Q2

State of the Market Report for PJM

January through June

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

8.15.2013

2013

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 *2013 Quarterly State of the Market Report for PJM: January through June.*

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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

2013 Q2 in Review

The state of the PJM markets in the first six months of 2013 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 six months of 2013. 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 continued in the first half of 2013.

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. Information about the sources of operating reserve charges is notably opaque.

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.

The market dynamics changed in the first half of 2013. A combination of increased, weather related, demand, and higher fuel costs led to a reversal of the downward trend in LMP. PJM LMPs were substantially higher than in the first half of 2012. The load-weighted average LMP was $37.96 per MWh, 21.6 percent higher in the first half of 2013 than in the first half of 2012.

The price of natural gas, especially in the eastern part of PJM, increased in January but then decreased to the levels of December, 2012, higher than in the first six months of 2012, and coal prices were mixed but relatively unchanged in the first six months of 2013 compared to the first six months of 2012.

As a result of the relative changes in fuel costs, coal-fired units were more competitive with gas-fired units, coal output increased in the first half and gas output decreased in the first half of 2013, also reversing the trend towards reduced coal output. Existing coal units were competitive with new combined cycle gas units on the basis of fuel-only marginal cost.

The results of the energy market dynamics in the first six months of 2013 were generally positive for new coal units. In a continuation from the fourth quarter of 2012, new coal units ran at a lower fuel-only marginal cost than new combined cycle units. The combination of higher energy prices and gas prices increasing relative to coal prices resulted in significantly higher energy market net revenues for the new entrant coal plant in the first six months of 2013. In the first six months of 2013, energy market net revenues for a coal plant in nine zones exceeded 2012 annual energy market net revenues.

Markets need accurate and understandable information about fundamental market parameters in order to function effectively. For example, the markets need good information about constraints that can have substantial impacts on energy prices. 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. Data on the units receiving operating reserve credits and the reasons for those credits should be made publicly available to permit better understanding of operating reserve levels and to facilitate competition for providing the same services.

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 fact that up to congestion transactions are provided an artificial advantage over other virtual transactions must be addressed.

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 Summary Statistics

Table 1-1 shows selected summary statistics describing PJM markets.

Table 1–1 PJM Market Summary Statistics, January through June 2012 and 2013[1]

	Jan – Jun 2012	Jan – Jun 2013
Load	376,062 GWh	382,635 GWh
Generation	382,015 GWh	387,313 GWh
Imports (+) / Exports (-)	1,480 GWh	3,058 GWh
Losses	8,099 GWh	8,622 GWh
Regulation Requirement*	943 MW	769 MW
RTO Primary Reserve Requirement	NA	2,063 MW
Total Billing	$13.991 Billion	$15.572 Billion
Peak	Jun 20, 2013 18:00	Jun 25, 2013 16:00
Peak Load	147,913 MW	139,778 MW
Load Factor	0.58	0.63
Installed Capacity	As of 6/30/2012	As of 6/30/2013
Installed Capacity	185,841 MW	185,560 MW

* Daily average

PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of June 30, 2013, had installed generating capacity of 185,560 megawatts (MW) and about 850 market buyers, sellers and traders of electricity[2] in a region including more than 60 million people[3] 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).[4] In the first six months of 2013, PJM had total billings of $15.57 billion,[5] up from $13.99 billion in the first six months of 2012. 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.

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1 The load reported in this table is the accounting load plus net withdrawals at generator buses. The average hourly accounting load is reported in Section 2, "Energy Market."

2 See PJM's "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
3 See PJM's "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
4 See the *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2013. <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012.shtml>.
5 Monthly billing values are provided by PJM.

Figure 1-1 PJM's footprint and its 20 control zones

Legend

- Allegheny Power Company (AP)
- American Electric Power Co., Inc (AEP)
- American Transmission Systems, Inc. (ATSI)
- Atlantic Electric Company (AECO)
- Baltimore Gas and Electric Company (BGE)
- ComEd
- Dayton Power and Light Company (DAY)
- Delmarva Power and Light (DPL)
- Dominion
- Duke Energy Ohio/Kentucky (DEOK)
- Duquesne Light (DLCO)
- Eastern Kentucky Power Cooperative (EKPC)
- Jersey Central Power and Light Company (JCPL)
- Metropolitan Edison Company (Met-Ed)
- PECO Energy (PECO)
- Pennsylvania Electric Company (PENELEC)
- Pepco
- PPL Electric Utilities (PPL)
- Public Service Electric and Gas Company (PSEG)
- Rockland Electric Company (RECO)

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.[6,7]

On June 1, 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC).

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first six months of 2013, including market structure, participant behavior and market performance. This report was prepared by and represents the analysis of the Independent Market Monitor for PJM, also referred to as the Market Monitoring Unit or MMU.

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

The MMU also evaluates the market design for each market. The market design serves as the vehicle for translating participant behavior within the market structure into market performance. This report evaluates the effectiveness

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6 See also the *2012 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones." <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012.shtml>.

7 Analysis of 2013 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. In June 2013, the Eastern Kentucky Power Cooperative (EKPC) 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 2013, see *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

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 (TPS) 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 six months of 2013:

Table 1–2 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 six months of 2013 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1204 with a minimum of 947 and a maximum of 1610 in the first six months of 2013.

- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test mitigated local market power and forced competitive offers, correcting for structural issues created by local transmission constraints.

- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.

- Market performance was evaluated as competitive because market results in the Energy Market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.

- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes, with prices reflecting, on average, the marginal cost to produce energy. In aggregate, PJM's Energy Market design provides incentives for competitive

behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design mitigates market power and causes the market to provide competitive market outcomes.

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.[8] 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.[9]

Table 1-3 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	Competitive	
Market Performance	Competitive	Mixed

- The aggregate market structure was evaluated as not competitive. 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.[10]

- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[11]

- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded the defined offer cap, and the submitted sell offer, absent mitigation, would increase the market clearing price. Market power mitigation rules were also applied when the Capacity Market Seller submitted a sell offer for a new resource or uprate that was below the Minimum Offer Price Rule (MOPR) threshold.

- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.

- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design, there are several features of the RPM design which threaten competitive outcomes. These include the 2.5 percent reduction in demand in Base Residual Auctions and the definition of DR which permits inferior products to substitute for capacity.

Table 1-4 The Regulation Market results were indeterminate for January through June, 2013

| | January through June 2013 | |
Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	To Be Determined	To Be Determined

- The Regulation Market structure was evaluated as not competitive for the year because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 90 percent of the hours in January through June, 2013.

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

11 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.

- Participant behavior in the Regulation Market was evaluated as competitive for January through June, 2013 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 indeterminate, after the introduction of the new market design. It is too early to reach a definitive conclusion about performance under the new market design because important parts of the design are inefficient and because there is not yet enough information on performance.

- Market design was evaluated as indeterminate, after the introduction of the new market design. While the market design continues to include the incorrect definition of opportunity cost, overall the changes were positive. The market design also includes the incorrect definition of the marginal benefits factor for purposes of settlement. It is too early to reach a definitive conclusion about the new market design because there is not yet enough information about actual implementation of the design.

Table 1-5 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. The MMU estimates that the Synchronized Reserve Market would have had one or more pivotal suppliers which failed the three pivotal supplier test in 6.1 percent of the hours in January through June, 2013.

- 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 competitive prices.

- Market design was evaluated as effective because market power mitigation rules result in competitive outcomes despite high levels of supplier concentration.

Table 1-6 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 market participants did not fail the three pivotal supplier test.

- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs (zero), 13 percent of offers reflected economic withholding.

- 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 1-7 The FTR Auction Markets results were competitive

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

- 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.

- Market 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 mixed because while there are many positive features of the FTR design including a wide range of options for market participants to acquire FTRs and a competitive auction mechanism, there are several features of the FTR design which result in underfunding and features of the FTR design which incorporate subsidies which also contribute to underfunding. The market design incorporates widespread cross subsidies which are not consistent with an efficient market design.

Role of MMU

The FERC assigns three core functions to MMUs: reporting, monitoring and market design.[12] 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.[13]

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.[14] The MMU has direct, confidential access to the FERC.[15] The MMU may also refer matters to the attention of state commissions.[16]

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12 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).
13 OATT Attachment M § IV; 18 CFR § 1c.2.

14 OATT Attachment M § IV.
15 OATT Attachment M § IV.K.3.
16 OATT Attachment M § IV.H.

The MMU monitors market behavior for violations of FERC Market Rules.[17] 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,[18] or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies..."[19] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[20]

The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation.[21] 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[22] and thereafter undertakes additional investigation of the specific matter only at the direction of FERC staff.[23] 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.

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).[24] 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.[25]

The MMU also reviews operational parameter limits included with unit offers,[26] evaluates compliance with the requirement to offer into the energy and capacity markets,[27] evaluates the economic basis for unit retirement requests[28] and evaluates and compares offers in the Day-Ahead and Real-Time Energy Markets.[29]

The MMU reviews offers and inputs in order to evaluate whether those offers raise market power concerns.[30] Market participants, not the MMU, determine and take responsibility for offers that they submit and the market conduct that those offers represent. If the MMU has a concern about an offer, the MMU may raise that concern with the FERC or other regulatory authorities. The FERC and other regulators have enforcement and regulatory authority that they may exercise with respect to offers submitted by market participants. PJM also reviews offers, but it does so in order to determine whether offers comply with the PJM tariff and manuals.[31] PJM, in its role as the market operator, may reject an offer that fails to comply with the market rules. The respective reviews performed by the MMU and PJM are separate and non-sequential.

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17 OATT Attachment M § II(d)&t(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.")

18 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.

19 OATT Attachment M § II(h-1).

20 OATT Attachment M § IV.C.

21 OATT Attachment M § IV.I.1.

22 *Id.*

23 *Id.*

24 See OATT Attachment M–Appendix § II.A.

25 OATT Attachment M–Appendix § II.E.

26 OATT Attachment M–Appendix § II.B.

27 OATT Attachment M–Appendix § II.C.

28 OATT Attachment M–Appendix § IV.

29 OATT Attachment M–Appendix § VII.

30 OATT Attachment M § IV.

31 OATT § 12A.

Market Design

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

Prioritized Summary of New Recommendations

Table 1-8 includes a brief description and a priority ranking of the MMU's new recommendations for this quarterly report.

Priority rankings are relative. The creation of rankings recognizes that there are limited resources available to address market issues and that problems must be ranked in order to determine the order in which to address them. It does not mean that all the problems should not be addressed. Priority rankings are dynamic and as new issues are identified, priority rankings will change. The rankings reflect a number of factors including the significance of the issue for efficient markets, the difficulty of completion and the degree to which items are already in progress. A low ranking does not necessarily mean that an issue is not important, but could mean that the issue would be easy to resolve.

There are three priority rankings: High, Medium and Low. High priority indicates that the recommendation requires action because it addresses a market design issue that creates significant market inefficiencies and/or long lasting negative market effects. Medium priority indicates that the recommendation addresses a market design issue that creates intermediate market inefficiencies and/or near term negative market effects. Low priority indicates that the recommendation addresses a market design issue that creates smaller market inefficiencies and/or more limited market effects.

Table 1-8 Prioritized summary of new recommendations

Priority	Section	Description
Low	2 - Energy Market	When generator is offline, treat as load (not negative generation) the energy drawn from PJM by those generators for calculating average hourly real-time and day-ahead load.
High	3 - Operating Reserve	Reexamine allocation of operating reserve charges to participants to ensure payment by all whose market actions result in the incurrence of such charges. • Eliminate the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. • Reallocate the operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts.
Low	5 - Demand Response	Load management resources whose load drop method is designated as "Other" should explicitly record the method of load drop.
Medium	9 - Ancillary Services	Remove the distinction between Tier 1 and Tier 2 synchronized reserve, remove the ability to offer MW of synchronized reserve capability, remove the ability to make reserve unavailable, and automatically dispatch primary reserve co-optimized with energy. In the interim, enforce a must-offer requirement for synchronized reserve based on physical capability and increase penalties for non-compliance during spinning events.
High	12 - FTRs	Fix the FTR overallocation issue: • Eliminate cross geographic subsidies. • Improve transmission outage modeling in the FTR auction models. • Reduce FTR sales on paths with persistent underfunding including clear rules for what defines persistent underfunding and how the reduction will be applied. • Implement a seasonal ARR and FTR allocation system to better represent outages. • Eliminate over allocation requirement of ARRs in the Annual ARR Allocation process.

32 OATT Attachment M § IV.D.
33 *Id.*
34 *Id.*
35 *Id.*
36 OATT Attachment M § VI.A.

Detailed Recommendations

Consistent with its core function to "[e]valuate existing and proposed market rules, tariff provisions and market design elements and recommend proposed rule and tariff changes,"[37] the MMU recommends specific enhancements to existing market rules and implementation of new rules that are required for competitive results in PJM markets and for continued improvements in the functioning of PJM markets. In this *2013 Quarterly State of the Market Report for PJM: January through June*, the MMU makes the following new recommendations.

From Section 2, "Energy Market":

- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load weighted LMP.

From Section 3, "Operating Reserve":

- The MMU recommends the reexamination of the allocation of operating reserve charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges.
  - The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges.
  - The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts.

From Section 4, "Capacity":

- There are no new recommendations in Section 4.

From Section 5, "Demand Response":

- The MMU recommends that load management resources whose load drop method is designated as "Other" explicitly record the method of load drop.

From Section 6, "Net Revenue":

- There are no new recommendations in Section 6.

From Section 7, "Environmental and Renewables":

- There are no new recommendations in Section 7.

From Section 8, "Interchange Transactions":

- There are no new recommendations in Section 8.

From Section 9, "Ancillary Services":

- FERC Order No. 719 makes synchronized reserve must-offer. Therefore the MMU recommends that PJM remove the distinction between Tier 1 and Tier 2 synchronized reserve, remove the ability of participants to offer MW of synchronized reserve capability, remove the ability of participants to make reserve unavailable, and automatically dispatch primary reserve co-optimized with energy. In the interim, PJM should enforce a must-offer requirement for synchronized reserve based on physical capability (with physical capability the default offer) and increase penalties for non-compliance during spinning events.

From Section 10, "Congestion and Marginal Losses":

- There are no new recommendations in Section 10.

From Section 11, "Planning":

- There are no new recommendations in Section 11.

From Section 12, "FTRs and ARRs":

The MMU makes the following new recommendations to address the FTR allocation issue:

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37 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

- Eliminate cross geographic subsidies.
- Improve transmission outage modeling in the FTR auction models.
- Reduce FTR sales on paths with persistent underfunding including clear rules for what defines persistent underfunding and how the reduction will be applied.
- Implement a seasonal ARR and FTR allocation system to better represent outages.
- Eliminate over allocation requirement of ARRs in the Annual ARR Allocation process.

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 1-9 provides the average price and total revenues paid, by component, for the first six months of 2012 and 2013.

Table 1-9 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 six months of 2013.

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.[38]
- The Operating Reserve (uplift) component is the average price per MWh of day ahead and real time operating reserve charges.[39]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[40]
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[41]
- 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.[42]
- 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.[43]
- 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.[44]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[45]
- The Black Start component is the average cost per MWh of black start service.[46]

38 OATT §§ 13.7, 14.5, 27A & 34.
39 OA Schedules 1 §§ 3.2.3 & 3.3.3.
40 OATT Schedule 2 and OA Schedule 1 § 3.2.3B.
41 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
42 OATT Schedule 12.
43 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
44 OATT Schedule 1A.
45 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
46 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.

- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[47]

- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[48]

- The Load Response component is the average cost per MWh of day ahead and real time load response program charges to LSEs.[49]

- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[50]

- The Non-Synchronized Reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[51]

Table 1-9 Total price per MWh by category and total revenues by category: January through June, 2012 and 2013

Category	Jan–Jun 2012 $/MWh	Jan–Jun 2013 $/MWh	Percent Change Totals	Jan–Jun 2012 Percent of Total	Jan–Jun 2013 Percent of Total
Load Weighted Energy	$31.21	$37.96	21.6%	68.4%	73.8%
Capacity	$7.22	$5.69	(21.3%)	15.8%	11.1%
Transmission Service Charges	$4.89	$4.97	1.5%	10.7%	9.7%
Operating Reserves (Uplift)	$0.65	$0.73	12.6%	1.4%	1.4%
Reactive	$0.47	$0.65	37.9%	1.0%	1.3%
PJM Administrative Fees	$0.44	$0.44	(0.8%)	1.0%	0.9%
Transmission Enhancement Cost Recovery	$0.30	$0.41	38.6%	0.7%	0.8%
Regulation	$0.20	$0.26	30.6%	0.4%	0.5%
Black Start	$0.02	$0.15	568.8%	0.1%	0.3%
Transmission Owner (Schedule 1A)	$0.08	$0.08	(6.7%)	0.2%	0.2%
Synchronized Reserves	$0.03	$0.03	1.3%	0.1%	0.1%
NERC/RFC	$0.02	$0.02	(0.5%)	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(1.8%)	0.0%	0.0%
Load Response	$0.01	$0.01	(17.5%)	0.0%	0.0%
Day Ahead Scheduling Reserve (DASR)	$0.03	$0.00	(86.2%)	0.1%	0.0%
Transmission Facility Charges	$0.00	$0.00	(4.6%)	0.0%	0.0%
Non-Synchronized Reserves		$0.00		0.0%	0.0%
Total	$45.61	$51.43	12.8%	100.0%	100.0%

Section Overviews
Overview: Section 2, "Energy Market"
Market Structure

- **Supply.** Average offered supply increased by 2,445, or 1.4 percent, from 168,828 MW in the first six months of 2012 to 171,274 MW in the first six months of 2013.[52] The increase in offered supply was in part the result of the integration of the East Kentucky Power Cooperative (EKPC) Transmission Zone in the second quarter of 2013. In 2013, 534.6 MW of new capacity were added to PJM. This new supply was partially offset by the deactivation of 4 units (233.8 MW) since January 1, 2013.

- **Demand.** The PJM system peak load for the first six months of 2013 was 139,778 MW in the HE 1600 on June 25, 2013, which was 8,135 MW, or 5.5 percent, lower than the PJM peak load for the first six months of 2012, which was 147,913 MW in the HE 1800 on June 20, 2012.[53]

- **Market Concentration.** Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.

- **Local Market Structure and Offer Capping.** PJM continued to apply a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in the first six months of 2013. PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer capping levels have historically been low in PJM. In the first six months of 2013, offer capping levels increased as a result of the inclusion

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47 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
48 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
49 OA Schedule 1 § 3.6.
50 OA Schedule 1 § 5.3b.
51 OA Schedule 1 § 3.2.3A.001.

52 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.
53 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2012 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).

of units that are committed for reliability reasons to provide black start and reactive service. In the Day-Ahead Energy Market offer-capped unit hours increased from 0.1 percent in the first six months of 2012 to 3.9 percent in the first six months of 2013. In the Real-Time Energy Market offer-capped unit hours increased from 1.7 percent in the first six months of 2012 to 3.4 percent in the first six months of 2013.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 56 units eligible for FMU or AU status in at least one month during the first six months of 2013, 27 units (48.2 percent) were FMUs or AUs for all six months, and 13 units (23.2 percent) qualified in only one month of 2013.

- **Local Market Structure.** In the first six months of 2013, 11 Control Zones experienced congestion resulting from one or more constraints binding for 50 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.

Market Performance: Markup, Load, Generation and LMP

- **Markup.** The markup conduct of individual owners and units has an impact on market prices. The markup analysis is a key indicator of the competitiveness of the Energy Market.

  All generating units, including coal units, are allowed to include a 10 percent adder in their cost offer. The 10 percent adder was included in the definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. Coal units do not face the same cost uncertainty as gas-fired CTs. A review of actual participant behavior supports this view, as the owners of coal units, facing competition, typically remove the 10 percent adder from their actual offers. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the 10 percent adder in the cost offer. The

adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder from the cost offer.

In the first six months of 2013, the unadjusted markup was negative, -$2.09 per MWh, primarily as a result of competitive behavior by coal units and the competitive removal of the 10 percent adder. . The adjusted markup was less negative, -$0.53 per MWh or -1.4 percent of the PJM real-time, load-weighted average LMP.

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

- **Load.** PJM average real-time load in the first six months of 2013 increased by 2.3 percent from the first six months of 2012, from 84,946 MW to 86,897 MW. The PJM average real-time load in 2013 would have increased by 2.0 percent from the first six months of 2012, from 84,946 MW to 86,675 MW, if the EKPC Transmission Zone had not been included in this comparison for the months prior to its integration to PJM.[54]

  PJM average day-ahead load in the first six months of 2013, including DECs and up-to congestion transactions, increased by 11.9 percent from the first six months of 2012, from 129,881 MW to 145,280 MW. The PJM average day-ahead load, including DECs and up-to congestion transactions, would have increased 11.7 percent from the first six months of 2012, from 129,881 MW to 145,042 MW if the EKPC Transmission Zone had not been included. The day-ahead load growth was 417.4 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions.

- **Generation.** PJM average real-time generation in the first six months of 2013 increased by 1.9 percent from the first six months of 2012, from 86,310 MW to 87,974 MW. The PJM average real-time generation in the first six months of 2013 would have increased by 1.7 percent from the first six months of 2012, from 86,310 MW to 87,781 MW if the EKPC Transmission Zone had not been included.

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54 The EKPC zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013.

PJM average day-ahead generation in the first six months of 2013, including INCs and up-to congestion transactions, increased by 12.1 percent from the first six months of 2012, from 132,326 MW to 148,381 MW. The PJM average day-ahead generation, including INCs and up-to congestion transactions, would have increased by 12.0 percent from the first six months of 2012, from 132,326 MW to 148,167 MW if the EKPC Transmission Zone had not been included. The day-ahead generation growth was 536.8 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.

- **Generation Fuel Mix.** During the first six months of 2013, coal units provided 44.3 percent, nuclear units 35.1 percent and gas units 15.7 percent of total generation. Compared to the first six months of 2012, generation from coal units increased 11.3 percent, generation from nuclear units increased 0.8 percent, and generation from gas units decreased 17.9 percent. This represents a reversal of the recent trend of decreasing coal-fired output and increasing gas-fired output. The change is primarily a result of increased natural gas prices in the first six months of 2013, particularly in eastern zones, and lower or constant coal prices.

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

PJM Real-Time Energy Market prices increased in the first six months of 2013 compared to the first six months of 2012. The system average LMP was 22.9 percent higher in the first six months of 2013 than in the first six months of 2012, $36.56 per MWh versus $29.74 per MWh. The load-weighted average LMP was 21.6 percent higher in the first six months of 2013 than in the first six months of 2012, $37.96 per MWh versus $31.21 per MWh.

PJM Day-Ahead Energy Market prices increased in the first six months of 2013 compared to the first six months of 2012. The system average LMP

was 21.9 percent higher in the first six months of 2013 than in the first six months of 2012, $37.11 per MWh versus $30.44 per MWh. The load-weighted average LMP was 20.1 percent higher in the first six months of 2013 than in the first six months of 2012, $38.23 per MWh versus $31.84 per MWh.[55]

- **Load and Spot Market.** Companies that serve load in PJM can do so using 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. For the first six months of 2013, 10.6 percent of real-time load was supplied by bilateral contracts, 23.8 percent by spot market purchases and 65.6 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased 1.6 percentage points, reliance on spot market purchases increased by 0.6 percentage points and reliance on self-supply decreased by 2.2 percentage points. For the first six months of 2013, 7.3 percent of day-ahead load was supplied by bilateral contracts, 23.0 percent by spot market purchases, and 69.7 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased by 0.6 percentage points, reliance on spot market purchases increased by 0.7 percentage points, and reliance on self-supply decreased by 1.4 percentage points.

Scarcity

- **Scarcity Pricing Events in 2013.** PJM's market did not experience any reserve-based scarcity events in the first six months of 2013.

