFORd, XEFORd and EFORp are designed to measure the rate of forced outages, which are defined as outages that cannot be postponed beyond the end of the next weekend.[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. EFORp of nuclear units is slightly higher than EFORd and XEFORd, suggesting that nuclear units have a slightly higher rate of forced outages during the peak months of January, February, June, July and August.

Table 4-23 shows the contribution of each unit type to the system EFORd, XEFORd and EFORp, calculated as the total forced MW for the unit type divided by the total capacity of the system. Table 4-24 shows the capacity-weighted class average of EFORd, XEFORd and EFORp.

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

Table 4-23 Contribution to PJM EFORd, XEFORd and EFORp by unit type: January through March 2012 (See the 2011 SOM, Table 4-34)

	EFORd	XEFORd	EFORp
Combined Cycle	0.2	0.2	0.1
Combustion Turbine	1.5	1.0	0.1
Diesel	0.0	0.0	0.0
Hydroelectric	0.0	0.0	0.1
Nuclear	0.2	0.2	0.2
Steam	4.6	4.1	1.6
Total	6.6	5.5	2.1

Table 4-24 PJM EFORd, XEFORd and EFORp data by unit type: January through March 2012[53] (See the 2011 SOM, Table 4-35)

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	1.9%	1.8%	0.8%	0.1%	1.1%
Combustion Turbine	9.4%	6.3%	0.9%	3.1%	8.5%
Diesel	2.6%	1.4%	0.5%	1.2%	2.0%
Hydroelectric	1.0%	1.0%	1.4%	0.1%	(0.4%)
Nuclear	0.9%	0.9%	0.8%	0.0%	0.1%
Steam	9.3%	8.2%	3.3%	1.2%	6.1%
Total	6.6%	5.5%	2.1%	1.1%	4.5%

Comparison of Expected and Actual Performance

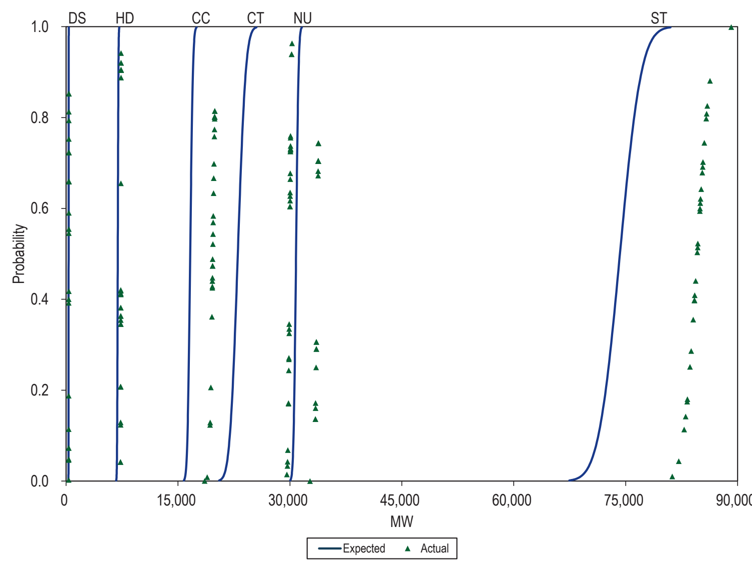
If the unit EFORd were normally distributed and if EFORd based planning assumptions were consistent with actual unit performance, the distribution of actual performance would be identical to a hypothetical normal distribution based on average EFORd performance. There are a limited number of units within each unit type and the distribution of EFORd may not be a normal distribution.

This analysis was performed based on resource-specific EFORd and Summer Net Capability capacity values for the three months ending March 31, 2012.[54] These values were used to estimate a normal distribution for each unit type,[55] which was superimposed on a distribution of actual historical availability for the same resources for the three months ending March 31, 2012.[56] The top thirty load days were selected for each year and the performance of the resources was evaluated for the peak hour of those days, a sample of 30 peak load hours.

Figure 4-6 compares the normal distribution to the actual distribution based on the defined sample.

Overall, generating units performed better during the selected peak hours than would have been expected based on the EFORd statistic. In particular, combustion turbine and steam units tend to have more capacity available during the sampled hours than implied by the EFORd statistic.

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



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

54 See "Manual 21: Rules and Procedures for Determination of Generating Capability," Revision 09 (May 1, 2010), Summer Net Capability.

55 The formulas used to approximate the parameters of the normal distribution are defined as:

$$\text{Mean} = \sum_i \left[MW_i * (1 - EFORd_i) \right]$$

$$\text{Variance} = \sum_i \left[MW_i * MW_i * (1 - EFORd_i) * EFORd_i \right]$$

$$\text{Standard Deviation} = \sqrt{\text{Variance}}$$

56 Availability calculated as net dependable capacity affected only by forced outage and forced derating events. Planned and maintenance events were excluded from this analysis.

Performance 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)

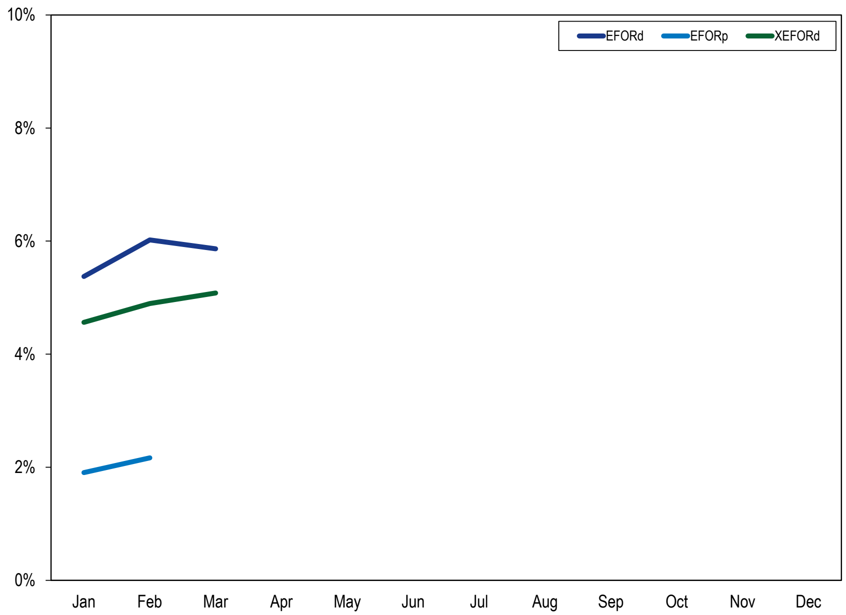
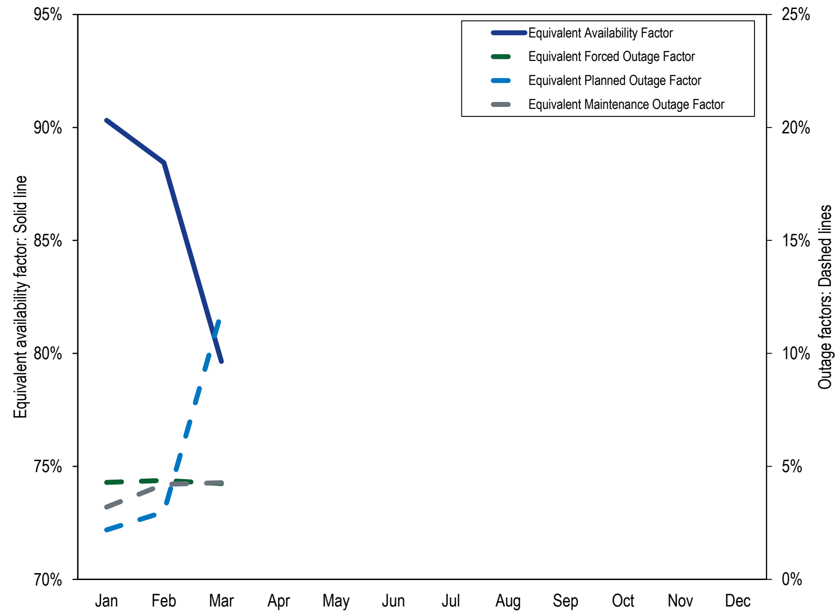


Figure 4-8 PJM monthly generator performance factors: 2012 (See the 2011 SOM, Figure 4-8)



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 March 2012, the total MWh of load reduction under the Economic Load Response Program decreased by 2,089 MWh compared to the same period in 2011, from 3,272 MWh in 2011 to 1,182 MWh in 2012, a 64 percent decrease. Total payments under the Economic Program decreased by $210,002, from $240,304 in 2011 to $30,302 in 2012, an 87 percent decrease.
- In January through March 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 $39.8 million, or 27.6 percent, compared to the same period in 2011, from $144 million in 2011 to $104 million in 2012.

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 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 (LMP), or the market price of capacity, the locational capacity market clearing price. 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. 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

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.

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 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 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. However, less than one percent of participants have taken this option while almost all participants received credits based on the zonal average 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.

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.[3]

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.

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

If retail markets reflected hourly wholesale prices and customers received direct savings associated with reducing consumption in response to real-time prices, there would not be a need for 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.

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.[4]

Table 5-1 Overview of Demand Side Programs (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 LMP less generation and transmission component of retail rate. Energy payment for hours of voluntary curtailment.

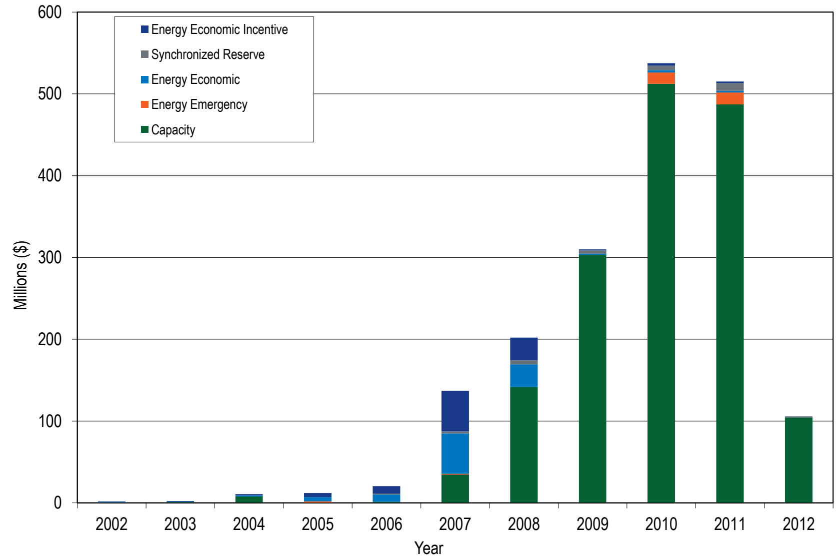
4 For more detail on the historical development of PJM Load Response Programs see the 2011 State of the Market Report for PJM, Volume II, Section 5, "Demand-Side Response" <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011.shtml>.

Participation in Demand Side Programs

In the first three 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 settled MWh 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 three months of 2012. Since the implementation of the RPM design on June 1, 2007, the capacity market has become the primary source of revenue to demand side participants. In the first three months of 2012, total payments under the Economic Program decreased by $210,002, from $240,304 in the first three months of 2011 to $30,302 in 2012, a 87 percent decrease. Capacity revenue decreased $39.8 million, or 27.6 percent, from $144 million to $104 million. Through January through March 2012, Synchronized Reserve credits for demand side resources decreased by $1.0 million compared to the same period in 2011, from $2.3 million in 2011 to $1.3 million in 2012. In the first three months of 2012, there were no Load Management Event Days.

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



Economic Program

Table 5-2 shows the number of registered sites and MW per peak load day for calendar years 2002 through the first three months of 2012.[5] On January 3, 2012, there were 2,385.2 MW registered in the Economic Program compared to the 2,041.8 MW on July 21, 2011, an 16.8 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 three months of 2012.[6] 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

5 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.

6 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.

have been signed up and can participate if they choose. Thus, registrations represent the maximum level of potential participation.

Table 5-2 Economic Program registration on peak load days: Calendar years 2002 to 2011 and January through March 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
3-Jan-12	1,993	2,385.2

Table 5-3 Economic Program registrations on the last day of the month: 2008 through March 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		
May	5,069	3,588	1,250	2,860	1,875	2,819	1,687	3,166		
Jun	3,112	3,014	1,265	2,461	813	1,608	1,143	1,912		
Jul	4,542	3,165	1,265	2,445	1,192	2,159	1,228	2,062		
Aug	4,815	3,232	1,653	2,650	1,616	2,398	1,987	2,194		
Sep	4,836	3,263	1,879	2,727	1,609	2,447	1,962	2,183		
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	1,995	2,375

Table 5-4 shows the zonal distribution of capability in the Economic Program on January 3, 2012. The ComEd Control Zone includes 741 sites and 286.7 MW, 30 percent of sites and 12 percent of registered MW in the Economic Program. The BGE Control Zone includes 36 sites and 529.4 MW, 2.6 percent of sites and 22 percent of registered MW in the Economic Program.

Table 5-4 Distinct registrations and sites in the Economic Program: January 3, 2012[7] (See the 2011 SOM, Table 5-4)

	Registrations	Sites	MW
AECO	38	41	18.3
AEP	26	71	130.6
AP	146	227	139.7
ATSI	11	11	78.9
BGE	56	65	529.4
ComEd	724	741	286.7
DAY	4	14	7.2
DEOK	0	0	0.0
DLCO	22	24	54.5
Dominion	76	88	188.3
DPL	34	41	147.0
JCPL	21	28	92.5
Met-Ed	83	87	81.7
PECO	326	407	184.4
PENELEC	131	158	92.3
Pepco	27	40	15.3
PPL	190	296	278.5
PSEG	78	106	59.9
RECO	0	0	0.0
Total	1,993	2,445	2,385.2

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.[8]

Table 5-5 Performance of PJM Economic Program participants without incentive payments: Calendar years 2002 through 2011 and January through March 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	1,182	$30,302	$26	0.5

Figure 5-2 shows monthly economic program payments, excluding incentive payments, for 2007 through 2010. 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.[9] Lower energy prices and growth in the capacity market program were the biggest factors. Energy prices declined significantly in 2008 and again in 2009.[10] In the first three months of 2012, credits were down compared to 2011, most likely due to low energy prices reducing the incentive to respond.

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

8 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.

9 March 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.

10 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[11] through 2011 (See the 2011 SOM, Figure 5-2)

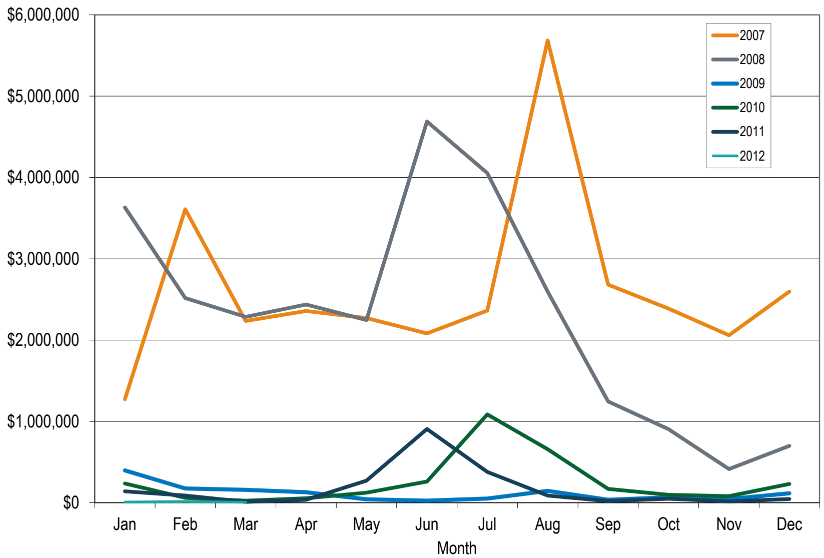


Table 5-6 shows the first three months of 2012 performance in the Economic Program by control zone and participation type. The total number of curtailed MWh for the Economic Program was 1,182 and the total payment amount was $30,302.[12] The Dominion Control Zone accounted for $29,774 or 98 percent of all Economic Program credits, associated with 1,182 or 85 percent of total program MWh reductions.

11 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.

12 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 March 2011 and 2012 (See the 2011 SOM, Table 5-6)

	Credits			MWh Reductions		
	2011	2012	Percent Change	2011	2012	Percent Change
AECO	$0	$0	0%	0.0	0.0	0%
AEP	$0	$0	0%	0.0	0.0	0%
AP	$6,081	$0	(100%)	129.2	0.0	(100%)
ATSI	$0	$0	0%	0.0	0.0	0%
BGE	$0	$0	0%	0.0	0.0	0%
ComEd	$0	$0	0%	0.0	0.0	0%
DAY	$0	$0	0%	0.0	0.0	0%
DEOK	$0	$0	0%	0.0	0.0	0%
DLCO	$44	$0	(100%)	1.9	0.0	(100%)
Dominion	$180,018	$29,774	(83%)	1,896.8	1,008.9	(47%)
DPL	$0	$0	0%	0.0	0.0	0%
JCPL	$0	$0	0%	0.0	0.0	0%
Met-Ed	$0	$133	NA	0.0	158.0	NA
PECO	$54,161	$395	(99%)	1,242.1	15.3	(99%)
PENELEC	$0	$0	0%	0.0	0.0	0%
Pepco	$0	$0	0%	0.0	0.0	0%
PPL	$0	$0	0%	1.6	0.0	(100%)
PSEG	$0	$0	0%	0.0	0.0	0%
RECO	$0	$0	0%	0.0	0.0	0%
Total	$240,304	$30,302	(87%)	3,271.6	1,182.2	(64%)

Table 5-7 shows total settlements submitted by month for calendar years 2007 through the first three months of 2012. For January through July of 2008, total monthly settlements were higher than the monthly totals for 2007, despite the recent expiration of the incentive program. In October of 2008, settlement submissions dropped significantly from the prior month and from the same month in 2007, a trend that continued through early 2009. This drop in participation corresponds with the implementation of the PJM daily review process, as well as the lower overall price levels in PJM. April of 2009 showed the lowest level of settlements submitted in the three year period, after which, settlements began to show steady growth. 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.

Table 5-7 Settlement days submitted by month in the Economic Program: Calendar years 2007 through 2011 and January through March 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	
May	1,649	3,336	918	673	298	
Jun	1,856	3,184	2,727	1,221	743	
Jul	2,534	3,339	2,879	3,007	1,411	
Aug	3,962	3,848	3,760	2,158	790	
Sep	3,388	3,264	2,570	660	294	
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	26,423	32,990	21,605	12,694	4,587	138

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 three 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 has been less activity in 2012 than in any of the past four years, however, this may change following the April 2 implementation of FERC 745 rules on demand resource compensation.

Table 5-9 shows a frequency distribution of MWh reductions and credits at each hour for January through March 2012. The period from hour ending 0800 EPT to 2300 EPT accounts for 70 percent of MWh reductions and 65 percent of credits.

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 48 percent of MWh reductions and 61 percent of program credits are associated with hours when the applicable zonal LMP was greater than or equal to $50.

Table 5-8 Distinct customers and CSPs submitting settlements in the Economic Program by month: Calendar years 2008 through 2011 and January through March 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		
May	12	233	9	201	6	140	6	144		
Jun	17	317	20	231	11	152	10	304		
Jul	16	295	21	183	18	243	15	214		
Aug	17	306	15	400	14	302	14	186		
Sep	17	312	11	181	11	97	7	47		
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	6	23

Table 5-9 Hourly frequency distribution of Economic Program MWh reductions and credits: January through March 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	0	0.00%	0	0.00%	$0	0.00%	$0	0.00%
2	0	0.00%	0	0.00%	$0	0.00%	$0	0.00%
3	0	0.00%	0	0.00%	$0	0.00%	$0	0.00%
4	0	0.00%	0	0.00%	$0	0.00%	$0	0.00%
5	7	0.58%	7	0.58%	$0	0.00%	$0	0.00%
6	8	0.64%	14	1.22%	$0	0.00%	$0	0.00%
7	335	28.35%	350	29.57%	$10,589	34.94%	$10,589	34.94%
8	394	33.36%	744	62.93%	$4,783	15.79%	$15,372	50.73%
9	227	19.19%	971	82.12%	$7,142	23.57%	$22,514	74.30%
10	87	7.36%	1,058	89.48%	$5,819	19.20%	$28,333	93.50%
11	20	1.68%	1,078	91.16%	$1,459	4.81%	$29,791	98.32%
12	14	1.21%	1,092	92.37%	$0	0.00%	$29,791	98.32%
13	8	0.65%	1,100	93.01%	$0	0.00%	$29,791	98.32%
14	7	0.60%	1,107	93.62%	$0	0.00%	$29,791	98.32%
15	7	0.60%	1,114	94.21%	$0	0.00%	$29,791	98.32%
16	8	0.70%	1,122	94.91%	$0	0.00%	$29,791	98.32%
17	16	1.32%	1,138	96.23%	$21	0.07%	$29,813	98.39%
18	13	1.09%	1,151	97.33%	$359	1.18%	$30,171	99.57%
19	12	1.02%	1,163	98.35%	$126	0.42%	$30,298	99.99%
20	13	1.12%	1,176	99.47%	$2	0.01%	$30,300	99.99%
21	3	0.24%	1,179	99.71%	$2	0.01%	$30,302	100.00%
22	2	0.14%	1,180	99.85%	$0	0.00%	$30,302	100.00%
23	1	0.07%	1,181	99.91%	$0	0.00%	$30,302	100.00%
24	1	0.09%	1,182	100.00%	$0	0.00%	$30,302	100.00%

Table 5-10 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through March 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	0	0.00%	0	0.00%	$0	0.00%	$0	0.00%
$25 to $50	612	51.80%	612	51.80%	$11,829	39.04%	$11,829	39.04%
$50 to $75	343	29.03%	956	80.84%	$5,085	16.78%	$16,914	55.82%
$75 to $100	150	12.72%	1,106	93.56%	$8,752	28.88%	$25,666	84.70%
$100 to $125	68	5.72%	1,174	99.27%	$4,062	13.41%	$29,728	98.11%
$125 to $150	1	0.07%	1,174	99.34%	$62	0.21%	$29,790	98.31%
$150 to $200	2	0.19%	1,177	99.53%	$293	0.97%	$30,083	99.28%
$200 to $250	1	0.11%	1,178	99.64%	$218	0.72%	$30,302	100.00%
$250 to $300	0	0.00%	1,178	99.64%	$0	0.00%	$30,302	100.00%
> $300	4	0.36%	1,182	100.00%	$0	0.00%	$30,302	100.00%

Load Management Program

Table 5-11 shows zonal monthly capacity credits that were paid during January through March 2012 to ILR and DR resources. Capacity revenue decreased by $39.8 million, or 27.6 percent, compared to the same period in 2011, from $144 million in 2011 to $104 million in 2012. Credits from January to May are associated with participation in the 2011/2012 RPM delivery year and decrease in capacity credits in 2012 is the result of a decrease in RPM clearing prices.

Table 5-11 Zonal monthly capacity credits: January through March 2012 (See the 2011 SOM, Table 5-13)

Zone	January	February	March	Total
AECO	$343,831	$321,649	$343,831	$1,009,311
AEP	$5,390,887	$5,043,088	$5,390,887	$15,824,863
APS	$3,410,799	$3,190,748	$3,410,799	$10,012,347
ATSI	$4,821	$4,510	$4,821	$14,151
BGE	$3,630,571	$3,396,340	$3,630,571	$10,657,481
ComEd	$6,180,266	$5,781,539	$6,180,266	$18,142,072
DAY	$824,485	$771,293	$824,485	$2,420,263
DEOK	$0	$0	$0	$0
DLCO	$2,418	$2,262	$2,418	$7,098
Dominion	$3,977,804	$3,721,172	$3,977,804	$11,676,781
DPL	$817,336	$764,605	$817,336	$2,399,277
JCPL	$883,220	$826,238	$883,220	$2,592,677
Met-Ed	$909,516	$850,837	$909,516	$2,669,868
PECO	$2,375,286	$2,222,042	$2,375,286	$6,972,615
PENELEC	$1,380,240	$1,291,192	$1,380,240	$4,051,672
Pepco	$1,174,938	$1,099,136	$1,174,938	$3,449,012
PPL	$2,739,610	$2,562,861	$2,739,610	$8,042,080
PSEG	$1,468,327	$1,373,596	$1,468,327	$4,310,250
RECO	$22,526	$21,072	$22,526	$66,123
Total	$35,536,881	$33,244,179	$35,536,881	$104,317,942

Table 5-12 shows data on compensation to a hypothetical demand response resource and a generation resource during calendar year 2011, using the BGE zone as an example. Both the DR and generation resource are assumed to be 100 MW. The table shows the revenues that would have been received by a demand resource, under four scenarios, and revenues that would have been received by three types of generation resources.

The four scenarios are:

- The actual six hour event on July 22, assuming that the demand and generation resources were price takers and received the actual hourly LMP.
- The actual six hour event on July 22, assuming that the demand resources specified a strike price of $999 per MWh and received that amount while the generation resources were price takers.
- The demand resource was dispatched for the maximum 10 events, each of six hours duration, during the ten highest LMP days from June through August 2011, assuming that the demand and generation resources were price takers and received the actual hourly LMP.
- The demand resource was dispatched for the maximum 10 events, each of six hours duration, assuming that the demand resources specified a strike price of $999 per MWh and received that amount while the generation resources were price takers.

In summary, the results show, for each scenario, the hours of operation, the E&AS (energy and ancillary services) market revenues, capacity market revenues, total revenues and the average net revenue margin per MWh provided.

The results show that a 100 MW demand resource, limited to operating for only ten events with a maximum duration of six hours, or a total of 60 hours, if it takes the strike price option, could earn about as much in total net revenue as a 100 MW combustion turbine unit or a 100 MW coal unit, operating over thousands of hours. The majority of demand resources use the strike price option. In addition, the results show that the average margin per MWh is substantially higher for the demand resources than for the generation resources.

Table 5-12 Comparison of Demand Response and Generation Resources, Calendar year 2011[13] (New Table)

	DSR (July 22, 2011 Event)	DSR (July 22, 2011 Event $999 Strike Price)	DSR (10x6 Events)	DSR ($999 strike price)	DSR (No Events)	CC	CT	Coal
Hours of Operation	6	6	60	60	0	7,524	2,489	4,751
E&AS	$230,244	$599,400	$1,751,744	$5,994,000	$0	$13,080,600	$4,864,200	$5,694,000
Capacity	$4,985,779	$4,985,779	$4,985,779	$4,985,779	$4,985,779	$4,985,779	$4,985,779	$4,985,779
Total	$5,216,023	$5,585,179	$6,737,523	$10,979,779	$4,985,779	$18,066,379	$9,849,979	$10,679,779
Average margin per MWh	$384	$999	$292	$999		$17	$20	$12

13 CC, CT, and Coal plant revenue for BGE zone from the *2011 State of the Market Report for PJM.*

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.

Highlights

- Energy prices decreased by 33 percent in the first three months of 2012 compared to the first three months of 2011. Gas prices decreased by 47 percent and coal prices decreased on average by 4 percent. This combination of factors resulted in lower energy net revenues for the new entrant CC unit in approximately half the zones and lower energy net revenues for the new entrant coal CT and CP unit in all zones in 2012.
- Energy net revenues for the new entrant coal unit were down 87 percent from the first quarter of 2011.

Net Revenue

Net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue 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.

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.[1]

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

Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Energy prices decreased by 33 percent in the first three months of 2012 over the first three months of 2011. Gas prices decreased by 47 percent and coal prices decreased by 4 percent. The combination of lower energy prices, lower gas prices and lower coal prices resulted in lower energy

1 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.

net revenues for the new entrant CC unit in approximately half the zones and lower energy net revenues for the new entrant CT and CP unit in all zones in 2012.

Only quarterly energy market net revenues are provided in this section.

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. All technology specific, zonal net revenue calculations included in the new entrant net revenue analysis in this section are based on the economic dispatch scenario.

Analysis of 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.[2] 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.[3,4] 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.[5]

A forced outage rate for each class of plant was calculated from PJM data.[6] 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 reactive revenues. Reactive service revenues are based on the weighted-

2 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.
3 Hourly ambient conditions supplied by Telvent DTN.
4 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.
5 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
6 Outage figures obtained from the PJM eGADS database.

average reactive service rate per MW-year calculated from the data in the FERC filings.

Zonal net revenues reflect zonal fuel costs which consider a variety of locational fuel indices, actual unit consumption patterns, and zone specific delivery charges.[7] The delivered fuel cost for 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.[8] Coal delivered cost incorporates the zone specific, delivered price of coal and was developed from the published prompt-month price, adjusted for rail transportation cost.[9]

Average zonal operating costs in 2012 for a CT were $36.33 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 $32.26 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 $21.31 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 by PJM operations. For this economic dispatch scenario, 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)[10] (See the 2011 SOM, Table 6-3)

Zone	2009 (Jan-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)	2012 (Jan-Mar)	Average
AECO	$5,055	$3,047	$9,882	$3,158	$5,285
AEP	$1,866	$1,238	$3,312	$2,085	$2,125
AP	$5,308	$3,176	$8,496	$3,271	$5,063
ATSI	NA	NA	NA	$2,230	$2,230
BGE	$5,054	$4,884	$8,947	$7,307	$6,548
ComEd	$721	$683	$1,964	$1,196	$1,141
DAY	$1,377	$786	$3,425	$2,515	$2,026
DEOK	NA	NA	NA	$1,996	$1,996
DLCO	$1,020	$4,204	$3,755	$2,297	$2,819
Dominion	$6,838	$5,067	$8,856	$4,271	$6,258
DPL	$5,897	$3,385	$8,858	$5,840	$5,995
JCPL	$4,949	$3,130	$10,499	$3,019	$5,399
Met-Ed	$4,642	$2,984	$9,180	$3,070	$4,969
PECO	$4,387	$2,952	$10,216	$2,965	$5,130
PENELEC	$3,531	$1,589	$7,840	$2,982	$3,986
Pepco	$5,191	$5,456	$9,025	$6,046	$6,430
PPL	$4,356	$2,547	$12,009	$2,698	$5,403
PSEG	$3,533	$3,505	$7,509	$2,643	$4,297
RECO	$2,730	$2,320	$5,656	$2,499	$3,301
PJM	$3,909	$2,997	$7,613	$3,268	$4,447

New Entrant Combined Cycle

Energy market net revenue was calculated for a CC plant dispatched by PJM operations. For this economic dispatch scenario, 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.[11] If the unit was not already committed day ahead, it was then run in real time in stand-alone profitable blocks of at least eight hours, or any hours bordering the profitable day ahead or real time block.

7 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.
8 Gas daily cash prices obtained from Platts.
9 Coal prompt prices obtained from Platts.
10 The energy net revenues presented for the PJM area in this section represent the simple average of all zonal energy net revenues.
11 All starts associated with combined cycle units are assumed to be hot starts.

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-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)	2012 (Jan-Mar)	Average
AECO	$22,722	$14,698	$28,962	$22,492	$22,218
AEP	$10,348	$6,772	$16,137	$23,268	$14,131
AP	$24,055	$13,822	$30,306	$26,488	$23,668
ATSI	NA	NA	NA	$24,003	$24,003
BGE	$23,159	$16,976	$24,566	$31,255	$23,989
ComEd	$6,435	$3,162	$7,450	$14,631	$7,919
DAY	$8,191	$5,488	$15,249	$24,254	$13,296
DEOK	NA	NA	NA	$20,617	$20,617
DLCO	$6,155	$7,973	$14,120	$23,666	$12,979
Dominion	$27,154	$20,647	$24,261	$25,733	$24,449
DPL	$24,115	$13,751	$26,601	$27,157	$22,906
JCPL	$23,004	$15,155	$30,131	$22,765	$22,764
Met-Ed	$20,630	$13,785	$25,071	$21,015	$20,125
PECO	$21,599	$14,214	$28,298	$21,447	$21,389
PENELEC	$19,615	$11,064	$28,688	$25,607	$21,244
Pepco	$22,991	$18,111	$23,545	$29,409	$23,514
PPL	$19,803	$12,849	$27,682	$20,340	$20,169
PSEG	$19,782	$13,017	$22,894	$17,934	$18,407
RECO	$17,153	$10,550	$16,219	$16,905	$15,207
PJM	$18,642	$12,473	$22,952	$23,104	$19,293

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-Mar)	2010 (Jan-Mar)	2011 (Jan-Mar)	2012 (Jan-Mar)	Average
AECO	$46,466	$41,402	$31,954	$1,201	$30,256
AEP	$9,988	$19,874	$20,657	$2,020	$13,135
AP	$26,199	$28,197	$32,831	$5,747	$23,244
ATSI	NA	NA	NA	$4,192	$4,192
BGE	$30,501	$19,758	$22,385	$2,324	$18,742
ComEd	$15,196	$33,059	$27,330	$10,614	$21,550
DAY	$9,576	$23,761	$17,989	$2,138	$13,366
DEOK	NA	NA	NA	$1,007	$1,007
DLCO	$9,214	$24,748	$5,655	$2,019	$10,409
Dominion	$29,546	$43,455	$33,824	$2,414	$27,310
DPL	$27,103	$41,814	$44,079	$2,982	$28,995
JCPL	$44,068	$41,732	$31,512	$2,962	$30,069
Met-Ed	$38,856	$40,208	$25,267	$6,551	$27,721
PECO	$44,165	$41,104	$30,217	$1,371	$29,214
PENELEC	$30,714	$34,842	$30,205	$6,190	$25,488
Pepco	$39,959	$45,999	$28,817	$2,101	$29,219
PPL	$41,900	$34,873	$30,211	$897	$26,970
PSEG	$55,259	$35,584	$24,381	$1,581	$29,201
RECO	$42,289	$40,942	$26,946	$2,786	$28,241
PJM	$31,823	$34,785	$27,309	$3,216	$24,284

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, as a result, had a significant impact on PJM wholesale markets.

Highlights

- The EPA issued the Mercury Air Toxics Rule December 16, 2011, which will require significant investments in control technology for Mercury and other pollutants, effective April 16, 2015.
- Generation from wind units increased from 3,647.6 GWh in January through March 2011 to 4,261.3 GWh in January through March 2012, an increase of 26.7 percent. Generation from solar units increased from 7.0 GWh in January through March 2011to 43.9 GWh in January through March 2012, an increase of 526.8 percent.
- At the end of 2011, the Cross-State Air Pollution Rule was subject to a stay pending further action on appeal, resulting in the reinstatement of the Clean Air Interstate Rule for 2012.
- Emission prices declined in January through March 2012 compared to 2011. NO_x prices declined 70.3 percent in 2012 compared to 2011, and SO_2 prices declined 34.4 percent in 2012 compared to 2011. RGGI CO_2 prices increased by 3.6 percent in 2012 compared to 2011, partially as a result of the increase in the price floor for RGGI CO_2 allowances.
- The price of RGGI CO_2 allowances remained at or near the floor price of $1.93 during January through March 2012, and as of January 1, 2012, the state of New Jersey will no longer be participating in the RGGI program.
- 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.

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 can provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

Environmental Regulation

Federal Environmental Regulation of Greenhouse Gas Emissions

On April 2, 2007, the U.S. Supreme Court overruled 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.[1] 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.[2]

1 Massachusetts v. EPA, 549 U.S. 497.
2 *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).

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 as opposed to other pollutants. Application of the prevailing 100 or 250 tons per year (tpy) annual emissions rates would overwhelm the capabilities of state permitting authorities and impede the ability to construct or modify regulated facilities.[3]

On May 13, 2010, the EPA issued a rule addressing greenhouse gases (GHG) from the largest stationary sources, including power plants.[4] 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. Affected facilities will be required 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.[5]

On July 1, 2011, step 2 expanded the rule 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.[6] These permits must demonstrate the use of best available control technology (BACT) to minimize GHG emission increases when facilities are constructed or significantly modified.[7]

On February 3, 2012, the EPA proposed step 3.[8] This proposed rule would leave the step 2 thresholds unchanged. Step 2 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.[9] Step 2 also allows for sources to obtain status as "synthetic minor sources," and avoid status as a regulated major source, on the basis of its voluntary acceptance of enforceable emissions limits.[10] For example, a generating unit that would be a major resource if it operated every hour of the year could become a synthetic minor resource by accepting enforceable emissions limits based on its practical physical and operational limitations.[11]

On March 27, 2012, the EPA proposed an emissions standard for CO_2 from new fossil-fired electric utility generating units.[12] 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)."[13] 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.[14] 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."[15]

State Regulation of Greenhouse Gas Emissions

The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont to cap CO_2 emissions from

3 EPA, *Proposed 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 (February 24, 2012) at 6-7 (Step 3 Tailoring Rule).
4 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.
5 *Id.* at 31516.
6 *Id.*
7 *Id.* at 31520.
8 Step 3 Tailoring Rule.
9 *Id.* at 8.
10 *Id.*
11 *See Id.*
12 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).
13 *Id.* at
14 *Id.* at 22392. EPA observes that PJM State Illinois, currently requires CCS for new coal generation.
15 *Id.* at 22406.

power generation facilities.[16] After December 31, 2011, 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 13 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 auction for the 2012-2014 compliance period held as of March 31, 2012. Auction prices within January through March 2012 for the 2012-2014 compliance period were $1.93 throughout the year. This price, $1.93 per allowance, is the current price floor for RGGI auctions, as determined in the first RGGI auction. The average January through March 2012 spot price for a 2012-2014 compliance period allowance was $1.98 per ton. Monthly average spot prices for the 2012-2014 compliance period varied during the year, peaking in February at $2.00 per ton and declining to $1.97 per ton during March.

Table 7-1 RGGI CO_2 allowance auction prices and quantities: 2009-2011 and 2012-2014 Compliance Period and 2012-2014 Compliance Period[17] (See 2011 SOM, Table 7-3)

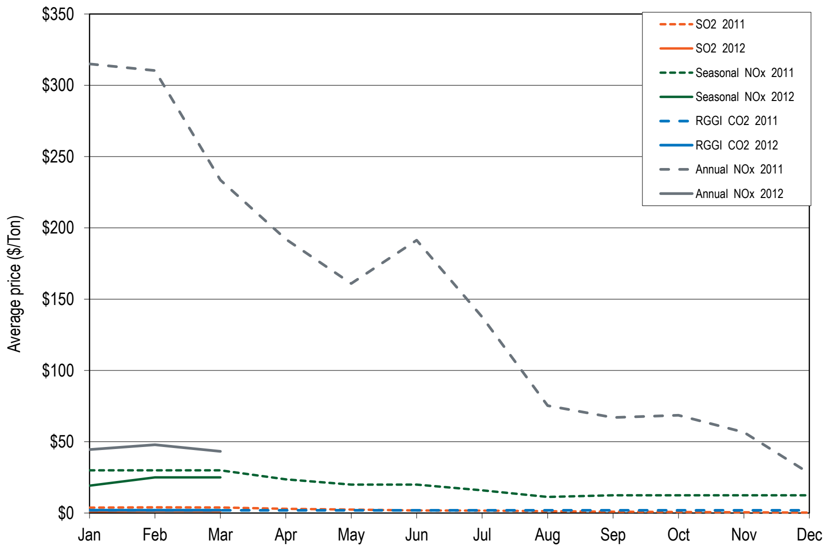
Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387
December 17, 2008	$3.38	31,505,898	31,505,898
March 18, 2009	$3.51	31,513,765	31,513,765
June 17, 2009	$3.23	30,887,620	30,887,620
September 9, 2009	$2.19	28,408,945	28,408,945
December 2, 2009	$2.05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

Figure 7-1 shows average, daily settled prices for NO_x and SO_2 emissions within PJM. In January through March 2012, NO_x prices were 70.3 percent lower than in 2011. SO_2 prices were 34.4 percent lower in January through March 2012than in 2011. Figure 7-1 also shows the average, daily settled price for the RGGI CO_2 allowances. RGGI allowances are required by generation in participating RGGI states. This includes PJM generation located in Delaware and Maryland.