Section 2 Recommendations

The zonal load-weighted LMP is calculated by weighting the zone's load bus LMPs by the zone's load bus accounting load. The classification of energy as load or generation impacts PJM's calculation of zonal load-weighted LMP.

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55 Tables reporting zonal and jurisdictional load and prices are in the *2012 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

PJM sums all negative (injections) and positive (withdrawals) load at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) generation at each generation bus when calculating net generation. Netting withdrawals and injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load weighted LMP.

- There is currently no PJM documentation in the tariff or manuals explaining how hubs are defined and how those definitions are changed. The MMU recommends that PJM include in the appropriate manual an explanation of the initial definition of hubs and the process for modifying hub definitions.[56]

- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders were added to the market rules in 2006 in order to address revenue inadequacy for frequently mitigated units. Since that time, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007, and changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. This recommendation is currently scheduled to be evaluated through the PJM stakeholder process in the fourth quarter of 2013.

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[56] According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

Section 2 Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in the first six months of 2013, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand-side response programs, loads and prices.

Average real-time supply offered increased by 2,445 MW in the first six months of 2013 compared to the first six months of 2012, while peak load decreased by 8,135 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. Market concentration levels remained moderate. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load in each hour. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price. Energy Market results for the first six months of 2013 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.[57] 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

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

a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not 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. PJM implemented new scarcity pricing rules in 2012. There are significant issues with the scarcity pricing true up mechanism in the new PJM scarcity pricing design, which will create issues when scarcity pricing occurs.

The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior remain potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in the first six months of 2013.

Overview: Section 3, "Operating Reserve"

Operating Reserve Results

- **Operating Reserve Charges.** Total operating reserve charges increased by 55.2 percent in the first six months of 2013 compared to the first six months of 2012, to a total of $433.6 million. Day-ahead operating reserve charges were 11.3 percent, balancing operating reserve charges were 52.6 percent, reactive services charges were 25.0 percent, synchronous condensing charges were 0.001 percent and black start services charges were 11.1 percent of total operating reserve charges.

- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.086 per MWh, the day-ahead operating reserve rate including unallocated congestion charges averaged $0.122 per MWh, the balancing operating reserve reliability rates averaged $0.050, $0.041 and $0.004 per MWh for the RTO, Eastern and Western Regions, the balancing operating reserve deviation rates averaged $0.887, $3.302 and $0.117 per MWh for the RTO, Eastern and Western Regions. Lost opportunity cost rate averaged $0.729 per MWh and canceled resources rate averaged $0.0003 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 53.7 percent of all day-ahead generator credits and 61.7 percent of all balancing generator credits. Combustion turbines and diesels received 69.7 percent of the lost opportunity cost credits. Combined cycles and coal units received 87.5 percent of all reactive services credits.

- **Economic and Noneconomic Generation.** In the first six months of 2013, 81.8 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.9 percent of the real-time generation eligible for operating reserve credits was economic.

Geography of Balancing Charges and Credits

- In the first six months of 2013, 80.7 percent of all charges allocated regionally were paid by transactions, demand and generators located in control zones, 6.4 percent by transactions at hubs and aggregates and 13.0 percent by transactions at interfaces.

- Generators in the Eastern Region paid 16.0 percent of all RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 80.2 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits. Generators in the Western Region paid 14.8 percent of all RTO and Western Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 19.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

- Generators paid 10.7 percent of all operating reserve charges (excluding charges for resources controlling local transmission constraints) and received 99.99 percent of all credits.

Operating Reserve Issues

- **Concentration of Operating Reserve Credits:** The top 10 units receiving operating reserve credits received 40.3 percent of all credits. The top 10 organizations received 86.9 percent of all credits. Concentration indexes for the three largest operating reserve categories classify them as highly concentrated. Day-ahead operating reserves HHI was 5223, balancing operating reserves HHI was 4392 and lost opportunity cost HHI was 4753.

- **Day-Ahead Unit Commitment for Reliability:** In the first six months of 2013, 4.5 percent of the total day-ahead generation was scheduled as must run by PJM, of which 67.3 percent was made whole.

- **Lost Opportunity Cost Credits:** In the first six months of 2013, lost opportunity cost credits decreased by $23.7 million compared to the first six months of 2012. In the first six months of 2013, the top three control zones receiving lost opportunity cost credits, ATSI, AP and ComEd combined for 56.0 percent of all lost opportunity cost credits, 43.7 percent of the credits for day-ahead generation from pool-scheduled combustion turbines and diesels, 57.9 percent of the credits for day-ahead generation not called in real time by PJM from those unit types and 67.1 percent of the credits day-ahead generation not called in real time by PJM and receiving lost opportunity cost credits from those unit types.

- **Lost Opportunity Cost Calculation:** In the first six months of 2013, lost opportunity cost credits would have been reduced by $12.9 million, or 29.2 percent, if all changes proposed by the MMU had been implemented.

- **Black Start Service Units:** Certain units located in the AEP zone are relied on for their black start capability on a regular basis even during periods when the units are not economic. The relevant black start units provide black start service under the ALR option, which means that the units must be running even if not economic. In the first six months of 2013, the cost of the noneconomic operation of ALR units in the AEP control zone was $47.9 million.

- **Con Edison – PSEG Wheeling Contracts Support:** 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. These units are often run out of merit and received substantial balancing operating reserves credits.

- **Impact of Quantifiable Recommendations:** The impact of implementing the recommendations proposed by the MMU related to increasing the pool of participants who pay operating reserve charges on operating reserve charge rates and on the payments by other participants would be significant. For example, in the first six months of 2013, the average rate paid by a DEC in the Eastern Region would have been $0.209 per MWh, $4.401 per MWh or 95.5 percent less than the actual average rate paid.

Section 3 Recommendations

- The MMU recommends the reexamination of the allocation of operating reserve charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges.
- The MMU recommends four modifications to the energy lost opportunity cost calculations.
  - The MMU recommends that the lost opportunity cost in the Energy and Ancillary Services Markets be calculated using the schedule on which the unit was scheduled to run in the Energy Market.
  - The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not called in real time.
  - The MMU recommends eliminating the use of the day-ahead LMP to calculate lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not called in real time.
  - The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost.
- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with operating reserve credits calculation
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges.
- The MMU recommends that up-to congestion transactions be required to pay operating reserve charges.
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts.

- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of information regarding the reasons for operating reserve payments in the PJM region.

Section 3 Conclusion

Day-ahead and real-time operating reserve credits are paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or make whole, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges.

From the perspective of those participants paying operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

The goal should be to reflect the impact of physical constraints in market prices to the maximum extent possible and thus to reduce the necessity for out of market operating reserve payments. When units receive substantial revenues through operating reserve payments, these payments are not transparent to the market and other market participants do not have the opportunity to compete for them. As a result, substantial operating reserve payments to a concentrated group of units and organizations persists.

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, the details of the rules which define payments and the decisions of PJM operators. Operating reserve credits result in part from decisions by PJM operators,

who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, no load and startup costs. But these costs are collected as operating reserves rather than reflected in price as a result of the rules governing the determination of LMP in situations where something other than a simple thermal transmission constraint affects unit dispatch.

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, the MMU recommends that PJM take another step towards more precise definition and clearly identify and classify all reasons for incurring operating reserve charges in order to ensure a long term solution of the allocation issue of the costs of operating reserves. The MMU recommends that the goal should be to have dispatcher decisions reflected in transparent market outcomes, preferably LMP, to the maximum extent possible and to minimize the level and rate of operating reserve charges.

The MMU recommended and supports PJM in the reexamination of the allocation of operating reserve charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges.[58] For example, there has not been an analysis of the impact of up-to congestion transactions and their impact on the payment of operating reserve credits. Up-to congestion transactions continue to pay no operating reserve charges, which means that all others who pay operating reserve charges are paying too much. In addition, the issue of netting using internal bilateral transactions should be addressed.

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

Overview: Section 4, "Capacity Market"

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market 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.[59]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each delivery year.[60] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[61] Also effective for the 2012/2013 Delivery Year, a conditional incremental auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[62]

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58 PJM presented a problem statement at the Markets and Reliability Committee (MRC) to perform a holistic review of operating reserves. See "Item 10 – Operating Reserves Problem Statement," <http://www.pjm.com/~/media/committees-groups/committees/mrc/20130425/20130425-item-10-operating-reserves-problem-statement.ashx> (Accessed April 26, 2013).

59 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2013 Quarterly State of the Market Report for PJM*, Section 4, "Capacity Market" and include all capacity within the PJM footprint.
60 See 126 FERC ¶ 61,275 (2009) at P 86.
61 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
62 See 126 FERC ¶ 61,275 (2009) at P 88.

RPM prices are locational and may vary depending on transmission constraints.[63] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power, that define offer caps based on the marginal cost of capacity, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Demand-side resources and Energy Efficiency resources may be offered directly into RPM Auctions and receive the clearing price without mitigation.

Market Structure

- **PJM Installed Capacity.** During the period January 1 through June 30, 2013, PJM installed capacity increased 3,549.2 MW or 1.9 percent from 182,011.1 MW on January 1 to 185,560.3 MW on June 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity on June 30, 2013, 42.0 percent was coal; 28.8 percent was gas; 17.8 percent was nuclear; 6.1 percent was oil; 4.4 percent was hydroelectric; 0.4 percent was solid waste; 0.5 percent was wind, and 0.0 percent was solar.

- **Market Concentration.** In the 2016/2017 RPM Base Residual Auction, all participants in the total PJM market as well as the LDA RPM markets failed the Three Pivotal Supplier (TPS) test. 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.[64],[65],[66]

- **Imports and Exports.** Of the 7,493.7 MW of imports offered in the 2016/2017 RPM Base Residual Auction, 7,482.7 MW cleared. Of the cleared imports, 4,723.1 MW (63.1 percent) were from MISO.

- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 8,490.0 MW for June 1, 2013 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2013/2014 Delivery Year (11,683.8 MW) less replacement capacity (3,193.8 MW).

Market Conduct

- **2016/2017 RPM Base Residual Auction.** Of the 1,199 generation resources which submitted offers, unit-specific offer caps were calculated for 139 generation resources (11.6 percent). The MMU calculated offer caps for 638 generation resources (53.2 percent), of which 491 were based on the technology specific default (proxy) ACR values.

Market Performance

- The 2016/2017 RPM Base Residual Auction was conducted in the second quarter of 2013. In the 2016/2017 RPM Base Residual Auction, the RTO clearing price for Annual Resources was $59.37 per MW-day. The weighted average capacity price for the 2016/2017 BRA was $89.29.

- The delivery year weighted average capacity price was $70.46 per MW-day in 2012/2013 and $161.62 per MW-day in 2015/2016.

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63 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

64 See OATT Attachment DD § 6.5.

65 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.

66 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).

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for January through June was 8.4 percent, an increase from the 7.5 percent average PJM EFORd for 2012.[67]

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for January through June was 81.4 percent, a decrease from the 84.1 percent PJM aggregate equivalent availability factor for 2012.

- **Outages Deemed Outside Management Control (OMC).** In the first six months of 2013, 15.6 percent of forced outages were classified as OMC outages. OMC outages are excluded from the calculation of the forced outage rate used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

Section 4 Conclusion

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, but no exercise of market power in the PJM Capacity Market in the first six months of 2013. 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 six months of 2013.[68]

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[69,70,71,72]

Overview: Section 5, "Demand Response"

- **Demand-Side Response Activity.** In the first six months of 2013, total load reduction under the Economic Load Response Program decreased by 3,773 MWh compared to the same period in 2012, from 38,692 MWh in the first six months of 2012 to 34,919 MWh in the first six months of 2013, a 10 percent decrease. Total credits under the Economic Program decreased by $321,417, from $2,172,454 in the first six months of 2012 to $1,851,037 in the same period of 2013, a 15 percent decrease. However, total credits increased by 516 percent from the first four months of 2012 to the first four months of 2013. May and June, 2013 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.

The capacity market is the primary source of revenue to participants in PJM demand side programs. In the first six months of 2013, Load Management (LM) Program revenue decreased $39.6 million, or 20.2 percent, from $196.2 million to $156.6 million. Through the first six months of 2013, Synchronized Reserve credits for demand side resources decreased by $1.4 million compared to the same period in 2012, from $2.5 million to $1.4 million in 2013.

Section 5 Conclusion

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

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67 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM Generator Availability Data Systems (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. Data is for the twelve months ending December 31 or the six months ending June 30, as downloaded from the PJM GADS database on August 5, 2013. 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.

68 For more complete conclusions, see *2012 State of the Market Report for PJM*, Volume II, Section 4, "Capacity Market."

69 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).

70 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).

71 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).

72 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).

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.

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 are not adequate to determine and quantify deliberate actions taken to reduce consumption. The MMU recommends that actual meter load data should be provided in order to measure and verify actual demand resource behavior.

The MMU recommends that demand side measurement and verification be further modified to more accurately reflect compliance. Increases in load by load management resources during event hours should not be considered zero response or ignored, but should be included for reporting and determining compliance. Load management testing does not adequately reflect actual resource performance during event days. Testing should be initiated by PJM with limited warning to CSPs in order to more accurately reflect the conditions of an emergency event.[73] The MMU recommends that load management resources whose load drop method is designated as "Other" explicitly record the method of load drop.

The load management product is currently defined as an emergency product. In fact, the load management product is an economic product and it is treated as an economic product in the PJM capacity market design where it competes directly with generation capacity, affects market clearing prices and

receives the market clearing price. The load management product should also be treated as an economic product in PJM dispatch meaning that demand resources should be called when the resources are required and prior to the declaration of an emergency. For these reasons, the MMU recommends that the DR program be classified as an economic program and not an emergency program.[74]

Overview: Section 6, "Net Revenue"

Net Revenue

- In the first six months of 2013, energy market net revenues for a new entrant coal plant exceeded 2012 annual energy market net revenues in nine zones. This increase in net revenues was a result of the change in the relative prices of coal and gas and higher energy market prices.

- In the first six months of 2013, average energy market net revenues for a new entrant CT were 43 percent of 2012 annual energy market net revenues. In the first six months of 2013, average energy market net revenues for a new entrant CC were 40 percent of 2012 annual energy market net revenues.

- In the first six months of 2013, average energy market net revenues for a new entrant wind plant were over 69 percent and for a new entrant solar plant were over 77 percent of 2012 annual net revenues.

Section 6 Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct capacity, or capacity markets of various types. Regardless of the enforcement

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73 For additional conclusions see the *2012 State of the Market Report for PJM*, Volume 2: Section 5, "Demand Response."

74 This issue is currently being discussed in the Capacity Senior Task Force (CSTF) with an expected resolution by summer 2014.

mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

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

The historical level of net revenues in PJM markets was not the result of the $1,000-per-MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market clearing prices. Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly compensate the resources needed to provide for reliability.

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

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices when they run. When this occurs, CT energy market net revenues tend to be low and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs and other inframarginal units.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. In the PJM design, the capacity market provides a significant stream of revenue that contributes to the recovery of total costs for new and existing peaking units that may be needed for reliability during years in which energy net revenues are not sufficient. The capacity market is also a significant source of net revenue to cover the fixed costs of investing in new intermediate and base load units, although capacity revenues are a larger part of net revenue for peaking units. However, when the actual fixed costs of capacity increase rapidly, or, when the energy net revenues used as the offset in determining capacity market prices are higher than actual energy net revenues, there is a corresponding lag in capacity market prices which will tend to lead to an under recovery of the fixed costs of CTs. The reverse can also happen, leading to an over recovery of the fixed costs of CTs, although it has happened less frequently in PJM markets.

Overview: Section 7, "Environmental and Renewables"

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.**[75] On December 16, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel,

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75 MATS replaces the Clean Air Mercury Rule (CAMR). It has been widely known previously as the "HAP" or "Utility MACT" rule.

selenium and cyanide.[76] The rule establishes a compliance deadline of April 16, 2015.

In addition, in a related EPA rule issued on the same date regarding utility New Source Performance Standards (NSPS), the EPA requires new coal and oil fired electric utility generating units constructed after May 3, 2011, to comply with amended emission standards for SO_2, NO_X and filterable particulate matter. On March 28, 2013, EPA issued a rule that raised the new source limits for new coal- and oil-fired power plants based on new information and analysis.[77]

- **Cross-State Air Pollution Rule.** On August 21, 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR, which previously had been subject to a stay.[78] The Supreme Court granted EPA's petition for certiorari on June 24, 2013, and its review of CSAPR is pending. Meanwhile, the Clean Air Interstate Rule (CAIR) remains in effect. The EPA continues to process a number of pending requests under CAIR, including State Implementation Plans (SIPs), originally submitted under CSAPR.

- **National Emission Standards for Reciprocating Internal Combustion Engines.** On January 14, 2013, EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[79] RICE includes certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE includes facilities located behind the meter. The rule exempts from its requirements one hundred hours of RICE operation in emergency demand response programs, provided that RICE uses ultra low sulfur diesel fuel (ULSD). Otherwise, a 15-hour exception applies. Emergency demand response programs include Demand Resources in RPM.

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76 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).

77 *Reconsideration of Certain New Source Issues: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR 2009-0234, 78 Fed. Reg. 24073 (April 24, 2013).

78 *See* EME Homer City Generations, L.P. v. EPA, NO. 11-1302.

79 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 9403 (January 30, 2013).

- **Greenhouse Gas Emissions Rule.** On June 13, 2013, pursuant to a Climate Action Plan, the President issued a memorandum directing that EPA propose a rule to replace the rule that had been proposed on April 13, 2012, entitled "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units." The President directed that EPA issue the new proposal no later than September 20, 2013, and that it issue a final rule "in a timely fashion."[80]

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as High Electric Demand Days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days.[81] New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.[82]

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities. Auction prices in 2013 for the 2012-2014 compliance period were $2.80 per ton, above the price floor for 2013.

Emissions Controls in PJM Markets

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. On June 30, 2013, 69.4 percent of coal steam

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80 77 Fed. Reg. 22392.

81 N.J.A.C. § 7:27-19.

82 CTs must have either water injection or Selective Catalytic Reduction (SCR) controls; steam units must have either an SCR or and Selective Non-Catalytic Reduction (SNCR).

MW had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units, while 97.6 percent of coal steam MW had some type of particulate control, and 91.3 percent of fossil fuel fired capacity in PJM had NO_x emission control technology in place.

State 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 June 30, 2013, Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 2015.

Renewable energy credits provide out of market payments to qualifying resources, primarily wind and solar. 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 LMP is equal to the marginal cost of producing minus the credit received for each MWh. As the net of LMP and credits can be negative, the credits can provide an incentive to make negative energy offers. These subsidies affect the offer behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

Section 7 Conclusion

Environmental requirements and renewable energy mandates at both the Federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. 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 formally recognized as part of 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 incorporates renewable resources and renewable energy credit markets, and ensures that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

Overview: Section 8, "Interchange Transactions"

Interchange Transaction Activity

- **East Kentucky Power Cooperative (EKPC).** On June 1, 2013, East Kentucky Power Cooperative was integrated into PJM. This integration eliminated the EKPC Interface. The integration did not result in any changes to interface pricing points.

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first six months of 2013, PJM was a monthly net importer of energy in the Real-Time Energy Market.[83] During the first six months of 2013, the real-time net interchange of 4,023.3 GWh was greater than net interchange of 2,351.1 GWh in the first six months of 2012.

- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first six months of 2013, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market. During the first six months of 2013, the total day-ahead net interchange of -9,161.6 GWh was greater than net interchange of -1,947.9 GWh during the first six months of 2012.

- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first six months of 2013, gross imports in the Day-Ahead Energy Market were 158.0 percent of gross imports in the Real-Time Energy Market (427.8 percent during the first six months of 2012), gross exports in the Day-Ahead Energy Market were 242.0 percent of the gross exports in the Real-Time Energy Market (487.3 percent during the first six months of 2012).

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83 Calculated values shown in Section 8, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first six months of 2013, there were net scheduled exports at ten of PJM's 21 interfaces.

- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first six months of 2013, there were net scheduled exports at eleven of PJM's 17 interface pricing points eligible for real-time transactions.[84]

- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first six months of 2013, there were net scheduled exports at ten of PJM's 21 interfaces.

- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first six months of 2013, there were net scheduled exports at nine of PJM's 19 interface pricing points eligible for day-ahead.

- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Market, for the first six months of 2013, up-to congestion transactions had net exports at five of PJM's 19 interface pricing points eligible for day-ahead transactions.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first six months of 2013, the direction of the average hourly flow was inconsistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. The direction of flow was consistent with price differentials in only 46.5 percent of hours in the first six months of 2013.

- **PJM and New York ISO Interface Prices.** In the first six months of 2013, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. The direction of flow was consistent with price differentials in 55.9 percent of the hours in the first six months of 2013.

- **Neptune Underwater Transmission Line to Long Island, New York.** In the first six months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus.[85] The average hourly flow during the first six months of 2013 was -293 MW.[86] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 78.3 percent of the hours in the first six months of 2013.

- **Linden Variable Frequency Transformer (VFT) Facility.** In the first six months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO LMP Linden Bus.[87] The average hourly flow during the first six months of 2013 was -139 MW.[88] The direction of flows was consistent with price differentials in 70.6 percent of the hours in the first six months of 2013.

- **Hudson DC Line.** The Hudson direct current (DC) line began commercial operation on June 3, 2013. The Hudson direct current (DC) line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM and NYISO. While the Hudson DC line is a bidirectional line, power flows will only be from PJM to New York. In the first month of operations, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO LMP Hudson Bus.[89] The average hourly flow during the first month of operation was -17 MW.[90] The direction of flows was consistent with price differentials in 60.9 percent of the hours during June, 2013.

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85 In the first six months of 2013, there were 833 hours where there was no flow on the Neptune DC Tie line. The PJM average hourly LMP at the Neptune Interface during non-zero flows was $40.03 while the NYISO LMP at the Neptune Bus during non-zero flows was $71.87, a difference of $31.84.

86 The average hourly flow during the first six months of 2013, ignoring hours with no flow, on the Neptune DC Tie line was -363 MW.

87 In the first six months of 2013, there were 841 hours where there was no flow on the Linden VFT line. The PJM average hourly LMP at the Linden Interface during non-zero flows was $41.32 while the NYISO LMP at the Neptune Bus during non-zero flows was $51.64, a difference of $10.32.

88 The average hourly flow during the first six months of 2013, ignoring hours with no flow, on the Linden VFT line was -173 MW.

89 In its first month of operation, there were 550 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $37.17 while the NYISO LMP at the Hudson Bus during non-zero flows was $39.26, a difference of $2.09.

90 The average hourly flow during the first months of operations, ignoring hours with no flow, on the Hudson line was -147 MW.

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84 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

Interchange Transaction Issues

- **Loop Flows.** Actual flows are the metered power flows at an interface for a defined period. Scheduled flows are the power 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 the difference between actual and scheduled power flows at one or more specific interfaces.

  For the first six months of 2013, net scheduled interchange was 2,989 GWh and net actual interchange was 3,058 GWh, a difference of 69 GWh. For the first six months of 2012, net scheduled interchange was 1,666 GWh and net actual interchange was 1,480 GWh, a difference of 185 GWh. This difference is inadvertent interchange.

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued 23 TLRs of level 3a or higher in the first six months of 2013, compared to eight TLRs issued in the first six months of 2012.

- **Up-To Congestion.** Following elimination of the requirement to procure transmission service for up-to congestion transactions in 2010, the volume of transactions increased significantly. The volumes of submitted and cleared up-to congestion bids continued to increase following the business rule change on November 1, 2012, which eliminated the requirement for either the source or sink of an up-to congestion transaction to be at an interface. The average number of up-to congestion bids submitted in the Day-Ahead Market increased to 107,215 bids per day, with an average cleared volume of 1,272,955 MWh per day, in the first six months of 2013, compared to an average of 54,180 bids per day, with an average cleared volume of 931,553 MWh per day, in the first six months of 2012.