16 A similar regional initiative has organized under the Western Climate Initiative, Inc. (WCI). The first mover is the California Air Resources Board (ARB), which has organized a cap and trade program that it will implement starting 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.

17 See "Regional Greenhouse Gas Initiative: Auction Results" <http://www.rggi.org/market/co2_auctions/results> (Accessed April 2, 2012).

Figure 7-1 Spot monthly average emission price comparison: 2011 and January through March 2012 (See 2011 SOM, Figure 7-1)



Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of utilities' 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.

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).

Table 7-2 Renewable standards of PJM jurisdictions to 2022[18,19] (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%
Indiana		4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%
Illinois	7.00%	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.50%
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%

Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation or any 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 each per MWh from generation from "alternative energy resources" such as waste coal or pumped-storage hydroelectric, but allows two credits each per MWh of electricity generated by "renewable energy resources", which includes resources such as wind, solar, and run-of-river hydroelectric. 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.

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 7-3 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.[20] Indiana, Michigan, Virginia, and West Virginia have no specific solar standard. In 2012, the most stringent standard in PJM was Washington D.C.'s, requiring 0.5 percent of load to be served by solar resources. As Table 7-3 shows, by 2022, the most stringent standard will be Delaware's which requires at least 2.75 percent of load to be served by solar.

18 This analysis shows the total standard of renewable resources in all PJM jurisdictions, including Tier I and Tier II resources.

19 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.

20 Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill the jurisdiction's solar requirement.

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%
Indiana	No Solar Standard										
Illinois	0.00%	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%	1.23%
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%	0.50%	0.62%	0.77%	0.93%	1.18%	1.33%	1.57%	1.84%	2.12%	2.12%
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**										

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 March 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 4,261.3 GWh of 7,029.0 Tier I GWh, or 60.6 percent, in the PJM footprint. As shown in Table 7-4, 12,038.8 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 58.3 percent.

Table 7-4 Renewable generation by jurisdiction and renewable resource type (GWh): 2011 (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	16.6	0.0	0.0	0.0	0.0	0.0	0.0	16.6	33.3
Indiana	0.0	0.0	11.7	0.0	0.0	0.0	927.8	939.5	939.5
Illinois	34.7	0.0	0.0	0.0	0.0	0.0	1,703.2	1,737.9	1,737.9
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	20.8	0.0	632.6	0.0	120.7	0.0	112.7	766.0	886.7
Michigan	8.4	0.0	19.4	0.0	0.0	0.0	0.0	27.8	27.8
New Jersey	95.3	69.3	4.8	40.6	321.2	0.0	3.1	143.8	534.3
North Carolina	0.0	0.0	111.8	0.0	0.0	0.0	0.0	111.8	111.8
Ohio	47.3	0.0	69.8	0.3	0.0	0.0	314.8	432.2	432.2
Pennsylvania	246.9	301.5	707.9	1.0	439.6	2,250.3	689.4	1,645.1	4,636.5
Tennessee	0.0	0.0	0.0	0.0	91.8	0.0	0.0	0.0	91.8
Virginia	120.5	857.1	221.2	2.1	275.7	0.0	0.0	343.8	1,476.6
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	3.2	0.0	350.8	0.0	0.0	282.7	510.4	864.4	1,147.1
Total	593.7	1,227.8	2,130.1	43.9	1,249.0	2,533.0	4,261.3	7,029.0	12,038.8

Table 7-5 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary or alternative fuel types being renewable.[21] This analysis includes various coal and natural gas units that have a renewable fuel as a secondary fuel, and thus are able to earn renewable energy credits. Pennsylvania has the largest amount of renewable capacity in PJM, 7,401.2 MW, or 27.1 percent of the total renewable capacity. New Jersey has the highest amount of solar capacity in PJM, 149.5 MW, or 97.3 percent of the total solar capacity. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 3,198.1 MW, or 57.7 percent of the total wind capacity.

Table 7-6 shows renewable capacity registered in the PJM Generation Attribute Tracking System (GATS), a system operated by PJM EIS, that are not PJM units. This includes solar capacity of 803.9 MW of which 522.8 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. Some of this capacity is located in jurisdictions outside PJM, but that may qualify for specific renewable energy credits in some jurisdictions. This includes both behind the meter generation located inside PJM, and generation connected to other RTOs outside PJM.

21 Defined by fuel type, or a generator being registered in PJM GATS. Includes only units that are interconnected to the PJM system.

Table 7-5 PJM renewable capacity by jurisdiction (MW), on March 31, 2012[22] (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	15.0	0.0	0.0	0.0	0.0	0.0	0.0	1,858.4
Illinois	0.0	64.9	0.0	0.0	0.0	0.0	0.0	20.0	0.0	2,144.9	2,229.8
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	24.5	129.0	31.9	0.0	590.0	0.0	109.0	0.0	120.0	1,064.4
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	149.5	191.1	0.0	7.5	838.6
North Carolina	0.0	0.0	0.0	0.0	0.0	315.0	0.0	95.0	0.0	0.0	410.0
Ohio	5,241.7	25.8	25.0	209.0	0.0	178.0	1.1	0.0	0.0	500.0	6,180.6
Pennsylvania	35.0	213.1	2,370.7	0.0	1,505.0	672.6	3.0	263.0	1,473.9	865.0	7,401.2
Tennessee	0.0	0.0	0.0	0.0	0.0	.	0.0	50.0	0.0	0.0	50.0
Virginia	0.0	114.9	80.0	16.9	3,588.0	457.1	0.0	215.0	0.0	0.0	4,471.9
West Virginia	500.0	2.0	0.0	0.0	0.0	244.0	0.0	0.0	130.0	663.5	1,539.5
PJM Total	5,836.7	543.6	4,440.0	272.8	5,493.0	2,481.7	153.7	943.1	1,603.9	5,539.1	27,307.5

Table 7-6 Renewable capacity by jurisdiction, non-PJM units registered in GATS[23,24] (MW), on March 31, 2012 (See 2011 SOM, Table 7-10)

Jurisdiction	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	28.1	0.0	0.1	28.2
Illinois	4.6	108.8	0.0	0.0	0.0	10.7	0.0	302.5	426.6
Indiana	0.0	43.6	0.0	679.1	0.0	0.8	0.0	0.0	723.6
Kentucky	2.0	16.0	0.0	0.0	0.0	0.5	88.0	0.0	106.5
Maryland	0.0	7.0	0.0	0.0	0.0	44.5	0.0	0.3	51.8
Michigan	0.0	1.6	0.0	0.0	0.0	0.2	0.0	0.0	1.8
Minnesota	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	146.0	146.0
New Jersey	0.0	39.9	0.0	0.0	23.3	522.8	0.0	0.4	586.4
New York	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	2.0	0.0	0.0	2.0
Ohio	1.0	37.3	52.6	67.0	1.0	45.5	109.3	15.9	329.6
Pennsylvania	0.2	10.0	4.8	85.5	0.3	137.5	0.0	3.2	241.5
Virginia	12.5	14.8	0.0	0.0	0.0	5.2	318.1	0.0	350.6
West Virginia	0.0	0.0	0.0	0.0	0.0	0.6	0.0	0.0	0.6
Wisconsin	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	4.8	0.0	0.0	4.8
Total	133.1	279.1	57.4	831.6	24.6	803.9	560.0	468.4	3,158.1

22 The correct value as of December 31, 2010 for Pumped Storage Hydro capacity in Pennsylvania was 1,505 MW, rather than the listed 2,575 MW.

23 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.

24 See "Renewable Generators Registered in GATS" <https://gats.pjm-eis.com/myModule/rpt/myrpt.asp?r=228> (Accessed April 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 84,019.7 MW of coal steam capacity in PJM, 54,210.2 MW of capacity, 64.5 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 March 31, 2012 (See 2011 SOM, Table 7-11)

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal Steam	54,210.2	29,809.5	84,019.7	64.5%
Combined Cycle	0.0	27,025.9	27,025.9	0.0%
Combustion Turbine	0.0	31,468.3	31,468.3	0.0%
Diesel	0.0	363.8	363.8	0.0%
Non-Coal Steam	0.0	9,357.8	9,357.8	0.0%
Total	54,210.2	98,025.3	152,235.5	35.6%

NO_x emission controlling 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, 136,686.5 MW, or 89.8 percent, of 152,235.5 MW of capacity in PJM, have emission controls for NO_x. Table 7-8 shows NO_x emission controls by unit type of fossil fuel units in PJM. 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. 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 March 31, 2012 (See 2011 SOM, Table 7-12)

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal Steam	80,611.9	3,407.8	84,019.7	95.9%
Combined Cycle	26,289.8	736.1	27,025.9	97.3%
Combustion Turbine	25,414.8	6,053.5	31,468.3	80.8%
Diesel	0.0	363.8	363.8	0.0%
Non-Coal Steam	4,370.0	4,987.8	9,357.8	46.7%
Total	136,686.5	15,549.0	152,235.5	89.8%

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, 81,754.7 MW, 97.3 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 March 31, 2012 (See 2011 SOM, Table 7-13)

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal Steam	81,754.7	2,265.0	84,019.7	97.3%
Combined Cycle	0.0	27,025.9	27,025.9	0.0%
Combustion Turbine	0.0	31,468.3	31,468.3	0.0%
Diesel	0.0	363.8	363.8	0.0%
Non-Coal Steam	3,047.0	6,310.8	9,357.8	32.6%
Total	84,801.7	67,433.8	152,235.5	55.7%

Wind Units

Table 7-10 shows the capacity factor of wind units in PJM. In January through March 2012, the capacity factor of wind units in PJM was 37.3 percent. Wind units that were capacity resources had a capacity factor of 39.2 percent and an installed capacity of 3,930 MW. Wind units that were classified as energy only had a capacity factor of 31.8 percent and an installed capacity of 1,610 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.

Table 7-10 Capacity[25] factor[26] of wind units in PJM, January through March 2012 (See 2011 SOM, Table 7-14)

Type of Resource	Capacity Factor	Capacity Factor by cleared MW	Total Hours	Installed Capacity (MW)
Energy-Only Resource	31.8%	NA	40,085	1,610
Capacity Resource	39.2%	269.1%	89,503	3,930
All Units	37.3%	269.1%	129,588	5,539

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, 1,044.1 MW of wind were offered daily at a negative price. Wind units with negative offers were marginal in 1,896 separate five minute intervals, or 7.2 percent of all intervals. On average, 3,014.4 MW of wind were offered daily. Overall, wind units were marginal in 4,907 separate five minute intervals, or 18.7 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 March 2012 (See 2011 SOM, Table 7-15)

	Average MW Offered	Intervals Marginal	Percent of Intervals
At Negative Price	1,044.1	1,896	7.2%
All Wind	3,014.4	4,907	18.7%

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 March, and lowest in February. The highest average hour, 2,429.0 MW, occurred in January, and the lowest average hour, 1,607.3 MW, occurred in February. 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 March 2012 (See 2011 SOM, Figure 7-2)

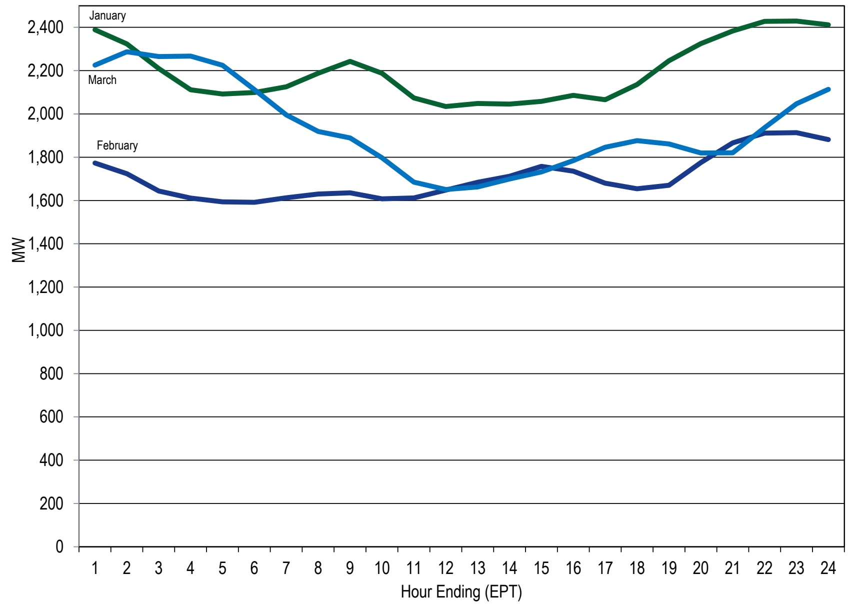


Table 7-12 shows the generation and capacity factor of wind units in each month of 2011 and January through March 2012. Capacity factors of wind units vary substantially by month. The highest capacity factor of wind units was 42.6 percent in January, and the lowest capacity factor was 33.0 percent in February. 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.

25 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.

26 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.

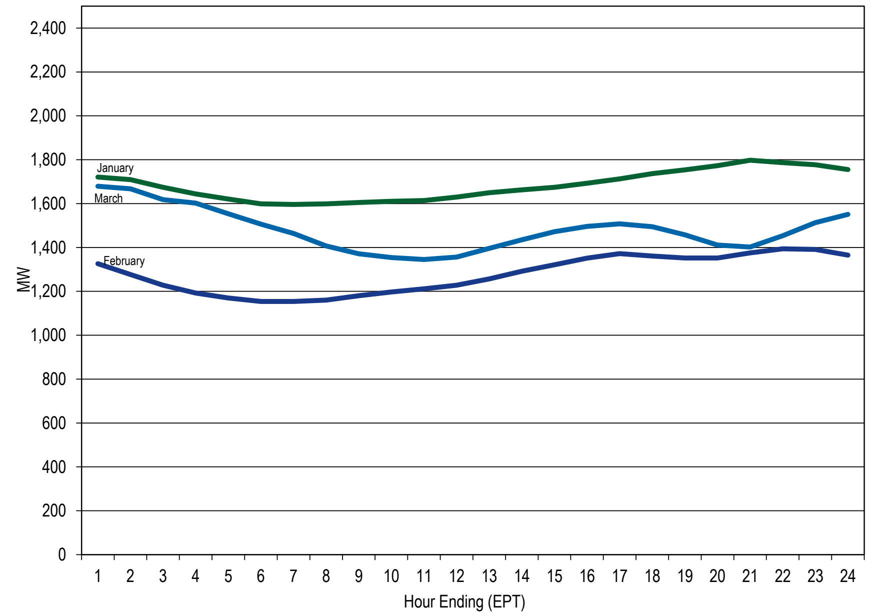
Table 7-12 Capacity factor of wind units in PJM by month, 2011 and 2012[27] (See 2011 SOM, Table 7-16)

	2011		2012	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	950,441.9	29.7%	1,634,860.9	42.6%
February	1,237,813.0	42.4%	1,186,724.6	33.0%
March	1,175,567.0	36.4%	1,439,707.9	36.2%
April	1,399,217.0	44.7%		
May	893,485.1	27.6%		
June	713,713.8	22.0%		
July	416,695.8	12.2%		
August	447,575.2	13.1%		
September	689,962.6	20.9%		
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%	4,261,293.3	37.3%

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 February, 2012.

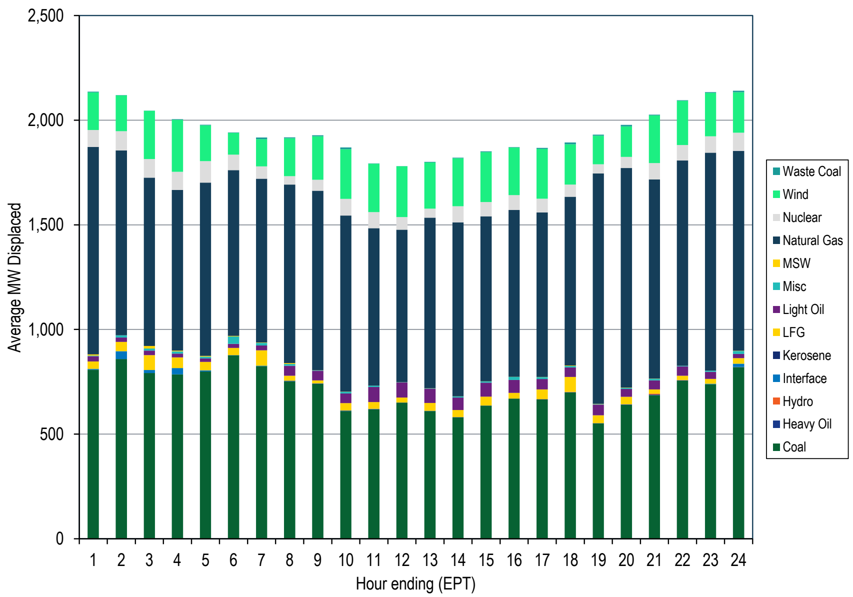
27 Capacity factor shown in Table 7-16 is based on all hours in January through March, 2012.

Figure 7-3 Average hourly day-ahead generation of wind units in PJM: January through March 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 March 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 361 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 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.

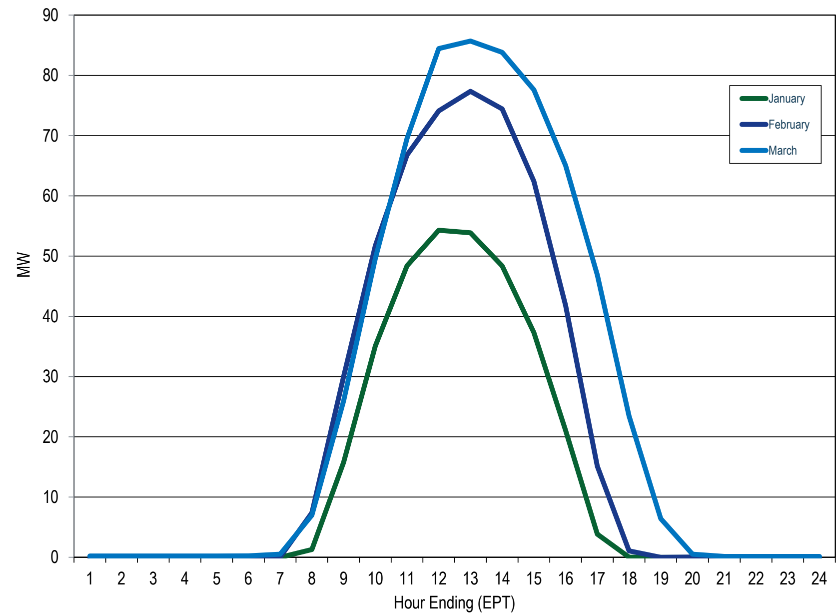
Figure 7-4 Marginal fuel at time of wind generation in PJM: January through March 2012 (See 2011 SOM, Figure 7-4)



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 March, the month with the most daylight hours. The highest average hour, 85.6 MW, occurred in March. In general, solar generation in PJM is highest during the hours of 11:00 through 13:00 EPT.

Figure 7-5 Average hourly real-time generation of solar units in PJM: January through March 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

- Real-time net imports were 800.7 GWh for the first three months of 2012. For the first three months of 2011, there were net exports of -802.0 GWh in real-time. Day-ahead net exports were -3,224.6 GWh for the first three months of 2012. For the first three months of 2011, there were net imports of 3,813.0 GWh in day-ahead.
- The direction of power flows was not consistent with real-time energy market price differences in 58 percent of hours at the border between PJM and MISO and in 49 percent of hours at the border between PJM and NYISO during the first three months of 2012.
- During the first three months of 2012, net scheduled interchange was 310 GWh and net actual interchange was 110 GWh, a difference of 200 GWh (during the first three months of 2011, net scheduled interchange was -74 GWh and net actual interchange was -211 GWh, a difference of 137 GWh).
- PJM initiated 6 TLRs during the first three months of 2012, a reduction from the 13 TLRs initiated during the first three months of 2011.
- The average daily volume of up-to congestion bids increased from 20,753 bids per day, during the first three months of 2011, to 50,305 bids per day during the first three months of 2012. A significant increase in bid volume occurred following the September 17, 2010, modification to the up-to congestion product that eliminated the requirement to procure transmission when submitting up-to congestion bids.
- Balancing operating reserve credits are paid to importing dispatchable transactions (also known as real-time with price) as a guarantee of the transaction price. Dispatchable transactions are made whole when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. During the first three months of 2012, there were no balancing operating reserve credits paid to dispatchable transactions, a decrease from $1.1 million for the first three 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 in three days during the first three 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 three months of 2012, including evolving transaction patterns, economics and issues. In the first three 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 three 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 many hours, 58 percent between PJM and MISO and 49 percent 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 reliance 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

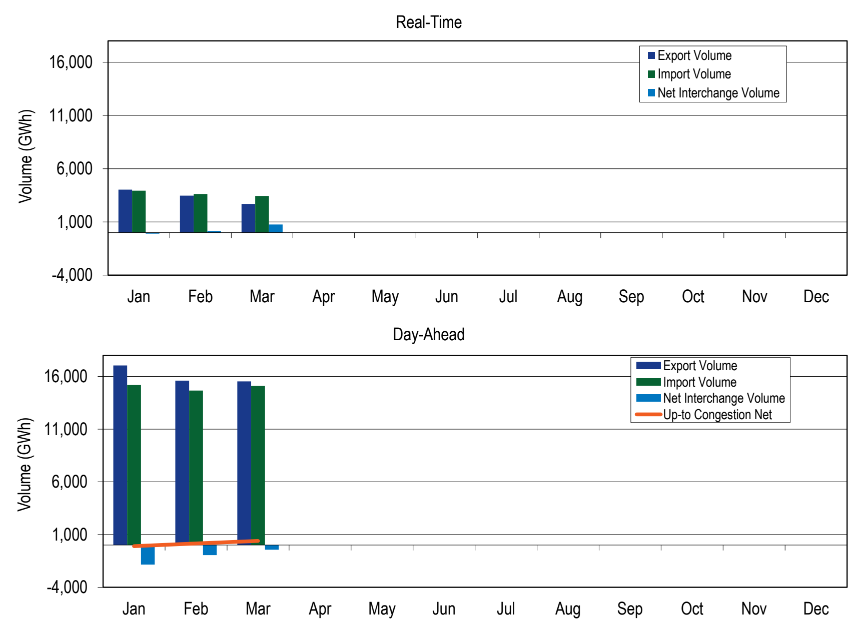
Aggregate Imports and Exports

During the first three months of 2012, PJM was a net exporter of energy in the Real-Time Energy Market in January, and a net importer of energy in February and March. During the first three 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 February and March. In the Real-Time Energy Market, monthly net interchange averaged 266.9 GWh for the first three months of 2012 compared to -213.3 GWh for the first three months of 2011.[1] Gross monthly import volumes during the first three months of 2012 averaged 3,663.7 GWh compared to 3,769.2 GWh for the first three months of 2011 while gross monthly exports averaged 3,396.8 GWh for the first three months of 2012 compared to 3,982.4 GWh for the first three months of 2011.

During the first three months of 2012, PJM was a net exporter of energy in the Day-Ahead Energy Market in all months. During the first three months of 2011, PJM was a net importer of energy in the Day-Ahead Energy Market in all months. In the Day-Ahead Energy Market, for the first three months of 2012, monthly net interchange averaged -1,074.9 GWh compared to 1,271.4 GWh for the first three months of 2011. Gross monthly import volumes averaged 14,981.4 GWh for the first three months of 2012 compared to 9,386.9 GWh for the first three months of 2011 while gross monthly exports averaged 16,056.3 GWh for the first three months of 2012 compared to 8,115.5 GWh for the first three months of 2011.

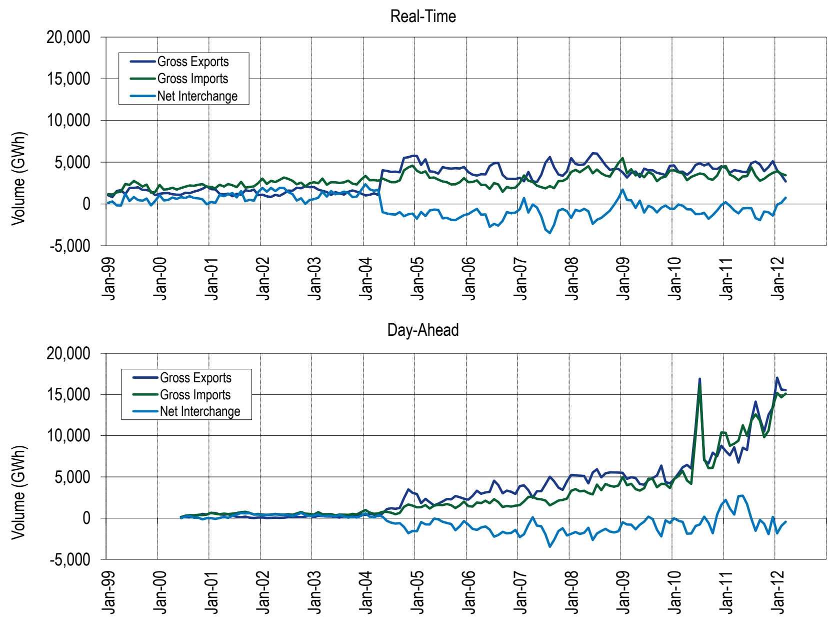
In the first three months of 2012, gross imports in the Day-Ahead Energy Market were 408.9 percent of gross imports in the Real-Time Energy Market (248.7 percent for the first three months of 2011). In the first three months of 2012, gross exports in the Day-Ahead Energy Market were 472.7 percent of gross exports in the Real-Time Energy Market (200.8 percent for the first three months of 2011). In the first three months of 2012, net interchange was -3,224.6 GWh in the Day-Ahead Energy Market and 800.7 GWh in the Real-Time Energy Market compared to 3,813.9 GWh in the Day-Ahead Energy Market and -802.0 GWh in the Real-Time Energy Market for the first three months of 2011.

Figure 8-1 PJM real-time and day-ahead scheduled imports and exports: January through March, 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 March, 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 (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 8-13 for a list of active interfaces in 2011. Figure 8-3 shows the approximate geographic location of the interfaces.) In the first quarter of 2012, PJM had 20 interfaces with neighboring balancing authorities.[2] The Linden (LIND) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface. However, 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 interfaces with the NYISO, 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 three 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 three months of 2012, there were net exports at 11 of PJM's 20 interfaces. The top four net exporting interfaces in the Real-Time Energy Market accounted for 81.0 percent of the total net exports: PJM/Eastern Alliant Energy Corporation with 23.0 percent, PJM/MidAmerican Energy Company (MEC) with 21.7 percent, PJM/New York Independent System Operator, Inc. (NYIS) with 19.6 percent and PJM/Neptune (NEPT) with 16.6 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 38.4 percent of the total net PJM exports in the Real-Time Energy Market. Seven PJM interfaces had net imports, with two importing interfaces accounting for 59.1 percent of the total net imports: PJM/Tennessee Valley Authority (TVA) with 30.7 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 28.5 percent of the net import volume.[3]

2 The number of interfaces with PJM was reduced to 20 when FE was removed as an interface coincident with the integration of ATSI into the PJM footpring on June 1, 2011.

3 In the Real-Time Market, two PJM interfaces had a net interchange of zero (PJM/western portion of Carolina Power & Light Company (CPLW) and PJM/City Water Light & Power (CWLP)).

Table 8-1 Real-time scheduled net interchange volume by interface (GWh): January through March, 2012 (See 2011 SOM, Table 8-1)

		Jan	Feb	Mar	Total
CPLE		(52.5)	(29.2)	(27.8)	(109.5)
CPLW		0.0	0.0	0.0	0.0
DUK		98.9	(85.3)	(13.0)	0.6
EKPC		(37.5)	(19.2)	(14.3)	(71.1)
LGEE		357.0	141.4	128.3	626.6
MEC		(468.8)	(446.6)	(430.5)	(1,345.9)
MISO		(368.7)	(141.8)	452.0	(58.5)
	ALTE	(693.8)	(557.5)	(179.2)	(1,430.5)
	ALTW	(49.7)	(22.7)	(4.9)	(77.3)
	AMIL	17.7	39.9	106.3	163.9
	CIN	377.7	179.8	300.2	857.7
	CWLP	0.0	0.0	0.0	0.0
	IPL	(172.2)	(76.5)	27.6	(221.1)
	MECS	378.4	488.4	348.5	1,215.3
	NIPS	(18.4)	(17.4)	14.3	(21.5)
	WEC	(208.4)	(175.8)	(160.7)	(545.0)
NYISO		(1,127.3)	(750.9)	(508.4)	(2,386.6)
	LIND	(63.9)	(6.3)	(64.5)	(134.7)
	NEPT	(415.7)	(329.7)	(288.4)	(1,033.7)
	NYIS	(647.8)	(414.9)	(155.5)	(1,218.2)
OVEC		712.5	693.4	588.3	1,994.1
TVA		783.0	787.2	580.6	2,150.8
Total		(103.4)	149.0	755.1	800.7

Table 8-2 Real-time scheduled gross import volume by interface (GWh): January through March, 2012 (See 2011 SOM, Table 8-2)

		Jan	Feb	Mar	Total
CPLE		0.3	0.0	0.4	0.7
CPLW		0.0	0.0	0.0	0.0
DUK		277.1	168.8	134.8	580.7
EKPC		41.0	31.5	26.7	99.2
LGEE		365.4	147.0	149.7	662.0
MEC		16.9	7.3	0.1	24.3
MISO		1,179.1	1,022.7	1,025.3	3,227.1
	ALTE	1.3	4.8	0.2	6.3
	ALTW	0.0	0.1	0.0	0.1
	AMIL	46.5	78.1	134.2	258.8
	CIN	526.9	330.4	340.5	1,197.8
	CWLP	0.0	0.0	0.0	0.0
	IPL	127.3	88.2	126.3	341.8
	MECS	408.3	520.4	390.7	1,319.4
	NIPS	59.4	0.7	32.5	92.6
	WEC	9.6	0.0	0.9	10.4
NYISO		506.4	678.3	887.4	2,072.1
	LIND	10.7	19.6	12.2	42.6
	NEPT	0.0	0.0	0.0	0.0
	NYIS	495.6	658.7	875.1	2,029.4
OVEC		738.2	716.7	611.5	2,066.5
TVA		802.8	845.0	610.7	2,258.6
Total		3,927.2	3,617.4	3,446.6	10,991.2

Table 8-3 Real-time scheduled gross export volume by interface (GWh): January through March, 2012 (See 2011 SOM, Table 8-3)

		Jan	Feb	Mar	Total
CPLE		52.8	29.2	28.2	110.3
CPLW		0.0	0.0	0.0	0.0
DUK		178.2	254.1	147.7	580.0
EKPC		78.5	50.7	41.1	170.3
LGEE		8.4	5.6	21.4	35.4
MEC		485.7	453.9	430.5	1,370.2
MISO		1,547.8	1,164.5	573.3	3,285.6
	ALTE	695.1	562.3	179.5	1,436.8
	ALTW	49.7	22.8	4.9	77.4
	AMIL	28.7	38.3	28.0	94.9
	CIN	149.2	150.6	40.3	340.0
	CWLP	0.0	0.0	0.0	0.0
	IPL	299.5	164.7	98.7	562.9
	MECS	29.9	32.0	42.2	104.1
	NIPS	77.8	18.1	18.2	114.1
	WEC	218.0	175.8	161.6	555.4
NYISO		1,633.7	1,429.2	1,395.7	4,458.7
	LIND	74.6	26.0	76.7	177.3
	NEPT	415.7	329.7	288.4	1,033.7
	NYIS	1,143.4	1,073.6	1,030.7	3,247.7
OVEC		25.7	23.3	23.3	72.3
TVA		19.8	57.8	30.2	107.8
Total		4,030.6	3,468.4	2,691.5	10,190.5

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 imports or exports will flow.[4] An interface pricing point defines the price at which transactions are priced, and is based on the path of the physical transfer of energy. While a market participant designates a market path based from a generation control area (GCA) to 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 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 a GCA of LGEE, at the SouthIMP interface pricing point.

Interfaces differ from interface pricing points. 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 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. 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.[7] Table 8-14 presents the interface pricing points used in the first three months of 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 only occasionally.

4 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.

5 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed March 1, 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 March 1, 2012)

7 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.

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.

In the Real-Time Energy Market, for the first three months of 2012, there were net exports at nine of PJM's 17 interface pricing points eligible for real-time transactions.[8] The top three net exporting interface pricing points in the Real-Time Energy Market accounted for 85.6 percent of the total net exports: PJM/MISO with 57.1 percent, PJM/NYIS with 15.5 percent and PJM/NEPTUNE (NEPT) with 13.0 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 30.2 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 79.8 percent of the total net imports: PJM/SouthIMP with 57.0 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 22.8 percent of the net import volume.[9]

Table 8-4 Real-time scheduled net interchange volume by interface pricing point (GWh): January through March, 2012 (See 2011 SOM, Table 8-4)

	Jan	Feb	Mar	Total
IMO	479.8	485.2	431.3	1,396.2
LINDENVFT	(63.9)	(6.3)	(64.5)	(134.7)
MISO	(1,992.3)	(1,601.0)	(940.0)	(4,533.3)
NEPTUNE	(415.7)	(329.7)	(288.4)	(1,033.7)
NORTHWEST	(1.6)	(1.5)	(1.2)	(4.3)
NYIS	(648.1)	(415.3)	(166.8)	(1,230.2)
OVEC	712.5	693.4	588.3	1,994.1
SOUTHIMP	2,164.4	1,722.9	1,465.1	5,352.4
CPLEIMP	0.0	0.0	0.4	0.4
DUKIMP	106.7	88.6	56.7	252.0
NCMPAIMP	44.7	44.2	25.2	114.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	2,013.0	1,590.1	1,382.9	4,986.1
SOUTHEXP	(338.5)	(398.7)	(268.6)	(1,005.9)
CPLEEXP	(52.8)	(26.6)	(26.0)	(105.4)
DUKEXP	(172.0)	(233.9)	(141.2)	(547.1)
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHWEST	(1.6)	(1.3)	0.0	(2.8)
SOUTHEXP	(112.1)	(136.9)	(101.4)	(350.5)
Total	(103.4)	149.0	755.1	800.7

8 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).
9 In the Real-Time Market, two PJM interface pricing points had a net interchange of zero (Southwest and NCMPAEXP).

Table 8-5 Real-time scheduled gross import volume by interface pricing point (GWh): January through March, 2012 (See 2011 SOM, Table 8-5)

	Jan	Feb	Mar	Total
IMO	480.4	486.8	434.3	1,401.5
LINDENVFT	10.7	19.6	12.2	42.6
MISO	38.8	14.6	62.0	115.4
NEPTUNE	0.0	0.0	0.0	0.0
NORTHWEST	0.0	0.0	0.0	0.0
NYIS	494.6	656.7	861.4	2,012.8
OVEC	738.2	716.7	611.5	2,066.5
SOUTHIMP	2,164.4	1,722.9	1,465.1	5,352.4
CPLEIMP	0.0	0.0	0.4	0.4
DUKIMP	106.7	88.6	56.7	252.0
NCMPAIMP	44.7	44.2	25.2	114.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	2,013.0	1,590.1	1,382.9	4,986.1
SOUTHEXP	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0
Total	3,927.2	3,617.4	3,446.6	10,991.2

Table 8-6 Real-time scheduled gross export volume by interface pricing point (GWh): January through March, 2012 (See 2011 SOM, Table 8-6)

	Jan	Feb	Mar	Total
IMO	0.7	1.6	3.1	5.4
LINDENVFT	74.6	26.0	76.7	177.3
MISO	2,031.1	1,615.6	1,002.0	4,648.7
NEPTUNE	415.7	329.7	288.4	1,033.7
NORTHWEST	1.6	1.5	1.2	4.3
NYIS	1,142.8	1,072.0	1,028.2	3,243.0
OVEC	25.7	23.3	23.3	72.3
SOUTHIMP	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0
SOUTHEXP	338.5	398.7	268.6	1,005.9
CPLEEXP	52.8	26.6	26.0	105.4
DUKEXP	172.0	233.9	141.2	547.1
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHWEST	1.6	1.3	0.0	2.8
SOUTHEXP	112.1	136.9	101.4	350.5
Total	4,030.6	3,468.4	2,691.5	10,190.5

Day-Ahead Interface Imports and Exports

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.[10] 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.

10 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.

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 below, the import transaction would appear as scheduled through the MISO Interface, and in the interface pricing point tables, the import transaction would appear as scheduled through the SouthIMP/EXP Interface Pricing Point, which reflects the expected power flow. 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 three months of 2012 in Table 8-7, while gross imports and exports are shown in Table 8-8 and Table 8-9.

In the Day-Ahead Energy Market, for the first three months of 2012, there were net exports at 13 of PJM's 20 interfaces. The top three net exporting interfaces accounted for 59.4 percent of the total net exports: PJM/Tennessee Valley Authority (TVA) with 26.4 percent, PJM/Easter Allient Energy Corporation (ALTE) with 17.6 percent and PJM/MidAmerican Energy Company (MEC) with 15.4 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 17.5 percent of the total net PJM exports in the Day-Ahead Energy Market. Seven PJM interfaces had net imports in the Day-Ahead Energy Market, with three interfaces accounting for 89.4 percent of the total net imports: PJM/OVEC with 45.8 percent, PJM/Cinergy Corporation (CIN) with 31.6 percent and PJM/Wisconsin Energy Corporation (WEC) with 12.0 percent.