- **Elimination of Sources and Sinks.** The MMU recommended that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets. On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink

designations in both the Day-Ahead and Real-Time Energy Markets.[91] On April 22, 2013, PJM implemented changes to its OASIS eliminating the internal source and sink designations on transmission reservations.

- **Spot Import.** Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. However, PJM interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction. The result was that the availability of spot import service was limited by ATC and not all spot transactions were approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

  The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all non-firm point-to-point willing to pay congestion imports and exports) at all PJM Interfaces in order to improve the efficiency of the market.

Section 8 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 offsets (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 six months of 2013, including evolving

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91 See "Meeting Minutes," Minutes from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx>.

transaction patterns, economics and issues. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Markets, coincident with the expansion of the PJM footprint. In January, 2012, the direction of real-time power flows started to fluctuate between net imports and exports. The net direction of power flows is generally a function of price differences net of transactions costs. Since the modification of the up-to congestion product in September 2010, up-to congestion transactions have played a significant role in power flows between PJM and external balancing authorities in the Day-Ahead Market. On November 1, 2012, PJM eliminated the requirement that market participants specify an interface pricing point as either the source or sink of an up-to congestion transaction. As a result, the volume of import and export up-to congestion transactions decreased, and the volume of internal up-to congestion transactions increased, reducing the day-ahead gross import and export volumes. While the gross import and export volumes in the Day-Ahead Market have decreased, the net direction of power flows has remained predominantly in the export direction.

In the first six months of 2013, 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 53.5 percent of the hours for transactions between PJM and MISO and for 44.1 percent of the hours for transactions between PJM and NYISO. The MMU recommends that PJM continue to work with both MISO and NYISO to improve the ways in which interface flows and prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to an LMP market. In an LMP market, redispatch based on LMP and generator offers would result in an efficient dispatch and efficient prices. Price differences at the seams continue to be determined by relying on market participants to see the prices and react to the prices by scheduling transactions with both an internal lag and an RTO administrative lag.

Loop flows remain a significant concern for the efficiency of the PJM market. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on

FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets. The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on market paths that reflect the expected actual flow. This validation method would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices. This validation method would provide PJM with a more accurate forecast of where actual energy flows are expected. This validation method would reduce the unscheduled power flows across neighboring balancing authorities that result in increased production costs caused by the increase of generation to control for the unscheduled loop flows without compensating transmission revenues associated with those flows. Requiring market paths to match as closely as possible to the expected actual power flows would result in a more economic dispatch of the entire Eastern Interconnection.

The MMU recommends that PJM perform a comprehensive evaluation of the up-to congestion product in coordination with the MMU and provide a joint report to PJM stakeholders to ensure that all market participants are aware of how these transactions impact the operation of the PJM Day-Ahead Market and charges and credits to market participants in all other areas of the PJM Energy Market. The MMU recommends that during the period of study, up-to congestion transactions be required to pay a fee in lieu of operating reserve charges equal to $0.50 per MWh. This rate is intended to reflect the lowest operating reserve rates charged to other virtual transactions in 2012.

Sham scheduling refers to a scheduling method under which a market participant breaks a single transaction, from generation balancing authority (source) to load balancing authority (sink), into multiple segments. Sham scheduling hides the actual source of generation from the load balancing authority. When unable to identify the source of the energy, the load balancing authority lacks a complete picture of how the power will flow to the load. This can create loop flows and inaccurate pricing for transactions. The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU also recommends that PJM, NYISO, MISO and Ontario work together to create

business rules that prevent sham scheduling among and between the RTO/ISO markets.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies plan to operate separately for a period of time, they have a Joint Dispatch Agreement, and a Joint Open Access Transmission Tariff.[92] The MMU has confirmed that the rules governing the assignment of interface pricing under the PJM/PEC JOA related to simultaneous imports or exports have been maintained. The MMU recommends the termination of the existing PJM/PEC JOA, as some of the assumptions used in the development of the JOA were based on explicit assumptions about the Progress generation fleet and the dispatch of that generation.

The MMU continues to recommend that PJM permit unlimited spot market imports as well as unlimited non-firm point-to-point willing to pay congestion imports and exports at all PJM Interfaces in order to improve the efficiency of the market.

Overview: Section 9, "Ancillary Services"

Regulation Market

The PJM Regulation Market continues to be operated as a single market.

Market Structure

- **Supply.** In January through June 2013, the supply of offered and eligible regulation in PJM was both stable and adequate. The ratio of offered and eligible regulation to regulation required averaged 3.99. This is a 22.4 percent increase over January through June 2012 when the ratio was 3.26.

- **Demand.** The on-peak regulation requirement is equal to 0.70 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement is equal to 0.70 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand in January

through June, 2013, was 770 MW. This is a 173 MW decrease in the average hourly regulation demand of 943 MW in the same period of 2012.

- **Market Concentration.** In January through June 2013, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 2134 which is classified as highly concentrated.[93] In January through June 2013, 90 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test (53 percent of hours failed the three pivotal supplier test in January through June 2012).

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost offer along with cost parameters to verify the offer, and may optionally submit a price offer. Under the new market design, offers include both a capability offer and a performance offer. The performance offer is converted to $/MW by multiplying the MW offer by the MW/MW value of the signal type of the unit. Owners must also specify which signal type the unit will be following, RegA or RegD.[94] As of June 30, 2013, there were 20 resources (eight generation and 12 demand response) offering performance regulation and following the RegD signal.

- **Price and Cost.** The weighted Regulation Market Clearing Price for the PJM Regulation Market for January through June 2013 was $31.80. This is an increase of $17.90, or 128.8 percent, from the weighted average price for regulation in January through June 2012. The cost of regulation from January through June 2013 was $36.47. This is an $18.12 (98.7 percent) increase from the same time period in 2012.

Synchronized Reserve Market

Although PJM has retained the two synchronized reserve markets it implemented on February 1, 2007, their definition has changed. The RFC Synchronized Reserve Zone has now merged with the former Southern

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92 See Docket Nos. ER12-1338-000 and ER12-1343-000.

93 See the *2012 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI). Consistent with common application, the market share and HHI calculations presented in the SOM are based on supply that is cleared in the market in every hour, not on measures of available capacity.

94 See the *2012 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

Synchronized Reserve Zone into the RTO Reserve Zone. The former Mid-Atlantic Synchronized Reserve Zone has incorporated Dominion to become the Mid-Atlantic Dominion Reserve Zone. PJM further retains the right to define new zones or subzones "as needed for system reliability."[95]

Market Structure

- **Supply.** In January through June, 2013, the supply of offered and eligible synchronized reserve was both stable and adequate. The contribution of DSR to the Synchronized Reserve Market remains significant. Demand side resources are relatively low cost, and their participation in this market lowers overall Synchronized Reserve prices.

- **Demand.** PJM made a minor change to the default hourly required synchronized reserve requirements on October 1, 2012. When the RFC Zone became the RTO Zone on October 1, 2012, the synchronized reserve requirement increased from 1,350 MW to 1,375 MW. Although the Mid-Atlantic Subzone became the Mid-Atlantic Dominion Subzone on October 1, 2012, the requirement remained at 1,300 MW. The integration of East Kentucky Power Cooperative (EKPC) into PJM on June 1, 2013 had no impact on the Synchronized Reserve Market requirement because the largest contingencies remain in the Mid-Atlantic Dominion Subzone. The EKPC integration did, however, increase the availability of both Tier 1 and Tier 2 MW available throughout the RTO.

  In early June 2013, PJM implemented a modification to the way the transfer interface defines the Mid-Atlantic Dominion Subzone within the RTO Zone. The change makes calculations of the unit DFAX values across the interface consistent with the way these values are calculated in the energy market. Additionally PJM changed the reserve interface from Bedington – Black Oak to AP South. The net effect of these changes was to increase the amount of Tier 1 available in the RTO and decrease the amount of Tier 2 required in the Mid-Atlantic Dominion Subzone.

- **Market Concentration.** For January through June 2013, the average weighted HHI for cleared synchronized reserve in the Mid-Atlantic Dominion Subzone was 4002 which is classified as highly concentrated.

The average weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone in January through June, 2012, was 3010, which is classified as "highly concentrated."[96] In January through June, 2013, 37 percent of hours had a maximum market share greater than 40 percent, compared to 56 percent of hours in January through June, 2012.

In the Mid-Atlantic Dominion Subzone, in January through June, 2013, the MMU estimates that 6.1 percent of hours that cleared a synchronized reserve market would have had three or fewer pivotal suppliers. In January through June, 2012, the MMU estimates that 40 percent of hours would have had three or fewer pivotal suppliers. The MMU concludes from these TPS results that the Mid-Atlantic Dominion Subzone Synchronized Reserve Market in January through June 2013 was characterized by structural market power.

Market Conduct

- **Offers.** Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds opportunity cost calculated using the average of 5-minute LMPs, which together comprise the total offer for each unit to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost.

Market Performance

- **Price.** The weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone was $6.38 per MW in January through June, 2013, an increase of $0.05 per MW over January through June, 2012. The total cost of synchronized reserves per MW in January through June 2013 was $12.89, a $4.73 increase from the $8.16 cost of synchronized reserve in January through June 2012. The market clearing price was 48 percent of the total synchronized reserve cost per MW in January through June, 2013, down from 77 percent in January through June, 2012.

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95 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 60 (June 1, 2013), p. 74.

96 See Section 2, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

- **Adequacy.** A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced a deficit in January through June period of 2013.

DASR

The purpose of the 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 a single market clearing price. The DASR 30-minute reserve requirements are determined for each reliability region.[97] If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

- **Concentration.** The MMU calculates that in January through June, 2013, zero hours in the DASR market would have failed the three pivotal supplier test. The current structure of PJM's DASR Market does not include the three pivotal supplier test. The MMU recommends that the three pivotal supplier test be incorporated in the DASR market.

- **Demand.** In 2013, the required DASR is 6.91 percent of peak load forecast, down from 7.03 percent in 2012.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero, but there is an opportunity cost associated with this direct marginal cost. As of June 30, 2013, thirteen percent of offers reflected economic withholding. PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[98] Units that do not offer have their offers set to zero.

- **DSR.** Demand side resources are eligible to participate in the DASR Market, but no demand resource cleared the DASR Market in January through June, 2013.

Market Performance

- **Price.** The weighted DASR market clearing price in January through June, 2013 was $0.06 per MW. In January through June, 2012, the weighted price of DASR was $0.41 per MW.

Black Start Service

Black start service is necessary to help ensure the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of a generating unit to automatically remain operating at reduced levels when disconnected from the grid.[99]

In January through June 2013, black start credits were $58.5 million. Black start zonal credits in January through June 2013 ranged from $0.03 per MW in the ATSI zone (total credits: $70,284) to $11.42 per MW in the AEP zone (total credits: $48,178,521).

Section 9 Recommendations

FERC Order No. 719 makes synchronized reserve must-offer. Therefore the MMU recommends that PJM remove the distinction between Tier 1 and Tier 2 synchronized reserve, remove the ability of participants to offer MW of synchronized reserve capability, remove the ability of participants to make reserve unavailable, and automatically dispatch primary reserve co-optimized with energy. In the interim, PJM should enforce a must-offer requirement for synchronized reserve based on physical capability (with physical capability the default offer) and increase penalties for non-compliance during spinning events.

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97 See PJM. "Manual 13: Emergency Operations," Revision 53, (June 1, 2013); pp 11-12.
98 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 60 (June 1, 2013), p. 144.

99 OATT Schedule 1 § 1.3BB.

Section 9 Conclusion

The design of the Regulation Market changed significantly effective October 1, 2012. While the market design continues to include the incorrect definition of opportunity cost, overall the changes were positive. It is too early to reach a definitive conclusion about performance under the new market design because there is not yet enough information on performance. It is essential that the Regulation Market incorporate the consistent implementation of the marginal benefit factor in optimization, pricing and settlement. But the experience of the last quarter of 2012 and the first two quarters of 2013 is cause for optimism with respect the performance of the Regulation Market under the new market design.

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. Compliance with calls to respond to actual spinning events has been an issue. Compliance with the synchronized reserve must-offer requirement has also been an issue.

The MMU concludes that the structure of the DASR Market was competitive in the first six months of 2013, although concerns remain about economic withholding and the absence of the three pivotal supplier test in this market.

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

Overall, the MMU concludes that it is not yet possible to reach a definitive conclusion about the new Regulation Market design, but there is reason for optimism. The MMU concludes that the Synchronized Reserve Market results were competitive in the first six months of 2013. The MMU concludes that the DASR Market results were competitive in the first six months of 2013.

Overview: Section 10, "Congestion and Marginal Losses"

Energy Cost

- **Total Energy Costs.** Total energy costs in the first six months of 2013 decreased by $70.6 million or 26.9 percent from the first six months of 2012, from -$262.0 million to -$332.6 million. Day-ahead net energy costs in the first six months of 2013 decreased by $110.4 million or 45.6 percent from the first six months of 2012, from -$241.9 million to -$352.2 million. Balancing net energy costs in the first six months of 2013 increased by $48.5 million or 177.2 percent from the first six months of 2012, from -$27.4 million to $21.1 million.

- **Monthly Total Energy Costs.** Significant monthly fluctuations in total energy costs were the result of load and energy import levels, and changes in dispatch of generation. Monthly total energy costs in the first six months of 2013 ranged from -$63.0 million in January to -$46.5 million in April.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs in the first six months of 2013 increased by $49.6 million or 11.2 percent from the first six months of 2012, from $444.9 million to $494.5 million. Day-ahead net marginal loss costs in the first six months of 2013 increased by $79.5 million or 17.1 percent from the first six months of 2012, from $466.5 million to $546.0 million. Balancing net marginal loss costs decreased in

the first six months of 2013 by $29.9 million or 138.5 percent from the first six months of 2012, from -$21.6 million to -$51.5 million.

- **Monthly Total Marginal Loss Costs.** Significant monthly fluctuations in total marginal loss costs were the result of changes in load and energy import levels, and changes in the dispatch of generation. Monthly total marginal loss costs in the first six months of 2013 ranged from $66.2 million in April to $101.1 million in January.

- **Marginal Loss Credits.** Marginal Loss Credits are calculated as total energy costs (net energy costs minus net energy credits plus net inadvertent energy charges) plus total marginal loss costs (net marginal loss costs minus net marginal loss credits plus net explicit loss costs plus net inadvertent loss charges) plus net residual market adjustments. Marginal loss credit or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for total net energy costs and net residual market adjustments, which is paid back in full to load and exports on a load ratio basis.[100] The marginal loss credits decreased in the first six months of 2013 by $20.8 million or 11.4 percent from the first six months of 2012, from $182.1 million to $161.3 million.

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $42.8 million or 16.3 percent, from $263.3 million in the first six months of 2012 to $306.1 million in the first six months of 2013.[101]

- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $137.5 million or 35.3 percent, from $389.6 million in the first six months of 2012 to $527.1 million in the first six months of 2013.

- **Balancing Congestion.** Balancing congestion costs decreased by $94.7 million or 74.9 percent from -$126.4 million in the first six months of 2012 to -$221.1 million in the first six months of 2013.

- **Monthly Congestion.** Monthly congestion costs in the first six months of 2013 ranged from $27.8 million in March to $77.4 million in February.

- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface, the Readington - Roseland and Laporte – Michigan line, the Cloverdale transformers, and the West Interface.

- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in the first six months of 2013. Day-ahead congestion frequency increased by 62.8 percent from 106,904 congestion event hours in the first six months of 2012 to 174,063 congestion event hours in the first six months of 2013. Day-ahead, congestion-event hours decreased on the flowgates while congestion frequency on internal PJM interfaces, transmission lines and transformers increased.

Real-time congestion frequency increased by 7.8 percent from 9,260 congestion event hours in the first six months of 2012 to 9,984 congestion event hours in the first six months of 2013. Real-time, congestion-event hours increased on the flowgates, the interfaces, and the transformers, and the transmission lines.

Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. In the first six months of 2013, for only 2.1 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. In the first six months of 2013, for 38.0 percent of Real-Time Market facility constrained hours, the same facilities were also constrained in the Day-Ahead Market.

The AP South Interface was the largest contributor to congestion costs in the first six months of 2013. With $104.3 million in total congestion costs, it accounted for 34.0 percent of the total PJM congestion costs in the first six months of 2013. The top five constraints in terms of congestion costs together contributed $132.2 million, or 43.2 percent, of the total PJM congestion costs in the first six months of 2013. The top five constraints

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100 See PJM. "Manual 28: Operating Agreement Accounting," Revision 60 (June 1, 2013). Note that the over collection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.
101 The total zonal congestion numbers were calculated as of July 18, 2013, and are based on continued PJM billing updates, subject to change.

were the AP South and West interfaces, the Readington – Roseland and the Laporte – Michigan transmission lines, and the Cloverdale transformer.

- **Zonal Congestion.** ComEd was the most congested zone in the first six months of 2013. ComEd had -$201.9 million in total load costs, -$277.4 million in total generation credits and -$8.6 million in explicit congestion, resulting in $66.9 million in net congestion costs, reflecting significant local congestion between local generation and load, despite being on the upstream side of system wide congestion patterns. The AP South interface, the Braidwood transformer, the Crete - St Johns Tap and Prairie State - W Mt. Vernon flowgates and the Braidwood - East Frankfort line contributed $25.6 million, or 38.3 percent of the total ComEd Control Zone congestion costs.

  The AP Control Zone was the second most congested zone in PJM in the first six months of 2013, with $50.2 million. The AP South interface contributed $33.4 million or 66.5 percent of the total AP Control Zone congestion cost in first six months of 2013. The AEP Control Zone was the third most congested zone in PJM in the first six months of 2013, with a cost of $35.0 million.

- **Ownership.** In the first six months of 2013, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In the first six months of 2013, financial companies received $54.3 million in net congestion credits, an increase of $11.5 million or 26.6 percent compared to the first six months of 2012. In the first six months of 2013, physical companies paid $360.7 million in net congestion charges, an increase of $54.3 million or 17.7 percent compared to the first six months of 2012.

Section 10 Conclusion

Energy costs are the incremental costs to the system, which are the same at every bus for each hour, without taking losses and congestion into account.

Marginal losses are the costs of incremental power losses which result from the geographic distribution of generation and load and the physical characteristics of the transmission system interconnecting generation and load. When calculating marginal losses, load is charged and generation is credited for the power losses to the system. Marginal loss costs had been decreasing since 2010, due to decreases in LMP and fuel costs. However, increases in the LMP and fuel costs have led to higher marginal loss costs in the first six months of 2013 compared to the first six months of 2012. Total marginal loss costs increased in the first six months of 2013 by $49.6 million or 11.2 percent from the first six months of 2012, from $444.9 million to $494.5 million.

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities and the geographic distribution of load.

ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 88.8 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2011 to 2012 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs. FTRs were paid at 80.6 percent of the target allocation level for the 2011 to 2012 planning period, and at 67.8 percent of the target allocation level for the 2012 to 2013 planning period.[102] Revenue adequacy, measured relative to target allocations for a planning period is not final until the end of the period.

Overview: Section 11, "Planning"

Planned Generation and Retirements

- **Planned Generation.** At June 30, 2013, 72,537 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 195,000 MW in the first six months of 2013. Wind projects account for 18,612 MW of nameplate capacity or 25.7 percent of the capacity in the queues and combined-cycle projects account for 42,925 MW of capacity or 59.2 percent of the capacity in the queues.

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102 See the *2012 State of the Market Report for PJM, Volume II:* Section 12, "Financial Transmission and Auction Revenue Rights," at Table 12-23, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2011 to 2012 and 2012 to 2013."

- **Generation Retirements.** 13,768.2 MW are planning to deactivate by the end of calendar year 2019. A total of 7,195.7 MW of generation capacity retired from January 1, 2012 through June 30, 2013, and it is expected that a total of 22,160.4 MW will have retired from 2011 through 2019, with most of this capacity retiring by the end of 2015. Retirements from January 1, 2011 through June 30, 2013, account for 8,392.2 MW, or 37.9 percent of retirements during this period. Units planning to retire in 2013 account for 2,402.6 MW, or 10.8 percent of retirements during this period. Overall, 3,508.1 MW, or 28.7 percent of all MW planned for deactivation from 2013 through 2019, are expected in the AEP zone.

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

Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[103] The process is complex and time consuming as a result of the nature of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants.

- The queue contains a substantial number of projects that are not likely to be built, including 19,043.7 MW that should already be in service based on the original queue date, but that is not yet even under construction. These projects may also create barriers to entry for projects that would

otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

Key Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects. The backbone projects are intended to resolve a wide range of reliability criteria violations and congestion issues and have substantial impacts on energy and capacity markets. The current backbone projects are: Mount Storm – Doubs; Jacks Mountain; and Susquehanna – Roseland.

Economic Planning Process

- **Transmission and Markets.** As a general matter, transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. PJM has taken a first step towards integrating transmission investments into the market through the use of economic evaluation metrics.[104] The goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.

Section 11 Conclusion

The goal of PJM market design should be to enhance competition and to ensure that competition is the driver for all the key elements of PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on energy and capacity markets. But when generating units retire, there is no market mechanism in place that would require direct competition between

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103 OATT Parts IV & VI.

104 *See* 126 FERC ¶ 61,152 (2009) (final approval for an approach with predefined formulas for determining whether a transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand-response trends), *order on reh'g*, 123 FERC ¶ 61,051 (2008).

transmission and generation to meet loads in that area. In addition, despite Order No. 1000, there is not yet a robust mechanism to permit competition between transmission developers to build transmission projects.[105] The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and effectively forestalls the ability of generation to compete. There is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no evaluation of whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. Creating such a mechanism should be a goal of PJM market design.

Overview: Section 12, "FTR and ARRs"

Financial Transmission Rights

Market Structure

- **Supply.** Market participants can also sell FTRs. In the 2013 to 2014 Annual FTR Auction, total participant FTR sell offers were 417,118 MW, up from 356,299 MW in the 2012 to 2013 planning period. In the Monthly Balance of Planning Period FTR Auctions for the 2012 to 2013 planning period, total participant FTR sell offers were 5,010,437 MW, down from 5,852,635 MW for the same period during the 2011 to 2012 planning period.

- **Demand.** There were 3,274,373 MW of buy and self-scheduled bids in the 2013 to 2014 Annual FTR Auction, up from 2,561,835 MW in the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the 2012 to 2013 planning period increased 11.6 percent from 17,634,256 MW for the same time period of the prior planning period, to 19,685,688 MW.

- **Patterns of Ownership.** For the 2013 to 2014 Annual FTR Auction, financial entities purchased 54.7 percent of prevailing flow FTRs and 82.2 percent of counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 73.4 percent of prevailing

flow and 83.1 percent of counter flow FTRs for January through June of 2013. Financial entities owned 59.0 percent of all prevailing and counter flow FTRs, including 50.6 percent of all prevailing flow FTRs and 75.3 percent of all counter flow FTRs during January through June 2013.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the 2012 to 2013 planning period were $523,227 for Increment Offers and Decrement Bids.

- **Credit Issues.** Six participants defaulted during 2013 from ten default events. The average of these defaults was $55,939 with seven based on inadequate collateral and three based on nonpayment. The average collateral default was $16,587 and the average nonpayment default was $147,761. The majority of these defaults were promptly cured, with one partial cure. These defaults were not necessarily related to FTR positions.

Market Performance

- **Volume.** In the Annual FTR Auction for the 2013 to 2014 planning period 420,489 MW (12.8 percent) of buy and self-schedule bids cleared. For the 2012 to 2013 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 2,246,640 MW (11.4 percent) of FTR buy bids and 737,111 MW (14.7 percent) of FTR sell offers.

- **Price.** The weighted-average buy-bid FTR price for the 2013 to 2014 Annual FTR Auction was $0.13 per MW, down from $0.23 per MW in the 2012 to 2013 planning period. The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the 2012 to 2013 planning period was $0.09, down from $0.14 per MW in the 2011 to 2012 planning period.

- **Revenue.** The 2013 to 2014 Annual FTR Auction generated $558.4 million in net revenue, down $44.5 million in the 2012 to 2013 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $23.9 million in net revenue for all FTRs for the 2012 to 2013 planning period, down from $26.3 million for the same time period in the 2011 to 2012 planning period.

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105 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012).

- **Revenue Adequacy.** FTRs were paid at 80.6 percent of the target allocation for the entire 2011 to 2012 planning period. FTRs were paid at 67.8 percent of the target allocation level for the entire 2012 to 2013 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $614.0 million of FTR revenues during the 2012 to 2013 planning period and $799.1 million during the 2011 to 2012 planning period. For the 2013 to 2014 planning period, the top sink and top source with the highest positive FTR target allocations were Dominion Zone and Mt. Storm. Similarly, the top sink and top source with the largest negative FTR target allocations were Quad Cities and Buchanan.

- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. The cost of self-scheduled FTRs is zero in the FTR profitability calculation. FTRs were profitable overall, with $83.7 million in profits for physical entities, of which $90.3 million was from self-scheduled FTRs, and $61.2 million for financial entities. As shown in Error! Reference source not found., not every FTR was profitable.

Auction Revenue Rights
Market Structure

- **Residual ARRs.** Effective August 1, 2012, PJM is required to offer ARRs to eligible participants when a transmission outage was modeled in the Annual ARR Allocation, but the facility becomes available during the relevant planning year. These ARRs are automatically assigned the month before the effective date and only available on paths prorated in Stage 1 of the Annual ARR Allocation. Residual ARRs are only effective for single, whole months, cannot be self scheduled and their clearing prices are based on monthly FTR auction clearing prices. In the 2012 to 2013 planning period PJM allocated a total of 17,467.5 MW of residual ARRs with a total target allocation of $5,083,608.

- **ARR Reassignment for Retail Load Switching.** There were 52,825 MW of ARRs associated with approximately $498,800 of revenue that were reassigned in the 2012 to 2013 planning period. There were 41,770 MW of ARRs associated with approximately $758.900 of revenue that were reassigned for the full twelve months of the 2011 to 2012 planning period.

Market Performance

- **Revenue Adequacy.** For the 2012 to 2013 planning period, the ARR target allocations were $570.5 million while PJM collected $626.7 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2011 to 2012 planning period, the ARR target allocations were $982.9 million while PJM collected $1,091.8 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

- **ARRs and FTRs as an Offset to Congestion.** The effectiveness of ARRs as an offset to congestion can be measured by comparing the revenue received by ARR holders to the congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market. For the 2012 to 2013 planning period, the total revenues received by ARR holders, including self-scheduled FTRs, offset 92.6 percent of the congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market. For the 2011 to 2012 planning period, the total revenues received by the holders of all ARRs and FTRs offset more than 88.8 percent of the total congestion costs within PJM and for the 2010 to 2011 planning period 97.3 percent.

Section 12 Recommendations

- Report correct monthly payout ratios to reduce overstatement of underfunding problem on a monthly basis.

- Eliminate portfolio netting to eliminate cross subsidies across FTR marketplace participants.

- Eliminate subsidies to counter flow FTR holders by treating them comparably to prevailing flow FTR holders when the payout ratio is applied.

- Eliminate cross geographic subsidies.

- Improve transmission outage modeling in the FTR auction models.
- Reduce FTR sales on paths with persistent underfunding including clear rules for what defines persistent underfunding and how the reduction will be applied.
- Implement a seasonal ARR and FTR allocation system to better represent outages.
- Eliminate over allocation requirement of ARRs in the Annual ARR Allocation process.

Section 12 Conclusion

The annual ARR allocation provides firm transmission service customers with the financial equivalent of physically firm transmission service, without requiring physical transmission rights that are difficult to define and enforce. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service. With the creation of ARRs, FTRs no longer serve their original function of providing firm transmission customers with the financial equivalent of physically firm transmission service. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy.

Revenue adequacy has received a lot of attention in the PJM FTR market. There are several factors that can affect the reported, distribution of and quantity of funding in the FTR market. Revenue adequacy is misunderstood. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy. ARR holders do have those rights based on their payment for the transmission system. FTR holders appropriately receive revenues based on actual congestion in both day-ahead and real-time markets. When day-ahead congestion differs significantly from real-time congestion, as has occurred only recently, this is evidence that there are reporting issues, cross subsidization issues, issues with the level of FTRs sold, and issues with modeling differences

between the day-ahead and real time. Such differences are not an indication that FTR holders are being underallocated total congestion dollars.

The market response to the revenue adequacy issue has been to reduce bid prices and to increase bid volumes and offer volumes. Clearing prices have fallen and cleared quantities have increased.

In the 2010 to 2011 planning period the clearing price for an FTR obligation was $0.71 per MW, and in the 2013 to 2014 planning period the clearing price was $0.30 per MW, a 57.7 percent decrease. In the 2010 to 2011 planning period, the clearing price for FTR Obligation sell offers was $0.22 per MW, and in the 2013 to 2014 planning period was $0.05 per MW for, a 340 percent decrease.

The volume of cleared buy bids and self-scheduled bids in the Annual FTR Auctions increased from 287,294 MW in the 2010 to 2011 planning period to 420,489 MW in the 2013 to 2014 planning period, an increase of 133,095 MW or 115.9 percent. The volume of cleared sell offers increased from 10,315 MW in the 2010 to 2011 planning period to 37,821 MW in the 2013 to 2014 planning period, an increase of 266.7 percent.

In June 2010, which includes the Annual, Long Term and monthly auctions, the bid volume was 3,894,566 MW, with a net bid volume of 3,177,131 MW. The net bid volume is the buy bid volume minus the sell bid volume. In June 2013 the bid volume was 7,909,805 MW (a 103.1 percent increase) and the net bid volume was 6,607,570 MW (a 108.0 percent increase). The net bid volume to bid volume ratio in June 2010 was 0.82, while the ratio was 0.84 in June 2013, indicating a slight increase in the ratio of sell offers to buy bids.

The payout ratio reported by PJM monthly is understated. The PJM reported monthly payout ratio does not appropriately consider negative target allocations as a source of revenue to fund FTRs on a monthly basis. The MMU recommends that the calculation of the monthly FTR payout ratio appropriately include negative target allocations as a source of revenue, consistent with actual settlement payout.

FTR target allocations are currently netted within each organization in each hour. This means that within an hour, positive and negative target allocations within an organization's portfolio are offset prior to the application of the payout ratio to the positive target allocation FTRs. The payout ratios are also calculated based on these net FTR positions. The current method requires those participants with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs. The current method treats a positive target allocation FTR differently depending on the portfolio of which it is a part. The correct method would treat all FTRs with positive target allocations exactly the same, which would eliminate this form of cross subsidy. This should also be extended to include the end of planning period FTR uplift calculation. The net of a participant's portfolio should not determine their FTR uplift liability, rather their portion of total positive target allocations should be used to determine a participant's uplift charge.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in the 2012 to 2013 planning period would have been 84.6 percent instead of the reported 67.8 percent. The MMU recommends that netting of positive and negative target allocations within portfolios be eliminated.

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. Counter flow FTR holders make payments over the planning period, in the form of negative target allocations. These negative target allocations are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the burden of underfunding among counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would increase the calculated payout ratio in the 2012 to 2013 planning period from the reported 67.8 percent to 88.6 percent. The MMU recommends that counter flow and prevailing flow FTRs should be treated symmetrically with respect to the application of a payout ratio.

In addition to addressing these issues, the approach to the question of FTR funding should also look at the fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion. These reasons include the inadequate transmission outage modeling which ignores all but long term outages known in advance; the different approach to transmission line ratings in the day-ahead and real time markets, including reactive interfaces; differences in day-ahead and real time modeling including the treatment of loop flows, the treatment of outages, the modeling of PARs and the nodal location of load; the overallocation of ARRs; the appropriateness of seasonal ARR allocations; and the role of up-to congestion transactions; reduced FTR capability on persistently underfunded pathways. The MMU recommends that these issues be reviewed and modifications implemented where possible. Funding issues that persist as a result of modeling differences should be borne by FTR holders operating in the voluntary FTR market.

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 six months of 2013, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM Energy Market results were competitive in the first six months of 2013.

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 six months of 2013 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1204 with a minimum of 947 and a maximum of 1610 in the first six months of 2013.

- The local market structure was evaluated as not competitive due to the highly concentrated ownership of supply in local markets created by transmission constraints. The results of the three pivotal supplier (TPS) test, used to test local market structure, indicate the existence of market

power in local markets created by transmission constraints. The local market performance is competitive as a result of the application of the TPS test. While transmission constraints create the potential for the exercise of local market power, PJM's application of the three pivotal supplier test mitigated local market power and forced competitive offers, correcting for structural issues created by local transmission constraints.

- Participant behavior was evaluated as competitive because the analysis of markup shows that marginal units generally make offers at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.

- Market performance was evaluated as competitive because market results in the Energy Market reflect the outcome of a competitive market, as PJM prices are set, on average, by marginal units operating at, or close to, their marginal costs in both Day-Ahead and Real-Time Energy Markets.

- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes, with prices reflecting, on average, the marginal cost to produce energy. In aggregate, PJM's Energy Market design provides incentives for competitive behavior and results in competitive outcomes. In local markets, where market power is an issue, the market design mitigates market power and causes the market to provide competitive market outcomes.

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

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1 Analysis of 2013 market results requires comparison to prior years. In 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. In June 2013, PJM integrated the Eastern Kentucky Power Cooperative (EKPC). 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 *2012 State of the Market Report for PJM*, Appendix A, "PJM Geography."

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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]

Overview

Market Structure

- **Supply.** Average offered supply increased by 2,445, or 1.4 percent, from 168,828 MW in the first six months of 2012 to 171,274 MW in the first six months of 2013.[4] The increase in offered supply was in part the result of the integration of the East Kentucky Power Cooperative (EKPC) Transmission Zone in the second quarter of 2013. In 2013, 534.6 MW of new capacity were added to PJM. This new supply was partially offset by the deactivation of 4 units (233.8 MW) since January 1, 2013.

- **Demand.** The PJM system peak load for the first six months of 2013 was 139,778 MW in the HE 1600 on June 25, 2013, which was 8,135 MW, or 5.5 percent, lower than the PJM peak load for the first six months of 2012, which was 147,913 MW in the HE 1800 on June 20, 2012.[5]

- **Market Concentration.** Analysis of the PJM Energy Market indicates moderate market concentration overall. Analyses of supply curve segments indicate moderate concentration in the baseload segment, but high concentration in the intermediate and peaking segments.

- **Local Market Structure and Offer Capping.** PJM continued to apply a flexible, targeted, real-time approach to offer capping (the three pivotal supplier test) as the trigger for offer capping in the first six months of 2013. PJM offer caps units when the local market structure is noncompetitive. Offer capping is an effective means of addressing local market power. Offer capping levels have historically been low in PJM. In the first six months of 2013, offer capping levels increased as a result of the inclusion of units that are committed for reliability reasons to provide black start and reactive service. In the Day-Ahead Energy Market offer-capped unit

hours increased from 0.1 percent in the first six months of 2012 to 3.9 percent in the first six months of 2013. In the Real-Time Energy Market offer-capped unit hours increased from 1.7 percent in the first six months of 2012 to 3.4 percent in the first six months of 2013.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 56 units eligible for FMU or AU status in at least one month during the first six months of 2013, 27 units (48.2 percent) were FMUs or AUs for all six months, and 13 units (23.2 percent) qualified in only one month of 2013.

- **Local Market Structure.** In the first six months of 2013, 11 Control Zones experienced congestion resulting from one or more constraints binding for 50 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.

Market Performance: Markup, Load, Generation and LMP

- **Markup.** The markup conduct of individual owners and units has an impact on market prices. The markup analysis is a key indicator of the competitiveness of the Energy Market.

  All generating units, including coal units, are allowed to include a 10 percent adder in their cost offer. The 10 percent adder was included in the definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions. Coal units do not face the same cost uncertainty as gas-fired CTs. A review of actual participant behavior supports this view, as the owners of coal units, facing competition, typically remove the 10 percent adder from their actual offers. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the 10 percent adder in the cost offer. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder from the cost offer.

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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.

4 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.

5 All hours are presented and all hourly data are analyzed using Eastern Prevailing Time (EPT). See the *2012 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).

In the first six months of 2013, the unadjusted markup was negative, -$2.09 per MWh, primarily as a result of competitive behavior by coal units and the competitive removal of the 10 percent adder. The adjusted markup was less negative, -$0.53 per MWh or -1.4 percent of the PJM real-time, load-weighted average LMP.

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

- **Load.** PJM average real-time load in the first six months of 2013 increased by 2.3 percent from the first six months of 2012, from 84,946 MW to 86,897 MW. The PJM average real-time load in 2013 would have increased by 2.0 percent from the first six months of 2012, from 84,946 MW to 86,675 MW, if the EKPC Transmission Zone had not been included in this comparison for the months prior to its integration to PJM.[6]

PJM average day-ahead load in the first six months of 2013, including DECs and up-to congestion transactions, increased by 11.9 percent from the first six months of 2012, from 129,881 MW to 145,280 MW. The PJM average day-ahead load, including DECs and up-to congestion transactions, would have increased 11.7 percent from the first six months of 2012, from 129,881 MW to 145,042 MW if the EKPC Transmission Zone had not been included. The day-ahead load growth was 417.4 percent higher than the real-time load growth as a result of the continued growth of up-to congestion transactions.

- **Generation.** PJM average real-time generation in the first six months of 2013 increased by 1.9 percent from the first six months of 2012, from 86,310 MW to 87,974 MW. The PJM average real-time generation in the first six months of 2013 would have increased by 1.7 percent from the first six months of 2012, from 86,310 MW to 87,781 MW if the EKPC Transmission Zone had not been included.

PJM average day-ahead generation in the first six months of 2013, including INCs and up-to congestion transactions, increased by 12.1 percent from the first six months of 2012, from 132,326 MW to 148,381

MW. The PJM average day-ahead generation, including INCs and up-to congestion transactions, would have increased by 12.0 percent from the first six months of 2012, from 132,326 MW to 148,167 MW if the EKPC Transmission Zone had not been included. The day-ahead generation growth was 536.8 percent higher than the real-time generation growth as a result of the continued growth of up-to congestion transactions.

- **Generation Fuel Mix.** During the first six months of 2013, coal units provided 44.3 percent, nuclear units 35.1 percent and gas units 15.7 percent of total generation. Compared to the first six months of 2012, generation from coal units increased 11.3 percent, generation from nuclear units increased 0.8 percent, and generation from gas units decreased 17.9 percent. This represents a reversal of the recent trend of decreasing coal-fired output and increasing gas-fired output. The change is primarily a result of increased natural gas prices in the first six months of 2013, particularly in eastern zones, and lower or constant coal prices.

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

PJM Real-Time Energy Market prices increased in the first six months of 2013 compared to the first six months of 2012. The system average LMP was 22.9 percent higher in the first six months of 2013 than in the first six months of 2012, $36.56 per MWh versus $29.74 per MWh. The load-weighted average LMP was 21.6 percent higher in the first six months of 2013 than in the first six months of 2012, $37.96 per MWh versus $31.21 per MWh.

PJM Day-Ahead Energy Market prices increased in the first six months of 2013 compared to the first six months of 2012. The system average LMP was 21.9 percent higher in the first six months of 2013 than in the first six months of 2012, $37.11 per MWh versus $30.44 per MWh. The load-weighted average LMP was 20.1 percent higher in the first six months of

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6 The EKPC zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013.

2013 than in the first six months of 2012, $38.23 per MWh versus $31.84 per MWh.[7]

- **Load and Spot Market.** Companies that serve load in PJM can do so using 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. For the first six months of 2013, 10.6 percent of real-time load was supplied by bilateral contracts, 23.8 percent by spot market purchases and 65.6 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased 1.6 percentage points, reliance on spot market purchases increased by 0.6 percentage points and reliance on self-supply decreased by 2.2 percentage points. For the first six months of 2013, 7.3 percent of day-ahead load was supplied by bilateral contracts, 23.0 percent by spot market purchases, and 69.7 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased by 0.6 percentage points, reliance on spot market purchases increased by 0.7 percentage points, and reliance on self-supply decreased by 1.4 percentage points.

Scarcity

- **Scarcity Pricing Events in 2013.** PJM's market did not experience any reserve-based scarcity events in the first six months of 2013.

Recommendations

The zonal load-weighted LMP is calculated by weighting the zone's load bus LMPs by the zone's load bus accounting load. The classification of energy as load or generation impacts PJM's calculation of zonal load-weighted LMP.

PJM sums all negative (injections) and positive (withdrawals) load at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) generation at each generation bus when calculating net generation. Netting withdrawals and

injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

- The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load weighted LMP.

- There is currently no PJM documentation in the tariff or manuals explaining how hubs are defined and how those definitions are changed. The MMU recommends that PJM include in the appropriate manual the explanation of the initial definition of hubs and the process for modifying hub definitions.[8]

- The MMU recommends the elimination of FMU and AU adders. FMU and AU adders were added to the market rules in 2006 in order to address revenue inadequacy for frequently mitigated units. Since that time, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007, and changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. This recommendation is currently scheduled to be evaluated through the PJM stakeholder process in the fourth quarter of 2013.

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7 Tables reporting zonal and jurisdictional load and prices are in the *2012 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

8 According to minutes from the first meeting of the Energy Market Committee (EMC) on January 28, 1998, the EMC unanimously agreed to be responsible for approving additions, deletions and changes to the hub definitions to be published and modeled by PJM. Since the EMC has become the Market Implementation Committee (MIC), the MIC now appears to be responsible for such changes.

Conclusion

The MMU analyzed key elements of PJM Energy Market structure, participant conduct and market performance in the first six months of 2013, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand-side response programs, loads and prices.

Average real-time supply offered increased by 2,445 MW in the first six months of 2013 compared to the first six months of 2012, while peak load decreased by 8,135 MW, modifying the general supply demand balance with a corresponding impact on energy market prices. Market concentration levels remained moderate. This relationship between supply and demand, regardless of the specific market, balanced by market concentration, is referred to as supply-demand fundamentals or economic fundamentals. While the market structure does not guarantee competitive outcomes, overall the market structure of the PJM aggregate Energy Market remains reasonably competitive for most hours.

Prices are a key outcome of markets. Prices vary across hours, days and years for multiple reasons. Price is an indicator of the level of competition in a market although individual prices are not always easy to interpret. In a competitive market, prices are directly related to the marginal cost of the most expensive unit required to serve load in each hour. The pattern of prices within days and across months and years illustrates how prices are directly related to supply and demand conditions and thus also illustrates the potential significance of price elasticity of demand in affecting price. Energy Market results for the first six months of 2013 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.[9] 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

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

a local market if the output of the owners' generation facilities is required in order to relieve a transmission constraint. When a generation owner or group of owners is pivotal, it has the ability to increase the market price above the competitive level. The three pivotal supplier test explicitly incorporates the impact of excess supply and implicitly accounts for the impact of the price elasticity of demand in the market power tests. The result of the introduction of the three pivotal supplier test was to limit offer capping to times when the local market structure was noncompetitive and specific owners had structural market power. The analysis of the application of the three pivotal supplier test demonstrates that it is working successfully to exempt owners when the local market structure is competitive and to offer cap owners when the local market structure is noncompetitive.

With or without a capacity market, energy market design must permit scarcity pricing when such pricing is consistent with market conditions and constrained by reasonable rules to ensure that market power is not exercised. Scarcity pricing can serve two functions in wholesale power markets: revenue adequacy and price signals. Scarcity pricing for revenue adequacy is not 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. PJM implemented new scarcity pricing rules in 2012. There are significant issues with the scarcity pricing true up mechanism in the new PJM scarcity pricing design, which will create issues when scarcity pricing occurs.

The overall market results support the conclusion that prices in PJM are set, on average, by marginal units operating at, or close to, their marginal costs. This is evidence of competitive behavior and competitive market outcomes. Given the structure of the Energy Market, tighter markets or a change in participant behavior remain potential sources of concern in the Energy Market. The MMU concludes that the PJM Energy Market results were competitive in the first six months of 2013.

Market Structure

Supply

Average offered supply increased by 2,445 MW, or 1.4 percent, from 168,828 MW in the first six months of 2012 to 171,274 MW in the first six months of 2013.[10] The increase in offered supply was in part the result of the integration of the East Kentucky Power Cooperative (EKPC) Transmission Zone in the second quarter of 2013. In 2013, 534.6 MW of new capacity were added to PJM. This new supply was partially offset by the deactivation of 4 units (233.8 MW) since January 1, 2013.

Figure 2-1 shows the average PJM aggregate supply curves, peak load and average load for the first six months of 2012 and 2013.

Figure 2-1 Average PJM aggregate supply curves: January through June of 2012 and 2013
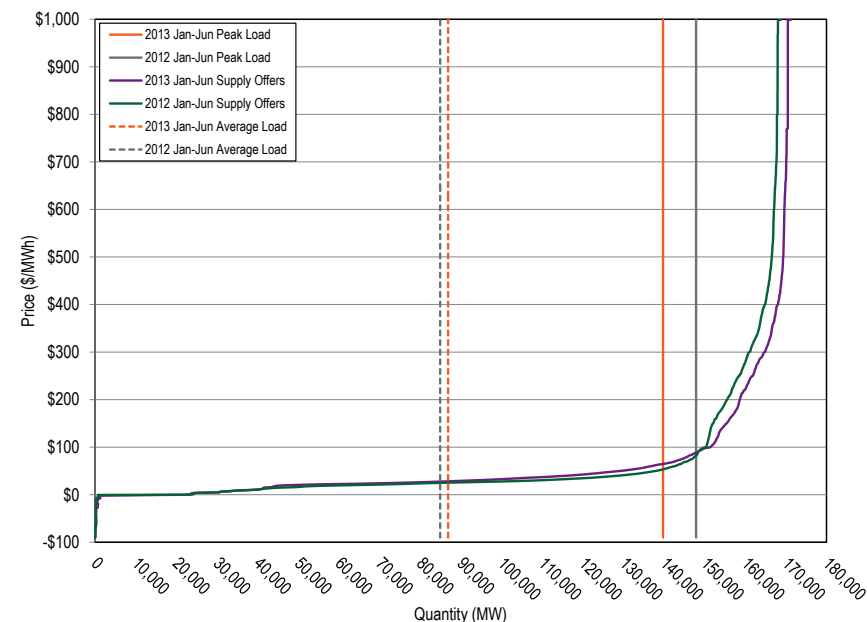
Energy Production by Fuel Source

Compared to the first six months of 2012, generation from coal units increased 11.3 percent and generation from natural gas units decreased 17.9 percent (Table 2-2). This represents a reversal of the recent trend of decreasing coal-fired output and increasing gas-fired output. The change is primarily a result of increased natural gas prices in the first six months of 2013, particularly in eastern zones, and lower or constant coal prices.

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10 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.