Table 8-7 Day-Ahead scheduled net interchange volume by interface (GWh): January through March, 2012 (See 2011 SOM, Table 8-7)

	Jan	Feb	Mar	Total
CPLE	(9.6)	17.0	20.1	27.6
CPLW	(6.3)	(37.9)	(67.2)	(111.4)
DUK	38.8	18.0	31.4	88.1
EKPC	(39.0)	(36.5)	(39.7)	(115.2)
LGEE	(4.4)	(63.5)	(36.7)	(104.6)
MEC	(537.1)	(511.3)	(478.1)	(1,526.6)
MISO	(752.9)	407.1	151.5	(194.3)
ALTE	(921.0)	(594.9)	(228.0)	(1,743.9)
ALTW	(294.3)	(316.0)	(336.5)	(946.8)
AMIL	33.8	13.1	33.3	80.2
CIN	323.2	725.8	1,056.2	2,105.2
CWLP	(0.1)	0.0	0.0	(0.1)
IPL	(371.7)	(316.9)	(214.5)	(903.1)
MECS	217.0	568.0	(274.6)	510.5
NIPS	28.6	11.4	(137.9)	(97.9)
WEC	231.7	316.5	253.5	801.6
NYISO	(981.5)	(503.0)	(247.7)	(1,732.3)
LIND	(35.8)	(6.3)	(44.2)	(86.3)
NEPT	(425.2)	(355.9)	(314.5)	(1,095.5)
NYIS	(520.5)	(140.9)	111.0	(550.4)
OVEC	1,186.9	535.4	1,333.3	3,055.7
TVA	(742.4)	(770.7)	(1,098.6)	(2,611.7)
Total	(1,847.5)	(945.4)	(431.7)	(3,224.6)

Table 8-8 Day-Ahead scheduled gross import volume by interface (GWh): January through March, 2012 (See 2011 SOM, Table 8-8)

	Jan	Feb	Mar	Total
CPLE	37.2	36.9	45.0	119.2
CPLW	22.0	27.4	34.6	84.0
DUK	54.7	51.8	47.7	154.2
EKPC	0.2	0.5	0.8	1.5
LGEE	56.0	4.4	11.7	72.0
MEC	189.3	126.6	202.6	518.6
MISO	9,151.4	9,200.8	8,689.6	27,041.7
ALTE	4,127.5	4,316.8	3,727.0	12,171.3
ALTW	21.1	46.7	66.3	134.1
AMIL	37.9	14.3	34.1	86.4
CIN	897.1	908.7	1,475.1	3,280.9
CWLP	0.0	0.0	0.0	0.0
IPL	19.3	17.9	15.7	52.9
MECS	3,191.6	2,857.0	2,455.8	8,504.3
NIPS	108.7	165.8	118.1	392.6
WEC	748.1	873.5	797.6	2,419.2
NYISO	1,245.5	1,440.8	1,684.0	4,370.3
LIND	1.8	5.2	5.6	12.6
NEPT	0.0	0.0	0.0	0.0
NYIS	1,243.7	1,435.6	1,678.4	4,357.7
OVEC	3,918.9	3,168.0	3,803.0	10,889.9
TVA	512.3	596.1	584.4	1,692.8
Total	15,187.4	14,653.3	15,103.4	44,944.1

Table 8-9 Day-Ahead scheduled gross export volume by interface (GWh): January through March, 2012 (See 2011 SOM, Table 8-9)

	Jan	Feb	Mar	Total
CPLE	46.8	19.9	24.9	91.6
CPLW	28.2	65.3	101.9	195.4
DUK	16.0	33.8	16.3	66.1
EKPC	39.2	37.1	40.4	116.7
LGEE	60.4	67.8	48.4	176.6
MEC	726.4	638.0	680.7	2,045.1
MISO	9,904.2	8,793.7	8,538.1	27,236.0
ALTE	5,048.5	4,911.7	3,955.0	13,915.2
ALTW	315.5	362.7	402.7	1,080.9
AMIL	4.1	1.3	0.8	6.2
CIN	573.9	182.9	418.9	1,175.7
CWLP	0.1	0.0	0.0	0.1
IPL	391.0	334.8	230.2	956.0
MECS	2,974.5	2,288.9	2,730.4	7,993.8
NIPS	80.1	154.4	255.9	490.5
WEC	516.4	557.1	544.1	1,617.6
NYISO	2,227.0	1,943.8	1,931.7	6,102.5
LIND	37.6	11.5	49.8	98.9
NEPT	425.2	355.9	314.5	1,095.5
NYIS	1,764.2	1,576.5	1,567.4	4,908.1
OVEC	2,731.9	2,632.6	2,469.7	7,834.2
TVA	1,254.7	1,366.8	1,682.9	4,304.5
Total	17,034.9	15,598.7	15,535.1	48,168.8

Day-Ahead Interface Pricing Point Imports and Exports

Table 8-10 through Table 8-12 show the Day-Ahead Market interchange totals at the individual interface pricing points, including those pricing points that make up the southern region. Net interchange in the Day-Ahead Market is shown by interface pricing point for the first three months of 2012 in Table 8-10, while gross imports and exports are shown in Table 8-11 and Table 8-12.

In the Day-Ahead Energy Market, for the first three months of 2012, there were net exports at eleven 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 67.4 percent of the total net exports: PJM/SouthEXP with 35.0 percent, PJM/Southwest with 18.5 percent and PJM/NEPTUNE (NEPT) with 13.9 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 14.0 percent of the total net PJM exports in the Real-Time Energy Market (PJM/NEPTUNE with 13.9 percent and PJM/LINDEN with 0.1 percent. The PJM/NYIS interface pricing point had net imports in the Day-Ahead Energy Market). Eight PJM interface pricing points had net imports, with two importing interface pricing points accounting for 50.8 percent of the total net imports: PJM/MISO with 25.6 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 25.2 percent of the net import volume.

Table 8-10 Day-Ahead scheduled net interchange volume by interface pricing point (GWh): January through March, 2012 (See 2011 SOM, Table 8-10)

	Jan	Feb	Mar	Total
IMO	(1,019.1)	(410.0)	(868.4)	(2,297.5)
LINDENVFT	9.2	(51.2)	23.5	(18.5)
MISO	1,268.5	1,277.6	1,419.8	3,965.9
NEPTUNE	(891.7)	(837.7)	(870.3)	(2,599.7)
NIPSCO	(47.9)	(33.1)	(630.3)	(711.4)
NORTHWEST	(524.9)	(353.4)	(499.9)	(1,378.1)
NYIS	(35.0)	300.8	573.1	838.9
OVEC	1,236.4	779.2	1,898.6	3,914.3
SOUTHIMP	2,041.5	2,471.4	2,283.8	6,796.8
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	3.9	12.2	3.5	19.6
NCMPAIMP	0.2	0.0	0.0	0.2
SOUTHEAST	552.6	756.9	613.5	1,923.0
SOUTHWEST	707.2	900.6	815.6	2,423.4
SOUTHIMP	777.6	801.7	851.2	2,430.6
SOUTHEXP	(3,884.4)	(4,089.1)	(3,761.8)	(11,735.3)
CPLEEXP	(46.7)	(19.8)	(24.9)	(91.4)
DUKEXP	(1.8)	(27.4)	(13.0)	(42.2)
NCMPAEXP	(0.1)	(0.1)	0.0	(0.2)
SOUTHEAST	(530.7)	(546.3)	(488.7)	(1,565.6)
SOUTHWEST	(1,146.0)	(1,425.1)	(912.1)	(3,483.2)
SOUTHEXP	(2,159.1)	(2,070.5)	(2,323.0)	(6,552.6)
Total	(1,847.5)	(945.4)	(431.7)	(3,224.6)

Table 8-11 Day-Ahead scheduled gross import volume by interface pricing point (GWh): January through March, 2012 (See 2011 SOM, Table 8-11)

	Jan	Feb	Mar	Total
IMO	545.7	587.1	505.6	1,638.5
LINDENVFT	350.2	372.2	459.9	1,182.3
MISO	4,021.4	3,236.4	3,339.4	10,597.3
NEPTUNE	0.0	0.0	0.0	0.0
NIPSCO	456.4	514.0	364.9	1,335.3
NORTHWEST	769.8	664.5	502.0	1,936.3
NYIS	1,592.7	1,890.4	2,212.4	5,695.6
OVEC	5,409.6	4,917.3	5,435.3	15,762.1
SOUTHIMP	2,041.5	2,471.4	2,283.8	6,796.8
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	3.9	12.2	3.5	19.6
NCMPAIMP	0.2	0.0	0.0	0.2
SOUTHEAST	552.6	756.9	613.5	1,923.0
SOUTHWEST	707.2	900.6	815.6	2,423.4
SOUTHIMP	777.6	801.7	851.2	2,430.6
SOUTHEXP	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0
Total	15,187.4	14,653.3	15,103.4	44,944.1

Table 8-12 Day-Ahead scheduled gross export volume by interface pricing point (GWh): January through March, 2012 (See 2011 SOM, Table 8-12)

	Jan	Feb	Mar	Total
IMO	1,564.8	997.1	1,374.0	3,935.9
LINDENVFT	341.0	423.5	436.3	1,200.8
MISO	2,753.0	1,958.8	1,919.6	6,631.4
NEPTUNE	891.7	837.7	870.3	2,599.7
NIPSCO	504.3	547.1	995.3	2,046.7
NORTHWEST	1,294.7	1,017.9	1,001.9	3,314.5
NYIS	1,627.7	1,589.6	1,639.4	4,856.7
OVEC	4,173.2	4,138.0	3,536.6	11,847.8
SOUTHIMP	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0
SOUTHEXP	3,884.4	4,089.1	3,761.8	11,735.3
CPLEEXP	46.7	19.8	24.9	91.4
DUKEXP	1.8	27.4	13.0	42.2
NCMPAEXP	0.1	0.1	0.0	0.2
SOUTHEAST	530.7	546.3	488.7	1,565.6
SOUTHWEST	1,146.0	1,425.1	912.1	3,483.2
SOUTHEXP	2,159.1	2,070.5	2,323.0	6,552.6
Total	17,034.9	15,598.7	15,535.1	48,168.8

Table 8-13 Active interfaces: January through March, 2012 (See 2011 SOM, Table 8-13)

	Jan	Feb	Mar
ALTE	Active	Active	Active
ALTW	Active	Active	Active
AMIL	Active	Active	Active
CIN	Active	Active	Active
CPLE	Active	Active	Active
CPLW	Active	Active	Active
CWLP	Active	Active	Active
DUK	Active	Active	Active
EKPC	Active	Active	Active
IPL	Active	Active	Active
LGEE	Active	Active	Active
LIND	Active	Active	Active
MEC	Active	Active	Active
MECS	Active	Active	Active
NEPT	Active	Active	Active
NIPS	Active	Active	Active
NYIS	Active	Active	Active
OVEC	Active	Active	Active
TVA	Active	Active	Active
WEC	Active	Active	Active

Figure 8-3 PJM's footprint and its external interfaces (See 2011 SOM, Figure 8-3)

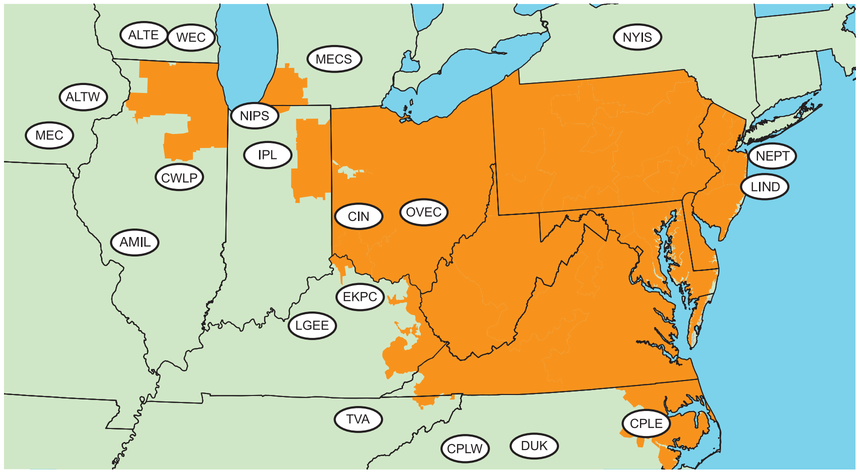


Table 8-14 Active pricing points: January through March, 2012 (See 2011 SOM, Table 8-14)

	Jan	Feb	Mar
CPLEEXP	Active	Active	Active
CPLEIMP	Active	Active	Active
DUKEXP	Active	Active	Active
DUKIMP	Active	Active	Active
LIND	Active	Active	Active
MISO	Active	Active	Active
NCMPAEXP	Active	Active	Active
NCMPAIMP	Active	Active	Active
NEPT	Active	Active	Active
NIPSCO	Active	Active	Active
Northwest	Active	Active	Active
NYIS	Active	Active	Active
Ontario IESO	Active	Active	Active
OVEC	Active	Active	Active
SOUTHEXP	Active	Active	Active
SOUTHIMP	Active	Active	Active

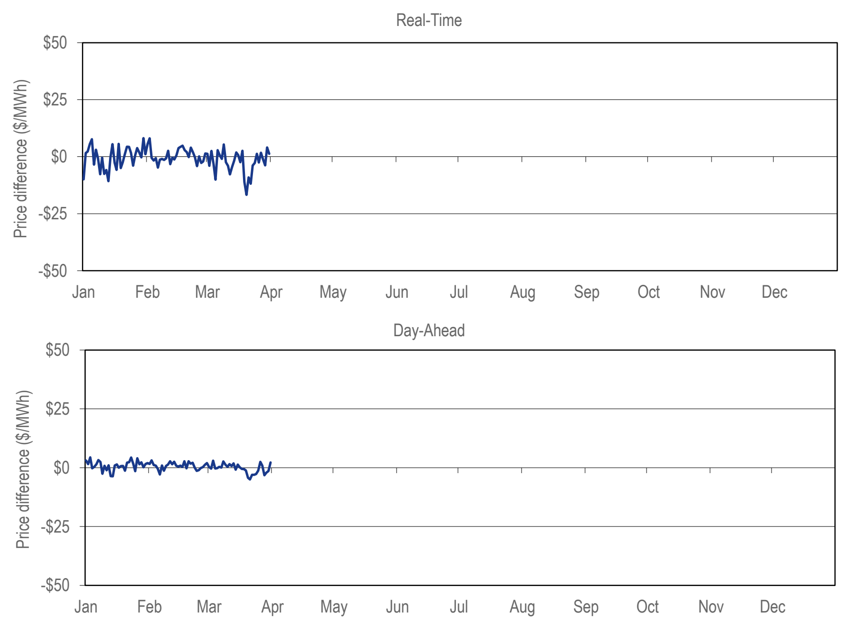
PJM and MISO Interface Prices

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 ensure that the prices are consistent with the underlying electrical flows. PJM uses the LMP at nine buses[11] 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.[12]

Real-Time and Day-Ahead Prices

In the first three months of 2012, the average price difference between the PJM/MISO Interface and the MISO/PJM Interface was inconsistent with the direction of the average flow. In the first three months of 2012, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $25.27 while the MISO LMP at the border was $24.47, a difference of $0.80. The average hourly flow during the first three months of 2012 was -1,776 MW. (The negative sign means that the flow was an export from PJM to MISO, which is inconsistent with the fact that the average MISO price was higher than the average PJM price.) However, the direction of flows was consistent with price differentials in only 42 percent of hours during the first three months of 2012.

Figure 8-4 Real-time and day-ahead daily hourly average price difference (MISO Interface minus PJM/MISO): January through March, 2012 (See 2011 SOM, Figure 8-4)



11 See "LMP Aggregate Definitions" (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed March 1, 2012). PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.

12 Based on information obtained from MISO's Extranet <http://extranet.midwestiso.org> (January 15, 2010).

Distribution of Economic and Uneconomic Hourly Flows

During the first three months of 2012, the direction of energy flow was consistent with PJM and MISO Interface Price differentials in 912 hours (42 percent of all hours), and were inconsistent with price differentials in 1,271 hours (58 percent). Table 15 shows the distribution of economic and uneconomic hours of energy flow between PJM and MISO based on the price differentials of the PJM and MISO Interface Prices. Of the 1,271 hours where flows were uneconomic, 1,038 of those hours (81.7 percent) had a price difference greater than or equal to $1.00 and 330 of all uneconomic hours (26.0 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $142.58. Of the 912 hours where flows were economic, 729 of those hours (79.9 percent) had a price difference greater than or equal to $1.00 and 353 of all economic hours (38.7 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $113.33.

Table 8-15 Distribution of economic and uneconomic hourly flows between PJM and MISO: January through March, 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	1,271	100.0%	912	100.0%
$1.00	1,038	81.7%	729	79.9%
$5.00	330	26.0%	353	38.7%
$10.00	138	10.9%	189	20.7%
$15.00	84	6.6%	109	12.0%
$20.00	58	4.6%	92	10.1%
$25.00	45	3.5%	74	8.1%
$50.00	15	1.2%	19	2.1%
$75.00	3	0.2%	4	0.4%
$100.00	2	0.2%	1	0.1%
$200.00	0	0.0%	0	0.0%
$300.00	0	0.0%	0	0.0%
$400.00	0	0.0%	0	0.0%
$500.00	0	0.0%	0	0.0%

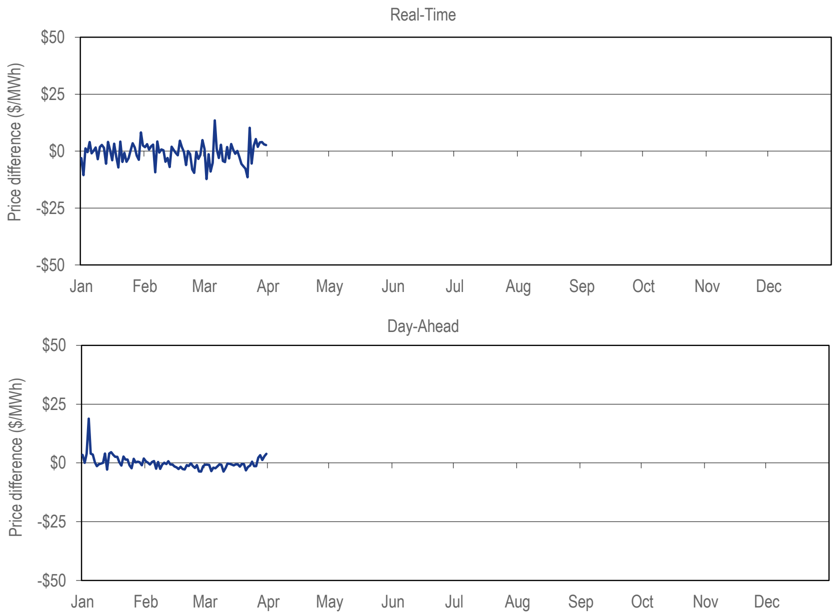
PJM and NYISO Interface Prices

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.

Real-Time and Day-Ahead Prices

In the first three months of 2012, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. In the first three months of 2012, the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus was inconsistent with the direction of the average flow. In the first three months of 2012, the PJM average hourly LMP at the PJM/NYISO border was $30.53 while the NYISO LMP at the border was $29.74, a difference of $0.79. The average hourly flow during the first three months of 2012 was -563 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is inconsistent with the fact that the average PJM price was higher than the average NYISO price.) However, the direction of flows was consistent with price differentials in only 51 percent of the hours during the first three months of 2012.

Figure 8-5 Real-time and day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): January through March, 2012 (See 2011 SOM, Figure 8-5)



Distribution of Economic and Uneconomic Hourly Flows

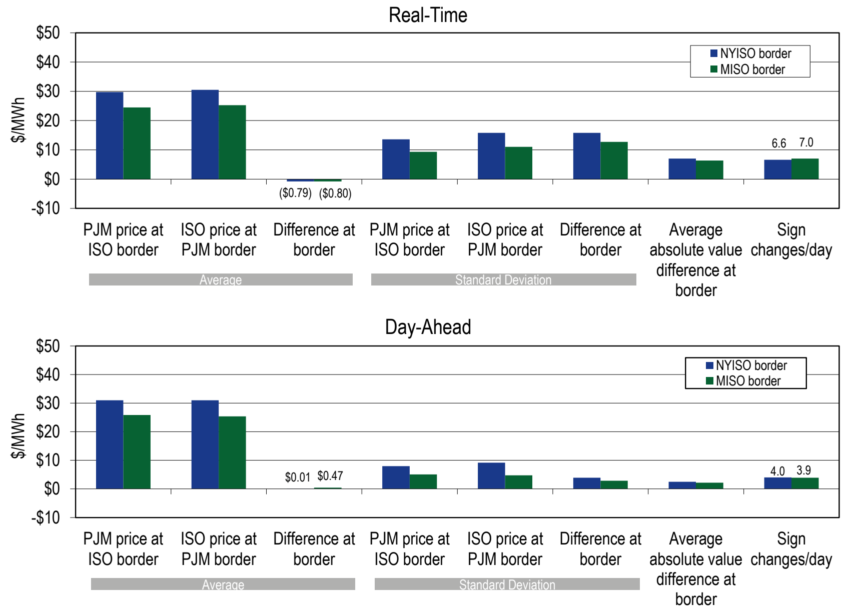
During the first three months of 2012, the direction of energy flow was consistent with PJM and NYIS Interface Price differentials in 1,103 hours (51 percent) of all hours, and were inconsistent with price diffeentials in 1,080 hours (49 percent). Table 8-16 shows the distribution of economic and uneconomic hours of energy flow between PJM and NYISO based on the price differentials of the PJM and NYISO Interface Prices. Of the 1,080 hours where flows were uneconomic, 920 of those hours (85.2 percent) had a price difference greater than or equal to $1.00 and 421 of all uneconomic hours (39.0 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $168.38. Of the 1,103 hours where flows were economic, 926 of those hours (84.0 percent) had a price difference greater than or equal to $1.00 and 349 of all economic hours (31.6 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $235.36.

Table 8-16 Distribution of economic and uneconomic hourly flows between PJM and NYISO: January through March, 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	1,080	100.0%	1,103	100.0%
$1.00	920	85.2%	926	84.0%
$5.00	421	39.0%	349	31.6%
$10.00	202	18.7%	145	13.1%
$15.00	131	12.1%	79	7.2%
$20.00	83	7.7%	61	5.5%
$25.00	57	5.3%	43	3.9%
$50.00	25	2.3%	18	1.6%
$75.00	10	0.9%	8	0.7%
$100.00	4	0.4%	4	0.4%
$200.00	0	0.0%	2	0.2%
$300.00	0	0.0%	0	0.0%
$400.00	0	0.0%	0	0.0%
$500.00	0	0.0%	0	0.0%

Summary of Interface Prices between PJM and Organized Markets

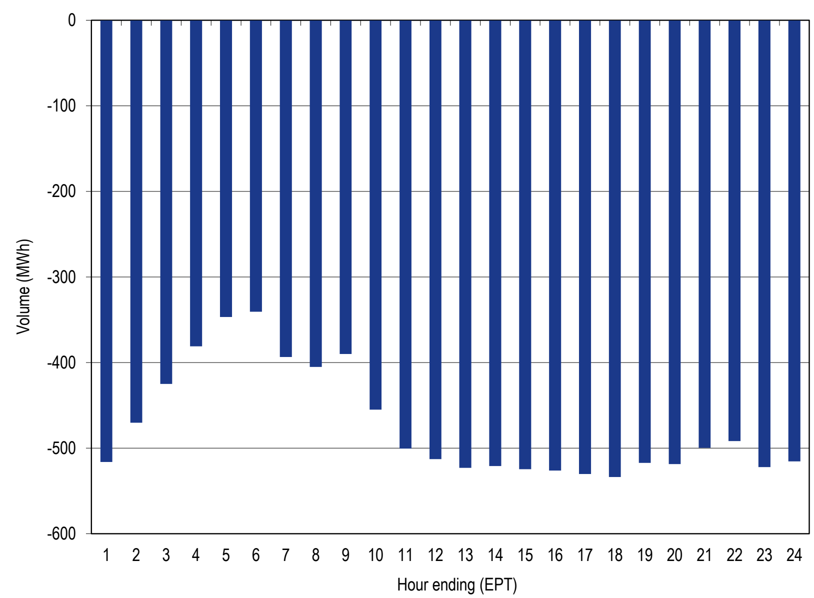
Figure 8-6 PJM, NYISO and MISO real-time and day-ahead border price averages: January through March, 2012 (See 2011 SOM, Figure 8-6)



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). The line is bidirectional, but Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. In the first three months of 2012, the average difference between the PJM/Neptune price and the NYISO/Neptune price was inconsistent with the direction of the average flow. In the first three months of 2012, the PJM average hourly LMP at the Neptune Interface was $30.98 while the NYISO LMP at the Neptune Bus was $35.54, a difference of $4.56. The average hourly flow during the first three months of 2012 was -474 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is inconsistent with the fact that the average PJM price was higher than the average Neptune price.) However, the direction of flows was consistent with price differentials in only 57 percent of the hours during the first three months of 2012.

Figure 8-7 Neptune hourly average flow: January through March, 2012 (See 2011 SOM, Figure 8-7)

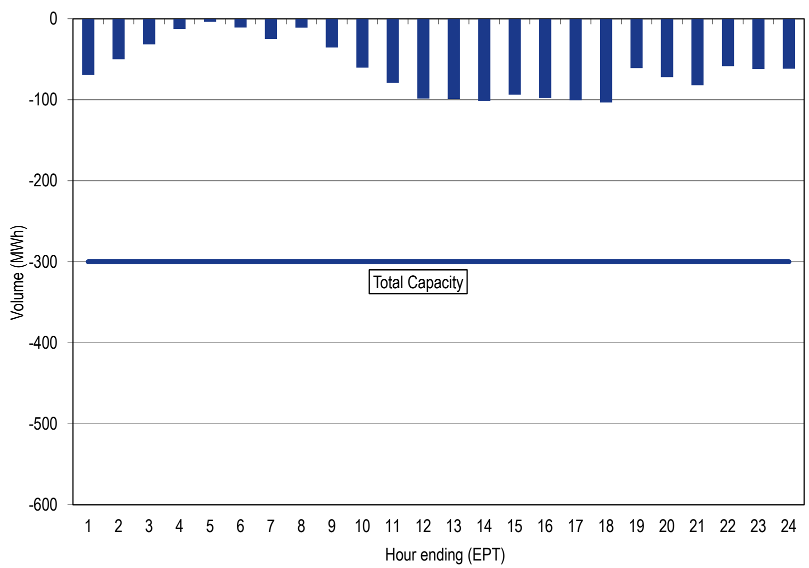


Linden Variable Frequency Transformer (VFT) facility

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 three months of 2012, the average price difference between the PJM/Linden price and the NYISO/Linden price was consistent with the direction of the average flow. In the first three months of 2012, the PJM average hourly

LMP at the Linden Interface was $31.04 while the NYISO LMP at the Linden Bus was $32.99, a difference of $1.95. The average hourly flow during the first three months of 2012 was -62 MW. (The negative sign means that the flow was an export from PJM to NYISO.) However, the direction of flows was consistent with price differentials in only 58 percent of the hours during the first three months of 2012.

Figure 8-8 Linden hourly average flow: January through March, 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[13]

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.

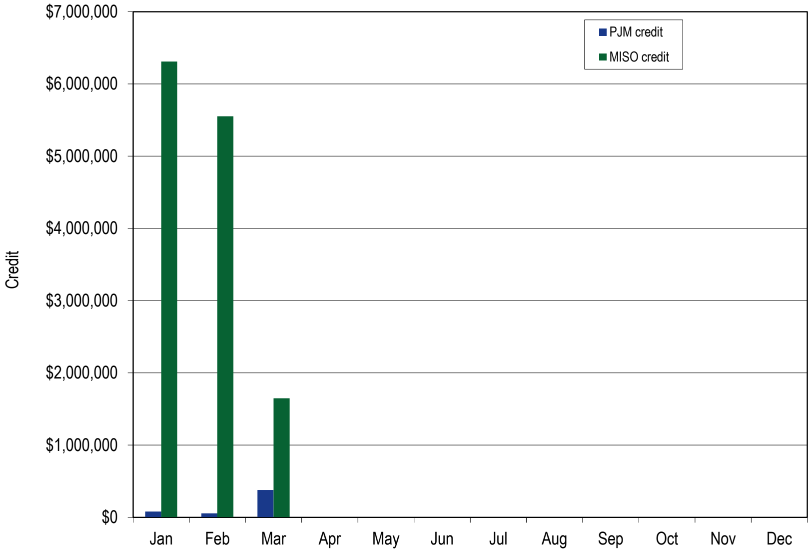
In 2011, PJM and MISO hired an independent auditor to review and identify any areas of the market to market coordination process that were not conforming to the JOA, and to identify differing interpretations of the JOA between PJM and MISO that may lead to inconsistencies in the operation and settlements 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.[14] The report also provided some potential areas of improvement including improved internal documentation, enhanced transparency, an increase of knowledge sharing and data exchange and an increase in attention to modeling differences.

In the first three 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.

13 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 March 1, 2012)

14 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 April 16, 2012)

Figure 8-9 Credits for coordinated congestion management: January through March, 2012 (See 2011 SOM, Figure 8-9)



PJM and New York Independent System Operator Joint Operating Agreement (JOA)[15]

On May 22, 2007, the PJM/NYISO JOA became effective. This agreement was developed to improve reliability. It also 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.[16] On December 30, 2011, PJM and the NYISO filed JOA revisions with FERC that included a draft market to market process.[17] 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.[18] 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.

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.[19] 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.

After years of litigation concerning whether or on what terms Con Edison's protocol would be renewed, PJM filed on February 23, 2009 a settlement on behalf of the parties to subsequent proceedings to resolve remaining issues with these contracts and their proposed rollover of the agreements under the PJM OATT.[20] By order issued September 16, 2010, the Commission approved this settlement,[21] which extends Con Edison's special protocol indefinitely. The Commission rejected objections raised first by NRG and FERC trial staff, and

15 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 March 1, 2012)

16 See the *2010 State of the Market Report*, Volume II, "Interchange Transactions," for the relevant history.

17 See "Jointly Submitted Market-to Market Coordination Compliance Filing," Docket No. ER12-718-000- (December 30,2011).

18 See "Second Jointly Submitted Market-to Market Coordination Compliance Filing," Docket No. ER12-718-000- (May 1, 2012).

19 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.

20 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.

21 132 FERC ¶ 61,221 (2010).

later by the MMU that this arrangement is discriminatory and inconsistent with the Commission's open access transmission policy.[22]

Table 8-17 Con Edison and PSE&G wheeling settlement data: January through March, 2012 (See 2011 SOM, Table 8-15)

	Con Edison			PSE&G		
Billing Line Item	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	$285,069	($299)	$284,771	$543,866	$0	$543,866
Congestion Credit			$87,953			$458,087
Adjustments			$87			($2,911)
Net Charge			$196,731			$88,690

Interchange Transaction Issues

Loop Flows

Actual flows are the metered flows at an interface for a defined period. Scheduled flows are the flows scheduled at an interface for a defined period. Inadvertent interchange is the difference between the total actual flows for the PJM system (net actual interchange) and the total scheduled flows for the PJM system (net scheduled interchange) for a defined period. Loop flows are defined as the difference between actual and scheduled power flows at one or more specific interfaces. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface. The result is loop flow, despite the fact that system actual and scheduled flow could net to a zero difference.

If PJM net actual interface flows were close to net scheduled interface flows, on average for the first three months of 2012, it would not necessarily mean that there was no loop flow. Loop flows are measured at individual interfaces. There can be no difference between scheduled and actual flows for PJM and still be significant differences between scheduled and actual flows for specific individual interfaces. From an operating perspective, PJM tries to balance overall actual and scheduled interchange, but does not have a mechanism to control the balance between actual and scheduled interchange at individual interfaces because there are free flowing ties with contiguous balancing authorities.

Table 8-18 Net scheduled and actual PJM flows by interface (GWh): January through March, 2012 (See 2011 SOM, Table 8-16)

Interface	Actual	Net Scheduled	Difference (GWh)
CPLE	2,078	(232)	2,310
CPLW	(253)	-	(253)
DUK	40	1	39
EKPC	573	(19)	592
LGEE	420	627	(207)
MEC	(680)	(1,344)	663
MISO	(3,878)	(121)	(3,756)
ALTE	(1,827)	(1,431)	(397)
ALTW	(760)	(77)	(683)
AMIL	3,225	143	3,082
CIN	(1,749)	857	(2,606)
CWLP	(105)	-	(105)
IPL	(163)	(262)	99
MECS	(1,750)	1,215	(2,966)
NIPS	(1,996)	(22)	(1,975)
WEC	1,249	(545)	1,794
NYISO	(2,398)	(2,455)	57
LIND	(135)	(135)	-
NEPT	(1,034)	(1,034)	-
NYIS	(1,230)	(1,286)	57
OVEC	2,719	1,994	725
TVA	1,489	1,860	(371)
Total	110	310	(200)

Every 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

22 *See, e.g.*, Motion to Intervene Out-of-Time and Comments of the Independent Market Monitor for PJM in Docket No. ER08-858-000, et al. (May 11, 2010). The MMU questioned whether allowing rollover is appropriate and raised concerns that continuing these agreements could interfere with the efficient management of the NYISO/PJM seam, accord preferential access to transmission service and limit security constrained least cost dispatch. The MMU questioned whether a valid offsetting reliability consideration had been identified and explained. The MMU noted, "the settling parties fail to demonstrate any circumstances that may now exist warranting a non-conforming agreement under the current approach to seams management, nor do they attempt to explain how such circumstances would continue to exist under the reforms to be implemented through the Broader Regional Markets Initiative." Additionally, that MMU argued, "the settling parties have failed to show that continuation of the grandfathered transmission service agreements will neither interfere with the efficient calculation of LMPs in both PJM and the NYISO, and at their interface, nor harm the ability of parties to efficiently transact business."

price.[23] 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 8-19 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 Interafce Pricing Points.

Because the SouthIMP and SouthEXP Interface Pricing Points are virtually the same point, if there are actual net exports from the PJM footprint to the southern region, by default, there will not be actual flows on the SouthIMP Interface Pricing Point. Conversely, if there are actual net imports into the PJM footprint from the southern region, there will not be actual flows on the SouthEXP interface pricing point. However, when analyzing the interface pricing points that make up the southern region, comparing the net scheduled and net actual flows from the aggregate pricing points provides some insight on how effective the interface pricing point mappings are.

The IMO Interface Pricing Point 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 one-to-one mapping could not be created. PJM created the IMO Interface Pricing Point that reflects the power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO Interface Pricing Point does not have physical ties with PJM. As a result, actual flows associated with the IMO Interface Pricing Point are zero. The actual flows between IMO and PJM are included in the actual flows at the MISO and NYISO interface pricing points.

23 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)

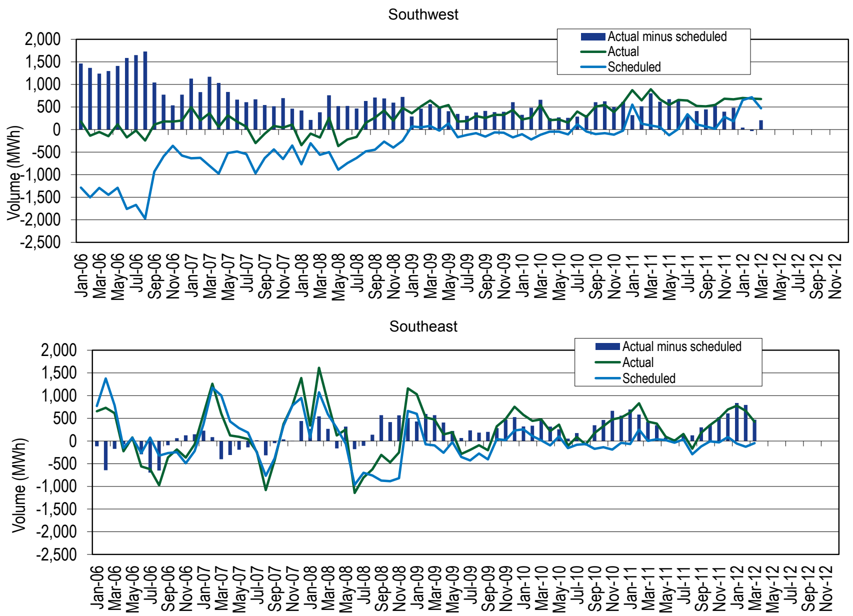
Table 8-19 Net scheduled and actual PJM flows by interface pricing point (GWh): January through March, 2012 (See 2011 SOM, Table 8-17)

Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
IMO	0	1,396	(1,396)
LINDENVFT	(135)	(135)	0
MISO	(3,304)	(4,544)	1,240
NEPTUNE	(1,034)	(1,034)	0
NORTHWEST	(680)	(2)	(678)
NYIS	(1,230)	(1,298)	69
OVEC	2,719	1,994	725
SOUTHIMP	3,773	4,939	(1,165)
CPLEIMP	0	0	(0)
DUKIMP	0	252	(252)
NCMPAIMP	0	114	(114)
SOUTHWEST	0	0	0
SOUTHIMP	3,773	4,572	(799)
SOUTHEXP	0	(1,006)	1,006
CPLEEXP	0	(105)	105
DUKEXP	0	(547)	547
NCMPAEXP	0	0	0
SOUTHWEST	0	(3)	3
SOUTHEXP	0	(350)	350
Total	110	310	(200)

Loop Flows at PJM's Southern Interfaces

Figure 8-10 illustrates the reduction in the previously persistent difference between scheduled and actual power flows at PJM's southern interfaces (PJM/TVA and PJM/EKPC to the west and PJM/CPLE, PJM/CPLW and PJM/DUK to the east) that grew to its largest volumes through the summer of 2006. A portion of the historic loop flows were the result of the fact that the interface pricing points (Southeast and Southwest) allowed the opportunity for market participants to falsely arbitrage pricing differentials, creating a mismatch between actual and scheduled flows. On October 1, 2006, PJM modified the southern interface pricing points by creating a single import pricing point (SouthIMP) and a single export interface pricing point (SouthEXP).

Figure 8-10 Southwest and southeast actual and scheduled flows: January, 2006 through March, 2012 (See 2011 SOM, Figure 8-10)



PJM Transmission Loading Relief Procedures (TLRs)

In the first three months of 2012, PJM issued 6 TLRs of level 3a or higher, compared to 13 for the first three months of 2011. Of the 6 TLRs issued, 4 events were TLR level 3a, and the remaining 2 events were TLR level 3b. TLRs are used to control congestion on the transmission system when it cannot be controlled via market forces.

Table 8-20 PJM and MISO TLR procedures: January, 2010 through March, 2012[24] (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

24 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>.

Table 8-21 Number of TLRs by TLR level by reliability coordinator: January through March, 2012 (See 2011 SOM, Table 8-18)

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2012	ICTE	6	2	2	8	10	0	28
	MISO	17	3	0	2	4	0	26
	NYIS	31	0	0	0	0	0	31
	ONT	15	1	0	0	0	0	16
	PJM	4	2	0	0	0	0	6
	SWPP	74	50	1	10	5	0	140
	TVA	20	18	7	0	0	0	45
	VACS	1	0	0	0	0	0	1
Total		168	76	10	20	19	0	293

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 specified on the OASIS reservation looks like a DEC bid. For export transactions, the specified source on the OASIS reservation 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. Additionally, effective September 17, 2010, up-to congestion transactions are no longer required to pay for transmission, which, prior to that time, was the only cost of submitting an up-to congestion transaction not incurred by a matched pair of INC offers and DEC bids, other than PJM administrative charges.

Following the elimination of the requirement to procure transmission for up-to congestion transactions in 2010, the volume of transactions significantly increased. The average number of up-to congestion bids that had approved MWh in the Day-Ahead Market increased to 50,305 bids per day, with an average cleared volume of 884,020 MWh per day, in the first three months of 2012, compared to an average of 20,753 bids per day, with an average cleared volume of 423,077 MWh per day, for the the first three months of 2011.