Table 2-2 PJM generation (By fuel source (GWh)): January through June 2012 and 2013[11]

	Jan–Jun 2012		Jan–Jun 2013		Change in
	GWh	Percent	GWh	Percent	Output
Coal	154,044.1	40.3%	171,440.7	44.3%	11.3%
Standard Coal	149,360.6	39.1%	166,494.3	43.0%	11.1%
Waste Coal	4,683.5	1.2%	4,946.4	1.3%	0.2%
Nuclear	134,802.4	35.3%	135,858.8	35.1%	0.8%
Gas	73,981.7	19.4%	60,747.3	15.7%	(17.9%)
Natural Gas	72,856.9	19.1%	59,623.6	15.4%	(18.2%)
Landfill Gas	1,124.6	0.3%	1,123.7	0.3%	(0.1%)
Biomass Gas	0.2	0.0%	0.0	0.0%	(99.0%)
Hydroelectric	6,815.9	1.8%	7,502.2	1.9%	10.1%
Wind	7,305.5	1.9%	8,561.5	2.2%	17.2%
Waste	2,560.9	0.7%	2,399.3	0.6%	(6.3%)
Solid Waste	2,060.0	0.5%	1,993.9	0.5%	(3.2%)
Miscellaneous	500.9	0.1%	405.4	0.1%	(19.1%)
Oil	2,387.2	0.6%	626.7	0.2%	(73.7%)
Heavy Oil	2,287.6	0.6%	557.8	0.1%	(75.6%)
Light Oil	94.1	0.0%	59.0	0.0%	(37.2%)
Diesel	4.4	0.0%	2.7	0.0%	(39.4%)
Kerosene	1.2	0.0%	7.2	0.0%	494.0%
Jet Oil	0.0	0.0%	0.0	0.0%	14.2%
Solar	117.7	0.0%	175.9	0.0%	49.5%
Battery	0.1	0.0%	0.2	0.0%	151.5%
Total	382,015.4	100.0%	387,312.7	100.0%	1.4%

Table 2-3 Monthly PJM Generation (By fuel source (GWh)): January through June, 2013

	Jan	Feb	Mar	Apr	May	Jun	Total
Coal	31,689.2	28,886.8	29,680.4	24,637.5	25,824.6	30,722.3	171,440.7
Standard Coal	30,814.3	28,102.4	28,670.2	24,060.8	24,962.6	29,884.0	166,494.3
Waste Coal	874.9	784.4	1,010.2	576.7	862.0	838.3	4,946.4
Nuclear	25,610.7	22,563.1	23,854.9	19,614.0	21,106.9	23,109.3	135,858.8
Gas	10,261.4	10,319.8	10,055.6	9,276.0	10,240.2	10,594.4	60,747.3
Natural Gas	10,072.4	10,143.6	9,859.7	9,096.1	10,047.2	10,404.5	59,623.6
Landfill Gas	189.0	176.2	195.9	179.9	193.0	189.8	1,123.7
Biomass Gas	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydroelectric	1,234.0	1,127.0	1,215.8	1,273.0	1,250.7	1,401.7	7,502.2
Wind	1,784.4	1,397.5	1,606.2	1,639.6	1,271.3	862.5	8,561.5
Waste	414.4	385.2	391.5	358.2	421.3	428.7	2,399.3
Solid Waste	324.8	301.5	325.2	323.9	349.9	368.6	1,993.9
Miscellaneous	89.6	83.7	66.2	34.3	71.4	60.2	405.4
Oil	62.5	23.8	50.3	79.1	220.3	190.7	626.7
Heavy Oil	55.8	21.9	27.9	66.8	206.1	179.4	557.8
Light Oil	4.2	1.5	17.7	11.7	13.2	10.7	59.0
Diesel	0.6	0.1	0.0	0.5	1.1	0.4	2.7
Kerosene	1.9	0.3	4.7	0.1	0.0	0.2	7.2
Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar	15.6	17.6	26.7	38.1	39.6	38.4	175.9
Battery	0.1	0.0	0.0	0.0	0.1	0.1	0.2
Total	71,072.0	64,720.7	66,881.4	56,915.4	60,374.9	67,348.2	387,312.7

Generator Offers

Generator offers are categorized as dispatchable and self-scheduled and are shown in Table 2-4 and Table 2-5.[12,13] Table 2-4 shows the average hourly distribution of MW offers by dispatchable units by offer prices for the first six months of 2013. Table 2-5 shows the average hourly distribution of MW offers by self-scheduled units by offer prices for the first six months of 2013. Of the dispatchable MW offered by combustion turbines (CT), 19.9 percent were dispatchable at an offered range of $600 to $800. Only wind and solar units have negative offer prices.

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

12 Each range in the tables is greater than or equal to the lower value and less than the higher value.
13 The unit type battery is not included in these tables because batteries do not make energy offers.

Table 2-4 Distribution of MW for dispatchable unit offer prices: January through June, 2013

| Unit Type | Dispatchable (Range) | | | | | | |
	($200)- $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Total
CC	0.0%	64.2%	12.5%	2.9%	4.1%	0.9%	84.6%
CT	0.0%	46.4%	19.9%	11.1%	19.9%	2.1%	99.5%
Diesel	0.0%	7.6%	51.9%	6.0%	1.2%	0.8%	67.4%
Hydro	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.1%
Nuclear	0.0%	10.0%	0.0%	0.0%	0.0%	0.0%	10.0%
Pumped Storage	0.0%	51.9%	0.0%	0.0%	0.0%	0.0%	51.9%
Solar	0.0%	58.2%	0.0%	0.0%	0.0%	0.0%	58.2%
Steam	0.0%	49.1%	10.7%	0.7%	0.1%	0.0%	60.6%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	27.2%	29.0%	0.0%	0.0%	0.0%	0.0%	56.2%
All Dispatchable Offers	0.8%	42.2%	10.2%	2.8%	4.4%	0.5%	60.9%

Table 2-5 Distribution of MW for self-scheduled unit offer prices: January through June, 2013

| Unit Type | Self Scheduled (Range) | | | | | | |
	($200)- $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Total
CC	0.0%	13.6%	1.7%	0.0%	0.0%	0.0%	15.4%
CT	0.0%	0.5%	0.0%	0.0%	0.0%	0.0%	0.5%
Diesel	0.0%	32.1%	0.2%	0.0%	0.0%	0.3%	32.6%
Hydro	0.0%	98.8%	0.0%	0.0%	0.0%	1.1%	99.9%
Nuclear	0.0%	90.0%	0.0%	0.0%	0.0%	0.0%	90.0%
Pumped Storage	0.0%	48.1%	0.0%	0.0%	0.0%	0.0%	48.1%
Solar	1.5%	40.2%	0.0%	0.0%	0.0%	0.1%	41.8%
Steam	0.0%	27.0%	12.2%	0.0%	0.1%	0.1%	39.4%
Transaction	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	13.0%	30.8%	0.0%	0.0%	0.0%	0.0%	43.8%
All Self-Scheduled Offers	0.4%	33.1%	5.4%	0.0%	0.1%	0.1%	39.1%

Demand

The PJM system peak load for the first six months 2013 was 139,778 MW in the HE 1600 on Jun 25, 2013, which was 8,135 MW, or 5.5 percent, lower than the PJM peak load for the first six months of 2012, which was 147,913 MW in the HE 1800 on June 20, 2012. The EKPC Transmission Zone accounted for 1,967 MW in the peak hour of the first six months of 2013. The peak load

excluding the EKPC transmission zone was 137,811 MW, also occurring on June 25, 2013, HE 1600, a decrease of 10,102 MW, or 6.8 percent.

Table 2-6 shows the coincident peak loads for the first six months of 1999 through 2013.

Table 2-6 Actual PJM footprint peak loads: January through June, 1999 to 2013[14]

(Jan – Jun)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Mon, June 07	17	48,129	NA	NA
2000	Mon, June 26	16	49,296	1,167	2.4%
2001	Thu, June 28	17	49,780	484	1.0%
2002	Wed, June 26	15	60,176	10,396	20.9%
2003	Thu, June 26	17	61,310	1,134	1.9%
2004	Wed, June 09	17	77,676	16,366	26.7%
2005	Tue, June 28	16	124,052	46,375	59.7%
2006	Tue, May 30	17	121,165	(2,887)	(2.3%)
2007	Wed, June 27	16	130,971	9,806	8.1%
2008	Mon, June 09	17	130,100	(871)	(0.7%)
2009	Fri, January 16	19	117,169	(12,930)	(9.9%)
2010	Wed, June 23	17	126,188	9,019	7.7%
2011	Wed, June 08	17	144,350	18,162	14.4%
2012	Wed, June 20	18	147,913	3,563	2.5%
2013 (with EKPC)	Tue, June 25	16	139,778	(8,135)	(5.5%)
2013 (without EKPC)	Tue, June 25	16	137,811	(10,102)	(6.8%)

Figure 2-2 shows the peak loads for the first six months of 1999 through 2013.

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14 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 PJM footprint calendar year peak loads: January through June of 1999 to 2013[15]

Figure 2-3 PJM peak-load comparison: Tuesday, June 25, 2013, and Wednesday, June 20, 2012
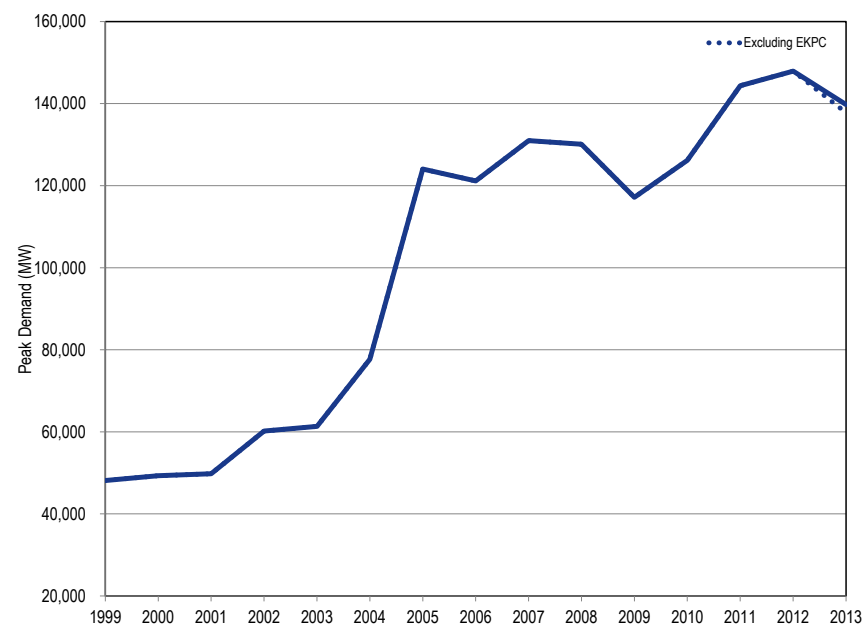
Figure 2-3 compares the peak load days in the first six months of 2012 and 2013. In every hour on June 25, 2013, the average hourly real-time load was lower than the average hourly real-time load on June 20, 2012. The average hourly real-time LMP peaked at $73.30 on June 25, 2013 and peaked at $122.60 on June 20, 2012.
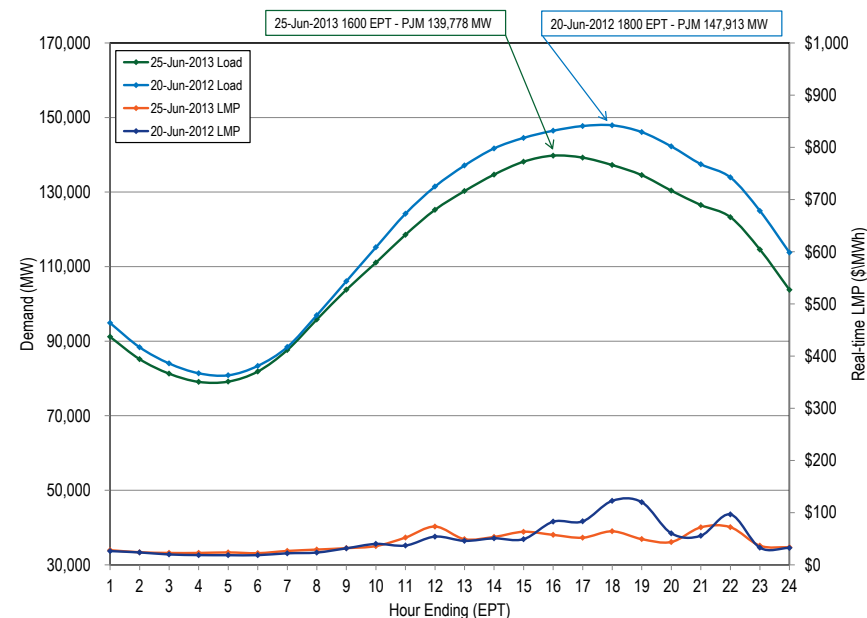
Market Concentration

Analyses of supply curve segments of the PJM Energy Market for the first six months of 2013 indicate moderate concentration in the base load segment, but high concentration in the intermediate and peaking segments.[16] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal during high demand periods. When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall Energy Market. PJM offer-capping rules that limit the exercise of local market power were generally effective in preventing the exercise of market power in these areas during the first six months of 2013.

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15 For additional information on the "PJM Integration Period", see the *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

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

The concentration ratio used here is the Herfindahl-Hirschman Index (HHI), calculated by summing the squares of the market shares of all firms in a market. Hourly PJM Energy Market HHIs were calculated based on the real-time energy output of generators, adjusted for hourly net imports by owner (Table 2-7).

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

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

- **Unconcentrated.** Market HHI below 1000, equivalent to 10 firms with equal market shares;
- **Moderately Concentrated.** Market HHI between 1000 and 1800; and
- **Highly Concentrated.** Market HHI greater than 1800, equivalent to between five and six firms with equal market shares.[17]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during the first six months of 2013 was moderately concentrated (Table 2-7).

Table 2-7 PJM hourly Energy Market HHI: January through June, 2012 and 2013[18]

	Hourly Market HHI (Jan – Jun, 2012)	Hourly Market HHI (Jan – Jun, 2013)
Average	1262	1204
Minimum	992	947
Maximum	1657	1610
Highest market share (One hour)	32%	31%
Average of the highest hourly market share	23%	22%
# Hours	4,367	4,343
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

Table 2-8 includes 2013 HHI values by supply curve segment, including base, intermediate and peaking plants.

Table 2-8 PJM hourly Energy Market HHI (By supply segment): January through June, 2012 and 2013

	Jan – Jun, 2012			Jan – Jun, 2013		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	1126	1308	1703	1038	1225	1679
Intermediate	1015	1664	4924	1046	2327	5484
Peak	614	6020	10000	608	6297	10000

Figure 2-4 presents the 2013 hourly HHI values in chronological order and an HHI duration curve.

17 Order No. 592, "*Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement*," 77 FERC ¶ 61,263, pp. 64-70 (1996)

18 This analysis includes all hours in the first six months of 2013, regardless of congestion.

Figure 2-4 PJM hourly Energy Market HHI: January through June, 2013
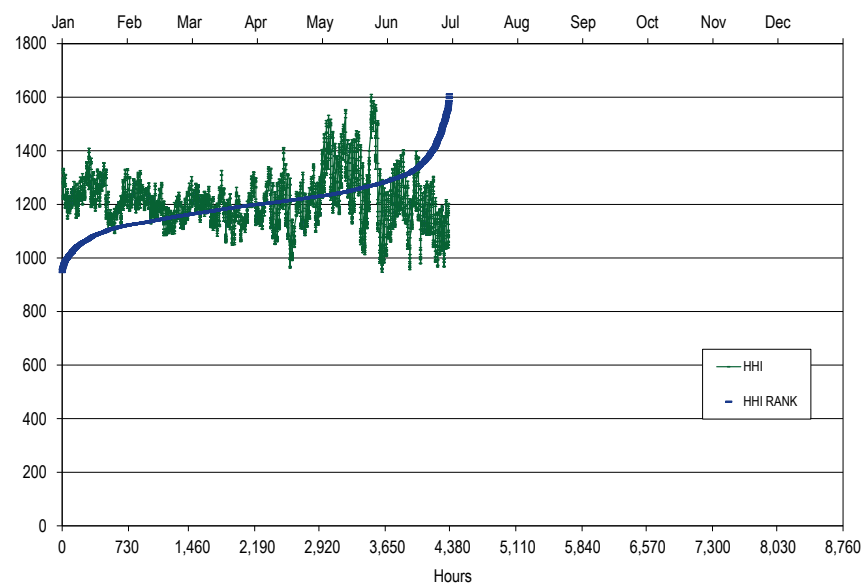
Local Market Structure and Offer Capping

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

Levels of offer capping have historically been low in PJM, as shown in Table 2-9. The offer capping percentages shown in Table 2-9 include all the units that are committed on their cost schedule, when their price schedule is available. This includes units that are committed to provide constraint relief whose owners failed the TPS test in the energy market, as well as, in 2013 for the first time, units that are committed for reliability reasons to provide black start and reactive service. The inclusion of these additional units means that the offer capping data for 2013 cannot usefully be compared to prior years.

Table 2-9 Offer-capping statistics: January through June, 2009 to 2013

(Jan – Jun)	Real Time		Day Ahead	
	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2009	0.5%	0.2%	0.1%	0.0%
2010	0.9%	0.3%	0.3%	0.1%
2011	0.7%	0.3%	0.0%	0.0%
2012	1.7%	1.1%	0.1%	0.1%
2013	3.4%	2.4%	3.9%	2.4%

Table 2-10 presents data on the frequency with which units were offer capped in the first six months of 2012 and 2013.

Table 2-10 Real-time offer-capped unit statistics: January through June, 2012 and 2013

Run Hours Offer-Capped, Percent Greater Than Or Equal To:	(Jan – Jun)	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2013	12	0	0	0	4	30
	2012	0	0	0	1	2	16
80% and < 90%	2013	10	0	0	0	0	6
	2012	0	0	0	0	1	5
75% and < 80%	2013	3	0	0	0	0	1
	2012	1	0	0	0	0	5
70% and < 75%	2013	4	0	0	0	1	2
	2012	1	0	0	0	0	7
60% and < 70%	2013	1	0	0	4	1	8
	2012	3	0	0	0	2	11
50% and < 60%	2013	1	0	0	2	0	15
	2012	3	0	1	0	1	12
25% and < 50%	2013	3	2	0	0	6	25
	2012	7	1	2	3	2	53
10% and < 25%	2013	0	0	0	1	0	22
	2012	0	1	1	2	4	50

Table 2-10 shows that a significant number of units are offer capped for 90 percent or more of their run hours in the first six months of 2013. The increase in the number of units that are capped for a high percentage of their run hours reflects, for the first time in 2013, units that are committed specifically for black start and reactive service.

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 six months of 2013, the AEP, AP, ATSI, BGE, ComEd, Dominion, DPL, PECO, Pepco, PPL and PSEG Control Zones experienced congestion resulting from one or more constraints binding for 50 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 six months of 2013.[19] The AECO, DAY, DEOK, DLCO, JCPL, Met-Ed, PENELEC and RECO Control Zones were not affected by constraints binding for 50 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, 2013, through June 30, 2013. 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.

Overall, the results confirm that the three pivotal supplier test results in offer capping when the local market is structurally noncompetitive and

does not result in offer capping when that is not the case. Local markets are noncompetitive when the number of suppliers is relatively small.

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 owners passing and failing for the transfer interface constraints.

Table 2-11 Three pivotal supplier test details for interface constraints: January through June, 2013

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	283	329	13	2	11
	Off Peak	170	281	12	4	8
AEP – DOM	Peak	169	87	6	0	6
	Off Peak	NA	NA	NA	NA	NA
AP South	Peak	289	439	10	1	9
	Off Peak	292	451	9	1	8
Bedington – Black Oak	Peak	156	139	11	2	10
	Off Peak	177	135	11	0	11
Cleveland	Peak	100	112	2	0	2
	Off Peak	NA	NA	NA	NA	NA
Eastern	Peak	463	619	16	2	14
	Off Peak	NA	NA	NA	NA	NA
Western	Peak	463	754	16	5	11
	Off Peak	1,438	2,068	21	8	14

The three pivotal supplier test is applied every time the PJM market system solution indicates that incremental relief is needed to relieve a transmission constraint. While every system solution that requires incremental relief to transmission constraints will result in a test, not all tested providers of effective supply are eligible for capping. Only uncommitted resources, which would be started as a result of incremental relief needs, are eligible to be offer capped. Already committed units that can provide incremental relief cannot, regardless of test score, be switched from price to cost offers. Table 2-12 provides, for the identified interface constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in

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

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 interface constraints: January through June, 2013

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	627	53	8%	17	3%	32%
	Off Peak	428	43	10%	8	2%	19%
AEP - DOM	Peak	34	0	0%	0	0%	0%
	Off Peak	NA	NA	NA	NA	NA	NA
AP South	Peak	3,727	176	5%	36	1%	20%
	Off Peak	2,117	67	3%	9	0%	13%
Bedington - Black Oak	Peak	11	0	0%	0	0%	0%
	Off Peak	84	2	2%	2	2%	100%
Cleveland	Peak	87	5	6%	2	2%	40%
	Off Peak	NA	NA	NA	NA	NA	NA
Eastern	Peak	8	0	0%	0	0%	0%
	Off Peak	NA	NA	NA	NA	NA	NA
Western	Peak	80	6	8%	2	3%	33%
	Off Peak	195	7	4%	5	3%	71%

Ownership of Marginal Resources

Table 2-13 shows the contribution to PJM real-time, six month, load-weighted LMP by individual marginal resource owner.[20] The contribution of each marginal resource to price at each load bus is calculated for the first six months of 2013, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. The results show that in the first six months of 2013, the offers of one company contributed 22.0 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 55.7 percent of the real-time, load-weighted, average PJM system LMP. In comparison, during the first six months of 2012, the offers of one company contributed 24.6 percent of the real time, load-weighted PJM system LMP and offers of the top four companies contributed 59.5 percent of the real-time, load-weighted, average PJM system LMP.

Table 2-13 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): January through June, 2012 and 2013

2012 (Jan - Jun)		2013 (Jan - Jun)	
Company	Percent of Price	Company	Percent of Price
1	24.6%	1	22.0%
2	15.1%	2	12.6%
3	11.1%	3	10.6%
4	8.8%	4	10.5%
5	8.5%	5	7.4%
6	4.8%	6	4.4%
7	4.7%	7	4.2%
8	4.4%	8	4.1%
9	3.5%	9	3.3%
Other (50 companies)	14.7%	Other (52 companies)	20.9%

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

Table 2-14 shows the contribution to PJM day-ahead, load-weighted LMP by individual marginal resource owner.[21] The contribution of each marginal resource to price at each load bus is calculated for the first six months of 2013, period and summed by the company that offers the marginal resource into the Day-Ahead Energy Market.

Table 2-14 Marginal resource contribution to PJM day-ahead, load-weighted LMP (By parent company): January through June, 2012 and 2013

2012 (Jan – Jun)		2013 (Jan – Jun)	
Company	Percent of Price	Company	Percent of Price
1	17.2%	1	17.5%
2	7.0%	2	10.7%
3	6.9%	3	6.7%
4	6.3%	4	5.3%
5	5.4%	5	5.1%
6	4.8%	6	4.9%
7	4.3%	7	4.3%
8	3.8%	8	3.5%
9	3.5%	9	3.1%
Other (121 companies)	40.9%	Other (134 companies)	38.7%

Type of Marginal Resources

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

Table 2-15 shows the type of fuel used by marginal resources in the Real-Time Energy Market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first six months of 2013, coal units were 58.4 percent and natural gas units were 32.6 percent of the total marginal resources. In the first six months of 2012, coal units were

59.4 percent and natural gas units were 30.0 percent of the total marginal resources.[22]

Table 2-15 Type of fuel used (By real-time marginal units): January through June, 2012 and 2013

Fuel Type	2012 (Jan – Jun)	2013 (Jan – Jun)
Coal	59.4%	58.4%
Gas	30.0%	32.6%
Municipal Waste	0.1%	0.1%
Oil	4.1%	2.9%
Other	0.3%	0.1%
Uranium	0.0%	0.0%
Wind	0.0%	5.9%

Table 2-16 shows the type, and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first six months of 2013, Up-to Congestion transactions were 96.6 percent of the total marginal resources. In comparison, Up-to Congestion transactions were 86.0 percent of the total marginal resources in the first six months of 2012.

Table 2-16 Day-ahead marginal resources by type/fuel: January through June, 2012 and 2013

Type/Fuel	2012 (Jan – Jun)	2013 (Jan – Jun)
Up-to Congestion Transaction	86.0%	96.6%
DEC	5.3%	0.9%
INC	5.0%	0.7%
Coal	2.5%	1.1%
Gas	1.0%	0.5%
Dispatchable Transaction	0.1%	0.1%
Price Sensitive Demand	0.1%	0.0%
Wind	0.0%	0.0%
Oil	0.0%	0.0%
Municipal Waste	0.0%	0.0%
Diesel	0.0%	0.0%
Total	100.0%	100.0%

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22 The percentages of marginal fuel reported in the *2011 State of the Market Report for PJM*, were based on both Locational Pricing Algorithm (LPA) and dispatch (SCED) marginal resources. Starting from *2012 State of the Market Report for PJM*, marginal fuel percentages are based only on resources that were marginal in dispatch (SCED). See the *MMU Technical Reference for PJM Markets*, at "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

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

Market Conduct: Markup

The markup index is a summary measure of participant offer behavior or conduct for individual marginal units. The markup index for each marginal unit is calculated as (Price – Cost)/Price.[23] The markup index is normalized and can vary from -1.00 when the offer price is less than marginal cost, to 1.00 when the offer price is higher than marginal cost. The markup index does not measure the impact of unit markup on total LMP.

Real-Time Mark Up Conduct

Table 2-17 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category. A unit is assigned to a price category for each dispatch solution associated with the interval in which it was marginal, based on its offer price at that time. The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point. The data show that despite the fact that markup had a negligible impact on LMP in the first half of 2013, some marginal units do have substantial markups.

Table 2-17 Average, real-time marginal unit markup index (By price category): January through June, 2012 and 2013

	2012 (Jan – Jun)			2013 (Jan – Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.09)	($3.14)	34.5%	(0.10)	($3.13)	16.3%
$25 to $50	(0.06)	($2.78)	48.0%	(0.03)	($2.39)	63.6%
$50 to $75	0.06	$1.45	3.5%	(0.01)	($4.17)	8.0%
$75 to $100	0.36	$31.14	0.2%	0.03	$0.96	1.4%
$100 to $125	0.22	$22.12	0.3%	0.08	$7.75	0.8%
$125 to $150	0.34	$44.36	0.1%	0.07	$9.05	0.6%
>= $150	0.04	$9.55	3.8%	0.02	$3.05	4.1%

Day–Ahead Mark Up Conduct

Table 2-18 shows the average markup index of marginal units in Day-Ahead Energy Market, by offer price category. A unit is assigned to a price category for each interval in which it was marginal, based on its offer price at that time.

Table 2-18 Average marginal unit markup index (By offer price category): January through June, 2012 and 2013

	2012 (Jan – Jun)			2013 (Jan – Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.10)	($3.12)	32.5%	(0.07)	($1.76)	14.5%
$25 to $50	(0.06)	($2.87)	64.9%	(0.04)	($2.35)	78.1%
$50 to $75	0.05	$1.58	2.4%	0.00	($1.95)	6.4%
$75 to $100	0.50	$41.32	0.1%	0.04	($2.47)	0.4%
$100 to $125	0.00	$0.00	0.0%	(0.08)	($14.63)	0.1%
$125 to $150	(0.05)	($7.19)	0.0%	0.58	$72.91	0.0%
>= $150	0.02	$3.02	0.1%	0.00	$0.00	0.0%

Market Performance

Markup

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

The MMU calculates the impact on system prices of marginal unit price-cost markup, based on analysis using sensitivity factors. The calculation shows the markup component of price based on a comparison between the price-based offer and the cost-based offer of each actual marginal unit on the system.[24]

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23 In order to normalize the index results (i.e., bound the results between +1.00 and -1.00), the index is calculated as (Price – Cost)/Price when price is greater than cost, and (Price – Cost)/Cost when price is less than cost.

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

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

The MMU calculated an explicit measure of the impact of marginal unit markups on LMP. The markup impact includes the impact of the identified markup conduct on a unit by unit basis, but the inclusion of negative markup impacts has an offsetting effect. The markup analysis does not distinguish between intervals in which a unit has local market power or has a price impact in an unconstrained interval. The markup analysis is a more general measure of the competitiveness of the Energy Market.

Real-Time Markup

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

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

Table 2-19 shows the average unit markup component of LMP for marginal units, by unit type and primary fuel. The markup component of LMP is a measure of the impact of the markups of marginal units shown in Table 2-19 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 2-17.

Table 2-19 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through June, 2012 and 2013[25]

Fuel Type	Unit Type	2012 (Jan –Jun) Markup Component of LMP	Percent	2013 (Jan – Jun) Markup Component of LMP	Percent
Coal	Steam	($2.03)	85.5%	($0.74)	35.4%
Gas	CC	($0.03)	1.3%	($0.80)	38.3%
Gas	CT	($0.26)	10.8%	($0.19)	8.9%
Gas	Diesel	$0.02	(0.8%)	$0.00	(0.2%)
Gas	Steam	($0.00)	0.1%	$0.02	(1.2%)
Municipal Waste	Diesel	$0.00	0.0%	$0.00	0.0%
Municipal Waste	Steam	$0.04	(1.7%)	($0.00)	0.0%
Oil	CT	$0.01	(0.4%)	($0.00)	0.1%
Oil	Diesel	$0.00	(0.0%)	$0.00	(0.0%)
Oil	Steam	($0.11)	4.6%	($0.38)	18.3%
Other	Solar	$0.00	0.0%	$0.00	(0.0%)
Other	Steam	($0.01)	0.3%	($0.02)	0.8%
Uranium	Steam	$0.00	0.0%	($0.00)	0.0%
Wind	Wind	($0.01)	0.4%	$0.01	(0.3%)
TOTAL		($2.37)	100.0%	($2.09)	100.0%

Markup Component of Real-Time System Price

Table 2-20 shows the markup component of average prices and of average monthly on-peak and off-peak prices. In the first six months of 2013, -$2.09 per MWh of the PJM real-time, load-weighted average LMP was attributable to markup. In the first six months of 2013, the markup component of LMP was -$2.84 per MWh off peak and -$1.38 per MWh on peak. In comparison, in the first six months of 2012, -$2.37 per MWh of the PJM real-time, load-weighted average LMP was attributable to markup. In the first six months of 2012, the markup component of LMP was -$3.21 per MWh off peak and -$1.58 per MWh on peak.

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

Table 2-20 Monthly markup components of real-time load-weighted LMP: January through June, 2012 and 2013

	2012 (Jan – Jun)			2013 (Jan – Jun)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($3.28)	($3.58)	($2.98)	($4.04)	($4.41)	($3.70)
Feb	($2.07)	($2.92)	($1.26)	($2.59)	($3.86)	($1.34)
Mar	($2.30)	($2.51)	($2.10)	($1.27)	($1.89)	($0.63)
Apr	($2.71)	($3.60)	($1.86)	($2.15)	($3.23)	($1.22)
May	($1.10)	($3.34)	$0.93	($1.13)	($2.59)	$0.10
Jun	($2.68)	($3.24)	($2.18)	($1.17)	($1.13)	($1.21)
Total	($2.37)	($3.21)	($1.58)	($2.09)	($2.84)	($1.38)

Markup Component of Real-Time Zonal Prices

Table 2-21 Average real-time zonal markup component: January through June, 2012 and 2013

	2012 (Jan – Jun)			2013 (Jan – Jun)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	($2.40)	($3.39)	($1.42)	($1.93)	($2.63)	($1.25)
AEP	($2.43)	($3.30)	($1.58)	($2.24)	($2.87)	($1.64)
APS	($2.34)	($3.19)	($1.52)	($2.29)	($3.12)	($1.48)
ATSI	($2.57)	($3.46)	($1.73)	($2.14)	($2.88)	($1.44)
BGE	($2.35)	($2.68)	($2.04)	($2.13)	($2.76)	($1.53)
ComEd	($2.45)	($3.20)	($1.75)	($2.07)	($2.80)	($1.40)
DAY	($2.57)	($3.41)	($1.79)	($2.34)	($2.94)	($1.78)
DEOK	($2.48)	($3.27)	($1.74)	($2.19)	($2.91)	($1.52)
Dominion	($2.15)	($2.65)	($1.67)	($1.98)	($3.03)	($0.96)
DPL	($2.58)	($3.76)	($1.42)	($2.18)	($2.72)	($1.66)
DUQ	($2.22)	($3.16)	($1.33)	($2.15)	($2.85)	($1.49)
EKPC	NA	NA	NA	($1.26)	($1.93)	($0.60)
JCPL	($1.97)	($3.38)	($0.68)	($1.92)	($2.75)	($1.17)
Met-Ed	($2.50)	($3.45)	($1.63)	($2.11)	($2.77)	($1.50)
PECO	($2.44)	($3.41)	($1.53)	($2.13)	($2.61)	($1.68)
PENELEC	($2.45)	($3.45)	($1.52)	($2.24)	($3.08)	($1.44)
Pepco	($1.93)	($2.74)	($1.18)	($2.04)	($2.89)	($1.27)
PPL	($2.56)	($3.44)	($1.74)	($2.25)	($2.97)	($1.58)
PSEG	($2.22)	($3.39)	($1.15)	($1.31)	($2.19)	($0.50)
RECO	($2.16)	($3.55)	($0.98)	($0.90)	($1.80)	($0.13)

The six month average real-time price component of unit markup is shown for each zone in Table 2-21. While all were negative, the smallest zonal all hours average markup component for the first six months of 2013 was in the DAY Control Zone, -$2.34 per MWh, while the highest all hours average zonal markup component for the first six months of 2013 was in the RECO Control Zone, -$0.90 per MWh. The smallest zonal on peak average markup was in the DAY Control Zone, -$1.78 per MWh, while the highest zonal on peak average markup was in the RECO Control Zone, -$0.13 per MWh.

Markup by Real-Time System Price Levels

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

Table 2-22 shows the average markup component of observed prices when the PJM system LMP was in the identified price range.

Table 2-22 Average real-time markup component (By price category): January through June, 2012 and 2013

	2012 (Jan – Jun)		2013 (Jan – Jun)	
	Average Markup		Average Markup	
LMP Category	Component	Frequency	Component	Frequency
< $25	($1.01)	29.4%	($0.39)	10.2%
$25 to $50	($1.91)	64.0%	($1.67)	78.4%
$50 to $75	$0.28	2.8%	$0.04	6.8%
$75 to $100	$0.18	0.9%	($0.06)	1.5%
$100 to $125	$0.07	0.4%	($0.04)	0.6%
$125 to $150	($0.01)	0.1%	($0.01)	0.2%
>= $150	$0.03	0.2%	$0.05	0.3%

Day-Ahead Markup

Markup Component of Day-Ahead Price by Fuel, Unit Type

The markup component of the overall PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 2-23.

Table 2-23 Markup component of the overall PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through June, 2012 and 2013

Fuel Type	Unit Type	2012 (Jan – Jun) Markup Component of LMP	Percent	2013 (Jan – Jun) Markup Component of LMP	Percent
Coal	Steam	($1.85)	78.5%	($0.74)	50.3%
Gas	Steam	($0.34)	14.3%	($0.69)	47.2%
Oil	Steam	($0.11)	4.7%	($0.00)	0.2%
Gas	CT	($0.06)	2.4%	($0.03)	2.2%
Municipal Waste	Steam	($0.00)	0.1%	($0.00)	0.1%
Wind	Wind	($0.00)	0.0%	$0.00	(0.0%)
Total		($2.36)	100.0%	($1.47)	100.0%

Markup Component of Day-Ahead System Price

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

Table 2-24 Monthly markup components of day-ahead, load-weighted LMP: January through June, 2012 and 2013

	2012 (Jan – Jun) Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	2013 (Jan – Jun) Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($2.76)	($2.22)	($3.28)	($3.77)	($3.99)	($3.54)
Feb	($3.01)	($3.61)	($2.38)	($2.53)	($1.43)	($3.67)
Mar	($2.30)	($1.99)	($2.63)	($1.84)	($0.18)	($3.45)
Apr	($2.67)	($2.36)	($2.98)	($0.11)	($0.01)	($0.22)
May	($1.52)	($1.11)	($1.97)	($0.10)	($0.04)	($0.17)
Jun	($1.93)	($1.09)	($2.88)	($0.06)	$0.03	($0.14)
Annual	($2.36)	($2.04)	($2.70)	($1.47)	($1.00)	($1.98)

Table 2-24 shows the markup component of average prices and of average monthly on-peak and off-peak prices.

Markup Component of Day-Ahead Zonal Prices

The annual average price component of unit markup is shown for each zone in Table 2-25.

Table 2-25 Day-ahead, average, zonal markup component: January through June, 2012 and 2013

	2012 (Jan – Jun)			2013 (Jan – Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($2.43)	($1.90)	($2.99)	($1.56)	($1.16)	($1.98)
AEP	($2.36)	($2.03)	($2.70)	($1.44)	($0.92)	($1.98)
AP	($2.24)	($2.15)	($2.33)	($1.55)	($1.04)	($2.08)
ATSI	($2.47)	($2.20)	($2.75)	($1.46)	($0.95)	($2.03)
BGE	($2.51)	($2.36)	($2.68)	($1.50)	($1.10)	($1.92)
ComEd	($2.13)	($1.78)	($2.51)	($1.37)	($0.85)	($1.92)
DAY	($2.35)	($2.01)	($2.73)	($1.49)	($0.94)	($2.08)
DEOK	($2.29)	($1.99)	($2.60)	($1.41)	($0.86)	($2.00)
DLCO	($2.20)	($1.87)	($2.57)	($1.40)	($0.92)	($1.92)
DPL	($2.48)	($2.06)	($2.92)	($1.57)	($1.02)	($2.14)
Dominion	($2.37)	($2.00)	($2.76)	($1.45)	($1.02)	($1.89)
EKPC	NA	NA	NA	($0.05)	$0.04	($0.14)
JCPL	($2.32)	($1.88)	($2.83)	($1.83)	($1.68)	($2.00)
Met-Ed	($2.50)	($2.20)	($2.84)	($1.58)	($1.17)	($2.03)
PECO	($2.45)	($1.96)	($2.97)	($1.50)	($1.02)	($2.02)
PENELEC	($2.50)	($2.24)	($2.77)	($1.46)	($0.94)	($2.03)
PPL	($2.47)	($2.03)	($2.95)	($1.65)	($1.24)	($2.09)
PSEG	($2.39)	($1.98)	($2.86)	($1.46)	($1.01)	($1.97)
Pepco	($2.53)	($2.42)	($2.64)	($1.44)	($1.06)	($1.86)
RECO	($2.44)	($2.21)	($2.72)	($1.41)	($0.93)	($1.97)

Markup by Day-Ahead System Price Levels

The six month average markup component of the identified price range and its frequency are shown in Table 2-26.

Table 2-26 shows the average markup component of observed price when the PJM day-ahead, system LMP was in the identified price range.

Table 2-26 Average, day-ahead markup (By LMP category): January through June, 2012 and 2013

	2012 (Jan – Jun)		2013 (Jan – Jun)	
	Average Markup		Average Markup	
LMP Category	Component	Frequency	Component	Frequency
< $25	($3.49)	23.7%	($0.90)	5.3%
$25 to $50	($3.00)	74.4%	($2.05)	87.5%
$50 to $75	($0.32)	1.2%	$0.78	6.3%
$75 to $100	$17.77	0.3%	$0.05	0.7%
$100 to $125	($19.60)	0.1%	$0.01	0.2%
$125 to $150	$12.41	0.1%	$0.00	0.0%
>= $150	$0.69	0.2%	$0.00	0.0%

Frequently Mitigated Units and Associated Units

An FMU is a frequently mitigated unit. FMUs were first provided additional compensation as a form of scarcity pricing in 2005.[26] 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 for 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 for 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.[27] These categories are designated Tier 1, Tier 2 and Tier 3, respectively.[28,29]

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 with identical electrical impacts on the system, one of which was offer capped for more than 80 percent of its run hours, that unit would be designated a Tier

26 110 FERC ¶ 61,053 (2005).
27 OA, Schedule 1 § 6.4.2.
28 114 FERC ¶ 61, 076 (2006).
29 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).

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.

The MMU recommends the elimination of FMU and AU adders. FMU and AU adders were added to the market rules in 2006 to address revenue inadequacy for frequently mitigated units. Since that time, PJM has undertaken major redesigns of its market rules addressing revenue adequacy, including implementation of the RPM capacity market construct in 2007, and changes to the scarcity pricing rules in 2012. The reasons that FMU and AU adders were implemented no longer exist. FMU and AU adders no longer serve the purpose for which they were created and interfere with the efficient operation of PJM markets. This recommendation is currently scheduled to be evaluated through the PJM stakeholder process in the fourth quarter of 2013.

FMUs and AUs are designated monthly, and a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[30]

Table 2-27 shows, by month, the number of FMUs and AUs in 2012 and 2013. For example, in January 2013, there were 18 FMUs and AUs in Tier 1, 17 FMUs and AUs in Tier 2, and 10 FMUs and AUs in Tier 3.

Table 2–27 Number of frequently mitigated units and associated units (By month): 2012 and January through June, 2013

| | FMUs and AUs | | | | | | | |
| | 2012 | | | | 2013 | | | |
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	26	21	52	99	18	17	10	45
February	26	22	47	95	18	11	12	41
March	25	17	47	89	18	8	12	38
April	23	17	46	86	16	5	15	36
May	23	14	47	84	11	5	15	31
June	22	13	48	83	24	8	12	44
July	25	11	50	86				
August	25	23	43	91				
September	17	6	33	56				
October	10	18	14	42				
November	9	21	10	40				
December	14	17	10	41				

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.

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30 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 June, 2013

Table 2–28 Frequently mitigated units and associated units total months eligible: 2012 and January through June, 2013

Months Adder–Eligible	FMU & AU Count	
	2012	2013
1	25	13
2	12	5
3	4	2
4	9	1
5	2	8
6	4	27
7	14	
8	16	
9	15	
10	5	
11	2	
12	25	
Total	188	56
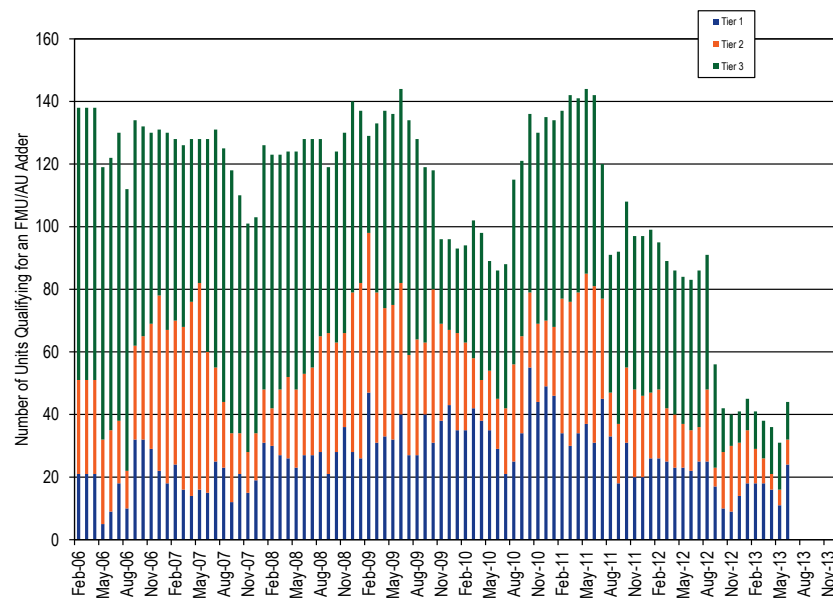
Table 2-28 shows the number of units that were eligible for an FMU or AU adder (Tier 1, Tier 2 or Tier 3) by the number of months they were eligible in 2012 and during the first six months of 2013. Of the 56 units eligible in at least one month during the first six months of 2013, 27 units (48.2 percent) were FMUs or AUs for all six months, and 13 units (23.2 percent) qualified in only one month of 2013. The reduction in the total number of units qualifying for an FMU or AU adder resulted from the decrease in congestion, which was in turn the result of changes in fuel costs and changes in system topology.

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 June 30, 2013, there have been 317 unique units that have qualified for an FMU adder in at least one month. Of these 317 units, no unit qualified for an adder in all potential months. Two units qualified in 89 of the 90 possible months, and 110 of the 317 units (34.7 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 June, 2013
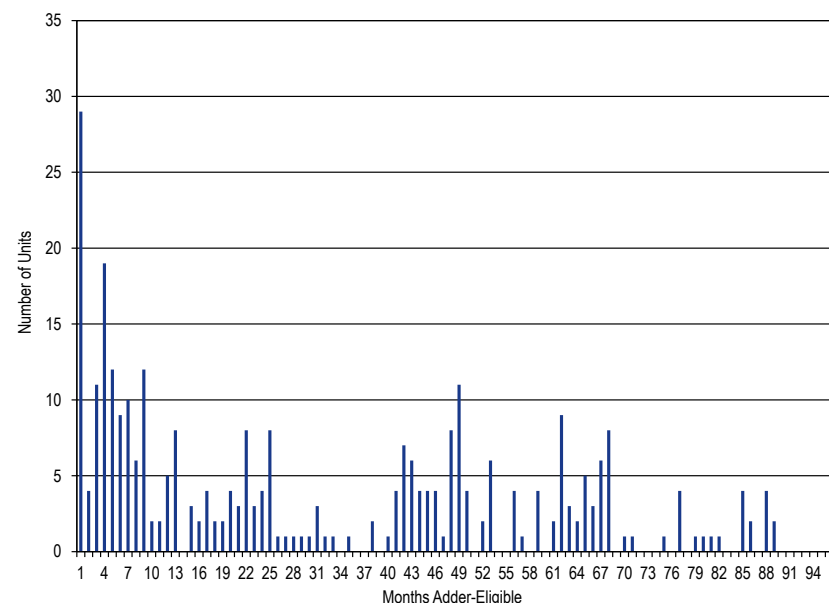
Market Performance: Load and LMP

The PJM system load and average 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 six months of 2013 increased by 2.3 percent from the first six months of 2012, from 84,946 MW to 86,897 MW. The PJM average real-time load in the first six months of 2013 would have increased by 2.0 percent from the first six months of 2012, from 84,946 MW to 86,675 MW, if the EKPC Transmission Zone had not been included in the comparison.[31]

PJM average day-ahead load, including DECs and up-to congestion transactions, in the first six months of 2013 increased by 11.9 percent from the first six months of 2012, from 129,881 MW to 145,280 MW. The PJM average day-ahead load, including DECs and up-to congestion transactions, would have increased 11.7 percent from the first six months of 2012, from 129,881 MW to 145,042 MW if the EKPC Transmission Zone had not been included in the comparison.

The day-ahead load growth was 417.4 percent higher than the real-time load growth because of the continued growth of up-to congestion transactions. If the first six months of 2013 up-to congestion transactions had been held to the first six months of 2012 levels, the day-ahead load, including DECs and up-to congestion transactions, would have increased 0.9 percent instead of 11.9 percent. The day-ahead load growth would have been 60.9 percent lower than the real-time load growth.

Real-Time Load

PJM Real-Time Load Duration

Figure 2-7 shows the hourly distribution of PJM real-time load for the first six months of 2012 and 2013.[32]

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31 The EKPC Transmission Zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013.