Figure 8-11 Monthly up-to congestion cleared bids in MWh: January, 2006 through March, 2012 (See 2011 SOM, Figure 8-11)

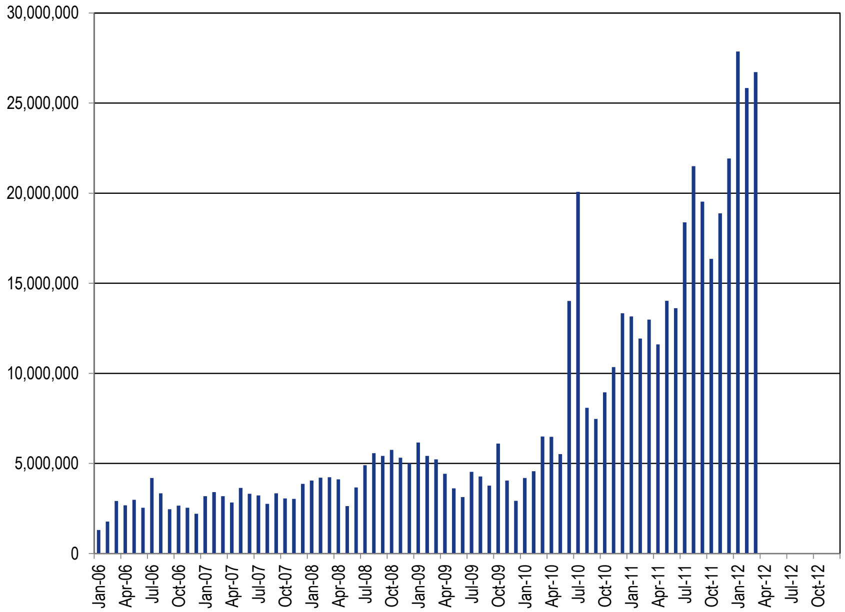


Figure 8-12 Total settlements showing positive, negative and net gains for up-to congestion bids with a matching Real-Time Energy Market transaction (physical) and without a matching Real-Time Energy Market transaction (financial): January through March, 2012 (See 2011 SOM, Figure 8-12)

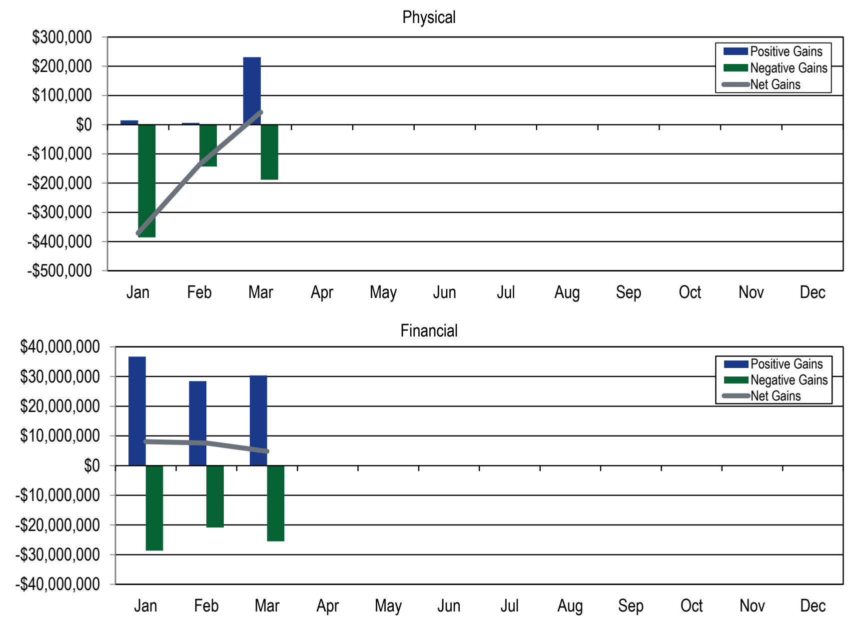


Table 8-22 Monthly volume of cleared and submitted up-to congestion bids: January, 2009 through March, 2012 (See 2011 SOM, Table 8-20)

	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	38,944,873	37,006,724	503,224	76,454,821	746,076	691,873	12,702	1,450,651	13,629,676	14,149,243	98,370	27,877,288	289,814	305,070	3,790	598,674
Feb-12	37,241,552	36,801,215	248,813	74,291,580	739,421	726,346	6,482	1,472,249	12,889,962	12,907,675	45,995	25,843,632	299,159	276,636	1,998	577,793
Mar-12	38,834,123	39,165,771	285,530	78,285,424	803,126	843,024	8,661	1,654,811	13,334,937	13,306,764	83,218	26,724,918	320,301	320,267	2,925	643,493
TOTAL	516,370,951	465,207,832	23,241,663	1,004,820,445	10,907,007	8,797,650	323,842	20,028,499	223,929,177	203,891,027	14,129,702	441,949,905	5,002,106	4,017,582	175,153	9,194,841

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.[25] Table 8-23 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. Some market participants complained that their interests were harmed by PJM's consolidation of the southeast and southwest interface pricing points.

Table 8-23 Real-time average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: January through March, 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	$53.10	$44.81	$48.12	$46.15	$4.98	($3.31)	$6.95	($1.34)
2008	$60.33	$52.96	$55.85	$55.74	$4.48	($2.89)	$4.59	($2.78)
2009	$45.76	$38.72	$41.17	$41.17	$4.60	($2.44)	$4.60	($2.44)
2010	$44.57	$37.19	$40.33	$39.74	$4.25	($3.13)	$4.83	($2.55)
2011	$42.19	$36.24	$38.71	$38.71	$3.47	($2.47)	$3.47	($2.47)
2012	$29.80	$27.96	$28.81	$28.81	$0.99	($0.85)	$0.99	($0.85)

PJM subsequently entered into confidential bilateral locational interface pricing agreements with three companies affected by the revised interface pricing point that provided more advantageous pricing to these companies than the applicable interface pricing rules. The three companies involved and the effective date of their agreements are: Duke Energy Carolinas, January 5, 2007;[26] Progress Energy Carolinas, February 13, 2007;[27] and North Carolina Municipal Power Agency (NCMPA), March 19, 2007.[28]

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.[29] [30] On January 20, 2011, the Commission issued an Order conditionally accepting the compliance filing submitted by PJM and PEC.[31]

The PJM/PEC JOA allows for the PECIMP and PECEXP interface pricing points to be calculated using the "Marginal Cost Proxy Pricing" methodology as defined in the PJM Tariff.[32]

The DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP interface pricing points are calculated based on the "high-low" pricing methodology as defined in the PJM Tariff.

25 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>.

26 See "Duke Energy Carolinas Interface Pricing Arrangements" (January 5, 2007) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/duke-pricing-agreement.ashx>. (Accessed March 1, 2012)

27 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 March 1, 2012).

28 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 March 1, 2012)

29 See *PJM Interconnection, L.L.C.*, and Progress Energy Carolinas, Inc. Docket No. ER10-713-000 (February 2, 2010).

30 See the *2010 State of the Market Report*, Volume II, "Interchange Transactions," for the relevant history.

31 134 FERC ¶ 61,048 (2011).

32 See *PJM Interconnection, L.L.C*, Docket No. ER10-2710-000 (September 17, 2010).

Table 8-24 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through March, 2012 (See 2011 SOM, Table 8-22)

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$29.30	$29.38	$28.81	$28.81	$0.49	$0.57
PEC	$29.68	$29.90	$28.81	$28.81	$0.87	$1.09
NCMPA	$29.40	$29.38	$28.81	$28.81	$0.59	$0.57

Figure 8-13 Real-time interchange volume vs. average hourly LMP available for Duke and PEC imports: January through March, 2012 (See 2011 SOM, Figure 8-13)

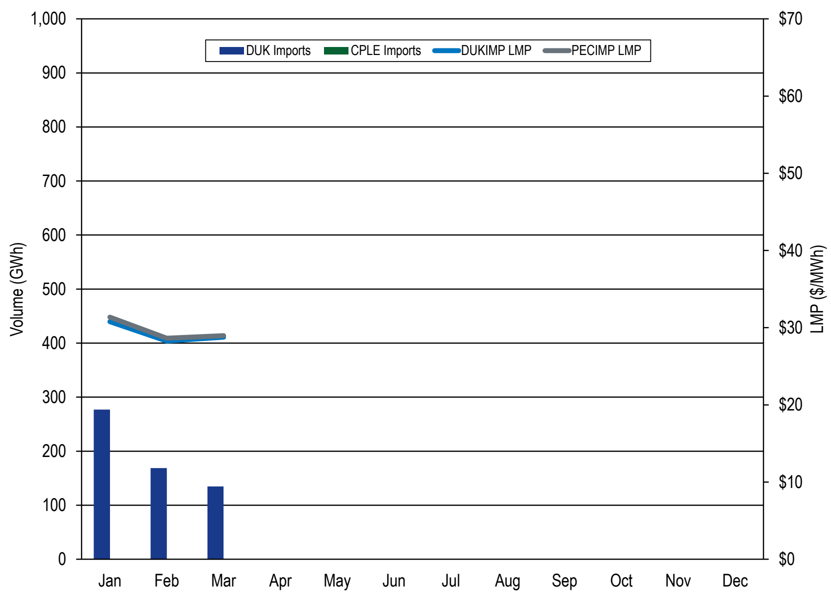


Figure 8-14 Real-time interchange volume vs. average hourly LMP available for Duke and PEC exports: January through March, 2012 (See 2011 SOM, Figure 8-14)

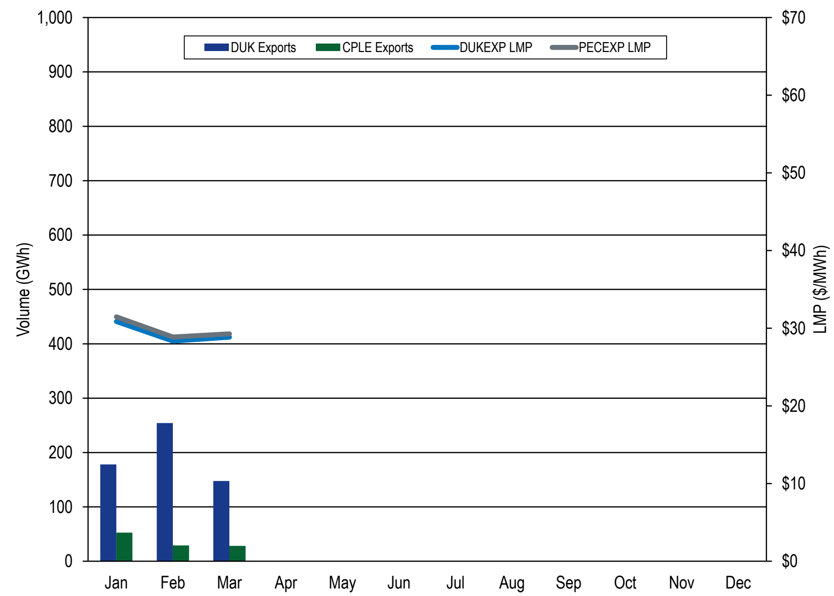


Table 8-25 Day-ahead average hourly LMP comparison for southeast, southwest, SouthIMP and SouthEXP Interface pricing points: January through March, 2007 through 2012 (See 2011 SOM, Table 8-23)

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	$51.80	$44.25	$48.23	$45.55	$3.57	($3.97)	$6.25	($1.30)
2008	$61.71	$53.52	$56.45	$56.45	$5.26	($2.93)	$5.26	($2.93)
2009	$46.49	$38.58	$41.37	$41.37	$5.12	($2.78)	$5.12	($2.78)
2010	$47.69	$38.43	$41.63	$41.63	$6.07	($3.20)	$6.07	($3.20)
2011	$43.68	$36.97	$39.26	$39.26	$4.42	($2.30)	$4.42	($2.30)
2012	$30.31	$28.33	$29.11	$29.12	$1.20	($0.78)	$1.20	($0.79)

Table 8-26 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through March, 2012 (See 2011 SOM, Table 8-24)

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$29.25	$30.08	$29.11	$29.11	$0.14	$0.96
PEC	$30.02	$30.42	$29.11	$29.11	$0.90	$1.31
NCMPA	$29.67	$29.72	$29.11	$29.11	$0.56	$0.60

Figure 8-15 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC imports: January through March, 2012 (See 2011 SOM, Figure 8-15)

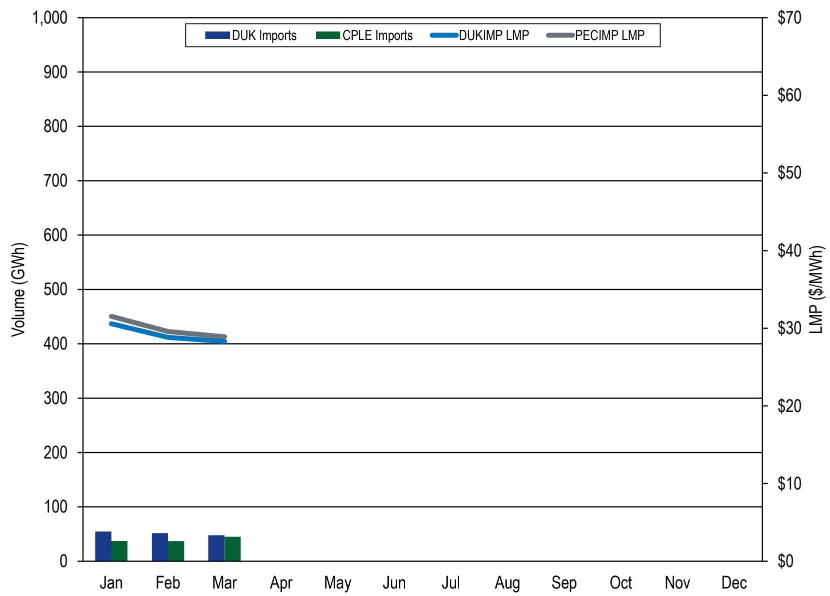
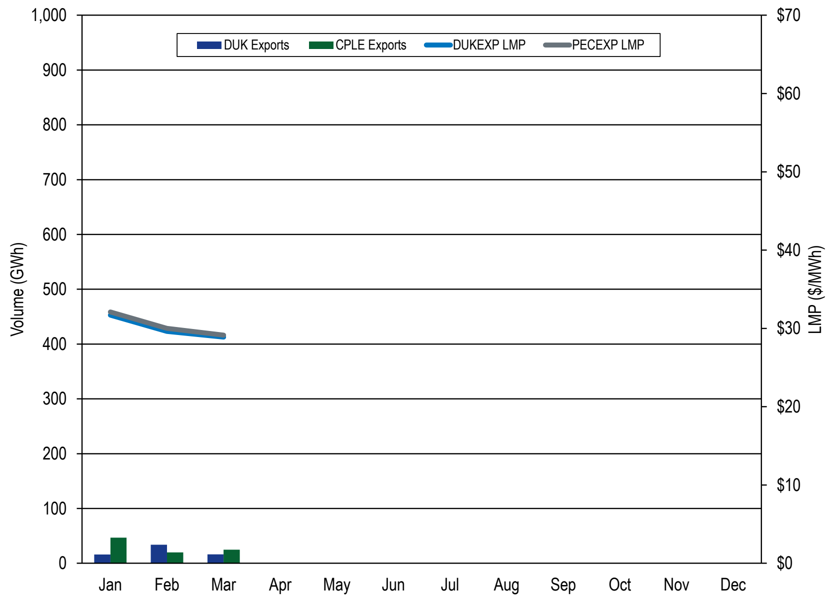


Figure 8-16 Day-ahead interchange volume vs. average hourly LMP available for Duke and PEC exports: January through March, 2012 (See 2011 SOM, Figure 8-16



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. The system redispatch often creates price separation across buses on the PJM system. The difference in LMPs between two buses in PJM is the congestion cost (and losses) that the market participants pay in order for their transaction to continue to flow.

Total uncollected congestion charges in the first three months of 2012 were -$15.00, compared to $4,669 for the the first three 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 three months of 2012.

Table 8-27 Monthly uncollected congestion charges: Calendar years 2010 and 2011 and January through March, 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	
May	$41,025	$0	
Jun	$169,197	$1,354	
Jul	$827,617	$1,115	
Aug	$731,539	$37	
Sep	$119,162	$0	
Oct	$257,448	($31,443)	
Nov	$30,843	($795)	
Dec	$127,176	($659)	
Total	$3,314,018	($20,955)	($15)

Spot Import

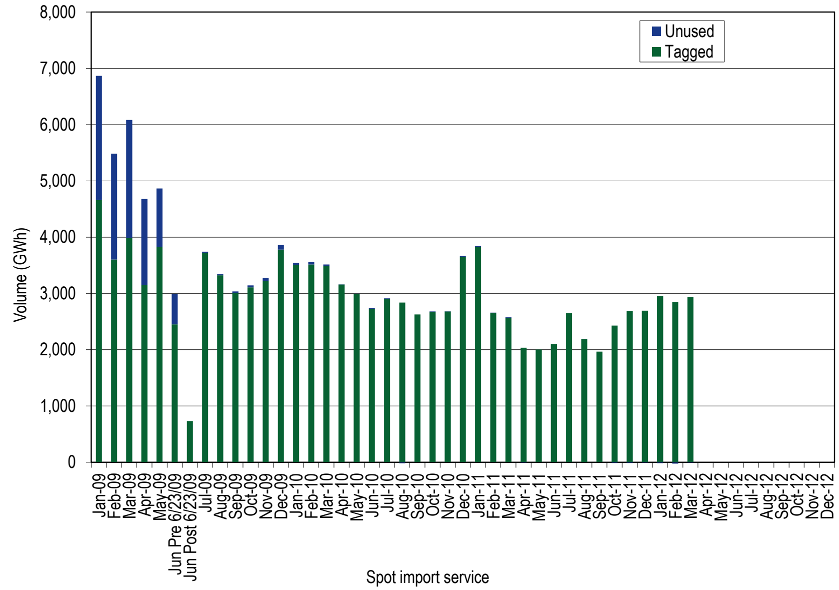
Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. Spot market imports, non-firm point-to-point and network services that are willing to pay congestion, collectively Willing to Pay Congestion (WPC), were part of the PJM LMP energy market design implemented on April 1, 1998. WPC provided market participants the ability to offer energy into or bid to buy from the PJM spot market at the border/interface as price takers without restrictions based on estimated available transmission capability (ATC). Price and PJM system conditions, rather than ATC, were the only limits on interchange.

However, PJM interpreted its JOA with MISO to require a limitation on cross-border transmission service and energy schedules in order to limit the impact of such transactions on selected external flowgates.[33] The rule caused the availability of spot import service to be limited by ATC on the transmission path. As a result, requests for service sometimes exceeded the amount of service available to customers. 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, 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 sixty percent, rather than reducing the ATC to zero when a 1,000 MW reservation is made, there would still be 400 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 is expected that implementation of these changes will occur by the end of the third quarter 2012.

33 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 March 1, 2012)

Figure 8-17 Spot import service utilization: January, 2009 through March, 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 initially a valuable tool for market participants. 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. The value that dispatchable transactions once provided market participants no longer exist, but the risk to other market participants is substantial, as they are subject to providing the operating reserve credits. Dispatchable transactions now only serve as a potential mechanism for receiving those operating reserve credits.

Balancing operating reserve credits are paid to importing dispatchable transactions as a guarantee of the transaction price. Dispatchable transactions are made whole when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. During the first three months of 2012, there were no balancing operating reserve credits paid to dispatchable transactions, a decrease from $1.1 million for the first three 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 in three days during the first three 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 (i.e., less than five minutes) or by demand-side response (DSR). Longer-term deviations between system load and generation are met via primary and secondary reserve and generation responses to economic signals. Synchronized reserve is a form of primary reserve. To provide synchronized reserve a generator must be synchronized to the system and capable of providing output within 10 minutes. Synchronized reserve can also be provided by DSR. The term, Synchronized Reserve Market, refers only to supply of and demand for Tier 2 synchronized reserve.

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

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 2011.

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**

- 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 67 percent of the hours in January through March 2012.

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.

- 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.[5]
- 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 49 percent of the hours in January through March 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 failed the three pivotal supplier test in only a limited number of hours.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs (zero), about 12 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 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 March 2012 was $12.64 per MW.[6] This was an increase of $1.13, or 10 percent, from the average price for regulation in January through March 2011. The total cost of regulation decreased by $8.07 from $24.83 per MW in January through March 2011, to $16.76, or 33 percent. In January through March 2012 the weighted Regulation Market clearing price was 75 percent of the total regulation cost per MW, compared to 46 percent of the total regulation cost per MW in January through March 2011.
- The weighted average clearing price for Tier 2 Synchronized Reserve Market in the Mid-Atlantic Subzone was $6.06 per MW in January through March 2012, a $4.94 per MW decrease from January through March 2011.[7] The total cost of synchronized reserves per MWh in January through March 2012 was $7.76, a 59 percent decrease from the total cost of synchronized reserves ($13.19) during January through March 2011. The weighted average Synchronized Reserve Market clearing price was 78 percent of the weighted average total cost per MW of synchronized reserve in January through March 2012, down slightly from 83 percent in January through March 2011.
- The weighted DASR market clearing price in January through March 2012 was $0 per MW. In January through March 2011, the weighted price of DASR was $0.02 per MW. The average hourly purchased DASR increased by eight percent from 6,145 MW to 6,634 MW reflecting PJM's larger footprint with the integration of Duke on January 1, 2012.
- Black start zonal charges in January through March 2012 ranged from $0.02 per MW in the ATSI zone to $1.90 per MW in the AEP zone

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

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 March 2001 through January through March 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]: Q1 2001 through Q1 2012 (See 2011 SOM, Table 9-4)

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve
2001	$0.49	$0.40	$0.22	$0.00	$0.94
2002	$0.37	$0.59	$0.24	$0.00	$0.56
2003	$0.65	$0.59	$0.22	$0.00	$0.98
2004	$0.53	$0.63	$0.26	$0.17	$0.89
2005	$0.46	$0.51	$0.25	$0.07	$0.57
2006	$0.48	$0.46	$0.28	$0.09	$0.32
2007	$0.58	$0.46	$0.30	$0.11	$0.50
2008	$0.59	$0.47	$0.29	$0.07	$0.52
2009	$0.37	$0.37	$0.34	$0.16	$0.56
2010	$0.34	$0.38	$0.35	$0.05	$0.68
2011	$0.27	$0.33	$0.39	$0.12	$0.84
2012	$0.18	$0.41	$0.49	$0.03	$0.53

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 logic and the definition of opportunity cost elsewhere in the PJM tariff. This

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."

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 March 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.

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.[10] 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.[11]

On March 5, 2012, PJM filed proposed tariff revisions intended to implement Order No. 755.[12] PJM proposed a two-part compensation method, and requested, in order to implement its preferred approach, that the Commission approve its filing to implement tariff revisions for scarcity pricing in compliance with Order No. 719.[13] A two-part compensation method provides for (i) "a capacity payment, or option payment, for a resource keeping its capacity in reserve in the event that it is needed to provide real-time frequency regulation service" and "a performance payment that reflects the amount of work each resource performs in real-time."[14] The MMU protested that the Commission should not approve PJM's filing until PJM completed and filed undeveloped aspects of its proposal.[15] The MMU also protested that PJM's proposal fails to reflect the incremental cost of providing capability (AReg MW) or the true lost opportunity cost of capability, and, consequently, fails to eliminate the need for after-market make whole payments even if actual real-time opportunity costs are used. On April 19, 2012, the Commission issued an order approving PJM's scarcity proposal, which the MMU had also protested.[16] An order on PJM's Order No. 755 compliance proposal is currently pending at the Commission.

Overall, the MMU concludes that the Regulation Market results were not competitive in January through March 2012 as a result of the identified market design changes and their implementation. The MMU is hopeful that the opportunity cost can be resolved in 2012 as part of the regulation market

10 See *2011 State of the Market Report for PJM*, "Appendix F."
11 *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, 137 FERC ¶ 61,064 (2011) ("Order No. 755").
12 PJM filing in Docket No. ER12-1204.
13 *Wholesale Competition in Regions with Organized Markets*, Order No. 719, 125 FERC ¶ 61,071 (2008), *order on reh'g*, Order No. 719-A, 128 FERC ¶ 61,059 (2009).
14 Order No. 755 at PP 197–199.
15 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).
16 139 FERC ¶ 61,057.

redesign. This conclusion is not the result of participant behavior, which was generally competitive. The MMU concludes that the Synchronized Reserve Market results were competitive in January through March 2012. The MMU concludes that the DASR Market results were competitive in January through March 2012.

Regulation Market

The PJM Regulation Market in January through March 2012 continued to be operated as a single market. There have been no structural changes since December 1, 2008.[17]

Market Structure

Supply

Table 9-5 shows capability, 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 March of 2012, to 9,257 MW from 7,847 MW in the same time period of 2011, primarily as a result of the integration of two new areas into PJM.

Table 9-5 PJM regulation capability, daily offer[18] and hourly eligible: January through March 2012 (See 2011 SOM, Table 9-5)[19]

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
All Hours	9,257	6,878	74%	3,209	35%
Off Peak	9,257			3,032	33%
On Peak	9,257			3,405	37%

The supply of regulation can be impacted by regulating units retiring from service. Table 9-6 shows the impact on the Regulation Market if all units requesting retirement retire through the end of 2015.

17 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."

18 Average Daily Offer MW exclude units that have offers but make themselves unavailable for the day.

19 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-Mar, 2012	Settled MWh, January through March 2012	Units Scheduled To Retire Through 2015	Settled MWh of Units Scheduled To Retire Through 2015	Percent Of January through March, 2012 Regulation MWh Scheduled To Retire Through 2015
225	2,763,249	35	39,390	1.4%

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. In August 2008, the requirement was adjusted to be 1.0 percent of the forecast peak load for on peak hours and 1.0 percent of the forecast valley load for off peak hours. 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 March 2012 and 2011 (See 2011 SOM, Table 9-6)

Month	Average Required Regulation (MW), Q1 2011	Average Required Regulation (MW), Q1 2012	Ratio of Supply To Requirement, Q1 2011	Ratio of Supply To Requirement, Q1 2012
Jan	960	1,006	3.19	3.35
Feb	897	978	3.06	3.51
Mar	823	875	3.01	3.35
Off Peak	830	883	3.18	3.49
On Peak	964	1,030	3.03	3.31

Market Concentration

Table 9-8 shows Herfindahl-Hirschman Index (HHI) results for the January through March 2012 period. The average HHI of 1611 is classified as "moderately concentrated."

Table 9-8 PJM cleared regulation HHI: January through March 2012 and 2011 (See 2011 SOM, Table 9-7)

Market Type	Minimum HHI	Load-weighted Average HHI	Maximum HHI
Cleared Regulation, January through March, 2012	814	1611	4429
Cleared Regulation, January through March, 2011	916	1785	3550

Figure 9-1 compares the January through March 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 March of 2010, 2011 and 2012 (See 2011 SOM, Figure 9-1)

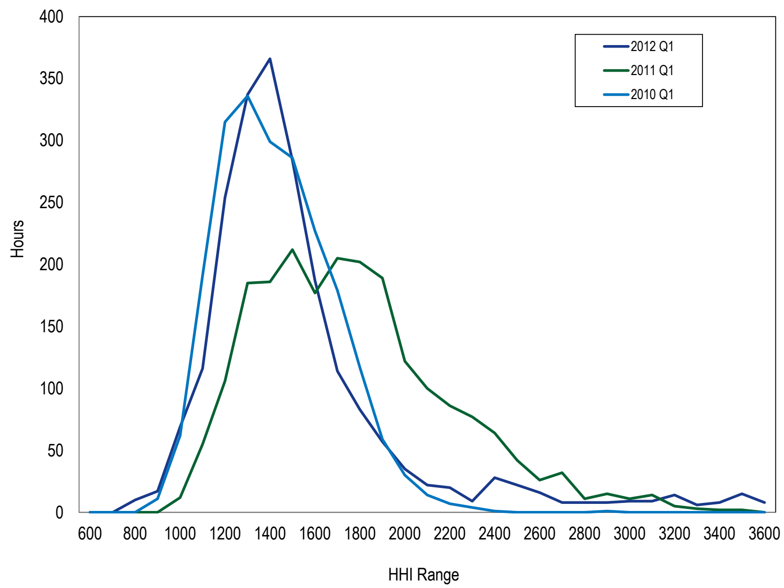


Table 9-9 includes a monthly summary of three pivotal supplier results. In January through March 2012, 67 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test. The MMU concludes from these results that the PJM Regulation Market in January through March 2012 was characterized by structural market power in 67 percent of the hours.

Table 9-9 Regulation market monthly three pivotal supplier results: January through March 2010, 2011 and 2012 (See 2011 SOM, Table 9-9)

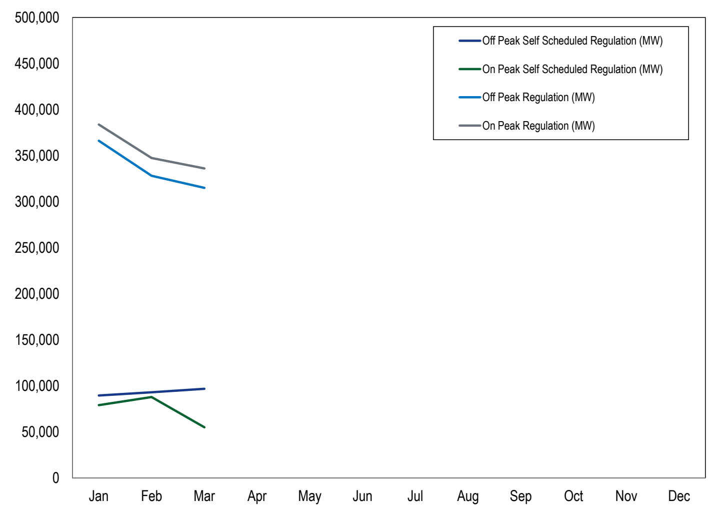
	2012		2011		2010	
Month	Percent of Hours Pivotal	Percent of Hours When Marginal Supplier is Pivotal	Percent of Hours Pivotal	Percent of Hours When Marginal Supplier is Pivotal	Percent of Hours Pivotal	Percent of Hours When Marginal Supplier is Pivotal
Jan	71%	60%	95%	88%	74%	67%
Feb	67%	60%	93%	87%	70%	58%
Mar	64%	52%	94%	89%	83%	73%

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]

Figure 9-2 Off peak and on peak regulation levels: January through March 2012 (See 2011 SOM, Figure 9-2)



20 See PJM "Manual 28: Operating Agreement Accounting," Revision 50, (January 1, 2012); para 4.2, pp 14-15.

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 March 2012, 74 percent was purchased in the spot market (79 percent in January through March 2011), 23 percent was self scheduled (18 percent in January through March 2011), and 3 percent was purchased bilaterally (3 percent in January through March 2011). (Table 9-10.)

Table 9-10 Regulation sources: spot market, self-scheduled, bilateral purchases: January through March 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	480,989	175,757	20,456	677,202
Mar	426,032	122,444	17,464	565,940

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.

Market Performance

Price

The weighted average regulation market clearing price for January through March, 2012 was $12.64. 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. 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 weighted average offer (excluding opportunity cost) of the marginal unit for the PJM Regulation Market during January through March 2012 was $9.60 per MWh, an increase from the weighted average offer in January through March 2011 of $8.81. The weighted average opportunity cost of the marginal unit for the PJM Regulation Market in January through March 2012 was $2.72. In the PJM Regulation Market the marginal unit opportunity cost averaged 22 percent of the RMCP. This is a small increase from the January through March 2011 level of 19 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 March 2012 (See 2011 SOM, Figure 9-3)

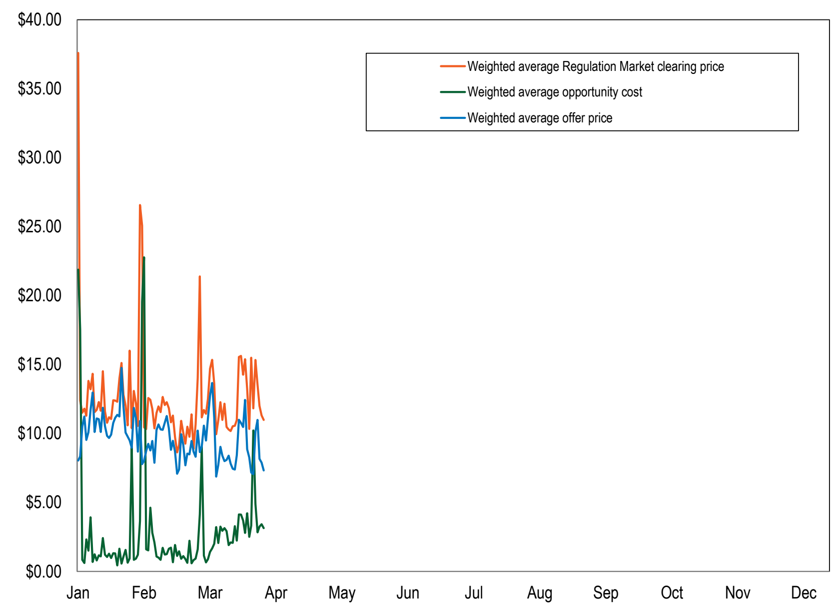


Figure 9-4 shows the level of demand for regulation by month in January through March 2012 and the corresponding level of regulation price.

21 The reason for this is that SPREGO might otherwise schedule them for energy which they cannot provide.
22 See PJM. "Manual 28: Operating Agreement, Accounting," Revision 50, Section 4.2, "Regulation Credits" (January 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.

Figure 9-4 Monthly average regulation demand and price: January through March 2012 (See 2011 SOM, Figure 9-4)

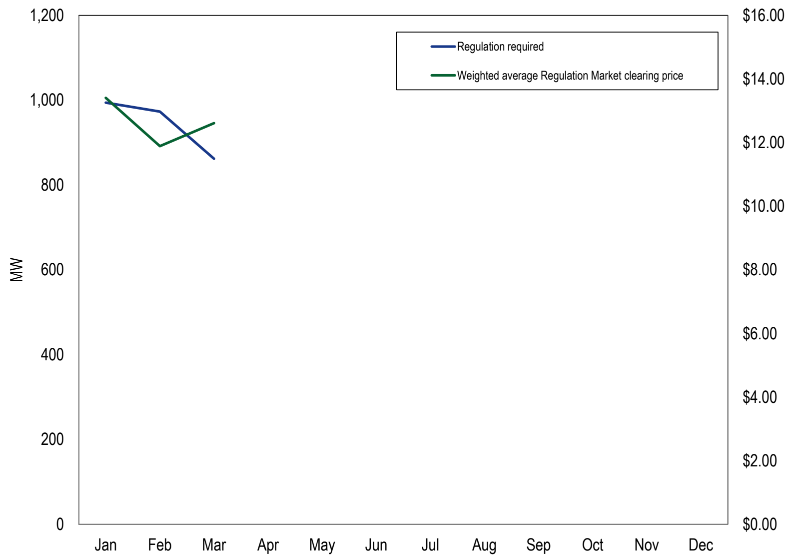
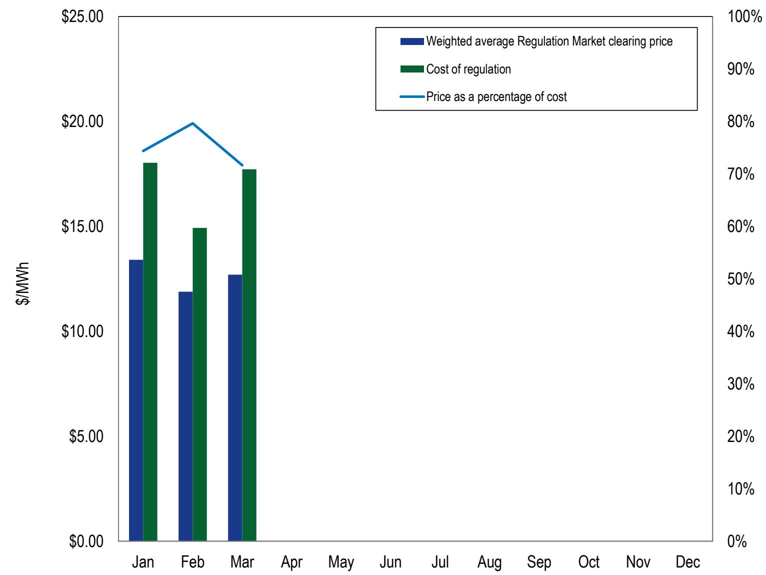


Figure 9-5 compares the regulation total cost per MWh (clearing price plus post market opportunity costs) with the regulation clearing price.

Figure 9-5 Monthly weighted, average regulation cost and price: January through March 2012 (See 2011 SOM, Figure 9-5)



Total scheduled regulation MW, total regulation charges, regulation price and regulation cost are shown in Table 9-11.

Table 9-11 Total regulation charges: January through March 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	677,202	$10,107,959	$12.09	$11.89	$14.93
Mar	641,655	$11,109,763	$12.54	$12.61	$17.31

Table 9-12 provides a comparison of the weighted annual price and cost for PJM Regulation. The difference between the Regulation Market price and the actual cost of regulation was less in January through March 2012 than it was in the same period of 2011.

Table 9-12 Comparison of weighted price and cost for PJM Regulation, August 2005 through March 2012[23] (See 2011 SOM, Table 9-12)

Year	Simple Average Regulation Market Price	Weighted Average Regulation Market Price	Regulation Cost	Regulation Price as a Percentage of Cost
2005	$59.60	$64.03	$77.39	83%
2006	$27.02	$32.69	$44.98	73%
2007	$31.87	$36.86	$52.91	70%
2008	$27.61	$42.09	$64.43	65%
2009	$22.28	$23.56	$29.87	79%
2010	$18.09	$18.05	$30.67	59%
2011	$11.69	$11.51	$24.83	46%
2012	$12.75	$12.61	$16.76	75%

Synchronized Reserve Market

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

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.[24] 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.[25] From May 20, 2011, through the end of September 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 has changed the transfer capacity several times varying from 50 percent to 15 percent at the end of 2011. From January through March 2012 the transfer capacity has remained at 15 percent. Synchronized reserves added out of market were 3.9 percent of all synchronized reserves in January through March 2012, up from 1.1 percent in January through March 2011. After-market opportunity cost payments accounted for 22.2 percent of total costs in January through March 2012 compared to 17.1 percent in January through March 2011.

Market Structure

Supply

In January through March 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 1.08 for the Mid-Atlantic Subzone.[26] This is a six percent decrease from 2010 when the ratio was 1.16. Much of the required synchronized reserve is supplied from on-line (Tier 1) synchronized reserve resources. The ratio of eligible synchronized reserve MW to the required Tier 2 MW is much higher. The ratio of offered and eligible synchronized reserve to the required Tier 2 depends on how much Tier 2 synchronized reserve is needed but the median ratio for all cleared Tier 2 hours in January through March 2012 was 3.40 for the Mid-Atlantic Subzone. This is a 10 percent increase from January through March 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 is usually a significant amount of Tier 1 synchronized reserve available. (See Figure 9-6)

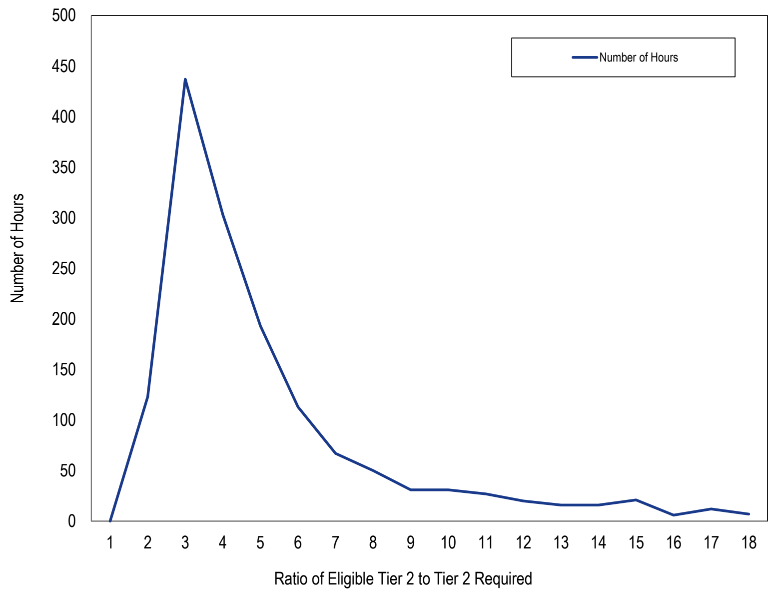
23 The PJM Regulation Market in its current structure began August 1, 2005. See the *2005 State of the Market Report for PJM*, "Ancillary Service Markets." pp. 249-250.