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

Figure 2-7 Distribution of PJM real-time accounting load: January through June of 2012 and 2013[33]
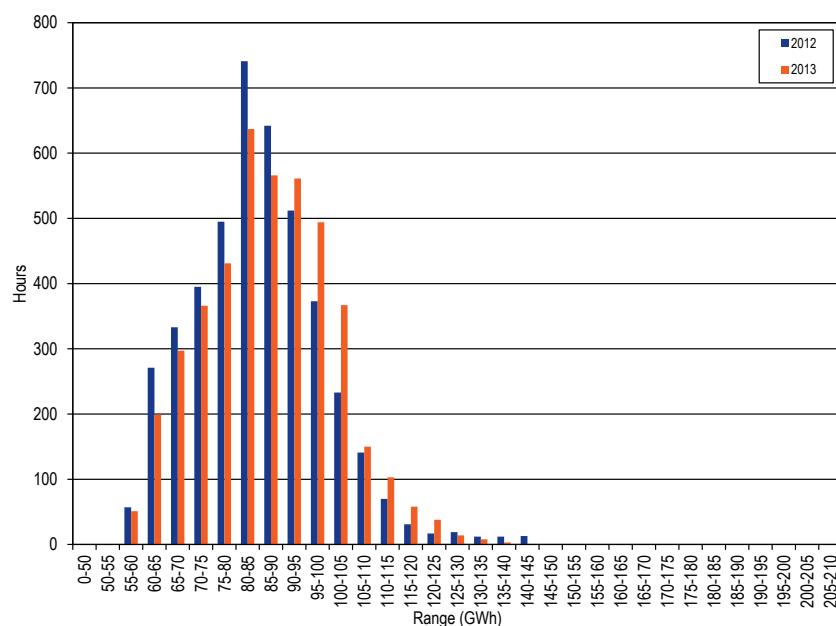
PJM Real-Time, Average Load

Table 2-29 presents summary real-time load statistics for the first six months of each year during the 16 year period 1998 to 2013. 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.[34]

Table 2-29 PJM real-time average hourly load: January through June of 1998 through 2013[35]

| | PJM Real-Time Load (MWh) | | Year-to-Year Change | |
| | | Load Standard | | Load Standard |
(Jan–Jun)	Average Load	Deviation	Average Load	Deviation
1998	27,662	4,703	NA	NA
1999	28,714	5,113	3.8%	8.7%
2000	29,649	5,382	3.3%	5.3%
2001	30,180	5,274	1.8%	(2.0%)
2002	32,678	6,457	8.3%	22.4%
2003	36,727	6,428	12.4%	(0.4%)
2004	41,787	8,999	13.8%	40.0%
2005	71,939	13,603	72.2%	51.2%
2006	77,232	12,003	7.4%	(11.8%)
2007	81,110	13,499	5.0%	12.5%
2008	78,685	12,819	(3.0%)	(5.0%)
2009	75,991	12,899	(3.4%)	0.6%
2010	78,106	13,643	2.8%	5.8%
2011	78,823	13,931	0.9%	2.1%
2012	84,946	13,940	7.8%	0.1%
2013	86,897	13,871	2.3%	(0.6%)

PJM Real-Time, Monthly Average Load

Figure 2-7 compares the real-time, monthly average hourly loads in 2013 with those in 2012.

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

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

35 The data used in the version of this table in the *2012 State of the Market Report for PJM: January through June* have been updated by PJM and the updates are accounted for in this table.

Figure 2-8 PJM real-time monthly average hourly load: January 2012 through June 2013

Figure 2-9 PJM Heating and Cooling Degree Days: January of 2012 through June of 2013
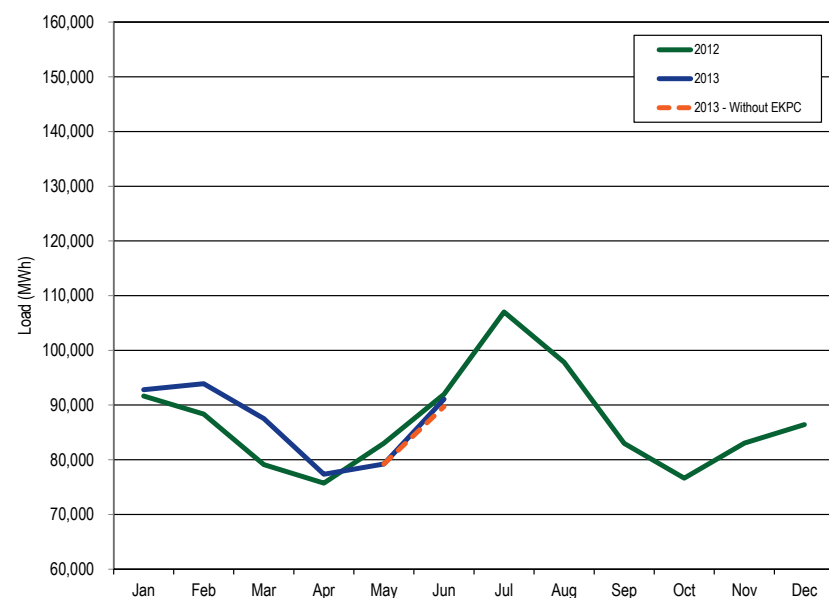
PJM real-time load is significantly affected by temperature. Figure 2-9 compares the total PJM monthly heating and cooling degree days in the first six months of 2013 with those in 2012.[36] The figure shows that in the first six months of 2013, the heating degree days were higher and the cooling degree days were lower than in the corresponding months of 2012.

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.

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36 A heating degree day is defined as the number of degrees that a day's average temperature is below 65 degrees F (the temperature below which buildings need to be heated). A cooling degree day is the number of degrees that a day's average temperature is above 65 degrees F (the temperature when people will start to use air conditioning to cool buildings).
Heating and cooling degree days are calculated by weighting the temperature at each weather station in the individual transmission zones using weights provided by PJM in Manual 19. Then the temperature is weighted by the real-time zonal accounting load for each transmission zone. After calculating an average daily temperature across PJM, the heating and cooling degree formulas are used to calculate the daily heating and cooling degree days, which are summed for monthly reporting.
The weather stations that provided the basis for the analysis are ABE, ACY, AVP, BWI, CAK, CLE, CMH, CRW, CVG, DAY, DCA, ERI, EWR, FWA, IAD, ILG, IPT, ORD, ORF, PHL, PIT, RIC, ROA, SDF, TOL and WAL.

- **Up-to Congestion Transaction.** 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. In the PJM Day-Ahead Market, an up-to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid. 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.[37]

PJM Day-Ahead Load Duration

Figure 2-10 shows the hourly distribution of PJM day-ahead load for the first six months of 2012 and 2013.

Figure 2-10 Distribution of PJM day-ahead load: January through June of 2012 and 2013
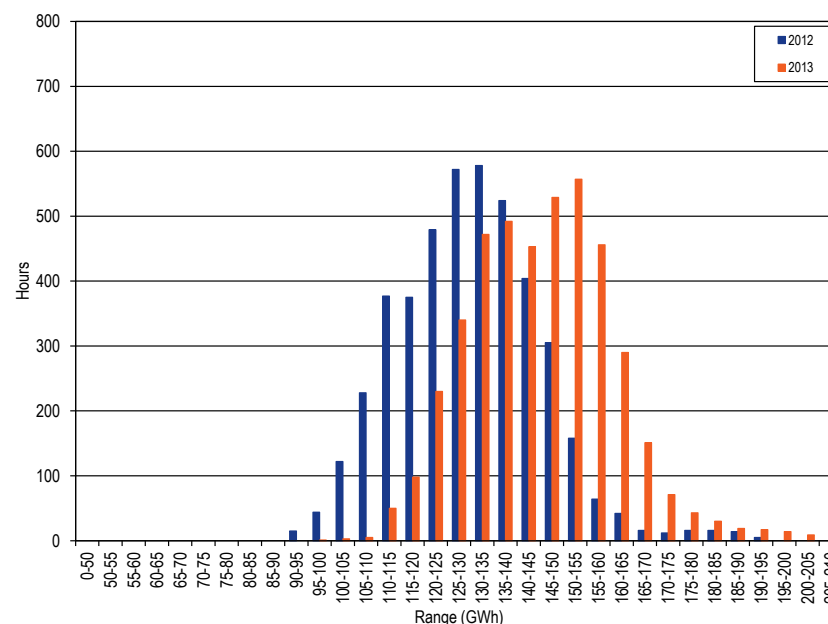
PJM Day-Ahead, Average Load

Table 2-30 presents summary day-ahead load statistics for the first six months of each year of the 13-year period 2001 to 2013.

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37 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 2-30 PJM day-ahead average load: January through June of 2001 through 2013

| | PJM Day-Ahead Load (MWh) | | | | | | Year-to-Year Change | | |
| | Average | | | Standard Deviation | | | Average | | |
(Jan–Jun)	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load	Load	Up-to Congestion	Total Load
2001	32,413	11	32,425	6,016	39	6,014	NA	NA	NA
2002	37,497	65	37,561	8,268	149	8,293	15.7%	481.9%	15.8%
2003	44,112	279	44,391	7,730	289	7,717	17.6%	332.5%	18.2%
2004	49,393	768	50,161	10,003	575	10,304	12.0%	175.1%	13.0%
2005	85,784	1,106	86,890	14,632	737	14,677	73.7%	44.0%	73.2%
2006	91,060	3,410	94,470	12,862	1,383	12,925	6.1%	208.3%	8.7%
2007	100,097	4,640	104,737	14,532	1,455	15,019	9.9%	36.1%	10.9%
2008	95,486	5,462	100,948	13,724	1,642	14,255	(4.6%)	17.7%	(3.6%)
2009	88,688	6,441	95,130	14,650	2,134	15,878	(7.1%)	17.9%	(5.8%)
2010	89,830	9,861	99,691	15,372	5,836	18,097	1.3%	53.1%	4.8%
2011	87,260	17,810	105,070	15,402	3,081	16,452	(2.9%)	80.6%	5.4%
2012	91,062	38,820	129,881	14,851	5,803	15,268	4.4%	118.0%	23.6%
2013	92,228	53,052	145,280	14,536	10,043	15,552	1.3%	36.7%	11.9%

PJM Day-Ahead, Monthly Average Load

Figure 2-11 compares the day-ahead, monthly average hourly loads of 2013 with those of 2012.

Figure 2-11 PJM day-ahead monthly average hourly load: January 2012 through June 2013

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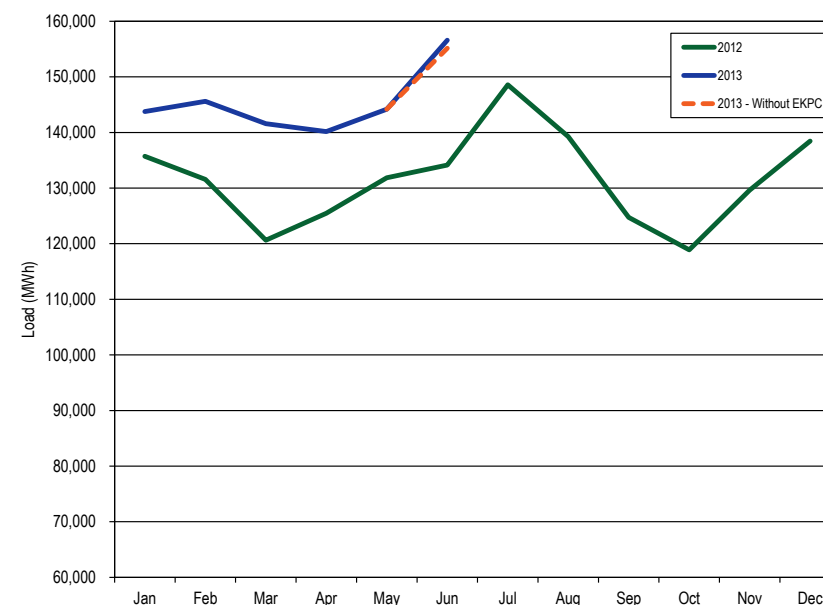
Real-Time and Day-Ahead Load

Table 2-31 presents summary statistics for the first six months of 2012 and 2013 day-ahead and real-time loads.

Table 2-31 Cleared day-ahead and real-time load (MWh): January through June of 2012 and 2013[38]

| | (Jan–Jun) | Day Ahead | | | | | Real Time | Average Difference | |
		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	2012	82,005	803	8,254	38,820	129,881	84,946	44,935	(2,138)
	2013	83,854	1,074	7,300	53,052	145,280	86,897	58,383	(1,968)
Median	2012	81,798	786	7,941	37,924	129,714	84,338	45,376	(489)
	2013	83,413	1,098	7,021	53,783	145,267	86,231	59,036	(1,768)
Standard Deviation	2012	13,458	145	1,826	5,803	15,268	13,940	1,328	(6,302)
	2013	13,293	238	1,612	10,043	15,552	13,871	1,681	(9,974)
Peak Average	2012	90,072	863	9,047	39,039	139,020	93,094	45,927	(2,160)
	2013	92,416	1,165	8,144	53,172	154,896	95,564	59,332	(1,983)
Peak Median	2012	87,994	835	8,704	38,201	137,526	90,635	46,891	(14)
	2013	91,916	1,251	7,720	54,255	153,907	94,737	59,170	(2,804)
Peak Standard Deviation	2012	10,646	142	1,809	5,675	11,984	11,283	701	(6,784)
	2013	10,099	251	1,534	9,738	13,025	10,753	2,272	(9,000)
Off-Peak Average	2012	74,775	750	7,543	38,623	121,691	77,645	44,046	(2,119)
	2013	76,327	994	6,557	52,947	136,825	79,276	57,549	(1,955)
Off-Peak Median	2012	73,291	722	7,265	37,511	120,445	75,931	44,515	(261)
	2013	75,657	1,034	6,290	53,268	135,677	78,519	57,158	(2,400)
Off-Peak Standard Deviation	2012	11,459	126	1,524	5,909	13,092	11,901	1,192	(6,241)
	2013	11,014	193	1,279	10,306	12,352	11,653	699	(10,886)

Figure 2-12 shows the average 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.

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38 The data used in the version of this table in the *2012 State of the Market Report for PJM: January through June* have been updated by PJM and the updates are accounted for in this table.

Figure 2-12 Day-ahead and real-time loads (Average hourly volumes): January through June of 2013

Figure 2-13 Difference between day-ahead and real-time loads (Average daily volumes): January 2012 through June of 2013
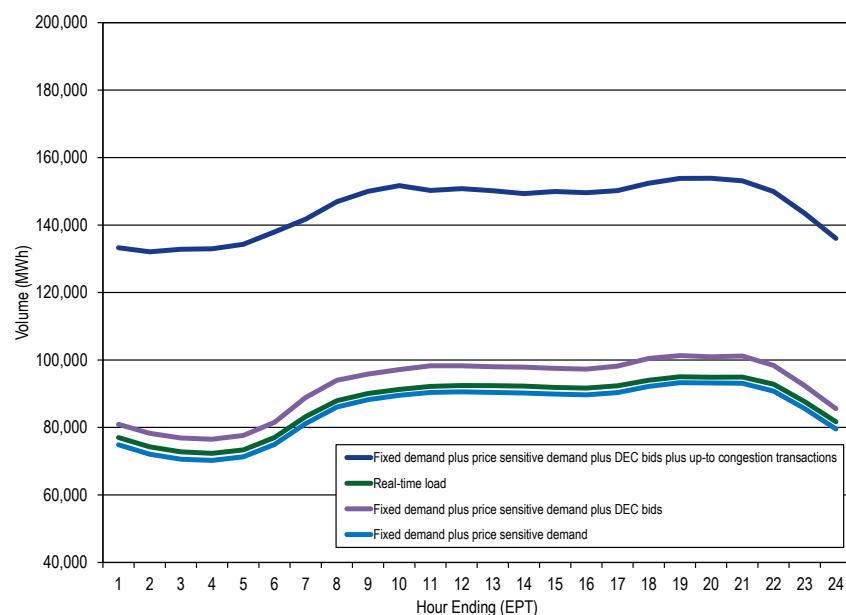
Figure 2-13 shows the difference between the day-ahead and real-time average daily loads in 2012 through the first six months of 2013.
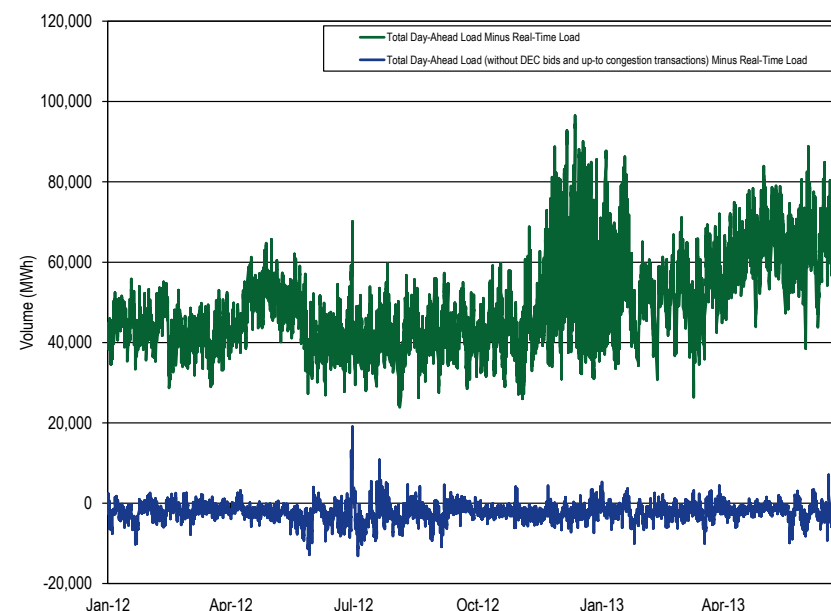
Real-Time and Day-Ahead Generation

PJM average real-time generation in the first six months of 2013 increased by 1.9 percent from the first six months of 2012, from 86,310 MW to 87,974 MW. The PJM average real-time generation in the first six months of 2013 would have increased by 1.7 percent from the first six months of 2012, from 86,310 MW to 87,781 MW if the EKPC Transmission Zone had not been included in the comparison.[39]

PJM average day-ahead generation in the first six months of 2013, including INCs and up-to congestion transactions, increased by 12.1 percent from the first six months of 2012, from 132,326 MW to 148,381 MW. The PJM average day-ahead generation in the first six months of 2013, including INCs

39 The EKPC Transmission Zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013.

and up-to congestion transactions, would have increased 12.0 percent from the first six month of 2012, from 132,326 MW to 148,167 MW if the EKPC Transmission Zone had not been included in the comparison.

The day-ahead generation growth was 536.8 percent higher in the first six months of 2013 than the real-time generation growth in the first six months of 2012 because of the continued growth of up-to congestion transactions. If the first six months of 2013 up-to congestion transactions had been held to first six months of 2012 levels, the day-ahead generation, including INCs and up-to congestion transactions, would have increased 1.4 percent instead of 12.1 percent and day-ahead generation growth would have been 26.3 percent lower than the real-time generation growth.

PJM sums all negative (injections) and positive (withdrawals) load at each designated load bus when calculating net load (accounting load). PJM sums all of the negative (withdrawals) and positive (injections) generation at each generation bus when calculating net generation. Netting withdrawals and injections by bus type (generation or load) affects the measurement of total load and total generation. Energy withdrawn at a generation bus to provide, for example, auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps, is actually load, not negative generation. Energy injected at load buses by behind the meter generation is actually generation, not negative load.

The MMU recommends that during hours when a generation bus shows a net withdrawal, the energy withdrawal be treated as load, not negative generation, for purposes of calculating load and load weighted LMP. The MMU also recommends that during hours when a load bus shows a net injection, the energy injection be treated as generation, not negative load, for purposes of calculating generation and load weighted LMP.

In the Day-Ahead Energy Market, four types of financially binding generation offers are made and cleared:[40]

- **Self-Scheduled Generation Offer.** Offer to supply a fixed block of MWh from a specific unit, including a minimum MWh level from a specific unit that also has a dispatchable component above the minimum.[41]
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a specific unit.
- **Increment Offer (INC).** Financial offer to supply MWh and corresponding offer prices. An increment offer is a financial offer that can be submitted by any market participant.
- **Up-to Congestion Transaction.** 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. In the PJM Day-Ahead Market, an up-to congestion transaction is evaluated as a matched pair of an injection and a withdrawal analogous to a matched pair of an INC offer and a DEC bid. 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 2-32 presents summary real-time generation statistics for the first six months of each year for the 11-year period from 2003 through 2013.

Table 2-32 PJM real-time average hourly generation: January through June of 2003 through 2013

(Jan–Jun)	PJM Real-Time Generation (MWh)		Year-to-Year Change	
	Average Generation	Generation Standard Deviation	Average Generation	Generation Standard Deviation
2003	36,034	6,008	NA	NA
2004	41,430	9,435	15.0%	57.0%
2005	74,365	12,661	79.5%	34.2%
2006	80,249	11,011	7.9%	(13.0%)
2007	83,478	12,105	4.0%	9.9%
2008	83,294	12,458	(0.2%)	2.9%
2009	77,508	12,961	(6.9%)	4.0%
2010	80,702	13,968	4.1%	7.8%
2011	81,483	13,677	1.0%	(2.1%)
2012	86,310	13,695	5.9%	0.1%
2013	87,974	13,528	1.9%	(1.2%)

Table 2-33 presents summary day-ahead generation statistics for the first six months of each year of the 11-year period from 2003 through 2013.

Table 2-33 PJM day-ahead average hourly generation: January through June of 2003 through 2013

(Jan–Jun)	PJM Day-Ahead Generation (MWh)						Year-to-Year Change		
	Average			Standard Deviation			Average		
	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	36,141	279	36,420	7,036	289	7,000	NA	NA	NA
2004	49,321	768	50,089	9,796	575	10,108	36.5%	175.1%	37.5%
2005	86,749	1,106	87,855	14,310	737	14,365	75.9%	44.0%	75.4%
2006	92,153	3,410	95,562	12,581	1,383	12,620	6.2%	208.3%	8.8%
2007	101,830	4,640	106,470	14,029	1,455	14,522	10.5%	36.1%	11.4%
2008	99,243	5,462	104,705	13,565	1,642	14,124	(2.5%)	17.7%	(1.7%)
2009	91,166	6,441	97,607	15,055	2,134	16,283	(8.1%)	17.9%	(6.8%)
2010	92,765	9,861	102,626	15,591	5,836	18,206	1.8%	53.1%	5.1%
2011	90,332	17,810	108,143	15,618	3,081	16,666	(2.6%)	80.6%	5.4%
2012	93,507	38,820	132,326	15,375	5,803	15,710	3.5%	118.0%	22.4%
2013	95,329	53,052	148,381	14,879	10,043	15,606	1.9%	36.7%	12.1%

Table 2-34 presents summary statistics for the first six months of 2012 and 2013 for day-ahead and real-time generation.