24 PJM.com "TrAIL Operational Impacts," <http://www.pjm.com/~/media/committees-groups/committees/oc/20111018/20111018-item-08-trail-operational-impacts.ashx> (October 2011).

25 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 49 (January 1, 2012), p. 67.

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

Figure 9-6 Ratio of Eligible Synchronized Reserve to Required Tier 2 for all cleared hours in the Mid-Atlantic Subzone: January through March 2012 (See 2011 SOM, Figure 9-6)



Demand

PJM made no changes to the default hourly required synchronized reserve requirement in January through March 2012.

In January through March 2012, in the Mid-Atlantic Subzone, a Tier 2 synchronized reserve market was cleared in 73 percent of hours compared to 99.9 percent of hours for January through March 2011. In January through March 2012, the average required Tier 2 synchronized reserve (including self scheduled) for all cleared hours was 356 MW. In January through March 2011 the average required Tier 2 synchronized reserve was 742 MW.

Synchronized reserves added out of market were 3.9 percent of all Mid-Atlantic Subzone synchronized reserves in January through March 2012, compared to 1.1 percent in January through March 2011.

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.[27]

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 March 2012. For the Mid-Atlantic Subzone the requirement was 1,300 MW for January through March 2012 (Ref. Table 9-13).

Table 9-13 Synchronized Reserve Market required MW, RFC Zone and Mid-Atlantic Subzone, December 2008 through March 2012 (See 2011 SOM, Table 9-16)

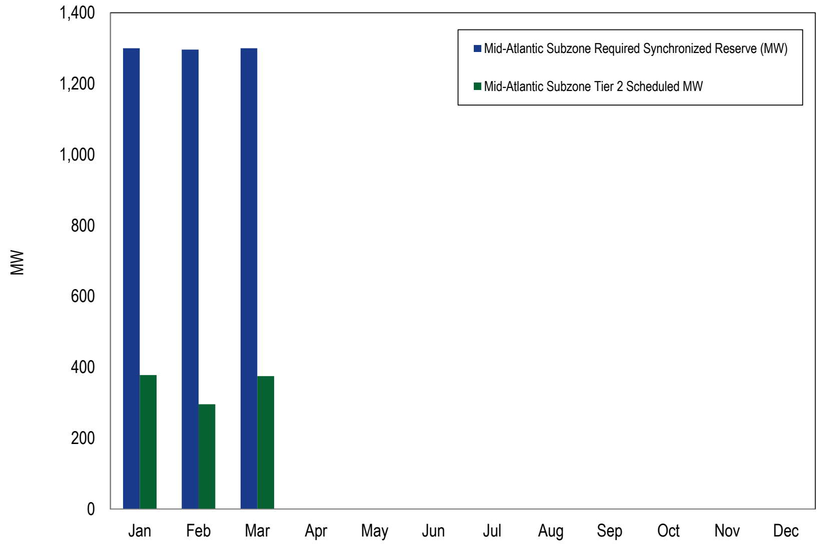
Mid-Atlantic Subzone			RFC Synchronized Reserve Zone		
From Date	To Date	Required MW	From Date	To Date	Required MW
Dec 2008	May 2010	1,150	Dec 2008	Jan 2009	1,305
May 2010	Jul 2010	1,200	Jan 2009	Mar 2010	1,320
Jul 2010	Mar2012	1,300	Mar 2010	Mar 2012	1,350

Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency. There were no hourly exceptions during January through March 2012. Figure 9-7 shows the average monthly

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

synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during January through March 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 March 2012 (See 2011 SOM, Figure 9-7)

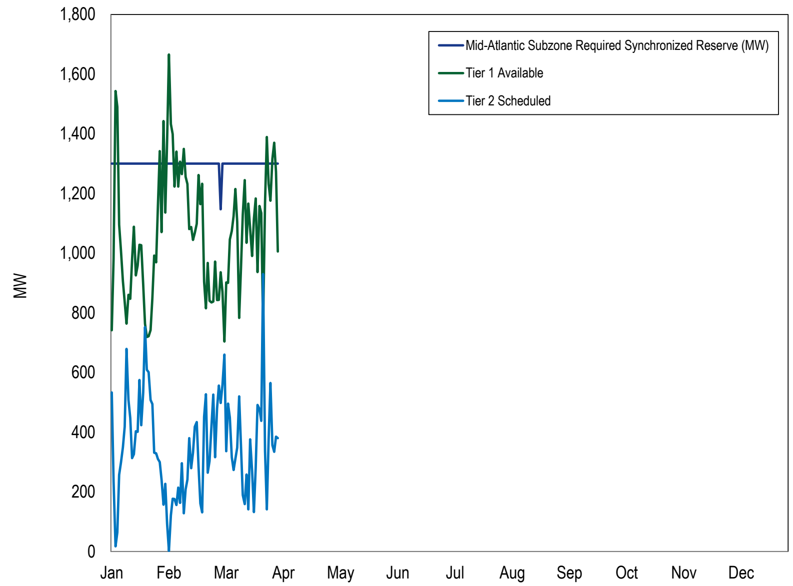


The RFC Synchronized Reserve Zone almost always has enough Tier 1 to cover its synchronized reserve requirement. Available Tier 1 in the western part of the RFC Synchronized Reserve Zone generally exceeds the total synchronized reserve requirement in the west. In January through March 2012, the RFC Synchronized Reserve Zone did not clear a Tier 2 Synchronized Reserve Market in any hour. The Mid-Atlantic Subzone of the RFC Synchronized Reserve Zone cleared a separate Tier 2 market in 73 percent of all hours during January through March 2012. 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 March 2012 was always 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 March 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.[28] The amount of

28 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 49 (January 1, 2012), p. 66.

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 26 hours in January through March 2012.

Market Concentration

The RFC Tier 2 Synchronized Reserve Market was less concentrated in January through March 2012 than it had been in the same period of 2011. Nevertheless the RFC Synchronized Reserve Market remains highly concentrated and dominated by a relatively small number of companies. The participation of demand resources in the market continued to have a significant impact on the market, resulting in lower prices and less concentration. The HHI for the Mid-Atlantic Subzone of the January through March 2012 RFC cleared Synchronized Reserve Market was 2638, which is defined as "highly concentrated." The largest hourly market share was 94 percent and 43 percent of all hours had a maximum market share greater than or equal to 40 percent (compared to 46 percent of all hours in January through March 2011).

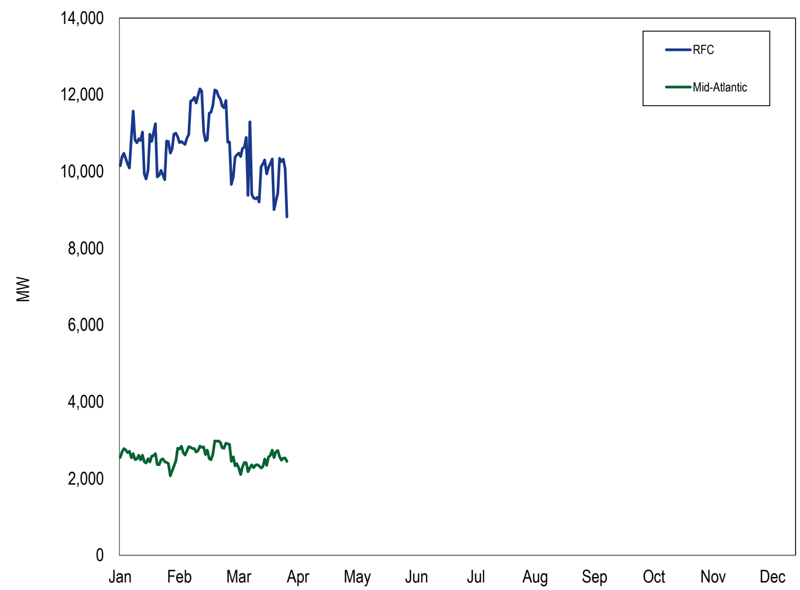
In January through March 2012, 49 percent of hours in the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market failed the three pivotal supplier test. These results indicate that the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market, the only synchronized reserve market that clears on a regular basis, is not structurally competitive.

Market Conduct

Offers

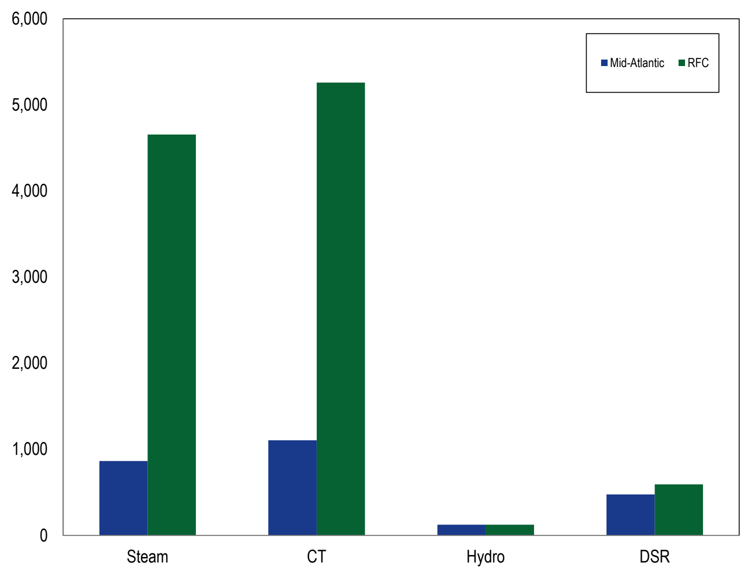
Figure 9-9 shows the daily average hourly offered Tier 2 synchronized reserve MW.

Figure 9-9 Tier 2 synchronized reserve average hourly offer volume (MW): January through March 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 March 2012 (See 2011 SOM, Figure 9-11)



DSR

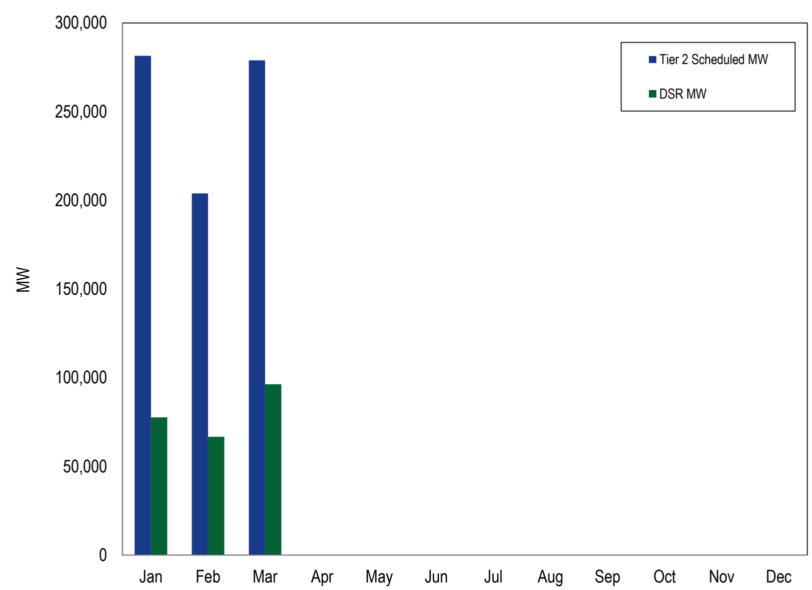
Demand-side resources were permitted to participate in the Synchronized Reserve Markets effective August 2006. DSR continues to have a significant impact on the Synchronized Reserve Market. (Figure 9-10.) In January through March 2012, DSR accounted for 38 percent of all cleared Tier 2 synchronized reserves, compared to 16 percent for the same period in 2011. In 14 percent of hours when a synchronized reserve market was cleared, all cleared MW were DSR compared to one percent in January through March 2011. (See Table 9-14.) In the hours when all supply was DSR, the simple average SRMCP was $1.63. The simple average SRMCP for all cleared hours was $4.87 (the simple average SRMCP in January through March 2011 was $9.76).

Table 9-14 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 March 2010, 2011, 2012 (See 2011 SOM, Table 9-18)

Year	Month	Weighted Average SRMCP	Weighted Average SRMCP when all cleared synchronized reserve is DSR	Percentage 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	$2.03	6%
2011	Jan	$10.75	$0.10	0%
2011	Feb	$10.91	n/a	0%
2011	Mar	$11.34	$2.04	2%
2012	Jan	$6.30	$1.71	11%
2012	Feb	$5.47	$1.78	24%
2012	Mar	$6.40	$1.40	6%

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 March 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).

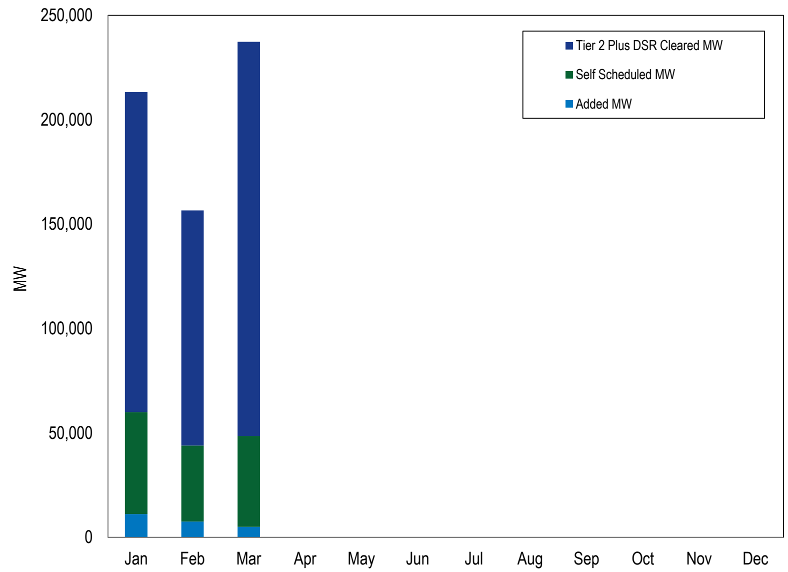
The weighted, average price for synchronized reserve in the PJM Mid-Atlantic Subzone of the RFC Synchronized Reserve Market in January through March 2012 was $6.06 while the corresponding cost of synchronized reserve was $7.76.

The RFC Synchronized Reserve requirement was satisfied by Tier 1 in every hour of January through March 2012 so no RFC Synchronized Reserve Market was cleared. The Southern Synchronized Reserve Zone did clear a market in 26 hours of January through March 2012 with a weighted average clearing price of $11.12.

Price and Cost

A high price to cost ratio is an indicator of an efficient market design, where the costs are the result of the economic solution. The primary reason for the relatively low price to cost ratio is the difference in opportunity cost calculated using the forecast LMP and the actual LMP. In addition, a 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.

Figure 9-12 Tier 2 synchronized reserve purchases by month for the Mid-Atlantic Subzone: January through March 2012 (See 2011 SOM, Figure 9-4)



The difference between the Tier 2 Synchronized Reserve Market price and the cost for Tier 2 synchronized reserve in January through March 2012 was less than in the same period of 2011 (Figure 9-13). In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market for January through March 2012, the cost of Tier 2 synchronized reserves was 28 percent higher than the weighted price. In January through March 2011 this difference was 21 percent.

Figure 9-13 Impact of Tier 2 synchronized reserve added MW to the RFC Synchronized Reserve Zone, Mid-Atlantic Subzone: January through March 2012 (See 2011 SOM, Figure 9-15)

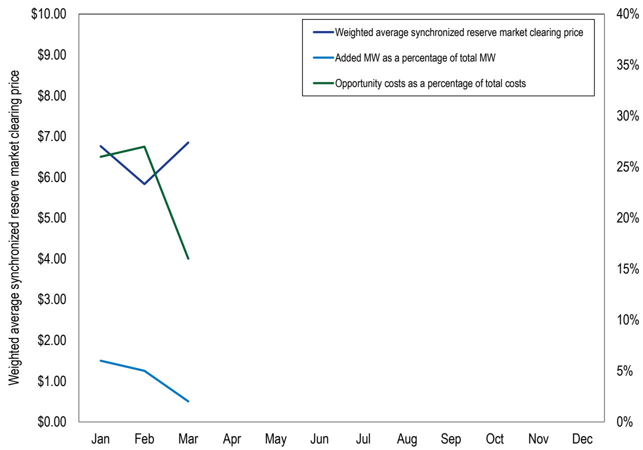


Figure 9-14 Comparison of Mid-Atlantic Subzone Tier 2 synchronized reserve weighted average price and cost (Dollars per MW): January through March 2012 (See 2011 SOM, Figure 9-16)

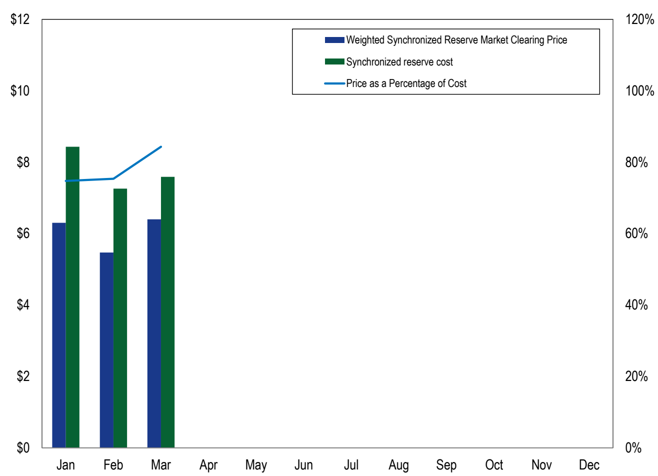


Table 9-15 shows the price and cost history of the Synchronized Reserve Market since 2005.

Table 9-15 Comparison of weighted average price and cost for PJM Synchronized Reserve, January through March, 2005 through 2012 (See 2011 SOM, Table 9-19)

Year	Load Weighted Synchronized Reserve Market Price	Load Weighted Synchronized Reserve Cost	Synchronized Reserve Price as Percent of Cost
2005	$13.29	$17.59	76%
2006	$14.57	$21.65	67%
2007	$11.22	$16.26	69%
2008	$10.65	$16.43	65%
2009	$7.75	$9.77	79%
2010	$10.55	$14.41	73%
2011	$10.96	$13.22	83%
2012	$6.06	$7.76	78%

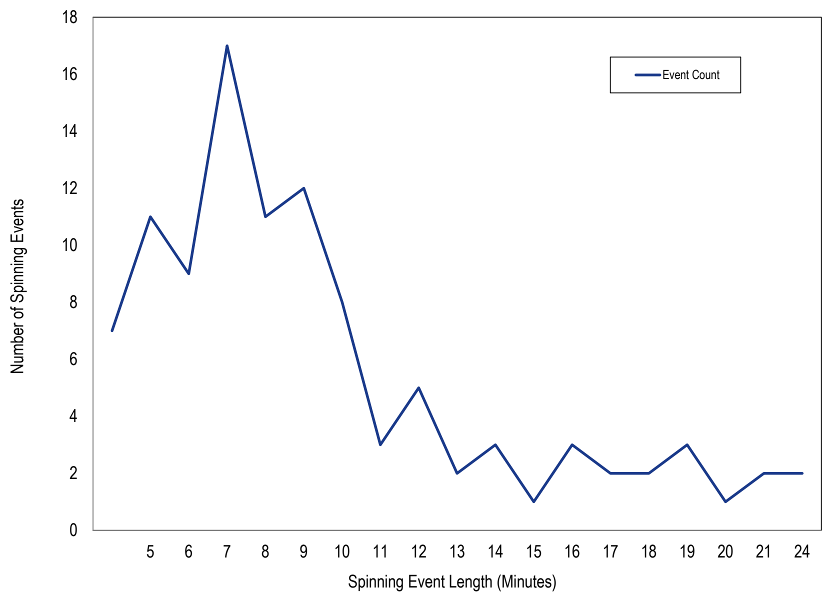
Spinning events (Table 9-16) are usually caused by a sudden generation outage or transmission disruption requiring PJM to load primary synchronized reserve (spinning reserve).[29] The reserve remains loaded until system balance is recovered. From January 2009 through March 2012 PJM experienced 109 spinning events. This is almost three events per month. Spinning events generally last between 7 minutes and twenty minutes with an average length of eleven and a half minutes although several events have lasted longer than thirty minutes.

29 See PJM. "Manual 12, Balancing Operations," Revision 23 (November 16, 2011), pp. 34-35.

Table 9-16 Spinning Events, January 2009 through March 2012 (See 2011 SOM, Table 9-20)

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	FEB-09-2011 11:40	Mid-Atlantic	16
JAN-20-2009 17:33	RFC	10	MAR-18-2010 11:02	RFC	27	FEB-13-2011 15:35	Mid-Atlantic	14
JAN-21-2009 11:52	RFC	9	MAR-23-2010 20:14	RFC	13	FEB-24-2011 11:35	Mid-Atlantic	14
FEB-18-2009 18:38	Mid-Atlantic	10	APR-11-2010 13:12	RFC	9	FEB-25-2011 14:12	RFC	10
FEB-19-2009 11:01	RFC	6	APR-28-2010 15:09	Mid-Atlantic	8	MAR-30-2011 19:13	RFC	12
FEB-28-2009 06:19	RFC	5	MAY-11-2010 19:57	Mid-Atlantic	9	APR-02-2011 13:13	Mid-Atlantic	11
MAR-03-2009 05:20	Mid-Atlantic	11	MAY-15-2010 03:03	RFC	6	APR-11-2011 00:28	RFC	6
MAR-05-2009 01:30	Mid-Atlantic	43	MAY-28-2010 04:06	Mid-Atlantic	5	APR-16-2011 22:51	RFC	9
MAR-07-2009 23:22	RFC	11	JUN-15-2010 00:46	RFC	34	APR-21-2011 20:02	Mid-Atlantic	6
MAR-23-2009 23:40	Mid-Atlantic	10	JUN-19-2010 23:49	Mid-Atlantic	9	APR-27-2011 01:22	RFC	8
MAR-23-2009 23:42	RFCNonMA	8	JUN-24-2010 00:56	RFC	15	MAY-02-2011 00:05	Mid-Atlantic	21
MAR-24-2009 13:20	Mid-Atlantic	8	JUN-27-2010 19:33	Mid-Atlantic	15	MAY-12-2011 19:39	RFC	9
MAR-25-2009 02:29	RFC	9	JUL-07-2010 15:20	RFC	8	MAY-26-2011 17:17	Mid-Atlantic	20
MAR-26-2009 13:08	RFC	10	JUL-16-2010 20:45	Mid-Atlantic	19	MAY-27-2011 12:51	RFC	6
MAR-26-2009 18:30	Mid-Atlantic	20	AUG-11-2010 19:09	RFC	17	MAY-29-2011 09:04	RFC	7
APR-24-2009 16:43	RFC	11	AUG-13-2010 23:19	RFC	6	MAY-31-2011 16:36	RFC	27
APR-26-2009 03:04	Mid-Atlantic	5	AUG-16-2010 07:08	RFC	17	JUN-03-2011 14:23	RFC	7
MAY-03-2009 15:07	RFC	10	AUG-16-2010 19:39	Mid-Atlantic	11	JUN-06-2011 22:02	Mid-Atlantic	9
MAY-17-2009 07:41	RFC	5	SEP-15-2010 11:20	RFC	13	JUN-23-2011 23:26	RFC	8
MAY-21-2009 21:37	RFC	13	SEP-22-2010 15:28	Mid-Atlantic	24	JUN-26-2011 22:03	Mid-Atlantic	10
JUN-18-2009 17:39	RFC	12	OCT-05-2010 17:20	RFC	10	JUL-10-2011 11:20	RFC	10
JUN-30-2009 00:17	Mid-Atlantic	8	OCT-16-2010 03:22	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12
JUL-26-2009 19:07	RFC	18	OCT-16-2010 03:25	RFCNonMA	7	AUG-02-2011 01:08	RFC	6
JUL-31-2009 02:01	RFC	6	OCT-27-2010 10:35	RFC	7	AUG-18-2011 06:45	Mid-Atlantic	6
AUG-15-2009 21:07	RFC	17	OCT-27-2010 12:50	Mid-Atlantic	10	AUG-19-2011 14:49	RFC	5
SEP-08-2009 10:12	Mid-Atlantic	8	NOV-26-2010 14:24	RFC	13	AUG-23-2011 17:52	RFC	7
SEP-29-2009 16:20	RFC	7	NOV-27-2010 11:34	RFC	8	SEP-24-2011 15:48	RFC	8
OCT-01-2009 10:13	RFC	11	DEC-08-2010 01:19	RFC	11	SEP-27-2011 14:20	RFC	7
OCT-18-2009 22:40	Mid-Atlantic	8	DEC-09-2010 20:07	RFC	5	SEP-27-2011 16:47	RFC	9
OCT-26-2009 01:01	RFC	7	DEC-14-2010 12:02	Mid-Atlantic	24	OCT-30-2011 22:39	Mid-Atlantic	10
OCT-26-2009 11:05	RFC	13	DEC-16-2010 18:40	Mid-Atlantic	20	DEC-15-2011 14:35	Mid-Atlantic	8
OCT-26-2009 19:55	RFC	8	DEC-17-2010 22:09	Mid-Atlantic	6	DEC-21-2011 14:26	RFC	18
NOV-20-2009 15:30	RFC	8	DEC-29-2010 19:01	Mid-Atlantic	15	JAN-03-2012 16:51	RFC	9
DEC-09-2009 22:34	Mid-Atlantic	34	JAN-11-2011 15:10	Mid-Atlantic	6	JAN-06-2012 23:25	RFC	8
DEC-09-2009 22:37	RFCNonMA	31	FEB-02-2011 01:21	RFC	5	JAN-23-2012 15:02	Mid-Atlantic	8
DEC-14-2009 11:11	Mid-Atlantic	8	FEB-08-2011 22:41	Mid-Atlantic	11	MAR-02-2012 19:54	RFC	9

Figure 9-15 Spinning events duration distribution curve, January 2009 through March 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 March 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.[30]

The DASR 30-minute reserve requirements are determined by the reliability region.[31] In the Reliability*First* (RFC) region, reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[32] 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 March 2012, the required DASR was 7.03 percent of peak load forecast, up from 7.11 percent in 2011.[33] DASR MW purchased increased by 9 percent in January through March 2012 over the same period in 2011, from 13.3 MW to 14.5 MW.

In January through March 2012, zero hours failed the three pivotal supplier test. 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 March 2012.

Market Conduct

PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market, but any offer price will satisfy the requirement.[34] Units that do not offer have their offers set to $0/MW.

Economic withholding remains an issue in the DASR Market. The marginal cost of providing DASR is zero. Between January and March 2012, twelve percent of all units offered DASR at levels above $5. The impact on DASR prices of high offers was minor as a result of a favorable balance between supply and demand.

30 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.

31 PJM. "Manual 13, Emergency Requirements," Revision 47 (January 1, 2012), pp. 11-12.
32 PJM. "Manual 10, Pre-Scheduling Operations," Revision 25 (January 1, 2010), p. 17.
33 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at Day Ahead Scheduling Reserve *(DASR)*.
34 PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 49 (January 1, 2012), p. 122.

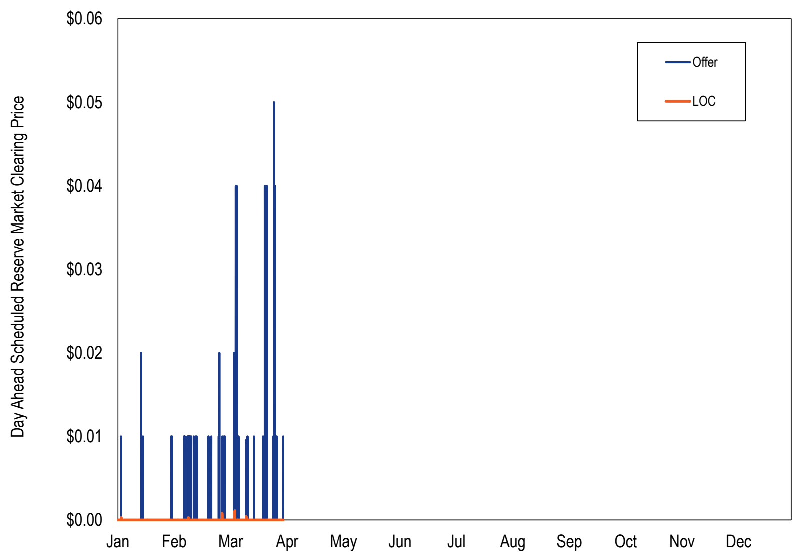
Market Performance

For 96 percent of hours in January through March 2012 DASR cleared at a price of $0.00. Redispatch was required in only six hours (Figure 9-16).

Table 9-17 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: January through March 2011 and 2012 (See 2011 SOM, Table 9-21)

Year	Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Weighted Average Clearing Price	Total DASR MW Purchased	Total DASR Credits
2011	Jan	6,536	$0.00	$1.00	$0.03	4,862,520	$127,837
2011	Feb	6,180	$0.00	$1.00	$0.02	4,152,665	$61,682
2011	Mar	5,720	$0.00	$1.00	$0.01	4,249,733	$45,885
2012	Jan	6,944	$0.00	$0.02	$0.00	5,166,216	$604
2012	Feb	6,777	$0.00	$0.02	$0.00	4,716,710	$2,037
2012	Mar	6,180	$0.00	$0.05	$0.00	4,591,937	$5,031

Figure 9-16 Hourly components of DASR clearing price: January through March 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 with a high operating factor to automatically remain operating at reduced levels 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 all costs associated with providing this service.

PJM ensures the availability of black start by charging transmission customers according to their zonal load ratio share and compensating black start unit owners according to an incentive rate or their revenue requirements (Table 9-18).

In January through March 2012, charges were $6.11 million. This is 114 percent higher than January through March 2011, when total black start service charges were $2.86 million. There was substantial zonal variation. Black start zonal charges in January through March 2012 ranged from $0.02 per MW in the ATSI zone to $1.90 per MW in the AEP 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 in the AEP zone that should have been included in black start charges. The black start charges in Table 9-18 for the AEP zone include an estimated $2.04 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.[35]

35 See the *2011 State of the Market Report for PJM*, Volume II, Section 3, "Operating Reserves."

Table 9-18 Black start yearly zonal charges for network transmission use: January through March 2012[36] (See 2011 SOM, Table 9-22)

ZONE	Network Charges	Black Start Rate ($/MW)
AECO	$138,751	$0.51
AEP	$2,194,032	$1.90
AP	$38,529	$0.05
ATSI	$19,569	$0.02
BGE	$769,776	$1.17
ComEd	$1,042,565	$0.48
DAY	$39,302	$0.12
DEOK	$58,378	$0.11
DLCO	$9,621	$0.04
DPL	$126,172	$0.33
JCPL	$127,840	$0.21
Met-Ed	$128,016	$0.45
PECO	$299,284	$0.37
PENELEC	$86,707	$0.31
Pepco	$85,278	$0.13
PPL	$34,983	$0.05
PSEG	$911,492	$0.92

36 Network charges for the AEP Zone include an additional $2.06M that is accounted as operating reserves by PJM but incurred for the purpose of satisfying the black start requirement. This allocation was not included in the black start rates reported for the first quarter of 2011.

Congestion and Marginal Losses

The Locational Marginal Price (LMP) is the incremental price of energy at a bus. The LMP at any 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 power losses caused by changes in the system load and generation patterns. Congestion occurs when available, least-cost energy cannot be delivered to all loads for a period because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[1] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation.

Congestion is neither good nor bad but is a direct measure of the extent to which there are differences in the cost of generation that cannot be equalized because of transmission constraints.

The components of LMP are the basis for determining participant and location specific congestion and marginal losses. The Market Monitoring Unit (MMU) analyzed marginal losses and congestion in PJM markets for the first three months of 2012.

Highlights

- Total marginal loss costs decreased by $169.1 million or 42.8 percent, from $409.6 million in the first quarter of 2011 to $234.4 million in the first quarter of 2012.
- Total monthly marginal loss costs in the first quarter of 2012 were lower than monthly marginal loss costs in the first quarter of 2011.[2]
- Day-ahead marginal loss costs were $248.3 million in the first quarter of 2012 and balancing marginal loss costs were -$13.9 million in the first quarter of 2012.
- The marginal loss credits (loss surplus) decreased in the first quarter of 2012 to $97.7 million compared to $200.1 million in the first quarter of 2011.
- Congestion costs in the first three months 2012 decreased by 65.9 percent compared to congestion costs in the first three months of 2011.
- Monthly congestion costs in the first three months of 2012 were lower than monthly congestion costs in the first three months of 2011.
- Day–ahead congestion costs were $181.3 million in the first three months of 2012 and $407.3 in the first three months of 2011.
- Balancing congestion costs were -$58.5 million in the first three months of 2012 and -$47.4 million in the first three months of 2011.

Conclusion

Marginal losses are incremental change in real system power losses caused by changes in system load and generation patterns. Total marginal loss costs decreased by $169.1 million or 42.8 percent, from $409.6 million in the first quarter of 2011 to $234.4 million in the first quarter of 2012. Marginal loss costs were significantly higher in the Day-Ahead Market than the Real-Time Market.

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

2 See the *2011 State of the Market Report for PJM*, Volume II, "Energy Market, Part 1," Table 2-60.

The net marginal loss bill is calculated by subtracting the generation loss credits from the sum of load loss charges, net explicit loss charges and net inadvertent loss charges. Since the net marginal bill is calculated on the basis of marginal, rather than average losses, there is an overcollection of marginal loss related costs. This overcollection, net of total energy charges and residual market adjustments, is the source of marginal loss credits. Marginal loss credits are fully distributed back to load and exports. Marginal loss credits were $97.7 million in the first quarter of 2012.

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the cost and geographical distribution of generation facilities and the geographical distribution of load. Total congestion costs decreased by $237.1 million or 65.9 percent, from $359.9 million in the first three months of 2011 to $122.8 million in the first three 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 97.3 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2010 to 2011 planning period.[3] During the first ten months (Jun 2011 through March 2012) of the 2011 to 2012 planning period, total ARR and FTR revenues offset more than 100 percent of the congestion costs within PJM. FTRs were paid at 88.1 percent of the target allocation level for the 12-month period of the 2010 to 2011 planning period, and at 83.2 percent of the target allocation level for the first ten months of the 2011 to 2012 planning period.[4] Revenue adequacy, measured relative to target allocations for a planning period is not final until the end of the period.

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. 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.[5] While total congestion costs represent the overall charge or credit to a zone, the components of congestion costs measure the extent to which load or generation bear total congestion costs. Load congestion payments, when positive, measure the total congestion cost to load in an area. Load congestion payments, when negative, measure the total congestion credit to load in an area. Negative load congestion payments result when load is on the lower priced side of a constraint or constraints. For example, congestion across the AP South interface means lower prices in western control zones and higher prices in eastern and southern control zones. Load in western control zones will benefit from lower prices and receive a congestion credit (negative load congestion payment). Load in the eastern and southern control zones will incur a congestion charge (positive load congestion payment). The reverse is true for generation congestion credits. Generation congestion credits, when positive, measure the total congestion credit to generation in an area. Generation congestion credits, when negative, measure the total congestion cost to generation in an area. Negative generation congestion credits 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).

3 See the *2012 Quarterly State of the Market Report for PJM: January through March*, Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-19, "ARR and FTR congestion hedging: Planning periods 2010 to 2011 and 2011 to 2012.

4 See the *2012 Quarterly State of the Market Report for PJM: January through March*, Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-11, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2010 to 2011 and 2011 to 2012"

5 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.

As an example, total congestion costs in PJM in the first three months of 2012 were $122.8 million, which was comprised of load congestion payments of $19.1 million, negative generation credits of $118.2 million and negative explicit congestion of $14.5 million (Table 10-14).

Locational Marginal Price (LMP)

Components

Table 10-1 shows the PJM real-time, load-weighted average LMP components for the first quarter for years 2009 to 2012.

Table 10-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): January through March, 2009 to 2012 (See 2011 SOM, Table 10-1)

(Jan-Mar)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	$49.60	$49.51	$0.05	$0.04
2010	$45.92	$45.81	$0.06	$0.05
2011	$46.35	$46.30	$0.03	$0.03
2012	$31.21	$31.18	$0.02	$0.00

The PJM price is weighted by accounting load, which differs from the state-estimated load used in determination of the energy component (SMP). The components of the average PJM system price result from these different weights. In the Real-Time Energy Market, the distributed load reference bus is weighted by system estimates of the load in real time. At the time the LMP is determined in the Real-Time Energy Market, the energy component equals the system load-weighted price. However, real-time bus-specific loads are adjusted, after the fact, according to updated information from meters. This meter adjusted load is accounting load that is used in settlements and forms the basis of the reported PJM load weighted prices. This after the fact adjustment means that the Real-Time Energy Market energy component of LMP (SMP) and the PJM real-time load-weighted LMP are not equal.

Table 10-2 shows the PJM day-ahead, load-weighted average LMP components for the first quarter for years 2009 through 2012.

Table 10-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through March, 2009 to 2012 (See 2011 SOM, Table 10-2)

(Jan-Mar)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2009	$49.44	$49.75	($0.18)	($0.13)
2010	$47.77	$47.74	$0.01	$0.02
2011	$47.14	$47.36	($0.11)	($0.11)
2012	$31.51	$31.45	$0.08	($0.03)

In the Day-Ahead Energy Market, the distributed load reference bus is weighted by fixed-demand bids only and the day-ahead energy component is, therefore, a system fixed demand weighted price. The day-ahead weighted system price calculation uses all types of demand, including fixed, price-sensitive and decrement bids.

Zonal Components

The components of LMP were calculated for each PJM control zone. The real time components of LMP for the control zones are presented in Table 10-3 for January through March of years 2011 and 2012. The day-ahead components of LMP for the control zones are presented in Table 10-4 for January through March of years 2011 and 2012.

Table 10-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): January through March, 2011 and 2012 (See 2011 SOM, Table 10-3)

	2011 (Jan-Mar)				2012 (Jan-Mar)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$54.19	$46.25	$5.42	$2.52	$31.86	$31.17	($0.34)	$1.03
AEP	$39.41	$46.16	($4.99)	($1.76)	$29.96	$31.10	($0.39)	($0.75)
AP	$45.91	$46.34	($0.48)	$0.05	$31.75	$31.21	$0.34	$0.19
ATSI	NA	NA	NA	NA	$30.37	$31.06	($0.83)	$0.13
BGE	$53.86	$46.70	$4.94	$2.23	$36.38	$31.30	$3.30	$1.78
ComEd	$35.23	$45.79	($7.33)	($3.23)	$27.87	$31.01	($1.32)	($1.82)
DAY	$39.33	$46.25	($5.71)	($1.21)	$30.53	$31.15	($0.52)	($0.10)
DEOK	NA	NA	NA	NA	$29.14	$31.17	($0.44)	($1.59)
DLCO	$51.82	$46.85	$4.23	$0.74	$29.94	$31.01	($0.31)	($0.77)
Dominion	$54.14	$46.75	$4.14	$3.25	$33.01	$31.38	$1.19	$0.44
DPL	$37.14	$45.88	($7.38)	($1.36)	$35.06	$31.28	$2.23	$1.54
JCPL	$54.19	$46.35	$5.02	$2.82	$32.13	$31.31	($0.36)	$1.18
Met-Ed	$51.40	$46.26	$3.87	$1.28	$31.39	$31.25	($0.35)	$0.49
PECO	$52.74	$46.31	$4.41	$2.02	$31.53	$31.22	($0.42)	$0.73
PENELEC	$45.63	$46.01	($0.84)	$0.46	$31.04	$31.15	($0.63)	$0.53
Pepco	$53.35	$46.61	$5.39	$1.35	$35.23	$31.33	$2.69	$1.21
PPL	$52.84	$46.42	$5.18	$1.24	$31.19	$31.27	($0.53)	$0.44
PSEG	$54.43	$45.99	$5.71	$2.73	$32.25	$31.15	($0.15)	$1.26
RECO	$48.68	$46.12	$0.05	$2.51	$32.00	$31.31	($0.43)	$1.12
PJM	$46.35	$46.30	$0.03	$0.03	$31.21	$31.18	$0.02	$0.00

Table 10-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through March, 2011 and 2012 (See 2011 SOM, Table 10-4)

	2011 (Jan-Mar)				2012 (Jan-Mar)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$56.13	$47.42	$5.58	$3.13	$32.54	$31.48	$0.10	$0.96
AEP	$39.70	$47.24	($5.17)	($2.37)	$30.33	$31.41	($0.24)	($0.83)
AP	$46.59	$47.42	($0.72)	($0.11)	$31.92	$31.53	$0.23	$0.16
ATSI	NA	NA	NA	NA	$30.58	$31.33	($0.71)	($0.04)
BGE	$55.47	$47.74	$5.23	$2.50	$36.54	$31.59	$3.04	$1.91
ComEd	$34.93	$46.71	($8.01)	($3.77)	$27.84	$31.32	($1.55)	($1.93)
DAY	$39.41	$47.25	($5.91)	($1.93)	$30.83	$31.46	($0.35)	($0.28)
DEOK	NA	NA	NA	NA	$29.17	$31.33	($0.18)	($1.99)
DLCO	$53.76	$48.01	$4.52	$1.23	$30.54	$31.33	$0.06	($0.85)
Dominion	$57.23	$47.90	$5.41	$3.92	$33.49	$31.66	$1.24	$0.59
DPL	$37.25	$46.94	($7.85)	($1.84)	$34.86	$31.56	$1.53	$1.77
JCPL	$56.60	$47.47	$5.54	$3.59	$32.77	$31.59	$0.11	$1.07
Met-Ed	$53.28	$47.21	$4.66	$1.41	$31.55	$31.36	($0.21)	$0.40
PECO	$56.02	$47.54	$5.76	$2.72	$32.01	$31.49	($0.16)	$0.69
PENELEC	$46.51	$47.39	($1.10)	$0.23	$31.53	$31.35	($0.52)	$0.70
Pepco	$54.87	$47.59	$5.48	$1.79	$35.60	$31.52	$2.46	$1.62
PPL	$54.72	$47.54	$5.88	$1.30	$31.43	$31.49	($0.36)	$0.30
PSEG	$57.49	$47.21	$6.55	$3.73	$32.90	$31.49	$0.15	$1.26
RECO	$53.93	$47.42	$3.27	$3.25	$32.38	$31.47	($0.23)	$1.13
PJM	$47.14	$47.36	($0.11)	($0.11)	$31.51	$31.45	$0.08	($0.03)

Energy Costs

Energy Accounting

The energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The energy charge is based on the applicable day-ahead and real-time energy component of LMP (SMP). Total energy charges are equal to the load energy payments minus generation energy credits, plus explicit energy charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

Due to losses, total generation will be greater than total load in any hour. Since the hourly integrated energy component of LMP is the same across every bus in every hour, the net energy bill is negative, with more generation credits than load charges in any given hour. This net energy bill is netted against total net marginal loss charges plus net residual market adjustments, which provides for full recovery of generation charges, with any remainder distributed back to load and exports as marginal loss credits.

Total Calendar Year Energy Costs

Table 10-5 shows total energy, loss and congestions charges and total PJM billing, for the January through March period of each year from 2009 through 2012.

Table 10-5 Total PJM charges by component (Dollars (Millions)): January through March, 2011 and 2012[6] (See 2011 SOM, Table 10-5)

	PJM Billing Charges (Millions)					
(Jan-Mar)	Energy Charges	Loss Charges	Congestion Charges	Total Charges	Total PJM Billing	Total Charges Percent of PJM Billing
2009	($218)	$454	$309	$544	$7,515	7.2%
2010	($208)	$417	$345	$554	$8,415	6.6%
2011	($210)	$410	$361	$561	$9,584	5.9%
2012	($137)	$234	$123	$221	$6,938	3.2%

Total energy charges are shown in Table 10-6. Table 10-6 shows the first quarter for 2009 through 2012 energy costs by market category.

Table 10-6 Total PJM energy costs by market category (Dollars (Millions)): January through March, 2011 and 2012 (See 2011 SOM, Table 10-7)

	Energy Costs (Millions)									
	Day Ahead				Balancing					
(Jan-Mar)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2009	$14,129.6	$14,375.6	$0.0	($246.0)	($71.2)	($98.2)	$0.0	$27.0	$0.7	($218.3)
2010	$13,408.9	$13,619.2	$0.0	($210.2)	$15.5	$9.8	$0.0	$5.6	($3.0)	($207.6)
2011	$12,055.5	$12,259.3	$0.0	($203.9)	($111.6)	($98.6)	$0.0	($12.9)	$6.9	($209.9)
2012	$8,407.2	$8,521.8	$0.0	($114.5)	($47.2)	($18.4)	$0.0	($28.8)	$6.8	($136.5)

6 The Energy Charges, Loss Charges and Congestion Charges include net inadvertent charges.

Monthly Energy Costs

Table 10-7 shows a monthly summary of energy costs by type for the first quarter of 2011 and 2012.

Table 10-7 Monthly energy costs by type (Dollars (Millions)): January through March, 2011 and 2012 (See 2011 SOM, Table 10-8)

	Energy Costs (Millions)							
	2011 (Jan-Mar)				2012 (Jan-Mar)			
	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)	($47.8)	($10.1)	$2.5	($55.4)
Feb	($61.1)	($2.4)	$2.3	($61.2)	($35.4)	($9.4)	$2.4	($42.3)
Mar	($52.4)	($5.4)	$2.4	($55.4)	($31.4)	($9.3)	$1.9	($38.8)
Total	($203.9)	($12.9)	$6.9	($209.9)	($114.5)	($28.8)	$6.8	($136.5)

Marginal Losses

Marginal Loss Accounting

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

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

Marginal loss charges can be both positive and negative and consequently the load payments and generation credits can also be both positive and negative. The loss component of LMP is calculated with respect to the system reference bus LMP, also called 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.

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 March.

Monthly marginal loss costs in the first quarter of 2012 ranged from $61.9 million in March to $95.2 million in January.

The marginal loss credits decreased by $102.4 million or 51.2 percent, from $200.1 million in the first quarter of 2011 to $97.7 million in the first quarter of 2012.

Total Calendar Year Marginal Loss Costs.

Table 10-8 shows total marginal loss charges for the first quarter for 2009 through 2012.

Table 10-8 Total[7] PJM Marginal Loss Charges (Dollars (Millions)): January through March, 2011 and 2012 (See 2011 SOM, Table 10-9)

	Marginal Loss Costs (Millions)				
(Jan-Mar)	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2009	($21.3)	($460.6)	$14.7	$0.0	$454.0
2010	($3.8)	($414.1)	$6.3	($0.0)	$416.6
2011	($26.5)	($421.2)	$14.9	$0.0	$409.6
2012	($11.1)	($252.1)	($6.6)	$0.0	$234.4

Total marginal loss costs for the first quarter for 2009 through 2012 are shown in Table 10-9 and Table 10-10. Table 10-9 shows the first quarter for 2009 through 2012 PJM marginal loss costs by category and Table 10-10 shows the first quarter for 2009 through 2012 PJM marginal loss costs by market category.

7 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 10-9 Total PJM marginal loss costs by category (Dollars (Millions)): January through March, 2011 and 2012 (See 2011 SOM, Table 10-10)

	Marginal Loss Costs (Millions)				
(Jan-Mar)	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2009	($21.3)	($460.6)	$14.7	$0.0	$454.0
2010	($3.8)	($414.1)	$6.3	($0.0)	$416.6
2011	($26.5)	($421.2)	$14.9	$0.0	$409.6
2012	($11.1)	($252.1)	($6.6)	$0.0	$234.4

Table 10-10 Total PJM marginal loss costs by market category (Dollars (Millions)): January through March, 2011 and 2012 (See 2011 SOM, Table 10-11)

	Marginal Loss Costs (Millions)									
	Day Ahead				Balancing					
(Jan-Mar)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2009	($23.3)	($457.6)	$30.9	$465.2	$2.1	($3.0)	($16.3)	($11.2)	$0.0	$454.0
2010	($8.5)	($413.5)	$12.8	$417.8	$4.7	($0.6)	($6.5)	($1.2)	($0.0)	$416.6
2011	($37.1)	($430.1)	$26.0	$419.1	$10.6	$8.9	($11.1)	($9.5)	$0.0	$409.6
2012	($16.5)	($256.8)	$8.0	$248.3	$5.4	$4.7	($14.6)	($13.9)	$0.0	$234.4

Monthly Marginal Loss Costs

Table 10-11 shows a monthly summary of marginal loss costs by type for the first quarter for 2011 and 2012.

Table 10-11 Monthly marginal loss costs by type (Dollars (Millions)): January through March, 2011 and 2012 (See 2011 SOM, Table 10-12)

	Marginal Loss Costs (Millions)							
	2011 (Jan-Mar)				2012 (Jan-Mar)			
	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	($3.2)	$0.0	$77.2
Mar	$108.7	($4.8)	$0.0	$103.9	$67.2	($5.3)	$0.0	$61.9
Total	$419.0	($9.5)	$0.0	$409.5	$248.3	($13.9)	$0.0	$234.4

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 charges). 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 charges). Ignoring interchange, the existence of losses will cause total generation to be greater than total load in any hour. Since the hourly integrated energy component of LMP is the same across every generator and load bus in every hour, the net energy bill will be negative (ignoring net interchange), with more generation credits than load charges collected in any given hour. This net energy bill is netted against total net marginal loss charges and net residual market adjustments, with the remainder distributed back to load and exports as marginal loss credits. Residual market adjustments consist of the known day-ahead error value, day-ahead loss MW congestion value and balancing loss MW congestion value. The known day-ahead error value is the financial calculation for the MW imbalance created when the day-ahead case is solved. The day-ahead and balancing loss MW congestion values are congestion values associated with loss MW that need to be deducted from the net of the total marginal loss costs, total energy costs and day-ahead known error value before marginal loss credits can be distributed.

Table 10-12 shows the total net energy charges, the total net marginal loss charges collected, the net residual market adjustments and total loss credits redistributed in the first quarter for 2009 and 2012.

Table 10-12 Marginal[8] loss credits (Dollars (Millions)): January through March, 2009 through 2012 (See 2011 SOM, Table 10-13)

	Loss Credit Accounting (Millions)			
(Jan-Mar)	Total Energy Charges	Total Marginal Loss Charges	Adjustments	Loss Credits
2009	($218.3)	$454.0	($0.9)	$236.6
2010	($207.6)	$416.6	$0.0	$208.9
2011	($209.9)	$409.6	($0.5)	$200.1
2012	($136.5)	$234.4	$0.1	$97.7

Congestion

Congestion Accounting

Transmission congestion can exist in PJM's Day-Ahead and Real-Time Energy Market.[9] Total congestion charges are equal to the net congestion bill plus explicit congestion charges plus net inadvertent congestions charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

The net congestion bill is calculated by subtracting generating congestion credits from load congestion payments. The logic is that increased congestion payments by load are offset by increased congestion revenues to generation, for the area analyzed. Whether the net congestion bill is an appropriate measure of congestion for load depends on who pays the load congestion payments and who receives the generation congestion credits. The net congestion bill is an appropriate measure of congestion for a utility that charges load congestion payments to load and credits generation congestion credits to

8 Based on currently available data, the MMU is not able to independently calculate residual market adjustments. The adjustments numbers included in the table are comprised of the sum of the known day-ahead error value, day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data. In sum, these elements reflect the difference between actual PJM loss credits and MMU calculations of loss credits based on available data.

9 The terms *congestion charges* and *congestion costs* are both used to refer to the costs associated with congestion. The term, *congestion charges*, is used in documents by PJM's Market Settlement Operations.

load. The net congestion bill is not an appropriate measure of congestion in situations where load pays the load congestion payments but does not receive the generation credits as an offset.

In the 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.[10] A billing organization may offset load congestion payments with its generation portfolio or by purchasing supply from another entity via a bilateral transaction.

Load Congestion Payments and Generation Congestion Credits are calculated for both the Day-Ahead and Balancing Energy Markets.

The congestion charges associated with specific constraints are the sum of the total day-ahead and balancing congestion costs associated with those constraints. The congestion charges in each zone are the sum of the congestion charges associated with each constraint that affects prices in the zone. The network nature of the transmission system means that congestion costs in a zone are frequently the result of constrained facilities located outside that zone.

Congestion costs can be both positive and negative and consequently load payments and generation credits can also 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.[11]

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 March.

Total Calendar Year Congestion

Congestion charges have ranged from 2.7 percent to 9.6 percent of annual total PJM billings since 2000.[12] Table 10-13 shows total congestion by year from 1999 through March 2012.[13]

Table 10-13 Total annual PJM congestion (Dollars (Millions)): Calendar years 1999 to March 2012 (See 2011 SOM, Table 10-14)

	Congestion Charges	Percent Change	Total PJM Billing	Percent of PJM Billing
1999	$65	NA	NA	NA
2000	$132	103.1%	$2,300	5.7%
2001	$271	105.3%	$3,400	8.0%
2002	$453	67.2%	$4,700	9.6%
2003	$464	2.4%	$6,900	6.7%
2004	$750	61.7%	$8,700	8.6%
2005	$2,092	178.8%	$22,630	9.2%
2006	$1,603	(23.4%)	$20,945	7.7%
2007	$1,846	15.1%	$30,556	6.0%
2008	$2,117	14.7%	$34,306	6.2%
2009	$719	(66.0%)	$26,550	2.7%
2010	$1,424	98.1%	$34,770	4.1%
2011	$998	(29.9%)	$35,887	2.8%
2012 (Jan - Mar)	$123		$6,938	1.8%

Figure 10-1 shows PJM monthly congestion for January 2008 through March 2012.

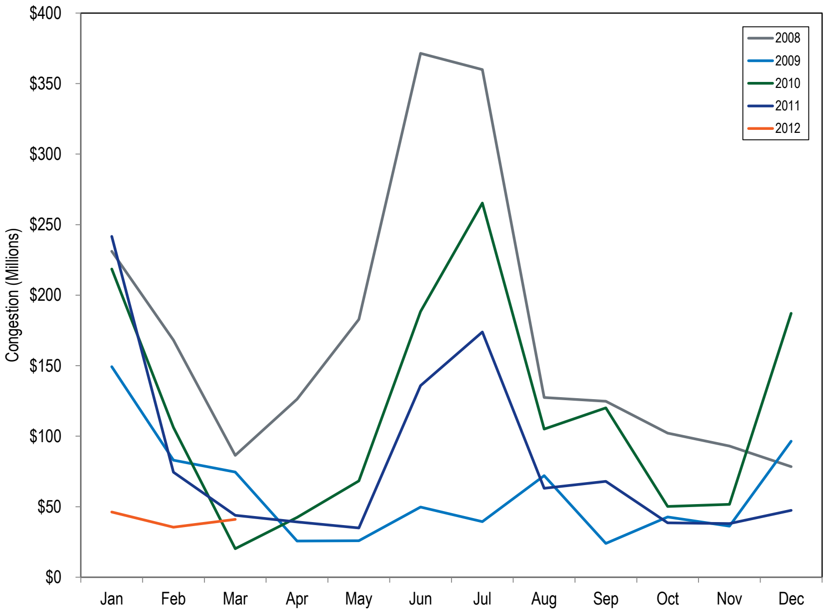
10 This analysis does not treat affiliated billing organizations as a single organization. Thus, the generation congestion credits from one organization will not offset the load payments of its affiliate. This may overstate or understate the actual load payments or generation credits of an organization's parent company.

11 For an example of the congestion accounting methods used in this section, see *MMU Technical Reference for PJM Markets*, at "FTRs and ARRs."

12 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.

13 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 March 2012 (New Figure)



Total congestion charges in Table 10-14 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO.[14]

Table 10-15 shows the PJM congestion costs by category for the first three months of 2012. The January through March 2012 PJM total congestion costs were comprised of $19.1 million in load congestion payments, $118.2 million in negative generation congestion credits, and $14.5 million in negative explicit congestion costs.

Table 10-14 Total annual PJM congestion costs by category (Dollars (Millions)): January through March, 2011 and 2012 (See 2011 SOM, Table 10-15)

	Congestion Costs (Millions)				
Year	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2011 (Jan - Mar)	$65.5	($331.6)	($37.2)	$0.0	$359.9
2012 (Jan - Mar)	$19.1	($118.2)	($14.5)	$0.0	$122.8

14 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 annual PJM congestion costs by market category (Dollars (Millions)): January through March, 2011 and 2012 (See 2011 SOM, Table 10-16)

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Year	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2011 (Jan - Mar)	$38.5	($364.7)	$4.1	$407.3	$27.0	$33.1	($41.2)	($47.4)	$0.0	$359.9
2012 (Jan - Mar)	$23.9	($129.9)	$27.5	$181.3	($4.8)	$11.7	($42.0)	($58.5)	$0.0	$122.8

Monthly Congestion

Table 10-16 shows that during the first three months of 2012, monthly congestion charges ranged from $35.5 million to $46.3 million. Table 10-17 shows the congestion charges during the first three months of 2011.

Monthly congestion costs in the first three months of 2012 were substantially lower than for corresponding months in the first three months of 2011.

Table 10-16 Monthly PJM congestion charges (Dollars (Millions)): January through March 2012 (See 2011 SOM, Table 10-17)

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Month	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	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	$9.2	($38.3)	$7.4	$54.9	($3.8)	$2.7	($12.8)	($19.4)	$0.0	$35.5
Mar	$10.7	($38.5)	$10.9	$60.1	($2.0)	$3.3	($13.8)	($19.1)	$0.0	$41.0
Total	$23.9	($129.9)	$27.5	$181.3	($4.8)	$11.7	($42.0)	($58.5)	$0.0	$122.8

Table 10-17 Monthly PJM congestion charges (Dollars (Millions)): January through March 2011 (See 2011 SOM, Table 10-18)

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Month	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	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
Total	$38.5	($364.7)	$4.1	$407.3	$27.0	$33.1	($41.2)	($47.4)	$0.0	$359.9

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 three months of 2012, there were 54,144 day-ahead, congestion-event hours compared to 25,088 day-ahead, congestion-event hours in the first three months of 2011. In the first three months of 2012, there were 4,101 real-time, congestion-event hours compared to 4,399 real-time, congestion-event hours in the first three months of 2011.

Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. Virtual transactions in the Day-Ahead Market can be used to discretely resolve, without eliminating, constraints on the transmission system. Relative to the Day-Ahead Market, the Real-Time Market has relatively inflexible resources to resolve transmission constraints which means that constraints are often eliminated, rather than discretely controlled.

During the first three months of 2012, for only 3.5 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. During the first three months of 2012, for 46.0 percent of Real-Time Market facility constrained hours, the same facilities were also constrained in the Day-Ahead Market.

The Graceton – Raphael Road transmission line was the largest contributor to congestion costs in the first three months of 2012. With $20.6 million in total congestion costs, it accounted for 16.8 percent of the total PJM congestion costs in the first three months of 2012. The top five constraints in terms of congestion costs together contributed $53.9 million, or 43.9 percent, of the total PJM congestion costs in the first three months of 2012. The top five constraints were the Graceton – Raphael Road transmission line, AP South interface, Belvidere – Woodstock flowgate, West interface, and the Breed – Wheatland flowgate.

Congestion by Facility Type and Voltage

In the first three months of 2012 compared to the first three 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 and transmission lines in the first three months of 2012 compared to the first three months of 2011 and decreased on PJM interfaces and transformers in the first three months of 2012 compared to the first three 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 three months of 2012 compared to first three months of 2011.

Table 10-18 provides congestion-event hour subtotals and congestion cost subtotals comparing the first three months of 2012 results by facility type: line, transformer, interface, flowgate and unclassified facilities. [15,16] For comparison, this information is presented in Table 10-19 for the first three months of 2011.[17]

Table 10-18 Congestion summary (By facility type): January through March 2012 (See 2011 SOM, Table 10-19)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	($13.4)	($48.4)	$12.2	$47.2	$0.3	$2.6	($28.8)	($31.0)	$16.2	6,983	1,572
Interface	$12.2	($25.4)	($0.2)	$37.5	$2.3	$3.5	($2.2)	($3.5)	$34.0	1,649	179
Line	$21.5	($41.5)	$12.5	$75.5	($6.8)	$4.5	($10.3)	($21.6)	$54.0	32,370	1,915
Other	$1.0	($0.9)	($0.1)	$1.8	($0.6)	($0.2)	$0.2	($0.3)	$1.5	799	196
Transformer	$2.2	($13.2)	$2.7	$18.1	$0.1	$1.3	($0.7)	($1.8)	$16.3	12,343	239
Unclassified	$0.2	($0.5)	$0.4	$1.0	($0.1)	$0.1	($0.2)	($0.3)	$0.8	NA	NA
Total	$23.9	($129.9)	$27.5	$181.3	($4.8)	$11.7	($42.0)	($58.5)	$122.8	54,144	4,101

Table 10-19 Congestion summary (By facility type): January through March 2011 (See 2011 SOM, Table 10-20)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
Flowgate	($22.0)	($39.9)	($0.9)	$17.0	$5.3	$4.2	($21.4)	($20.3)	($3.3)	2,759	1,100
Interface	$37.8	($215.0)	($5.4)	$247.4	$17.0	$17.4	$3.1	$2.7	$250.1	2,954	877
Line	$4.2	($63.6)	$6.0	$73.8	$3.5	$10.4	($18.6)	($25.5)	$48.3	13,626	1,482
Other	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.1	$0.1	0	2
Transformer	$17.5	($46.0)	$2.2	$65.7	$0.7	$1.1	($4.1)	($4.4)	$61.3	5,749	938
Unclassified	$1.0	($0.1)	$2.2	$3.3	$0.4	$0.0	($0.2)	$0.2	$3.5	NA	NA
Total	$38.5	($364.7)	$4.1	$407.3	$27.0	$33.1	($41.2)	($47.4)	$359.9	25,088	4,399

15 Unclassified constraints appear in the Day-Ahead Market only and represent congestion costs incurred on market elements which are not posted by PJM. Congestion frequency associated with these unclassified constraints is not presented in order to be consistent with the posting of constrained facilities by PJM.
16 The term flowgate refers to MISO flowgates.
17 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.

Table 10-20 and Table 10-21 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 10-20. In the first three months of 2012, there were 54,144 congestion event hours in the Day-Ahead Market. Among those, only 1,895 (3.5 percent) were also constrained in the Real-Time Market. In the first three months of 2011, among the 25,088 day-ahead congestion event hours, only 2,009 (8.0 percent) were binding in the Real-Time Market.[18]

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 10-21. In the first three months of 2012, there were 4,101 congestion event hours in the Real-Time Market. Among these, 1,877 (46.0 percent) were also constrained in the Day-Ahead Market. In the first three months of 2011, among the 4,399 real-time congestion event hours, only 2,010 (45.7 percent) were binding in the day-ahead.

Table 10-20 Congestion Event Hours (Day-Ahead against Real Time): January through March 2011 and 2012 (See 2011 SOM, Table 10-21)

	Congestion Event Hours					
	2012 (Jan - Mar)			2011 (Jan - Mar)		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	6,983	717	10.3%	2,759	460	16.7%
Interface	1,649	77	4.7%	2,954	683	23.1%
Line	32,370	971	3.0%	13,626	384	2.8%
Other	799	40	5.0%	0	0	0.0%
Transformer	12,343	90	0.7%	5,749	482	8.4%
Total	54,144	1,895	3.5%	25,088	2,009	8.0%

18 Both regular and contingency constraints are mapped to transmission facilities. In the day-ahead market, within a given hour, a single facility may be associated with both regular and multiple contingency 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. The result is that the number of hours where real time constraints are observed in day ahead market results may not match.

Table 10-21 Congestion Event Hours (Real Time against Day-Ahead): January through March 2011 and 2012 (See 2011 SOM, Table 10-22)

	Congestion Event Hours					
	2012 (Jan - Mar)			2011 (Jan - Mar)		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	1,572	755	48.0%	1,100	466	42.4%
Interface	179	77	43.0%	877	682	77.8%
Line	1,915	925	48.3%	1,482	380	25.6%
Other	196	40	20.4%	2	0	0.0%
Transformer	239	90	37.7%	938	482	51.4%
Total	4,101	1,887	46.0%	4,399	2,010	45.7%

Table 10-22 shows congestion costs by facility voltage class for the first three months of 2012. In comparison to the first three months of 2011 (shown in Table 10-23), congestion costs increased across 765 kV, 345 kV, 138 kV, 115 kV and 34 kV in the first three months of 2012.

Table 10-22 Congestion summary (By facility voltage): Calendar year 2012 (See 2011 SOM, Table 10-23)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	($0.1)	($1.6)	$1.2	$2.7	$0.1	($0.0)	($0.1)	($0.0)	$2.7	874	69
500	$13.0	($29.7)	$0.2	$42.9	$2.0	$4.7	($2.6)	($5.3)	$37.7	3,099	237
345	($8.6)	($32.4)	$5.1	$29.0	$0.8	$1.2	($12.8)	($13.3)	$15.7	8,305	684
230	$18.3	($13.2)	$0.1	$31.6	($1.2)	$1.0	$0.9	($1.3)	$30.3	8,718	1,003
161	($3.9)	($6.3)	$3.3	$5.8	($0.4)	$0.2	($4.4)	($5.0)	$0.8	1,320	340
138	($2.9)	($46.8)	$16.3	$60.3	($1.5)	$4.2	($22.0)	($27.7)	$32.5	26,301	1,551
115	$2.4	$0.1	$0.3	$2.6	($0.4)	$0.2	($0.0)	($0.7)	$2.0	3,137	75
69	$5.3	$0.3	$0.5	$5.5	($4.0)	$0.1	($0.9)	($5.0)	$0.5	2,386	142
34	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
12	($0.0)	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	4	0
Unclassified	$0.3	($0.2)	$0.4	$0.9	($0.1)	$0.1	($0.2)	($0.3)	$0.6	NA	NA
Total	$23.9	($129.9)	$27.5	$181.3	($4.8)	$11.7	($42.0)	($58.5)	$122.8	54,144	4,101

Table 10-23 Congestion summary (By facility voltage): Calendar year 2011 (See 2011 SOM, Table 10-24)

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
765	$0.4	($1.0)	$0.3	$1.6	$2.3	$1.7	($2.0)	($1.4)	$0.2	45	76
500	$56.2	($238.4)	($5.7)	$288.9	$20.3	$19.6	($0.6)	$0.2	$289.0	6,120	1,573
345	($24.6)	($63.3)	$3.6	$42.3	$4.2	$7.6	($27.0)	($30.4)	$11.9	6,063	1,044
230	($2.6)	($39.6)	($0.3)	$36.7	$1.1	$1.2	($0.3)	($0.3)	$36.4	4,264	420
161	($0.3)	($0.5)	$0.2	$0.4	($0.1)	$0.3	($1.3)	($1.7)	($1.2)	52	62
138	$3.5	($20.9)	$3.7	$28.1	($0.6)	$1.5	($9.6)	($11.6)	$16.5	5,908	1,071
115	$2.5	$0.4	$0.2	$2.3	($0.1)	$0.6	($0.1)	($0.7)	$1.6	940	84
69	$2.5	($1.2)	($0.0)	$3.6	($0.7)	$0.8	($0.2)	($1.6)	$2.0	1,687	69
34	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	0	0
12	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	9	0
Unclassified	$1.0	($0.1)	$2.2	$3.3	$0.4	$0.0	($0.2)	$0.2	$3.5	NA	NA
Total	$38.5	($364.7)	$4.1	$407.3	$27.0	$33.1	($41.2)	($47.4)	$359.9	25,088	4,399

Constraint Duration

Table 10-24 lists constraints in the first three months of 2011 and 2012 that were most frequently in effect and Table 10-25 shows the constraints which experienced the largest change in congestion-event hours from the first three months of 2011 to the first three months of 2012.

Table 10-24 Top 25 constraints with frequent occurrence: January through March 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	2,257	2,257	0	0	0	0%	26%	26%	0%	0%	0%
2	Graceton - Raphael Road	Line	10	1,392	1,382	11	407	396	0%	16%	16%	0%	5%	5%
3	Oak Grove - Galesburg	Flowgate	52	1,320	1,268	62	340	278	1%	15%	14%	1%	4%	3%
4	Crete - St Johns Tap	Flowgate	1,494	1,189	(305)	394	155	(239)	17%	14%	(4%)	4%	2%	(3%)
5	Rockwell - Crosby	Line	0	1,321	1,321	0	0	0	0%	15%	15%	0%	0%	0%
6	Belmont	Transformer	1,527	1,266	(261)	105	49	(56)	17%	14%	(3%)	1%	1%	(1%)
7	Wolfcreek	Transformer	716	1,187	471	94	9	(85)	8%	14%	5%	1%	0%	(1%)
8	Huntingdon - Huntingdon1	Line	0	1,126	1,126	0	0	0	0%	13%	13%	0%	0%	0%
9	Conesville 138	Transformer	0	1,107	1,107	0	0	0	0%	13%	13%	0%	0%	0%
10	Monticello - East Winamac	Flowgate	17	796	779	45	295	250	0%	9%	9%	1%	3%	3%
11	Conesville 345	Transformer	0	1,038	1,038	0	0	0	0%	12%	12%	0%	0%	0%
12	Kammer	Transformer	0	995	995	0	0	0	0%	11%	11%	0%	0%	0%
13	AP South	Interface	1,172	881	(291)	513	73	(440)	13%	10%	(3%)	6%	1%	(5%)
14	Howard - Shelby	Line	0	942	942	0	0	0	0%	11%	11%	0%	0%	0%
15	Belvidere - Woodstock	Line	68	537	469	12	374	362	1%	6%	5%	0%	4%	4%
16	Linden - VFT	Line	532	908	376	0	0	0	6%	10%	4%	0%	0%	0%
17	Brues - West Bellaire	Line	79	854	775	71	13	(58)	1%	10%	9%	1%	0%	(1%)
18	Emilie - Falls	Line	789	842	53	0	0	0	9%	10%	1%	0%	0%	0%
19	Silver Lake - Pleasant Valley	Line	0	817	817	0	0	0	0%	9%	9%	0%	0%	0%
20	East Towanda - S.Troy	Line	15	779	764	0	0	0	0%	9%	9%	0%	0%	0%
21	Big Sandy - Grangston	Line	29	777	748	0	0	0	0%	9%	9%	0%	0%	0%
22	Cumberland - Bush	Flowgate	211	646	435	22	119	97	2%	7%	5%	0%	1%	1%
23	Hillsdale - New Milford	Line	0	679	679	0	81	81	0%	8%	8%	0%	1%	1%
24	Breed - Wheatland	Flowgate	0	500	500	0	172	172	0%	6%	6%	0%	2%	2%
25	Belvidere - Woodstock	Flowgate	0	631	631	0	0	0	0%	7%	7%	0%	0%	0%

Table 10-25 Top 25 constraints with largest year-to-year change in occurrence: January through March 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	2,257	2,257	0	0	0	0%	26%	26%	0%	0%	0%
2	South Mahwah - Waldwick	Line	1,706	23	(1,683)	203	0	(203)	19%	0%	(19%)	2%	0%	(2%)
3	Graceton - Raphael Road	Line	10	1,392	1,382	11	407	396	0%	16%	16%	0%	5%	5%
4	Oak Grove - Galesburg	Flowgate	52	1,320	1,268	62	340	278	1%	15%	14%	1%	4%	3%
5	Wylie Ridge	Transformer	1,235	54	(1,181)	329	0	(329)	14%	1%	(13%)	4%	0%	(4%)
6	Rockwell - Crosby	Line	0	1,321	1,321	0	0	0	0%	15%	15%	0%	0%	0%
7	Huntingdon - Huntingdon1	Line	0	1,126	1,126	0	0	0	0%	13%	13%	0%	0%	0%
8	Conesville 138	Transformer	0	1,107	1,107	0	0	0	0%	13%	13%	0%	0%	0%
9	Conesville 345	Transformer	0	1,038	1,038	0	0	0	0%	12%	12%	0%	0%	0%
10	Monticello - East Winamac	Flowgate	17	796	779	45	295	250	0%	9%	9%	1%	3%	3%
11	Kammer	Transformer	0	995	995	0	0	0	0%	11%	11%	0%	0%	0%
12	Howard - Shelby	Line	0	942	942	0	0	0	0%	11%	11%	0%	0%	0%
13	Belvidere - Woodstock	Line	68	537	469	12	374	362	1%	6%	5%	0%	4%	4%
14	Silver Lake - Pleasant Valley	Line	0	817	817	0	0	0	0%	9%	9%	0%	0%	0%
15	East Towanda - S.Troy	Line	15	779	764	0	0	0	0%	9%	9%	0%	0%	0%
16	Hillsdale - New Milford	Line	0	679	679	0	81	81	0%	8%	8%	0%	1%	1%
17	Big Sandy - Grangston	Line	29	777	748	0	0	0	0%	9%	9%	0%	0%	0%
18	Pleasant Prairie - Zion	Flowgate	593	0	(593)	140	0	(140)	7%	0%	(7%)	2%	0%	(2%)
19	AP South	Interface	1,172	881	(291)	513	73	(440)	13%	10%	(3%)	6%	1%	(5%)
20	Brues - West Bellaire	Line	79	854	775	71	13	(58)	1%	10%	9%	1%	0%	(1%)
21	Breed - Wheatland	Flowgate	0	500	500	0	172	172	0%	6%	6%	0%	2%	2%
22	Belvidere - Woodstock	Flowgate	0	631	631	0	0	0	0%	7%	7%	0%	0%	0%
23	Evert - South Troy	Line	0	626	626	0	0	0	0%	7%	7%	0%	0%	0%
24	Lake Nelson - Middlesex	Line	22	621	599	0	0	0	0%	7%	7%	0%	0%	0%
25	Bedington - Black Oak	Interface	573	0	(573)	0	2	2	7%	0%	(7%)	0%	0%	0%

Constraint Costs

Table 10-26 and Table 10-27 present the top constraints affecting congestion costs by facility for the periods January through March 2012 and 201.

Table 10-26 Top 25 constraints affecting annual PJM congestion costs (By facility): January through March 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	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2012 (Jan - Mar)
1	Graceton - Raphael Road	Line	BGE	$12.8	($8.9)	($2.4)	$19.2	$0.1	$0.1	$1.3	$1.3	$20.6	17%
2	AP South	Interface	500	$14.3	($7.6)	$0.1	$22.0	$1.3	$1.0	($2.2)	($2.0)	$20.1	16%
3	Belvidere - Woodstock	Flowgate	ComEd	($2.2)	($13.0)	$1.3	$12.2	$0.0	$0.0	$0.0	$0.0	$12.2	10%
4	West	Interface	500	$0.4	($6.2)	($0.3)	$6.3	$0.0	$0.0	($0.0)	($0.0)	$6.3	5%
5	Breed - Wheatland	Flowgate	MISO	($0.7)	($4.0)	($0.0)	$3.4	$0.2	$0.3	($8.5)	($8.6)	($5.2)	(4%)
6	Crete - St Johns Tap	Flowgate	MISO	($2.7)	($9.7)	($0.4)	$6.6	$0.2	$0.5	($2.0)	($2.4)	$4.2	3%
7	Lancaster - Maryland	Line	ComEd	$0.2	($0.2)	$0.2	$0.7	($0.4)	$0.6	($3.5)	($4.4)	($3.8)	(3%)
8	East	Interface	500	($2.3)	($7.1)	($0.6)	$4.2	$0.1	$0.5	($0.1)	($0.5)	$3.7	3%
9	Silver Lake - Pleasant Valley	Line	ComEd	($2.2)	($4.8)	$1.0	$3.7	$0.0	$0.0	$0.0	$0.0	$3.7	3%
10	Belmont	Transformer	AP	$0.8	($4.2)	$0.4	$5.3	($0.3)	$1.1	($0.4)	($1.8)	$3.5	3%
11	Electric Jct - Nelson	Line	ComEd	($0.9)	($3.1)	$1.1	$3.3	$0.0	$0.0	($0.0)	($0.0)	$3.3	3%
12	5004/5005 Interface	Interface	500	$0.2	($3.0)	$0.4	$3.6	$0.7	$1.6	$0.1	($0.8)	$2.8	2%
13	Jefferson - Clifty Creek	Line	AEP	($0.1)	($1.9)	$0.8	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	2%
14	Kammer	Transformer	AEP	($0.8)	($3.2)	($0.3)	$2.1	$0.0	$0.0	$0.0	$0.0	$2.1	2%
15	Brues - West Bellaire	Line	AEP	$1.6	($0.6)	($0.3)	$1.9	($0.0)	$0.0	$0.0	($0.0)	$1.9	2%
16	Belvidere - Woodstock	Line	ComEd	($0.1)	($3.9)	$0.7	$4.6	($1.2)	$1.1	($4.0)	($6.3)	($1.7)	(1%)
17	Breed - Wheatland	Line	AEP	($0.9)	($2.6)	($0.0)	$1.6	$0.0	$0.0	$0.0	$0.0	$1.6	1%
18	Burnham - Munster	Line	ComEd	($0.1)	($0.3)	$0.1	$0.3	$0.0	$0.3	($1.6)	($1.9)	($1.6)	(1%)
19	Monticello - East Winamac	Flowgate	MISO	$0.0	($5.9)	$4.2	$10.1	$0.3	$1.2	($7.6)	($8.6)	$1.5	1%
20	Lake Nelson - Middlesex	Line	PSEG	$1.3	$0.2	$0.4	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	1%
21	Mazon - Mazon	Line	ComEd	($0.3)	($1.3)	$0.7	$1.8	($0.0)	($0.0)	($0.3)	($0.3)	$1.5	1%
22	Wolfcreek	Transformer	AEP	$0.1	($1.2)	$0.3	$1.5	($0.0)	($0.0)	($0.1)	($0.1)	$1.5	1%
23	Jefferson - Rockport	Line	AEP	($0.0)	($0.8)	$0.6	$1.5	$0.0	$0.0	$0.0	$0.0	$1.5	1%
24	Potomac River	Transformer	Pepco	$1.3	$0.0	$0.1	$1.4	$0.0	$0.0	$0.0	$0.0	$1.4	1%
25	Prairie State - W Mt. Vernon	Flowgate	MISO	($1.6)	($2.5)	$0.5	$1.4	($0.0)	($0.0)	($0.1)	($0.1)	$1.3	1%

Table 10-27 Top 25 constraints affecting annual PJM congestion costs (By facility): January through March 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	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	2011 (Jan - Mar)
1	AP South	Interface	500	$53.9	($78.9)	$0.5	$133.3	$9.9	$10.0	($0.6)	($0.7)	$132.6	37%
2	5004/5005 Interface	Interface	500	($22.1)	($85.8)	($4.4)	$59.3	$6.0	$5.7	$3.6	$4.0	$63.2	18%
3	Bedington - Black Oak	Interface	500	$10.4	($14.2)	($2.0)	$22.5	$0.0	$0.0	$0.0	$0.0	$22.5	6%
4	Belmont	Transformer	AP	$5.9	($20.4)	($2.2)	$24.1	($1.6)	($0.5)	($0.7)	($1.8)	$22.3	6%
5	Susquehanna	Transformer	PPL	($2.9)	($17.4)	($0.1)	$14.4	$0.0	$0.0	$0.0	$0.0	$14.4	4%
6	AEP-DOM	Interface	500	$4.7	($8.5)	$0.8	$14.0	$0.6	$0.4	($0.1)	$0.2	$14.2	4%
7	Crete - St Johns Tap	Flowgate	MISO	($19.5)	($34.0)	($4.0)	$10.6	$3.8	$1.8	($0.9)	$1.2	$11.7	3%
8	West	Interface	500	($3.4)	($13.2)	($0.1)	$9.7	$0.2	$0.0	$0.1	$0.3	$10.0	3%
9	Wylie Ridge	Transformer	AP	$10.9	$2.5	$1.7	$10.1	$1.5	$0.6	($2.2)	($1.4)	$8.7	2%
10	East	Interface	500	($4.5)	($12.3)	($0.2)	$7.6	$0.2	$1.3	$0.1	($1.0)	$6.6	2%
11	Lakeview - Pleasant Prairie	Flowgate	MISO	($0.1)	($0.2)	$0.2	$0.3	($0.2)	$0.0	($4.2)	($4.4)	($4.1)	(1%)
12	Bridgewater - Middlesex	Line	PSEG	$0.1	($4.1)	$0.1	$4.3	$0.1	$0.2	($0.3)	($0.4)	$3.9	1%
13	Cloverdale - Lexington	Line	500	$2.0	($0.9)	$0.1	$3.0	$2.7	$1.3	($0.5)	$1.0	$3.9	1%
14	Pleasant Prairie - Zion	Flowgate	MISO	($0.2)	($0.9)	$1.7	$2.5	($0.1)	($0.2)	($6.2)	($6.2)	($3.7)	(1%)
15	Butler - Karns City	Line	AP	$1.2	($2.3)	($0.1)	$3.4	($0.1)	($0.3)	($0.0)	$0.2	$3.5	1%
16	Unclassified	Unclassified	Unclassified	$1.0	($0.1)	$2.2	$3.3	$0.4	$0.0	($0.2)	$0.2	$3.5	1%
17	Cedar Grove - Roseland	Line	PSEG	($0.2)	($3.7)	($0.9)	$2.6	$0.4	$0.5	$0.8	$0.7	$3.3	1%
18	Electric Jct - Nelson	Line	ComEd	($1.2)	($6.1)	$1.4	$6.4	($0.1)	$0.3	($2.8)	($3.1)	$3.2	1%
19	Plymouth Meeting - Whitpain	Line	PECO	($0.3)	($3.2)	$0.0	$2.9	$0.1	$0.0	($0.1)	($0.0)	$2.9	1%
20	Wolfcreek	Transformer	AEP	$1.9	($1.0)	($0.3)	$2.6	($0.2)	($0.2)	($0.1)	($0.0)	$2.6	1%
21	Bristers - Ox	Line	Dominion	($0.1)	($2.7)	$0.0	$2.6	$0.3	$0.3	($0.1)	($0.2)	$2.4	1%
22	Collier - Elwyn	Line	DLCO	($0.1)	($2.1)	$0.1	$2.1	$0.1	($0.1)	($0.0)	$0.1	$2.3	1%
23	Rising	Flowgate	MISO	($1.0)	($1.5)	$0.1	$0.7	$0.2	$0.7	($2.3)	($2.8)	($2.1)	(1%)
24	Limerick	Transformer	PECO	($0.6)	($2.7)	($0.1)	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	1%
25	Cherry Valley	Transformer	ComEd	$0.8	($1.0)	$0.3	$2.2	$0.0	$0.1	($0.1)	($0.2)	$2.0	1%

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.[19] Aflowgate is a facility or group of facilities that may act as constraint points on the regional system.[20] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch. Table 10-28 and Table 10-29 show the MISO flowgates which PJM and/or MISO took dispatch action to control during the first three 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 three months of 2012, the Crete – St Johns Tap flowgate made the most significant contribution to positive congestion while the Breed - Wheatland flowgate made the most significant contribution to negative congestion.

Table 10-28 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through March 2012 (See 2011 SOM, Table 10-29)

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Breed - Wheatland	($0.7)	($4.0)	($0.0)	$3.4	$0.2	$0.3	($8.5)	($8.6)	($5.2)	500	172
2	Crete - St Johns Tap	($2.7)	($9.7)	($0.4)	$6.6	$0.2	$0.5	($2.0)	($2.4)	$4.2	1,189	155
3	Monticello - East Winamac	$0.0	($5.9)	$4.2	$10.1	$0.3	$1.2	($7.6)	($8.6)	$1.5	796	295
4	Prairie State - W Mt. Vernon	($1.6)	($2.5)	$0.5	$1.4	($0.0)	($0.0)	($0.1)	($0.1)	$1.3	387	110
5	Miami Fort - Hebron	($0.5)	($1.4)	$0.1	$1.1	($0.0)	($0.0)	($0.0)	($0.0)	$1.1	356	33
6	Oak Grove - Galesburg	($3.9)	($6.3)	$3.3	$5.8	($0.4)	$0.2	($4.4)	($5.0)	$0.8	1,320	340
7	Pana North	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.7)	($0.7)	($0.7)	0	11
8	Brokaw - Gibson	($0.5)	($0.9)	$0.2	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	160	0
9	Lanesville	$0.1	($0.1)	$0.3	$0.5	$0.0	$0.0	$0.0	$0.0	$0.5	199	0
10	Burnham - Munster	($0.3)	($0.6)	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	221	0
11	Cumberland - Bush	($0.4)	($2.4)	$2.0	$4.0	$0.0	$0.5	($3.9)	($4.3)	($0.4)	646	119
12	Benton Harbor - Palisades	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.3)	($0.4)	($0.4)	0	5
13	Bunsonville - Eugene	($0.3)	($0.5)	$0.1	$0.3	$0.0	($0.1)	($0.1)	($0.0)	$0.3	90	34
14	Baldwin-Mt Vernon	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.3)	($0.3)	($0.3)	0	137
15	Bloomton - Denoisck	($0.1)	($0.2)	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	42	0
16	Dunes Acres - Michigan City	($0.2)	($0.3)	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	172	0
17	Rising	($0.0)	($0.0)	$0.0	$0.0	($0.1)	$0.0	($0.1)	($0.2)	($0.2)	4	9
18	Gibson - Petersburg	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.1	$0.1	$0.1	0	27
19	Rantoul - Rantoul Jct	($0.1)	($0.2)	$0.1	$0.2	($0.0)	($0.1)	($0.3)	($0.3)	($0.1)	56	52
20	Edwards - Kewanee	($0.0)	($0.1)	$0.1	$0.1	$0.0	$0.0	($0.2)	($0.2)	($0.1)	33	24

19 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).
20 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 March 2011 (See 2011 SOM, Table 10-30)

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	Crete - St Johns Tap	($19.5)	($34.0)	($4.0)	$10.6	$3.8	$1.8	($0.9)	$1.2	$11.7	1,494	394
2	Lakeview - Pleasant Prairie	($0.1)	($0.2)	$0.2	$0.3	($0.2)	$0.0	($4.2)	($4.4)	($4.1)	24	164
3	Pleasant Prairie - Zion	($0.2)	($0.9)	$1.7	$2.5	($0.1)	($0.2)	($6.2)	($6.2)	($3.7)	593	140
4	Rising	($1.0)	($1.5)	$0.1	$0.7	$0.2	$0.7	($2.3)	($2.8)	($2.1)	48	54
5	Eugene - Bunsonville	$0.0	$0.0	$0.0	$0.0	$0.1	$0.2	($1.5)	($1.6)	($1.6)	0	52
6	Oak Grove - Galesburg	($0.3)	($0.5)	$0.2	$0.4	($0.1)	$0.3	($1.3)	($1.7)	($1.2)	52	62
7	Benton Harbor - Palisades	($0.2)	($1.0)	$0.2	$1.0	$1.1	$0.8	($2.3)	($2.0)	($1.0)	67	46
8	Cooper South	$0.0	$0.0	$0.0	$0.0	$0.0	$0.2	($0.6)	($0.8)	($0.8)	0	16
9	Monticello - East Winamac	$0.0	($0.1)	$0.0	$0.1	$0.1	$0.2	($0.7)	($0.8)	($0.7)	17	45
10	Pierce - Foster	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.5)	($0.5)	($0.5)	0	2
11	Rantoul - Rantoul Jct	($0.3)	($0.6)	$0.2	$0.4	$0.0	$0.0	($0.1)	($0.1)	$0.3	37	25
12	Pierce - Foster	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.3)	($0.3)	($0.3)	0	4
13	Lakeview - Zion	($0.0)	($0.1)	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	102	0
14	Roxana - Praxair	$0.0	$0.0	($0.0)	($0.0)	$0.2	$0.1	$0.1	$0.2	$0.2	42	10
15	Bunsonville - Eugene	($0.1)	($0.2)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	36	0
16	Babcock - Stillwell	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1	($0.1)	($0.1)	($0.1)	0	5
17	Cumberland - Bush	($0.1)	($0.4)	$0.1	$0.4	$0.0	$0.1	($0.2)	($0.3)	$0.1	211	22
18	Prairie State - W Mt. Vernon	($0.0)	($0.1)	$0.0	$0.1	($0.0)	$0.0	($0.1)	($0.1)	($0.1)	15	28
19	Dunes Acres - Michigan City	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	($0.1)	0	4
20	Goose Creek - Rising	($0.0)	($0.1)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	15	0

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 10-30 and Table 10-31 show the 500 kV constraints impacting congestion costs in PJM for the first three 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 10-30 Regional constraints summary (By facility): January through March 2012 (See 2011 SOM, Table 10-31)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$14.3	($7.6)	$0.1	$22.0	$1.3	$1.0	($2.2)	($2.0)	$20.1	881	73
2	West	Interface	500	$0.4	($6.2)	($0.3)	$6.3	$0.0	$0.0	($0.0)	($0.0)	$6.3	241	2
3	East	Interface	500	($2.3)	($7.1)	($0.6)	$4.2	$0.1	$0.5	($0.1)	($0.5)	$3.7	160	5
4	5004/5005 Interface	Interface	500	$0.2	($3.0)	$0.4	$3.6	$0.7	$1.6	$0.1	($0.8)	$2.8	131	64
5	Central	Interface	500	($0.6)	($1.2)	$0.1	$0.7	$0.0	$0.0	($0.0)	($0.0)	$0.7	170	2
6	AEP-DOM	Interface	500	$0.2	($0.3)	$0.1	$0.7	$0.3	$0.4	($0.1)	($0.2)	$0.5	66	31
7	Kammer	Transformer	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	19
8	Bedington - Black Oak	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	2

Table 10-31 Regional constraints summary (By facility): January through March 2011 (See 2011 SOM, Table 10-32)

				Congestion Costs (Millions)										
				Day Ahead				Balancing					Event Hours	
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$53.9	($78.9)	$0.5	$133.3	$9.9	$10.0	($0.6)	($0.7)	$132.6	1,172	513
2	5004/5005 Interface	Interface	500	($22.1)	($85.8)	($4.4)	$59.3	$6.0	$5.7	$3.6	$4.0	$63.2	513	241
3	Bedington - Black Oak	Interface	500	$10.4	($14.2)	($2.0)	$22.5	$0.0	$0.0	$0.0	$0.0	$22.5	573	0
4	AEP-DOM	Interface	500	$4.7	($8.5)	$0.8	$14.0	$0.6	$0.4	($0.1)	$0.2	$14.2	293	88
5	West	Interface	500	($3.4)	($13.2)	($0.1)	$9.7	$0.2	$0.0	$0.1	$0.3	$10.0	231	12
6	East	Interface	500	($4.5)	($12.3)	($0.2)	$7.6	$0.2	$1.3	$0.1	($1.0)	$6.6	127	22
7	Cloverdale - Lexington	Line	500	$2.0	($0.9)	$0.1	$3.0	$2.7	$1.3	($0.5)	$1.0	$3.9	172	155
8	Central	Interface	500	($1.2)	($2.2)	($0.1)	$1.0	$0.0	$0.0	$0.0	$0.0	$1.0	45	0
9	Harrison - Pruntytown	Line	500	$0.0	($0.1)	$0.0	$0.1	($0.0)	($0.0)	$0.0	$0.0	$0.1	10	4
10	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	0	9
11	Dominion East	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	0	1

Congestion Costs by Physical and Financial Participants

In the PJM market, both physical and financial participants make virtual supply offers (increments) and virtual demand bids (decrements). A participant is classified as a physical entity if the entity primarily takes physical positions in PJM markets. Physical entities include utilities and wholesale customers. Financial entities include banks, hedge funds, retail service providers and speculators, who primarily take financial positions in PJM markets. All affiliates are considered a single entity for this categorization. For example, under this classification, the trading affiliate of a utility would be treated as a physical company.

In the first three months of 2012, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In the first three months of 2012, financial companies received $17.9 million in net congestion credits, an increase of $8.6 million or 92.5 percent compared to the first three months of 2011. In the first three months of 2012, physical companies paid $140.7 million in net congestion charges, a decrease of $228.5 million or 61.9 percent compared to the first three months of 2011.

Table 10-32 Congestion cost by the type of the participant: January through March 2012 (See 2011 SOM, Table 10-33)

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
Financial	$7.0	$2.7	$20.8	$25.2	($7.6)	$1.7	($33.8)	($43.1)	$0.0	($17.9)
Physical	$16.8	($132.5)	$6.7	$156.1	$2.8	$10.0	($8.2)	($15.4)	$0.0	$140.7
Total	$23.9	($129.9)	$27.5	$181.3	($4.8)	$11.7	($42.0)	($58.5)	$0.0	$122.8

Table 10-33 Congestion cost by the type of the participant: January through March 2011 (See 2011 SOM, Table 10-34)

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Participant Type	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
Financial	$33.6	$10.5	$10.6	$33.7	($4.1)	($1.9)	($40.7)	($42.9)	$0.0	($9.3)
Physical	$5.0	($375.2)	($6.5)	$373.6	$31.0	$34.9	($0.5)	($4.4)	$0.0	$369.2
Total	$38.5	($364.7)	$4.1	$407.3	$27.0	$33.1	($41.2)	($47.4)	$0.0	$359.9

Generation and Transmission Planning

Highlights

- At March 31, 2012, 83,635 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 183,000 MW in 2012 including the January 1, 2012, DEOK integration. Wind projects account for approximately 29,418 MW, 35.2 percent of the capacity in the queues, and combined-cycle projects account for 38,177 MW, 45.6 percent of the capacity in the queues.

  A total of 955 MW of generation capacity retired in January through March 2012, and it is expected that a total of 18,825 MW will have retired from 2011 through 2019, with most of this capacity retiring by the end of 2015. Units planning to retire in 2012 make up up 6,012 MW, or 36 percent of all planned retirements.

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 March 31, 2012, 83,635 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of approximately 180,000 MW following the ATSI integration in 2011. 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, 373 MW of nameplate capacity were added in PJM in January through March 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 March 31, 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-March 2012	373

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 X was active through January 31, 2012.

Capacity in generation request queues for the seven year period beginning in 2012 and ending in 2018 decreased by 7,090 MW from 90,725 MW in 2011 to 83,635 MW in 2012, or 7.8 percent (Table 11-2).[3] Queued capacity scheduled for service in 2012 decreased from 27,184 MW to 23,371 MW, or 14 percent. Queued capacity scheduled for service in 2013 decreased from 13,051 MW to 10,645 MW, or 18.4 percent. The 83,635 MW includes generation with scheduled in-service dates in 2011 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* (March 10, 2011), pp. 205-206, for the queues in 2011.

Table 11-2 Queue comparison (MW): March 31, 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	23,371	(3,813)	(14.0%)
2013	13,051	10,645	(2,406)	(18.4%)
2014	17,036	13,130	(3,906)	(22.9%)
2015	19,251	23,208	3,957	20.6%
2016	9,288	8,966	(323)	(3.5%)
2017	1,720	2,720	1,000	58.1%
2018	3,194	1,594	(1,600)	(50.1%)
Total	90,725	83,635	(7,090)	(7.8%)

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 March 31, 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	1,086	555	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	148	150	2,345	2,643
L Expired 31-Jan-04	20	257	0	4,014	4,290
M Expired 31-Jul-04	0	505	150	3,828	4,482
N Expired 31-Jan-05	177	2,279	38	7,913	10,407
O Expired 31-Jul-05	746	1,471	880	4,495	7,592
P Expired 31-Jan-06	413	2,825	545	4,908	8,690
Q Expired 31-Jul-06	908	1,504	3,358	8,643	14,413
R Expired 31-Jan-07	2,666	1,216	178	18,394	22,455
S Expired 31-Jul-07	2,237	3,198	621	11,337	17,393
T Expired 31-Jan-08	8,836	950	287	17,473	27,546
U Expired 31-Jan-09	5,208	254	543	26,852	32,857
V Expired 31-Jan-10	8,104	188	1,762	6,766	16,820
W Expired 31-Jan-11	11,109	101	1,037	12,160	24,408
X Expired 31-Jan-12	27,530	6	137	4,380	32,053
Y Expires 31-Jan-13	5,439	0	0	5	5,444
Total	73,394	31,811	10,241	217,987	333,433

Data presented in Table 11-4 show that through the first three months of 2012, 40.1 percent of total in-service capacity from all the queues was from Queues A and B and an additional 6.8 percent was from Queues C, D and E.[7] As of March 31, 2012, 31.8 percent of the capacity in Queues A and B has been placed in service, and 9.5 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 State of the Market Report for PJM* 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 March 31, 2012.

The data presented in Table 11-4 show that for successful projects there is an average time of 809 days between entering a queue and the in-service date. The data also show that for withdrawn projects, there is an average time of 491 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 March 31, 2012 (See 2011 SOM, Table 11-5)

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	851	606	0	3,610
In-Service	809	673	0	3,602
Suspended	2,214	1,029	704	4,162
Under Construction	1,307	815	0	5,083
Withdrawn	491	496	0	3,186

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 March 31, 2012, 83,635 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of 183,000 MW in 2012 including the January 1, 2012, DEOK integration. Wind projects account for approximately 29,418 MW, 35.2 percent of the capacity in the queues, and combined-cycle projects account for 38,177 MW, 45.6 percent of the capacity in the queues. There has been a substantial increase in combined cycle units added to the queues. On March 31, 2012, there were 38,177 MW of capacity from combined cycle units in the queue, compared to 34,788 MW in 2011, an increase of 9.7 percent.

Table 11-5 shows the projects under construction or active as of March 31, 2012, by unit type and control zone. Most of the steam projects (93.2 percent of the MW) and most of the wind projects (94.0 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 18,106 MW, or 21.6 percent, are projected to be in EMAAC, while 8,221 MW or 9.8 percent are projected to be constructed in SWMAAC. Of total capacity additions, 35,747 MW, or 42.7 percent of capacity, is being added inside MAAC zones. Overall, 68.5 percent of capacity is being added outside EMAAC and SWMAAC, and 57.3 percent of capacity is being added outside MAAC zones.

Wind projects account for approximately 29,418 MW of capacity or 35.1 percent of the capacity in the queues and combined-cycle projects account for 38,177 MW of capacity or 45.6 percent of the capacity in the queues.[11] Wind projects account for 3,629 MW of capacity in MAAC LDAs, or 10.1 percent. While there are no wind projects in the SWMAAC LDA, in the EMAAC LDA wind projects account for 1,774 MW of capacity, or 9.8 percent.

Table 11-5 Capacity additions in active or under-construction queues by control zone (MW): At March 31, 2012 (See 2011 SOM, Table 11-6)

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	2,217	706	11	0	0	599	15	0	1,419	4,967
AEP	3,475	0	71	70	0	132	1,124	0	12,025	16,896
AP	930	0	18	105	0	232	597	0	1,085	2,966
ATSI	2,192	72	29	0	30	75	135	0	849	3,381
BGE	678	256	29	0	1,640	2	132	0	0	2,737
ComEd	1,080	444	103	23	607	95	1,366	0	10,028	13,745
DAY	0	0	2	112	0	23	12	0	935	1,084
DEOK	0	135	0	0	0	0	0	0	0	135
DLCO	0	0	0	5	91	0	0	0	0	96
Dominion	5,991	595	4	0	1,669	85	352	20	868	9,584
DPL	1,526	56	0	0	0	316	22	30	335	2,285
JCPL	3,514	27	30	0	0	992	0	0	0	4,562
Met-Ed	1,910	0	18	0	39	83	0	0	0	2,050
PECO	698	7	10	0	490	10	0	3	0	1,217
PENELEC	905	20	24	0	0	36	146	0	1,605	2,736
Pepco	5,468	0	6	0	0	10	0	0	0	5,484
PPL	4,126	11	4	3	100	106	34	0	250	4,634
PSEG	3,468	1,110	9	0	50	312	105	2	20	5,075
Total	38,177	3,439	367	318	4,716	3,106	4,040	55	29,418	83,635

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 29,418 MW of wind resources and 3,106 MW of solar resources, the 83,635 MW currently active in the queue would be reduced to 56,115 MW.

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 11-6)

Table 11-6 Capacity additions in active or under-construction queues by LDA (MW): At March 31, 2012[12] (See 2011 SOM, Table 11-7)

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
EMAAC	11,422	1,906	60	0	540	2,228	142	35	1,774	18,106
SWMAAC	6,146	256	35	0	1,640	12	132	0	0	8,221
WMAAC	6,941	31	46	3	139	225	180	0	1,855	9,420
Non-MAAC	13,668	1,246	226	315	2,397	641	3,586	20	25,789	47,887
Total	38,177	3,439	367	318	4,716	3,106	4,040	55	29,418	83,635

Table 11-7 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 11-5) 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.

Table 11-7 Existing PJM capacity: At April 1, 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	154	667	21	0	0	40	1,110	0	8	1,998
AEP	4,912	3,676	59	1,073	2,094	0	21,716	0	1,553	35,083
AP	1,129	1,180	36	80	0	0	8,451	27	799	11,702
ATSI	685	1,661	52	0	2,134	0	7,998	0	0	12,530
BGE	0	835	7	0	1,705	0	3,007	0	0	5,554
ComEd	1,763	7,178	86	0	10,421	0	6,275	0	2,145	27,868
DAY	0	1,369	48	0	0	1	4,368	0	0	5,785
DEOK	0	842	0	0	0	0	2,350	0	0	3,192
DLCO	244	15	0	6	1,777	0	1,244	0	0	3,286
Dominion	4,025	3,761	167	3,589	3,558	0	8,283	0	0	23,383
DPL	1,125	1,773	96	0	0	0	1,825	0	0	4,819
External	974	990	0	66	439	0	6,289	0	185	8,943
JCPL	1,693	1,225	33	400	615	22	15	0	0	4,003
Met-Ed	2,041	416	42	20	805	0	844	0	0	4,167
PECO	3,209	836	4	1,642	4,541	3	1,505	1	0	11,741
PENELEC	0	344	46	513	0	0	6,834	0	630	8,366
Pepco	230	1,327	12	0	0	0	4,679	0	0	6,248
PPL	1,810	618	49	581	2,470	0	5,518	0	220	11,265
PSEG	3,080	2,863	5	5	3,493	88	2,005	0	0	11,539
Total	27,073	31,573	761	7,975	34,051	154	94,315	28	5,539	201,469

12 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.

13 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Table 11-8 shows the age of PJM generators by unit type.

Table 11-8 PJM capacity (MW) by age: at April 1, 2012 (See 2011 SOM Table 11-9)

Age (years)	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 11	19,000	8,820	400	11	0	154	2,495	28	5,505	36,413
11 to 20	6,047	13,019	113	48	0	0	3,261	0	34	22,522
21 to 30	1,584	1,700	55	3,448	15,359	0	8,475	0	0	30,622
31 to 40	244	3,123	43	105	16,344	0	29,514	0	0	49,373
41 to 50	198	4,911	135	2,915	2,349	0	30,493	0	0	41,001
51 to 60	0	0	15	379	0	0	16,963	0	0	17,357
61 to 70	0	0	0	0	0	0	2,939	0	0	2,939
71 to 80	0	0	0	284	0	0	95	0	0	379
81 to 90	0	0	0	549	0	0	79	0	0	628
91 to 100	0	0	0	151	0	0	0	0	0	151
101 and over	0	0	0	84	0	0	0	0	0	84
Total	27,073	31,573	761	7,975	34,051	154	94,315	28	5,539	201,469

Table 11-9 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 74.2 percent of all new capability in EMAAC and 81.2 percent when the derating of wind capacity is reflected.

There is a planned addition of 1,640 MW of nuclear capacity in SWMAAC. Without the planned nuclear capability in SWMAAC, new gas-fired capability would represent 97.2 percent of all new capability in the SWMAAC. In 2018, this would mean that CC and CT generators would comprise 60.9 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, 89.0 percent of all generation 40 years or older is steam (primarily coal). With the retirement of these units in 2018, wind farms would comprise 21.5 percent of total capacity in Non-MAAC zones, if all queued capacity is built.

14 Non-MAAC zones consist of the AEP, AP, ComEd, DAY, DLCO, and Dominion Control Zones.

Table 11-9 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	2.2%	9,261	27.2%	11,422	20,485	46.6%
	Combustion Turbine	2,484	28.0%	7,364	21.6%	1,906	6,786	15.4%
	Diesel	51	0.6%	159	0.5%	60	168	0.4%
	Hydroelectric	2,042	23.0%	2,047	6.0%	0	620	1.4%
	Nuclear	615	6.9%	8,648	25.4%	540	8,574	19.5%
	Solar	0	0.0%	153	0.4%	2,228	2,380	5.4%
	Steam	3,472	39.2%	6,460	18.9%	142	3,130	7.1%
	Storage	0	0.0%	1	0.0%	35	36	0.1%
	Wind	0	0.0%	8	0.0%	1,774	1,782	4.1%
	EMAAC Total	8,861	100.0%	34,100	100.0%	18,106	43,960	100.0%
SWMAAC	Combined Cycle	0	0.0%	230	1.9%	6,146	6,376	43.1%
	Combustion Turbine	777	14.8%	2,162	18.3%	256	1,640	11.1%
	Diesel	0	0.0%	19	0.2%	35	54	0.4%
	Nuclear	0	0.0%	1,705	14.4%	1,640	3,345	22.6%
	Solar	0	0.0%	0	0.0%	12	12	0.1%
	Steam	4,459	85.2%	7,686	65.1%	132	3,359	22.7%
	SWMAAC Total	5,236	100.0%	11,801	100.0%	8,221	14,787	100.0%
WMAAC	Combined Cycle	0	0.0%	3,851	16.2%	6,941	10,792	76.6%
	Combustion Turbine	559	6.1%	1,377	5.8%	31	850	6.0%
	Diesel	46	0.5%	136	0.6%	46	136	1.0%
	Hydroelectric	887	9.6%	1,113	4.7%	3	1,116	7.9%
	Nuclear	0	0.0%	3,275	13.8%	139	3,414	24.2%
	Solar	0	0.0%	0	0.0%	225	225	1.6%
	Steam	7,737	83.8%	13,195	55.4%	180	5,639	40.0%
	Storage	0	0.0%	0	0.0%	0	0	0.0%
	Wind	0	0.0%	850	3.6%	1,855	2,705	19.2%
	WMAAC Total	9,228	100.0%	23,798	100.0%	9,420	14,084	100.0%
Non-MAAC	Combined Cycle	0	0.0%	13,731	10.4%	13,668	27,399	19.3%
	Combustion Turbine	1,092	2.8%	20,671	15.7%	1,246	20,825	14.7%
	Diesel	53	0.1%	447	0.3%	226	621	0.4%
	Hydroelectric	1,434	3.7%	4,814	3.7%	315	5,129	3.6%
	Nuclear	1,734	4.4%	20,423	15.5%	2,397	21,086	14.9%
	Solar	0	0.0%	1	0.0%	641	642	0.5%
	Steam	34,903	89.0%	66,974	50.8%	3,586	35,657	25.1%
	Storage	0	0.0%	27	0.0%	20	48	0.0%
	Wind	0	0.0%	4,682	3.6%	25,789	30,471	21.5%
	Non-MAAC Total	39,215	100.0%	131,771	100.0%	47,887	141,877	100.0%
All Areas	Total	62,539		201,469		83,635	214,708	

15 Percentages shown in Table 11-9 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

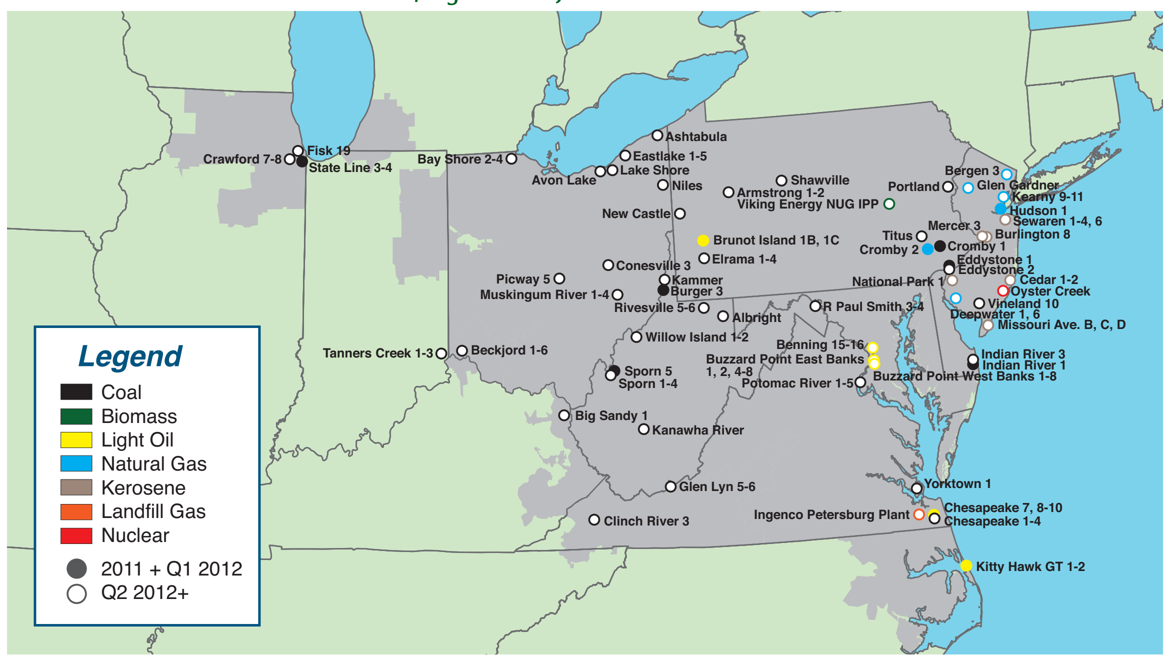
Planned Deactivations

As shown in Table 11-11, 16,547.7 MW are planning to deactivate by the end of calendar year 2019. Units planning to retire in 2012 make up 6,012 MW, or 36 percent of all planned retirements. Of planned deactivations in 2012, approximately 2,185 MW, or 36.3 percent are located in the ATSI zone. Overall, 3,951.1 MW, or 23.8 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 955 MW retired between January and March 2012. It is expected that a total of 18,824.7 MW will have retired by 2019, with most of this capacity retiring by the end of 2015.

Table 11-10 Summary of PJM unit retirements (MW): Calendar year 2011 through 2019[16] (See 2011 SOM, Table 11-11)

	MW
Retirements 2011	1,322.3
Retirements 2012	955.0
Planned Retirements 2012	6,012.0
Planned Retirements Post-2012	10,535.4
Total	18,824.7

Figure 11-1 Unit retirements in PJM Calendar year 2011 through 2019 (See 2011 SOM, Figure 11-1)



16 These totals include the retirements of Fisk 19 and Crawford 7&8.

Table 11-11 Planned deactivations of PJM units in Calendar year 2012 as of April 1, 2012[17] (See 2011 SOM, Table 11-12)

Unit	Zone	MW	Projected Deactivation Date
Beckjord 1	DEOK	94.0	01-May-12
Viking Energy NUG IPP	PPL	16.0	01-May-12
Benning 15-16	Pepco	548.0	31-May-12
Buzzard Point East Banks 1, 2, 4-8	Pepco	112.0	31-May-12
Buzzard Point West Banks 1-8	Pepco	128.0	31-May-12
Eddystone 2	PECO	309.0	31-May-12
Niles	ATSI	217.0	01-Jun-12
Elrama 1-4	DLCO	460.0	01-Jun-12
Kearny 10-11	PSEG	250.0	01-Jun-12
Vineland 10	AECO	23.0	01-Sep-12
Albright	APS	283.0	01-Sep-12
Armstrong 1-2	APS	343.0	01-Sep-12
R Paul Smith 3-4	APS	115.0	01-Sep-12
Rivesville 5-6	APS	121.0	01-Sep-12
Willow Island 1-2	APS	217.0	01-Sep-12
Ashtabula	ATSI	210.0	01-Sep-12
Bay Shore 2-4	ATSI	419.0	01-Sep-12
Eastlake 1-5	ATSI	1,149.0	01-Sep-12
Lake Shore	ATSI	190.0	01-Sep-12
Potomac River 1-5	Pepco	482.0	01-Oct-12
Fisk 19	ComEd	326.0	31-Dec-12
Total		6,012.0	

17 See "Pending Deactivation Requests" <http://pjm.com/planning/generation-retirements/~/media/planning/gen-retire/pending-deactivation-requests.ashx> (Accessed April 15, 2012).

Table 11-12 Planned deactivations of PJM units after calendar year 2012, as of April 1, 2012 (See 2011 SOM, Table 11-13)

Unit	Zone	MW	Projected Deactivation Date
Ingenco Petersburg Plant	Dominion	2.9	31-May-13
Indian River 3	DPL	169.7	31-Dec-13
Big Sandy 2	AEP	278.0	31-Dec-14
Clinch River 3	AEP	230.0	31-Dec-14
Conesville 3	AEP	165.0	31-Dec-14
Glen Lyn 5-6	AEP	325.0	31-Dec-14
Kammer	AEP	600.0	31-Dec-14
Kanawha River	AEP	400.0	31-Dec-14
Muskingum River 1-4	AEP	790.0	31-Dec-14
Picway 5	AEP	95.0	31-Dec-14
Sporn	AEP	580.0	31-Dec-14
Tanners Creek 1-3	AEP	488.1	31-Dec-14
Crawford 7-8	ComEd	532.0	31-Dec-14
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
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		10,535.4	

Table 11-13 HEDD Units in PJM as of March 31, 2012[18] (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

18 See "Current New Jersey Turbines that are HEDD Units," <http://www.state.nj.us/dep/workgroups/docs/apcrule_20110909turbinelist.pdf> (Accessed April 1, 2012)

Actual Generation Deactivations in 2012

Table 11-14 shows unit deactivations for 2012.[19] A total of 955 MW retired in January through March 2012, including 440.0 MW from American Electric Power Company, Inc., and 515.0 MW from Edison International. The retirements were 955.0 MW of coal steam generation. Of these retirements, 440.0 MW were in the AEP zone, and 515.0 MW were in the ComEd zone.

Table 11-14 Unit deactivations: January through March 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

19 "PJM Generator Deactivations," PJM.com <http://pjm.com/planning/generation-retirements/gr-summaries.aspx> (April 15, 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 from the inception of LMP markets on April 1, 1998.[3] In PJM, 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.

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.

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).

On June 1, 2007, PJM implemented marginal losses in the calculation of LMP. Since then, FTRs have been valued based on the difference in congestion prices rather than the difference in LMPs. 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 March* focuses on the Monthly Balance of Planning Period FTR Auctions during the 2011 to 2012 planning period, which covers June 1, 2011, through May 31, 2012.

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

- On January 1, 2012, the Duke Energy Ohio and Kentucky (DEOK) Control Zone was integrated into the PJM footprint. DEOK zonal customers were eligible to participate in a direct allocation of FTRs effective from January 1, 2012 through May 31, 2012.
- The total cleared FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2011 to 2012 planning period increased by 22 percent from 1,681,158 MW to 2,049,614 MW compared to the first ten months of the 2010 to 2011 planning period.
- FTRs were paid at 83.2 percent for the first ten months of the 2011 to 2012 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 and were not profitable for either physical or financial entities in January through March 2012. Total FTR profits were -$0.8 million for physical entities and -$11.3 million for financial entities. Self scheduled FTRs were the source of $40.8 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. 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. 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.

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 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.

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."

There are two FTR hedge type products: obligations and options. An obligation provides a credit, positive or negative, equal to the product of the FTR MW and the congestion price difference between FTR sink (destination) and source (origin) that occurs in the Day-Ahead Energy Market. An option provides only positive credits and options are available for only a subset of the possible FTR transmission paths.

There are three FTR class type products: 24-hour, on peak and off peak. The 24-hour products are effective 24 hours a day, seven days a week, while the on peak products are effective during on peak periods defined as the hours ending 0800 through 2300, Eastern Prevailing Time (EPT) Mondays through Fridays, excluding North American Electric Reliability Council (NERC) holidays. The off peak products are effective during hours ending 2400 through 0700, EPT, Mondays through Fridays, and during all hours on Saturdays, Sundays and NERC holidays.

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 underfunding, effective August 5, 2011, PJM no longer allows 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 customers or PJM members to bid for any FTR or to offer for sale any FTR that they currently hold. Market participants can bid for or offer monthly FTRs for any of the next three months remaining in the planning period, or quarterly FTRs for any of the quarters remaining in the 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.

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.

7 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 39.

Credit Issues

Default

There were three participants that defaulted during 2012 and 4 default events. The average default for 2012 was $47,188 with a maximum default of $111,600. Of all the defaults two were based on collateral and two were based on payments. All of the defaulting participants were financial companies. Two of the defaults were promptly cured and two are outstanding as of the last report.[8] These defaults were not related to FTR positions.

Patterns of Ownership

The ownership concentration of cleared FTR buy bids resulting from the 2011 to 2012 Annual FTR Auction was low for peak, off peak FTR obligations and moderately concentrated for 24-hour FTR obligations. The ownership concentration was highly concentrated for peak, off peak and 24-hour FTR buy bid options for the same time period. The overall ownership structure of FTRs and the ownership of prevailing flow and counter flow FTRs is descriptive and is not necessarily a measure of actual or potential FTR market structure issues, as the ownership positions result from competitive auctions. The percentage of FTR ownership shares may change when FTR owners buy or sell FTRs in the Monthly Balance of Planning Period FTR Auctions or secondary bilateral market.

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 March 2012, financial entities purchased 85.0 percent of prevailing flow and 84.9 percent of counter flow FTRs for 2012. Financial entities owned 65.6 percent of all prevailing and counter flow FTRs, including 60.0 percent of all prevailing flow FTRs and 79.8 percent of all counter flow FTRs.

Table 12-2 presents the Monthly Balance of Planning Period FTR Auction market cleared FTRs for January through March 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 March 2012 (See 2011 SOM, Table 12-6)

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	15.0%	15.1%	15.0%
	Financial	85.0%	84.9%	85.0%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	23.5%	4.8%	15.7%
	Financial	76.5%	95.2%	84.3%
	Total	100.0%	100.0%	100.0%

Table 12-3 presents the daily FTR net position ownership for January through March 2012 by FTR direction.

Table 12-3 Daily FTR net position ownership by FTR direction: January through March 2012 (See 2011 SOM, Table 12-7)

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	40.0%	20.2%	34.4%
Financial	60.0%	79.8%	65.6%
Total	100.0%	100.0%	100.0%

8 Email to Members Committee, "PJM Settlement Member Credit Exposure and Default Disclosure Report – March 2012," April 10, 2012.

Market Performance

Volume

In the Monthly Balance of Planning Period FTR Auctions for the first ten months (June 2011 through March 2012) of the 2011 to 2012 planning period, total participant FTR sell offers were 5,330,537 MW, up from 3,622,316 MW for the same period during the 2010 to 2011 planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2011 to 2012 (June 2011 through March 2012) planning period increased 29.7 percent from 12,615,413 MW, during the same time period of the prior planning period, to 16,367,977 MW. For the first ten months of the 2011 to 2012 planning period, FTR auctions cleared 2,049,614 MW (12.5 percent) of FTR buy bids and 604,749 MW (11.3 percent) of sell offers.

Table 12-4 provides the Monthly Balance of Planning Period FTR market volume for the first three months of 2012, the entire 2010 to 2011 planning period and the first ten months of the 2011 to 2012 planning period.

Table 12-4 Monthly Balance of Planning Period FTR Auction market volume: January through March 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%
2010/2011*	Obligations	Buy bids	2,378,154	12,888,263	1,975,624	15.3%	10,912,639	84.7%
		Sell offers	709,605	3,448,995	311,688	9.0%	3,137,308	91.0%
	Options	Buy bids	16,090	1,403,272	67,536	4.8%	1,335,736	95.2%
		Sell offers	60,091	568,271	147,251	25.9%	421,021	74.1%
2011/2012**	Obligations	Buy bids	2,555,847	13,958,148	1,994,133	14.3%	11,964,014	85.7%
		Sell offers	994,870	4,702,004	460,567	9.8%	4,241,436	90.2%
	Options	Buy bids	35,439	2,409,829	55,481	2.3%	2,354,349	97.7%
		Sell offers	93,911	628,533	144,181	22.9%	484,352	77.1%

* Shows Twelve Months for 2010/2011; ** Shows ten months ended 31-Mar-2012 for 2011/2012

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 March 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

On January 1, 2012 the Duke Energy Ohio and Kentucky (DEOK) zone was integrated into PJM. DEOK zonal customers were eligible to participate in a direct allocation of FTRs effective from January 1, 2012 through May 31, 2012. For a transitional period, those customers that receive, and pay for, firm transmission service that sources or sinks in the newly integrated PJM control zone may elect to receive a direct allocation of FTRs instead of an allocation of ARRs.

Table 12-6 lists the volume of directly allocated FTRs requested and granted for the DEOK control zone. This FTR volume is not included in the monthly data above. In the DEOK zone, 5,396 MW of FTRs were requested and 4,616 MW (86 percent) cleared. These FTRs are effective only from the date of integration to the end of the current planning period, January 1, 2012 through May 31, 2012.

Table 12-6 Directly allocated FTR volume for DEOK Control Zone: January 1, 2012 through May 31, 2012[9] (New Table)

Planning Period*	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2011/2012	519	5,396	4,616	86%	781	14%

*Effective January 1, 2012 through May 31, 2012

Figure 12-1 shows the cleared auction volume as a percent of the total FTR cleared volume by calendar months for June 2004 through March 2012. FTR volume is broken into 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.

9 The volume data presented in Table 12-6 are not included in the monthly FTR ownership, volume or revenue data.

Figure 12-1 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through March 2012 (See 2011 SOM, Figure 12-2)

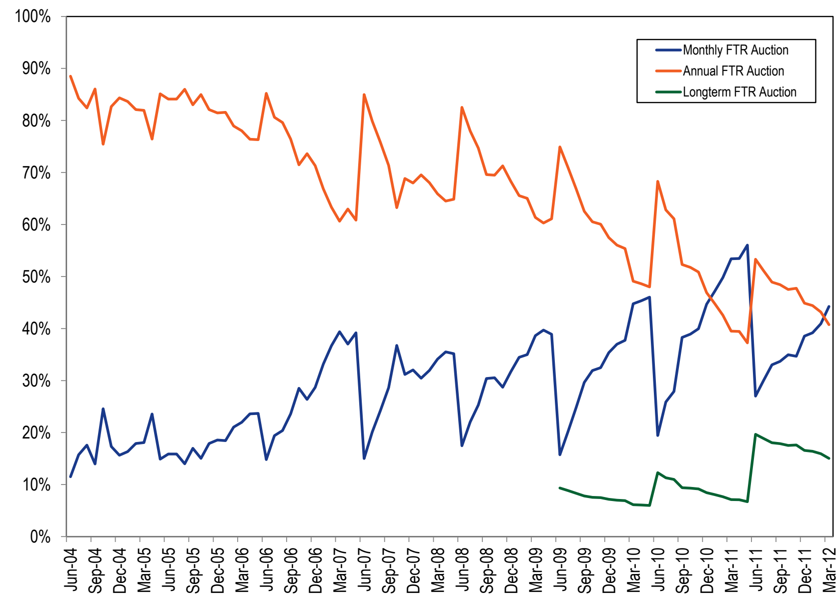


Table 12-7 provides the Secondary bilateral FTR market volume for the entire 2010 to 2011 planning period and the first ten months of the 2011 to 2012 planning period.

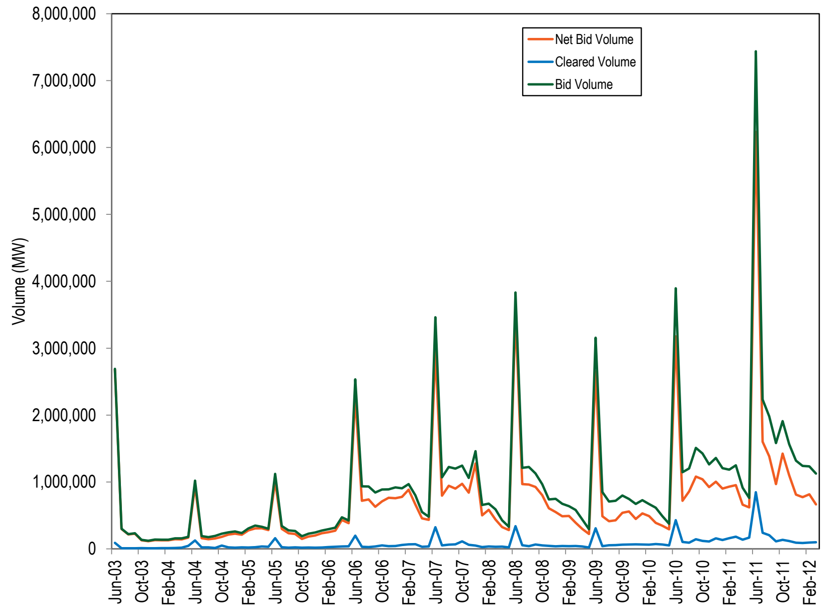
Table 12-7 Secondary bilateral FTR market volume: Planning periods 2010 to 2011 and 2011 to 2012[10] (See 2011 SOM, Table 12-13)

Planning Period	Hedge Type	Class Type	Volume (MW)
2010/2011	Obligation	24-Hour	1,687
		On Peak	10,035
		Off Peak	12,313
		Total	24,034
	Option	24-Hour	20
		On Peak	0
		Off Peak	0
		Total	20
2011/2012*	Obligation	24-Hour	216
		On Peak	11,916
		Off Peak	4,228
		Total	16,360
	Option	24-Hour	0
		On Peak	8,965
		Off Peak	6,330
		Total	15,296

* Shows ten months ended 31-Mar-2012

Figure 12-2 shows the historic FTR bid, cleared and net bid volume from June 2003 through December 2011 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.

Figure 12-2 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through March 2012[11] (See 2011 SOM, Figure 12-3)



Price

The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the first ten months of the 2011 to 2012 planning period was $0.10, down from $0.13 per MW in the first ten months of the 2010 to 2011 planning period.

Table 12-8 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2011 through December 2011.

10 The 2011 to 2012 planning period covers bilateral FTRs that are effective for any time between June 1, 2011 through March 31, 2012, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

11 The previous 3rd Quarter *State of the Market Report* did not contain volume data for Long Term FTR Auctions.

Table 12-8 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MW): January through March 2012 (See 2011 SOM, Table 12-16)

Monthly Auction	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-12	$0.10	$0.15	$0.04				$0.13	$0.11
Feb-12	$0.11	$0.09	$0.11				$0.16	$0.12
Mar-12	$0.06	$0.13	$0.11				$0.01	$0.07

Revenue

Monthly Balance of Planning Period FTR Auction Revenue

The Monthly Balance of Planning Period FTR Auctions generated $24.8 million in net revenue for all FTRs for the first ten months of the 2011 to 2012 planning period, up from $22.4 million for the same time period in the 2010 to 2011 planning period.

Table 12-9 shows Monthly Balance of Planning Period FTR Auction revenue data by trade type, hedge type and class type for January through March 2012.

Table 12-9 Monthly Balance of Planning Period FTR Auction revenue: January through March 2012 (See 2011 SOM, Table 12-20)

Monthly Auction	Hedge Type	Trade Type	Class 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
2010/2011*	Obligations	Buy bids	$6,072,755	$77,744,027	$59,368,920	$143,185,702
		Sell offers	$7,528,597	$41,402,197	$35,920,274	$84,851,069
	Options	Buy bids	$37,176	$3,175,707	$2,322,130	$5,535,014
		Sell offers	$1,880,624	$21,872,336	$15,718,885	$39,471,845
2011/2012**	Obligations	Buy bids	$10,794,948	$66,219,326	$40,265,486	$117,279,760
		Sell offers	$4,412,095	$41,804,004	$25,072,374	$71,288,473
	Options	Buy bids	$117,492	$4,339,293	$3,129,241	$7,586,026
		Sell offers	$9,737	$17,588,565	$11,226,300	$28,824,602
	Total		$6,490,608	$11,166,050	$7,096,053	$24,752,711

* Shows twelve Months for 2010/2011; ** Shows ten months ended 31-Mar-2012 for 2011/2012

Figure 12-3 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 ten months of the 2011 to 2012 planning period.

Figure 12-3 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2011 to 2012 through March 31, 2012 (See 2011 SOM, Figure 12-11)

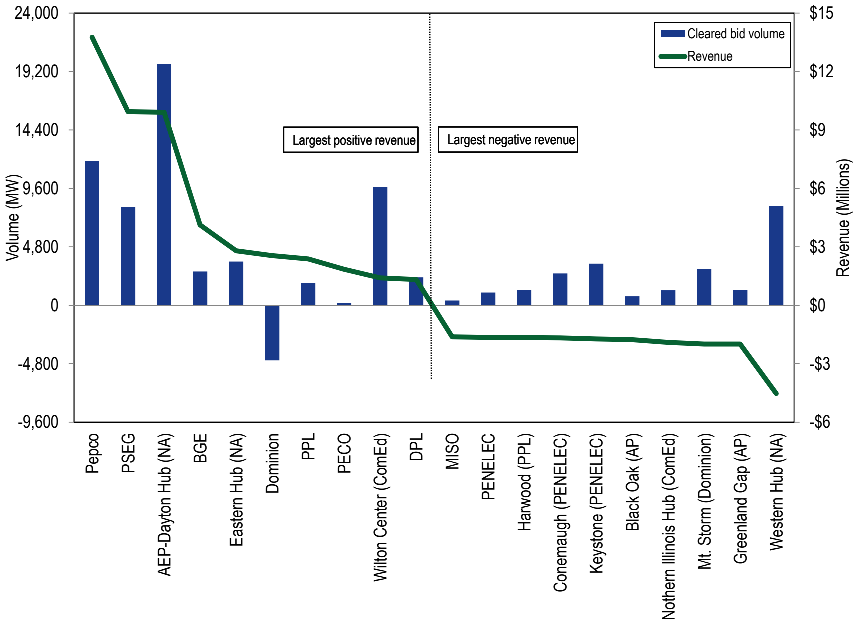


Figure 12-4 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2011 to 2012 through March 31, 2012 (See 2011 SOM, Figure 12-12)

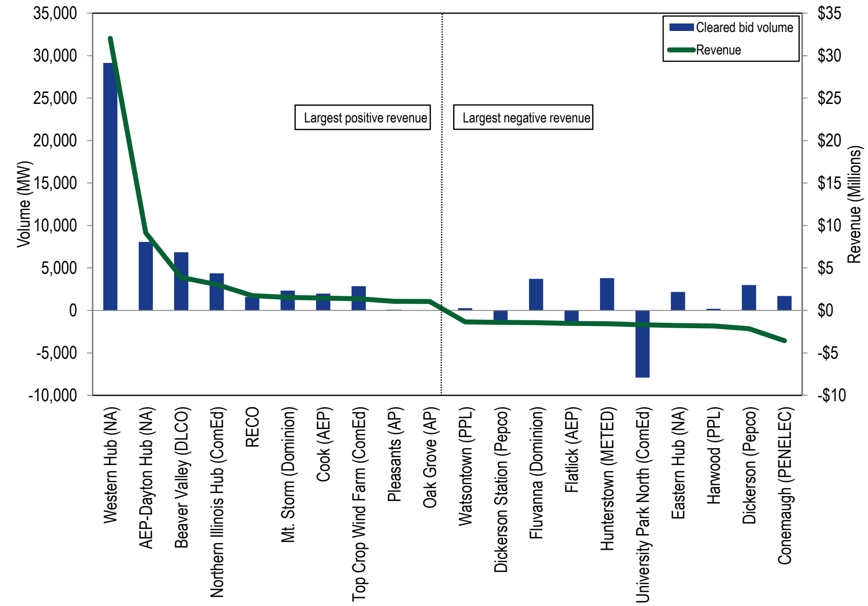


Figure 12-4 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Monthly Balance of Planning Period FTR Auctions during the first ten months of the 2011 to 2012 planning period.

Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay and all generators receive their respective LMPs. When load pays more than the amount that generators receive, excluding losses, positive congestion revenue exists and is available to cover the target allocations of FTR holders. The 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. 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.[12] 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 2010 to 2011 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 12-10 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.[13] The operating protocol governing the wheeling contracts between Public Service Electric and Gas Company (PSE&G) and Consolidated Edison Company of New York (Con Edison) resulted in a reimbursement of $0.2 million in congestion charges to Con Edison in the 2011 to 2012 planning period through March 31, 2012.[14,15]

For the current planning period, no charges have been made to the Day Ahead Operating Reserves. These charges may be necessary if the hourly congestion revenues are negative at the end of the month. If this happens, charges are made and allocated as additional Day-Ahead Operating Reserves charges during the month. This means that within an hour, the congestion dollars collected from load were less than the congestion dollars paid to generation. This is accounted for as a charge, which is allocated to Day-Ahead Operating Reserves. This type of adjustment is infrequent, occurring only three times in the 2010 to 2011 planning period.

FTRs were paid at 83.2 percent of the target allocation level for the first ten months of the 2011 to 2012 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $705.9 million of FTR revenues during the first ten months of the 2011 to 2012 planning period, and $1,430.7 million during the 2010 to 2011 planning period. For the first ten months of the 2011 to 2012 planning period, the top sink and top source with the highest positive FTR target allocations were AEP without Mon Power and the Western Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were AEP without Mon Power and Kammer.

Table 12-10 presents the PJM FTR revenue detail for all of the 2010 to 2011 planning period and the first ten months of the 2011 to 2012 planning period.

12 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."

13 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)

14 111 FERC ¶ 61,228 (2005).

15 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 12-10 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2010 to 2011 and 2011 to 2012 (See 2011 SOM, Table 12-21)

Accounting Element	2010/2011	2011/2012*
ARR information		
ARR target allocations	$1,031.0	$819.1
FTR auction revenue	$1,097.8	$909.8
ARR excess	$66.9	$90.7
FTR targets		
FTR target allocations	$1,687.6	$849.9
Adjustments:		
Adjustments to FTR target allocations	($1.8)	($1.0)
Total FTR targets	$1,685.8	$848.9
FTR revenues		
ARR excess	$66.9	$90.7
Competing uses	$0.1	$0.1
Congestion		
Net Negative Congestion (enter as negative)	($59.5)	($49.8)
Hourly congestion revenue	$1,464.9	$597.0
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($47.8)	($71.2)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	(0.8)	($0.2)
Adjustments:		
Excess revenues carried forward into future months	$0.0	$0.0
Excess revenues distributed back to previous months	$4.6	$0.0
Other adjustments to FTR revenues	$2.3	($0.3)
Total FTR revenues	$1,430.7	$705.9
Excess revenues distributed to other months	($4.6)	$0.0
Net Negative Congestion charged to DA Operating Reserves	$7.3	$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	$1,433.4	$705.9
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$1,434.2	$706.2
Remaining deficiency	$252.4	$142.9

* Shows ten months ended 31-Mar-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 12-11 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 12-11 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 12-11 Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2010 to 2011 and 2011 to 2012 (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%	($19.1)
Mar-12	$48.7	$57.8	84.2%	$48.7	84.2%	($9.2)
Summary for Planning Period 2011 to 2012 through March 31, 2012						
Total	$705.9	$848.9		$705.9	83.2%	($142.9)

Figure 12-5 shows the original FTR payout ratio with adjustments by month, excluding excess revenue distribution, for January 2004 through December 2011. The months with payout ratios above 100 percent are overfunded and the months with payout ratios under 100 percent are underfunded. Figure 12-5 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 2011 to 2012 planning period may change if excess revenue is collected in the remainder of the planning period.

Figure 12-5 FTR payout ratio with adjustments by month, excluding and including excess revenue distribution: January 2004 to March 2012 (See 2011 SOM, Figure 12-13)

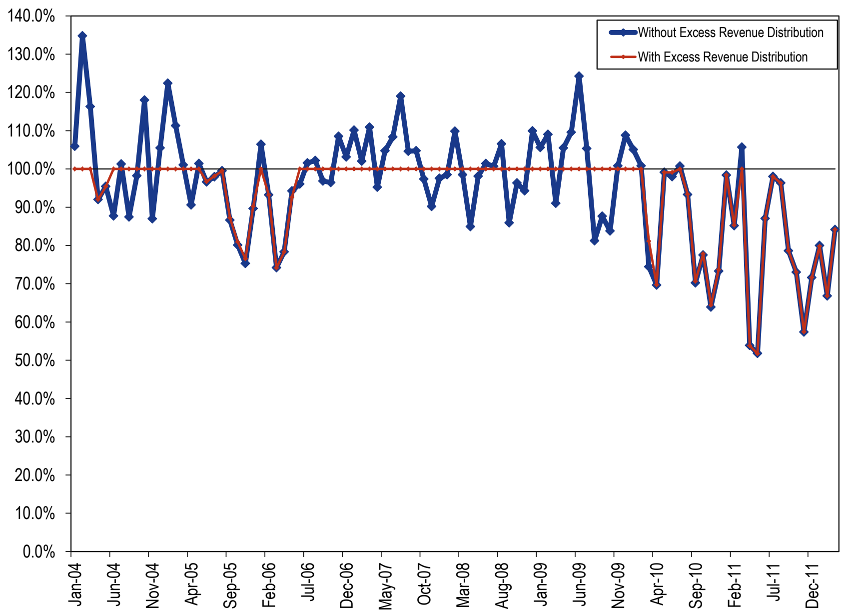


Table 12-12 shows the FTR payout ratio by planning period from the 2003 to 2004 planning period forward.

Table 12-12 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*	83.2%

* through March 31, 2012

Figure 12-6 shows the ten largest positive and negative FTR target allocations, summed by sink, for the 2011 to 2012 planning period through March 31, 2012.

Figure 12-6 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2011 to 2012 through March 31, 2012 (See 2011 SOM, Figure 12-14)

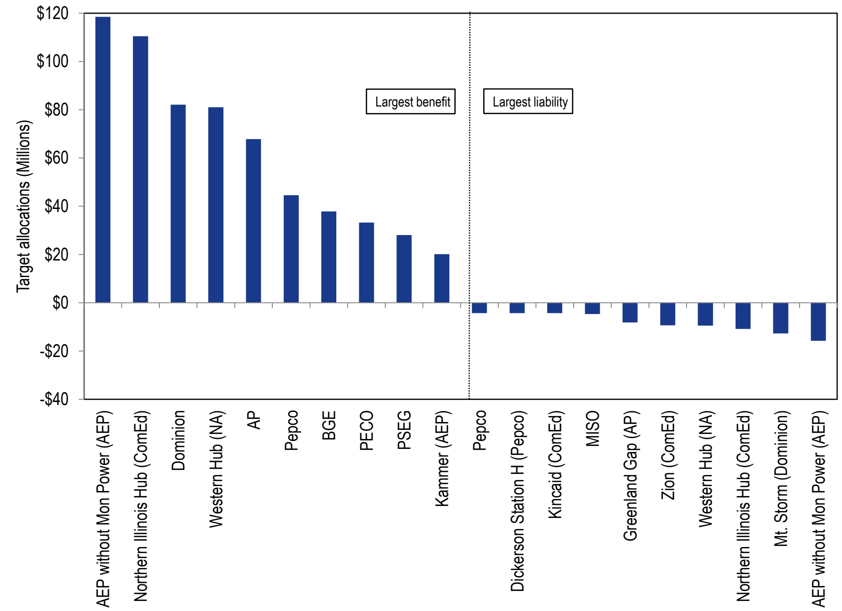


Figure 12-7 shows the ten largest positive and negative FTR target allocations, summed by source, for the 2011 to 2012 planning period through March 31, 2012.

Figure 12-7 Ten largest positive and negative FTR target allocations summed by source: Planning period 2011 to 2012 through March 31, 2012 (See 2011 SOM, Figure 12-15)

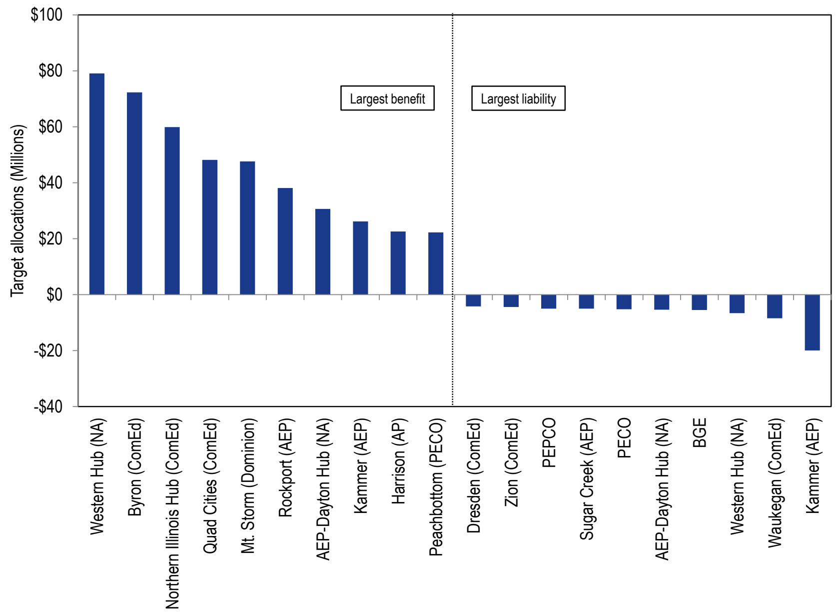
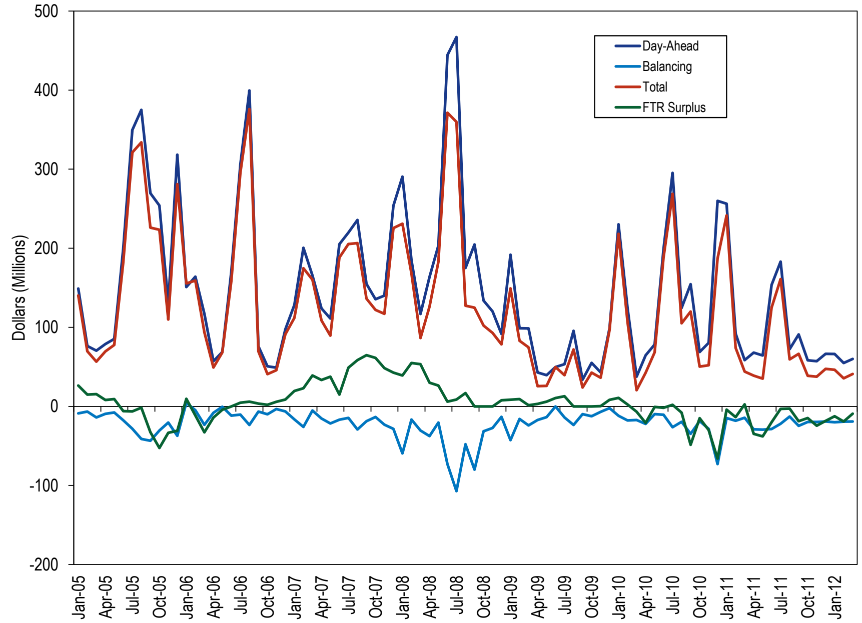


Figure 12-8 shows the FTR surplus, collected day-ahead, balancing and total congestion payments from January 2005 through March 2012.

Figure 12-8 FTR Surplus and the collected Day-Ahead, Balancing and Total congestion: January 2005 through March 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 12-13 lists FTR profits by organization type and FTR direction for the 2011 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, with -$0.8 million in profits for physical entities, of which $40.8 million was from self scheduled FTRs, and -$11.3 million for financial entities.

Table 12-13 shows FTR profits by organization from January through March 2012.

Table 12-13 FTR profits by organization type and FTR direction: January through March 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	($66,276,740)	$40,787,177	$24,660,450	$19,487	($809,625)
Financial	($61,989,880)	NA	$50,667,748	NA	($11,322,132)
Total	($128,266,619)	$40,787,177	$75,328,198	$19,487	($12,131,757)

Table 12-14 lists the monthly FTR profits in the 2011 calendar year by organization type.

Table 12-14 Monthly FTR profits by organization type: January through March 2012 (See 2011 SOM, Table 12-25)

	Organization Type			
Month	Physical	Self Scheduled FTRs	Financial	Total
Jan	($15,741,321)	$14,779,795	($1,887,863)	($2,849,389)
Feb	($14,797,921)	$13,247,875	($795,248)	($2,345,293)
Mar	($11,077,047)	$12,778,994	($8,639,021)	($6,937,074)
Total	($41,616,289)	$40,806,664	($11,322,132)	(12,131,757)

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.[16] These price differences are based on the bid prices of participants in the Annual FTR Auction which relate to their expectations about the level of congestion in the Day-Ahead Energy Market. The auction clears the set of feasible FTR bids which produce the highest net revenue. In other words, ARR revenues are a function of FTR auction participants' expectations of locational congestion price differences in the Day-Ahead Energy Market.

ARRs are available 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,

16 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.

the directly allocated FTRs are reallocated as load shifts between LSEs within the transmission zone.

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.

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.[17] 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 self scheduled as FTRs, these underlying self scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may diminish the value of the ARR for the receiving LSE compared to the total value held by the original ARR holder.

There were 41,069 MW of ARRs associated with approximately $753,500 of revenue that were reassigned in the first ten months of the 2011 to 2012 planning period. There were 56,296 MW of ARRs associated with approximately $1,043,700 of revenue that were reassigned for the full twelve months of the 2010 to 2011 planning period.

Table 12-15 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2010 and March 2012.

Table 12-15 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2010, through March 31, 2012 (See 2011 SOM, Table 12-29)

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2010/2011 (12 months)	2011/2012 (10 months)*	2010/2011 (12 months)	2011/2012 (10 months)*
AECO	887	436	$6.0	$4.7
AEP	961	5,919	$21.4	$117.9
AP	4,992	1,401	$481.1	$319.4
ATSI	0	2,920	$0.0	$13.0
BGE	3,359	2,599	$50.5	$45.6
ComEd	3,064	3,215	$60.2	$58.0
DAY	193	382	$0.6	$0.6
DLCO	5,502	8,213	$25.7	$10.3
DPL	2,252	3,415	$20.4	$15.2
Dominion	0	1	$0.0	$0.0
JCPL	3,490	1,075	$28.8	$9.9
Met-Ed	3,947	1,178	$51.9	$20.7
PECO	12,284	1,751	$89.2	$21.7
PENELEC	3,745	1,042	$53.5	$21.0
PPL	5,734	3,339	$74.4	$37.6
PSEG	3,416	1,907	$52.8	$30.7
Pepco	2,470	2,277	$27.3	$27.2
RECO	143	57	$0.1	$0.0
Total	56,296	41,069	$1,043.7	$753.5

* Through 31-Mar-12

17 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 28.

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. Customers that self schedule ARRs 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. Customers that self schedule ARRs as FTRs provide the same offset to congestion as all other FTRs.

ARR holders will receive $947.3 million in credits from the Annual FTR Auction during the 2011 to 2012 planning period, with an average hourly ARR credit of $1.05 per MW. During the comparable 2010 to 2011 planning period, ARR holders received $1,028.8 million in ARR credits, with an average hourly ARR credit of $1.15 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 2010 to 2011 and the 2011 to 2012 (through March 31, 2012) planning periods.

Table 12-16 ARR revenue adequacy (Dollars (Millions)): Planning periods 2010 to 2011 and 2011 to 2012 (See 2011 SOM, Table 12-33)

	2010/2011	2011/2012
Total FTR auction net revenue	$1,074.3	$1,054.4
Annual FTR Auction net revenue	$1,049.8	$1,029.6
Monthly Balance of Planning Period FTR Auction net revenue*	$24.5	$24.8
ARR target allocations	$1,028.8	$947.3
ARR credits	$1,028.8	$947.3
Surplus auction revenue	$45.5	$107.1
ARR payout ratio	100%	100%
FTR payout ratio*	85.0%	83.2%

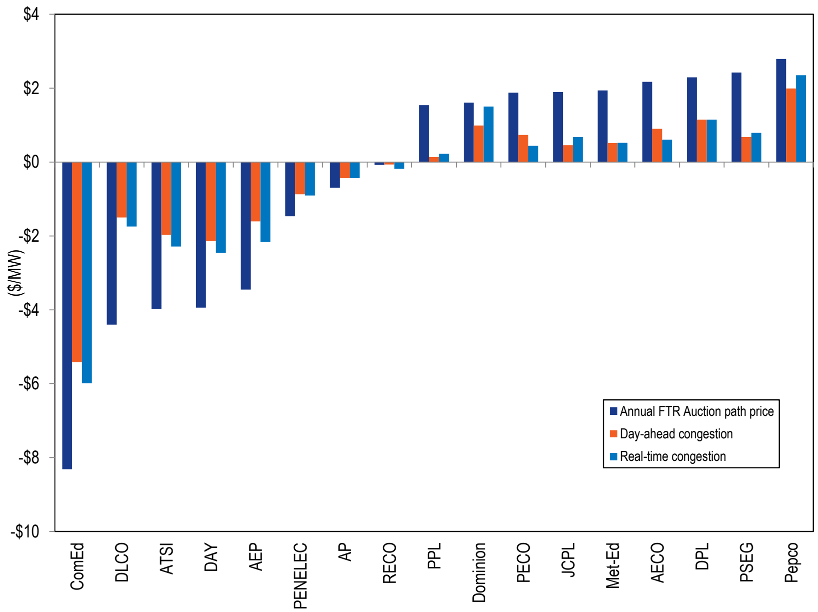
* Shows twelve months for 2010/2011 and ten months ended 31-Mar-11 for 2011/2012

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 12-9 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone for the 2011 to 2012 planning period through March 31, 2012. The day-ahead and real-time congestion are based on the difference between zonal congestion prices and Western Hub congestion prices.

Figure 12-9 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub[18]: Planning period 2011 to 2012 through March 31, 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 ten months of the 2011 to 2012 planning period, the total revenues received by the holders of all ARRs and FTRs offset more than 100 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.[19] 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 are paid to FTR holders and may be less than the target allocation. The FTR payout ratio was 83.2 percent of the target allocation for the 2011 to 2012 planning period through March 31, 2012.

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.

18 DEOK was integrated into PJM on January 1, 2012 so was not available in the 2011 to 2012 Annual FTR Auction and therefore is not included in Figure 12-9.

19 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.

Table 12-17 ARR and self scheduled FTR congestion offset (in millions) by control zone: Planning period 20101to 2012 through March 31, 2012[20] (See 2011 SOM, Table 12-34)

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Hedged
AECO	$10.2	$0.0	$10.2	$25.5	($15.3)	40.0%
AEP	$8.9	$112.2	$121.1	$129.4	($8.3)	93.6%
APS	$93.4	$39.6	$133.0	$25.1	$107.9	>100%
ATSI	$12.3	$0.0	$12.3	($1.9)	$14.2	>100%
BGE	$37.9	$2.3	$40.2	$30.7	$9.5	>100%
ComEd	$120.2	$0.0	$120.2	($207.0)	$327.2	>100%
DAY	$2.7	$1.2	$3.9	$1.4	$2.5	>100%
DEOK	$0.0	$0.0	$0.0	$0.5	($0.5)	7.3%
DLCO	$3.5	$0.0	$3.5	$8.4	($4.9)	42.1%
Dominion	$7.3	$71.1	$78.4	$18.0	$60.4	>100%
DPL	$14.2	$1.7	$15.9	$30.2	($14.3)	52.7%
External	$5.7	$1.5	$7.3	$12.6	($5.4)	57.5%
JCPL	$16.1	$0.9	$17.0	$34.0	($17.0)	49.9%
Met-Ed	$13.8	$2.6	$16.4	$14.9	$1.5	>100%
PECO	$23.7	$13.0	$36.7	$21.2	$15.5	>100%
PENELEC	$21.3	$4.7	$26.0	$20.9	$5.1	>100%
Pepco	$44.3	$4.3	$48.7	$71.3	($22.6)	68.3%
PPL	$22.8	$2.1	$24.9	$29.9	($5.0)	83.3%
PSEG	$54.2	$1.0	$55.3	$21.5	$33.8	>100%
RECO	($0.6)	$0.0	($0.6)	$1.5	($2.1)	0.0%
Total	$512.2	$270.1	$782.3	$288.2	$494.1	>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 2011 to 2012 planning period through March 31, 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. 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 83.2 percent of the target allocation for the 2011 to 2012 planning period through March 31, 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.[21] The last column shows the difference between the total ARR and FTR hedge and the congestion cost for each control zone.

20 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.

21 The total zonal congestion numbers were calculated as of March 2, 2012 and may change as a result of continued PJM billing updates. The total zonal congestion differs from the March 2, 2012 PJM total congestion by $4.2 Million, or 0.3 percent (.003).

Table 12-18 ARR and FTR congestion offset (in millions) by control zone: Planning period 2011 to 2012 through March 31, 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	$10.2	$10.2	$18.4	$2.0	$18.9	($16.9)	10.7%
AEP	$172.4	$179.4	$171.4	$180.4	$150.8	$29.6	>100%
APS	$173.4	$68.0	$127.2	$114.1	$73.5	$40.6	>100%
ATSI	$12.3	$8.7	$0.0	$21.0	($3.4)	$24.4	>100%
BGE	$41.1	$86.2	$42.1	$85.2	$48.5	$36.8	>100%
ComEd	$133.9	$107.9	$88.5	$153.4	$197.1	($43.7)	77.8%
DAY	$5.4	$3.5	$3.3	$5.6	$3.3	$2.4	>100%
DEOK	$0.1	$3.2	$0.0	$3.3	$0.1	$3.3	>100%
DLCO	$3.6	$11.2	$2.3	$12.5	$10.5	$2.0	>100%
Dominion	$167.2	$86.4	$166.0	$87.6	$75.0	$12.7	>100%
DPL	$15.6	$25.3	$27.7	$13.2	$19.5	($6.3)	67.6%
External	$9.4	($1.7)	$2.6	$5.0	($53.9)	$59.0	>100%
JCPL	$18.0	$18.8	$35.2	$1.6	$25.6	($24.0)	6.2%
Met-Ed	$19.0	$13.6	$28.7	$3.9	$2.8	$1.1	>100%
PECO	$36.5	$41.9	$36.5	$42.0	$14.7	$27.3	>100%
PENELEC	$29.2	$50.7	$73.3	$6.6	$38.4	($31.8)	17.1%
Pepco	$52.6	$89.5	$144.9	($2.8)	$56.4	($59.2)	0.0%
PPL	$26.9	$12.6	$35.4	$4.1	($3.1)	$7.3	>100%
PSEG	$56.6	$27.2	$105.4	($21.6)	$11.3	($32.9)	0.0%
RECO	($0.6)	($3.1)	($11.1)	$7.3	$1.4	$5.9	>100%
Total	$982.9	$839.6	$1,097.8	$724.8	$687.3	$37.4	>100%

Table 12-19 shows the total offset due to ARRs and FTRs for the entire 2010 to 2011 planning period and the first ten months of the 2011 to 2012 planning period.

Table 12-19 ARR and FTR congestion hedging (in millions): Planning periods 2010 to 2011 and 2011 to 2012 through March 31, 2012[22] (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
2010/2011	$1,029.3	$1,431.9	$1,097.8	$1,363.3	$1,401.9	($38.5)	97.3%
2011/2012*	$982.9	$839.6	$1,097.8	$724.8	$687.3	$37.4	>100%

* Shows ten months ended 31-Mar-12

22 The FTR credits do not include after-the-fact adjustments. For the 2011 to 2012 planning period, the ARR credits were the total credits allocated to all ARR holders for the first ten months (June 2011 through March 2012) 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 ten months of this planning period and the portion of Annual FTR Auction revenue distributed to the first ten months.