Table 2–34 Day-ahead and real-time generation (MWh): January through June of 2012 and 2013

		Day Ahead				Real Time	Average Difference	
	(Jan–Jun)	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	2012	87,146	6,361	38,820	132,326	86,310	836	46,017
	2013	89,788	5,541	53,052	148,381	87,974	1,814	60,408
Median	2012	86,700	6,320	37,924	132,286	85,685	1,015	46,601
	2013	89,640	5,512	53,783	148,414	87,534	2,106	60,880
Standard Deviation	2012	15,282	805	5,803	15,710	13,695	1,587	2,015
	2013	14,687	737	10,043	15,606	13,528	1,159	2,078
Peak Average	2012	95,968	6,612	39,039	141,619	93,959	2,009	47,660
	2013	98,929	5,883	53,172	157,983	96,119	2,809	61,864
Peak Median	2012	93,537	6,556	38,201	140,047	91,650	1,887	48,397
	2013	98,280	5,875	54,255	156,632	95,623	2,657	61,009
Peak Standard Deviation	2012	12,174	623	5,675	12,322	11,303	870	1,018
	2013	11,297	553	9,738	13,001	10,591	706	2,410
Off-Peak Average	2012	79,239	6,136	38,623	123,998	79,454	(215)	44,544
	2013	81,751	5,241	52,947	139,939	80,811	939	59,127
Off-Peak Median	2012	77,782	6,016	37,511	122,849	77,725	57	45,124
	2013	80,916	5,129	53,268	138,737	80,220	696	58,517
Off-Peak Standard Deviation	2012	13,332	880	5,909	13,608	11,904	1,428	1,704
	2013	12,454	748	10,306	12,521	11,648	806	873

Figure 2-14 shows the first six months average 2013 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.[42]

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

Figure 2-14 Day-ahead and real-time generation (Average hourly volumes): January through June of 2013

Figure 2-15 Difference between day-ahead and real-time generation (Average daily volumes): January 2012 through June of 2013
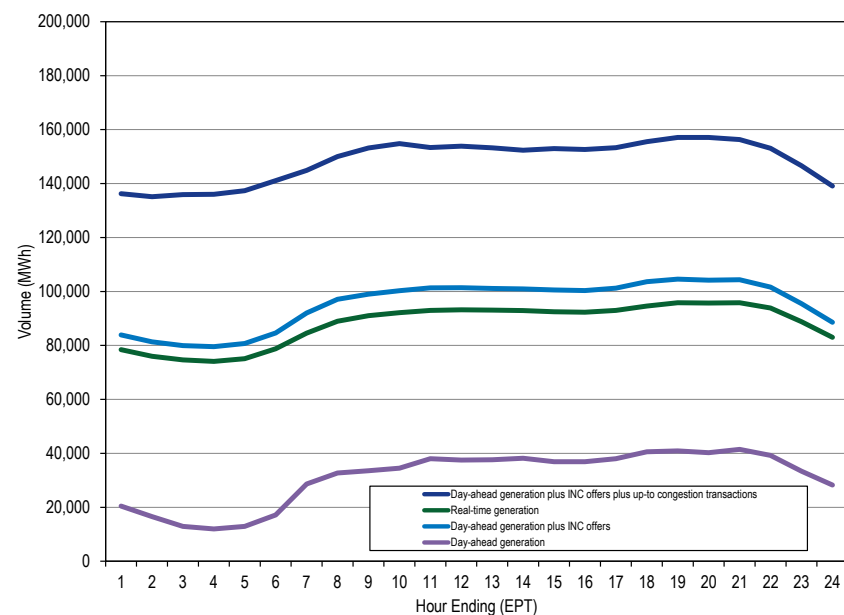
Figure 2-15 shows the difference between the day-ahead and real-time average daily generation in 2012 through the first six months of 2013.
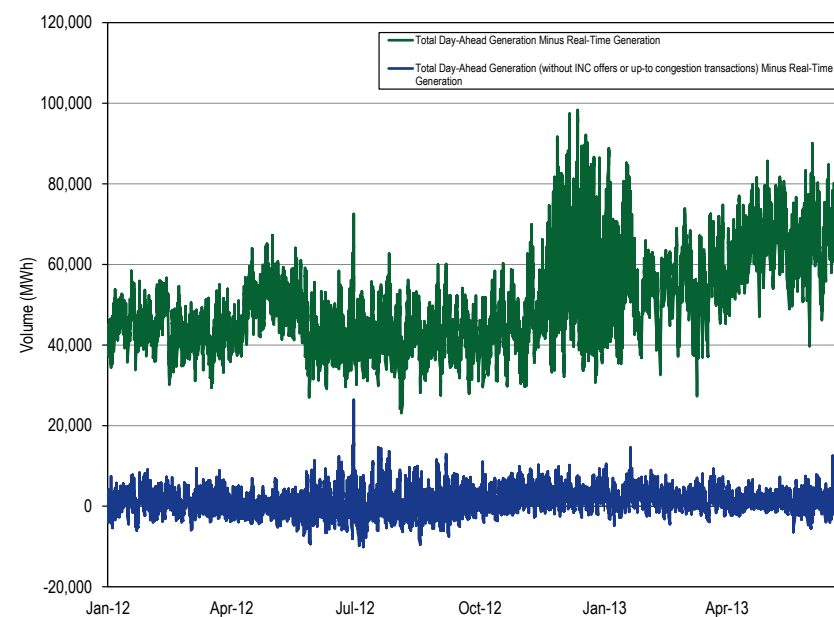
Figure 2-16 shows the difference between the PJM real-time generation and real-time load by zone in the first six months of 2013. Table 2-35 shows the difference between the PJM real-time generation and real-time load by zone in the first six month of 2012 and 2013. Figure 2-16 is color coded on a scale on which red shades represent zones that have less generation than load and green shades represent zones that have more generation than load, with darker shades meaning greater amounts of net generation or load. For example, the Pepco Control Zone has less generation than load, while the PENELEC Control Zone has more generation than load.

Figure 2-16 Map of PJM real-time generation less real-time load by zone: January through June of 2013[43]
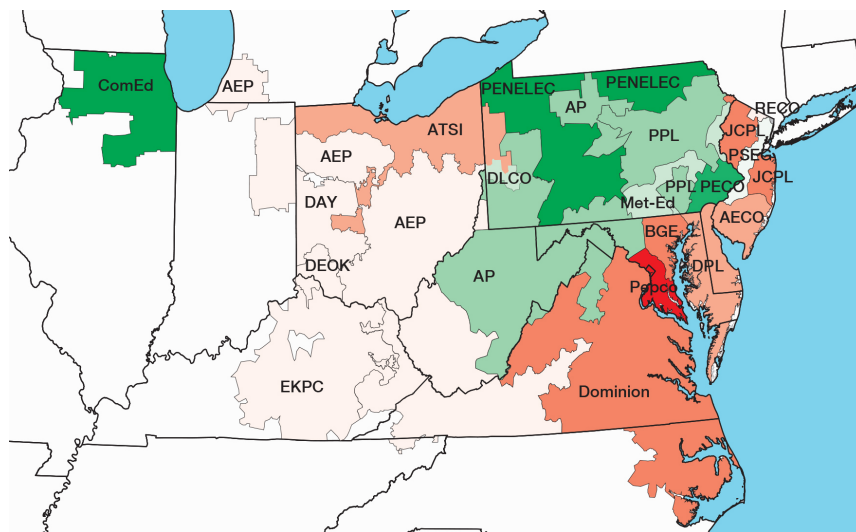
Table 2-35 PJM real-time generation less real-time load by zone (GWh): January through June of 2013

| Zone | Zonal Generation and Load (GWh) | | | | | |
| | 2012 (Jan–Jun) | | | 2013 (Jan–Jun) | | |
	Generation	Load	Net	Generation	Load	Net
AECO	772.9	4,894.2	(4,121.3)	942.9	4,891.5	(3,948.6)
AEP	69,132.5	64,987.9	4,144.6	64,822.7	65,047.3	(224.6)
AP	22,634.6	22,795.2	(160.7)	27,574.0	23,634.6	3,939.5
ATSI	30,007.5	32,793.0	(2,785.5)	27,317.5	32,901.2	(5,583.7)
BGE	9,423.7	15,724.3	(6,300.6)	9,983.0	15,769.2	(5,786.2)
ComEd	63,930.7	47,664.2	16,266.5	61,675.0	47,358.9	14,316.1
DAY	6,990.1	8,243.7	(1,253.5)	8,139.9	8,241.0	(101.1)
DEOK	8,583.1	12,897.2	(4,314.1)	12,073.2	13,053.9	(980.7)
DLCO	8,506.2	7,297.8	1,208.4	9,422.6	7,160.0	2,262.6
Dominion	37,264.8	43,856.3	(6,591.5)	39,002.8	46,175.4	(7,172.6)
DPL	4,043.0	8,655.7	(4,612.8)	3,449.6	9,057.2	(5,607.6)
EKPC	NA	NA	NA	839.1	964.3	(125.1)
JCPL	6,522.4	10,715.6	(4,193.2)	4,984.7	10,934.2	(5,949.5)
Met-Ed	10,141.8	7,297.0	2,844.8	9,783.6	7,433.1	2,350.5
PECO	30,907.7	18,981.6	11,926.1	29,863.6	19,485.6	10,378.0
PENELEC	18,039.9	8,457.8	9,582.1	21,796.9	8,653.7	13,143.3
Pepco	4,878.0	14,719.7	(9,841.8)	4,317.2	14,852.3	(10,535.1)
PPL	22,711.2	19,609.3	3,101.9	23,940.2	20,209.0	3,731.2
PSEG	22,424.5	20,655.4	1,769.1	22,141.5	20,843.6	1,297.9
RECO	0.0	714.7	(714.7)	0.0	726.2	(726.2)

Locational Marginal Price (LMP)

The conduct of individual market entities within a market structure is reflected in market prices.[44] PJM LMPs are a direct measure of market performance. Price level is a good, general indicator of market performance, although overall price results must be interpreted carefully because of the multiple factors that affect them. Among other things, overall average prices reflect changes in supply and demand, generation fuel mix, the cost of fuel, emission related expenses and local price differences caused by congestion. Real-Time and Day-Ahead Energy Market load-weighted prices were 21.6 percent and 20.1 percent higher in the first six months of 2013 than in the first six months of 2012 as a result of higher fuel costs and higher demand.[45] Natural gas prices

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43 Zonal real-time generation data for the map and corresponding table is based on the zonal designation for every bus listed in the most current PJM LMP bus model, which can be found at <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20130601-lmp-bus-model.ashx>.

44 See the *2012 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.

45 There was an average increase of 3.8 heating degree days and an average reduction of 0.4 cooling degree days in the first six months of 2013 compared to the first six months of 2012 which meant overall increased demand.

were higher, particularly in eastern zones, while coal prices were constant or decreased. The fuel-cost-adjusted, load weighted LMP in the first six months of 2013 shows that the mix of fuel types and fuel costs was the primary driver of higher prices than would have occurred if fuel prices had remained at the same levels as in the first six months of 2012.

PJM Real-Time Energy Market prices increased in the first six months of 2013 compared to the first six months of 2012. The system average LMP was 22.9 percent higher in the first six months of 2013 than in the first six months of 2012, $36.56 per MWh versus $29.74 per MWh. The load-weighted average LMP was 21.6 percent higher in the first six months of 2013 than in the first six months of 2012, $37.96 per MWh versus $31.21 per MWh.

PJM Day-Ahead Energy Market prices increased in the first six months of 2013 compared to the first six months of 2012. The system average LMP was 21.9 percent higher in the first six months of 2013 than in the first six months of 2012, $37.11 per MWh versus $30.44 per MWh. The load-weighted average LMP was 20.1 percent higher in the first six months of 2013 than in the first six months of 2012, $38.23 per MWh versus $31.84 per MWh.[46]

Real-Time LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[47]

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 2-17 shows the hourly distribution of PJM real-time average LMP for the first six months of 2012 and 2013.

Figure 2-17 Average LMP for the PJM Real-Time Energy Market: January through June of 2012 and 2013
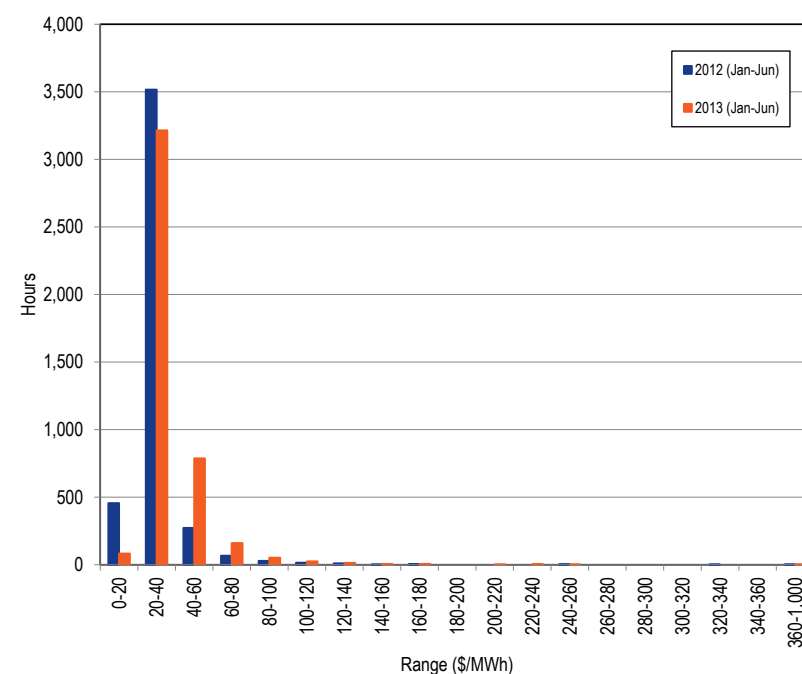
PJM Real-Time, Average LMP

Table 2-36 shows the PJM real-time, average LMP for the first six months of each year of the 16-year period 1998 to 2013.[48]

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46 Tables reporting zonal and jurisdictional load and prices are in the *2012 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

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

48 The system 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 2-36 PJM real-time, average LMP (Dollars per MWh): January through June of 1998 through 2013

(Jan–Jun)	Real-Time LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$20.13	$15.90	$15.59	NA	NA	NA
1999	$22.94	$17.84	$41.16	14.0%	12.2%	164.0%
2000	$25.38	$18.03	$25.65	10.6%	1.1%	(37.7%)
2001	$33.10	$25.69	$21.11	30.4%	42.5%	(17.7%)
2002	$24.10	$19.64	$13.21	(27.2%)	(23.6%)	(37.4%)
2003	$41.31	$33.74	$27.81	71.4%	71.8%	110.6%
2004	$44.99	$40.75	$22.97	8.9%	20.8%	(17.4%)
2005	$45.71	$39.80	$23.51	1.6%	(2.3%)	2.3%
2006	$49.36	$43.46	$25.26	8.0%	9.2%	7.5%
2007	$55.03	$48.05	$31.42	11.5%	10.6%	24.4%
2008	$70.19	$59.53	$41.77	27.6%	23.9%	33.0%
2009	$40.12	$35.42	$19.30	(42.8%)	(40.5%)	(53.8%)
2010	$43.27	$37.11	$22.20	7.9%	4.8%	15.0%
2011	$45.51	$37.40	$32.52	5.2%	0.8%	46.5%
2012	$29.74	$28.32	$16.10	(34.6%)	(24.3%)	(50.5%)
2013	$36.56	$32.79	$17.18	22.9%	15.8%	6.7%

Table 2-37 PJM real-time, load-weighted, average LMP (Dollars per MWh): January through June of 1998 through 2013

(Jan–Jun)	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.66	$16.80	$18.39	NA	NA	NA
1999	$25.34	$18.59	$52.06	17.0%	10.7%	183.1%
2000	$27.76	$18.91	$29.69	9.5%	1.7%	(43.0%)
2001	$35.27	$27.88	$22.12	27.0%	47.4%	(25.5%)
2002	$25.93	$20.67	$14.62	(26.5%)	(25.9%)	(33.9%)
2003	$44.43	$37.98	$28.55	71.4%	83.8%	95.2%
2004	$47.62	$43.96	$23.30	7.2%	15.8%	(18.4%)
2005	$48.67	$42.30	$24.81	2.2%	(3.8%)	6.5%
2006	$51.83	$45.79	$26.54	6.5%	8.3%	7.0%
2007	$58.32	$52.52	$32.39	12.5%	14.7%	22.1%
2008	$74.77	$64.26	$44.25	28.2%	22.4%	36.6%
2009	$42.48	$36.95	$20.61	(43.2%)	(42.5%)	(53.4%)
2010	$45.75	$38.78	$23.60	7.7%	5.0%	14.5%
2011	$48.47	$38.63	$37.59	5.9%	(0.4%)	59.3%
2012	$31.21	$28.98	$17.69	(35.6%)	(25.0%)	(52.9%)
2013	$37.96	$33.58	$18.54	21.6%	15.9%	4.8%

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 2-37 shows the PJM real-time, load-weighted, average LMP for the first six months of each year of the 16-year period 1998 to 2013.

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

Figure 2-18 shows the PJM real-time, monthly, load-weighted LMP from 2008 through the first six months of 2013.

Figure 2-18 PJM real-time, monthly, load-weighted, average LMP: January 2008 through June of 2013
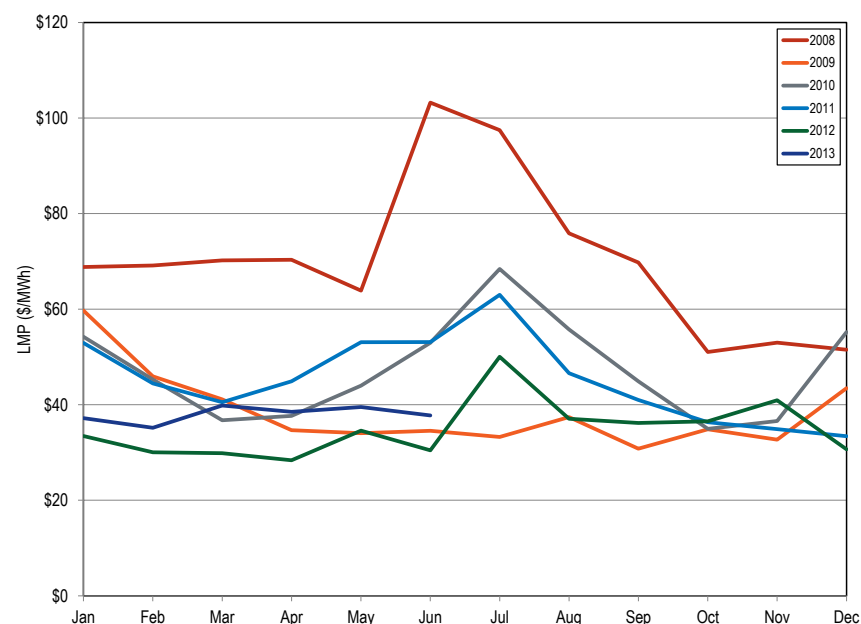
Fuel Price Trends and LMP

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. Natural gas, especially in the eastern part of PJM increased in price in the first six months of 2013. Comparing prices in the first six months of 2013 to prices in the first six months of 2012, the price of Northern Appalachian coal was 4.2 percent lower; the price of Central Appalachian coal was 3.8 percent higher; the price of Powder River Basin coal was 20.3 percent higher; the price of eastern natural gas was 73.4

percent higher; and the price of western natural gas was 57.3 percent higher. Figure 2-19 shows monthly average spot fuel prices for 2012 and the first six months of 2013.[49] Natural gas prices were above coal prices in the first six months of 2013, with prices above $10/MMBtu for some days. Coal prices increased during the first six months of 2013 but remained relatively flat in comparison to 2012.

Figure 2-19 Spot average fuel price comparison with fuel delivery charges: 2012 and January through June 2013 ($/MMBtu)
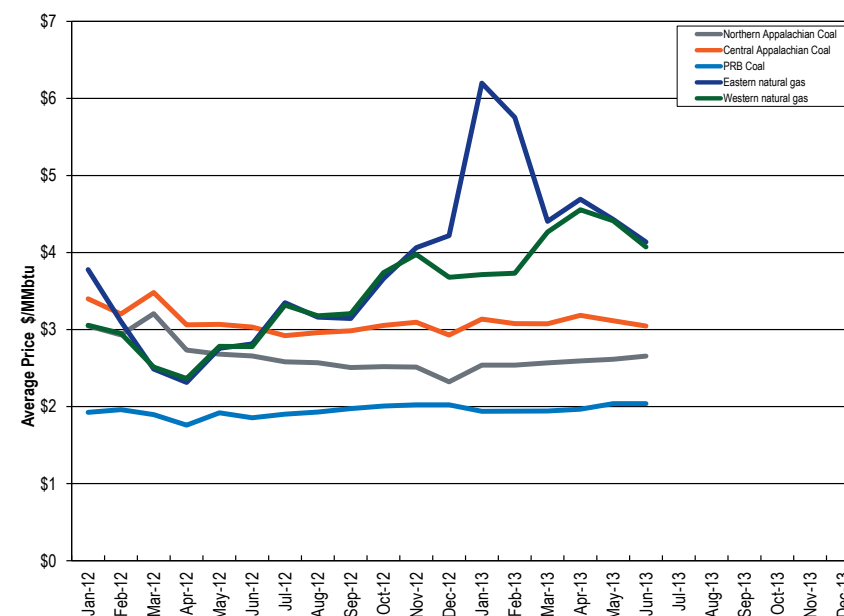
Figure 2-20 shows the average cost of generation, comparing the cost of energy generated by a coal plant, a combined cycle, and a combustion turbine in dollars per MWh. The cost of energy from a new entrant combined cycle was above the cost of energy from a new entrant coal plant for the first six months of 2013. The average spot fuel cost per MWh of a new entrant

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

combined cycle unit was $36.63/MWh, higher than the spot fuel cost per MWh of a new entrant coal plant, $27.20/MWh, in the first six months of 2013.

In the market, new combined cycles are competing with older coal plants. Most coal plants in PJM are 20 years or older, with heat rates greater than a new coal plant. Using average heat rates for existing sub-critical coal units, as well as delivery adders and variable operations and maintenance adders, the average cost of a sub-critical coal unit in PJM in the first six months of 2013 was $31.45, compared to $36.63 for a new entrant combined cycle in the eastern zones. In June, due to lower natural gas prices and slightly higher coal prices, the cost of a new entrant combined cycle unit was $30.99, or below that of a sub-critical coal unit in PJM, at $32.21.

Figure 2–20 Average spot fuel cost of generation of CP, CT, CC, and PJM average heat rate sub-critical coal plant: 2012 and January through June 2013 ($/MWh)
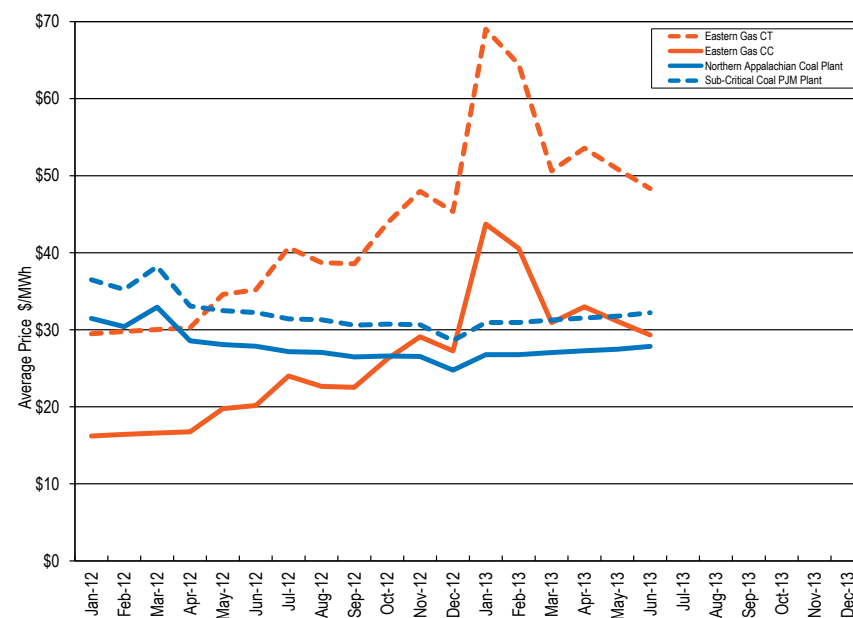
Table 2-38 compares the first six months of 2013 PJM real-time fuel cost adjusted, load weighted, average LMP to the first six months of 2012 load-weighted, average LMP. The fuel cost adjusted, load weighted, average LMP for the first six months of 2013 was 13.9 percent lower than the load weighted, average LMP for the first six months of 2013. The real-time, fuel cost adjusted, load weighted, average LMP for the first six months of 2013 was 4.8 percent higher than the load weighted LMP for the first six months of 2012. If fuel costs in 2013 had been the same as in 2012, holding everything else constant, the 2013 load weighted LMP would have been lower, $32.70 per MWh instead of the observed $37.96 per MWh. The mix of fuel types and fuel costs in 2013 were the primary driver of higher prices in 2013.

Table 2–38 PJM real-time annual, fuel-cost-adjusted, load-weighted average LMP (Dollars per MWh): Year-over-year method

	2013 Load-Weighted LMP	2013 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$37.96	$32.70	(13.9%)
	2012 Load-Weighted LMP	2013 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$31.21	$32.70	4.8%
	2012 Load-Weighted LMP	2013 Load-Weighted LMP	Change
Average	$31.21	$37.96	21.6%

Components of Real-Time, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, economic (least-cost) dispatch (SCED) in which marginal units determine system LMPs, based on their offers and five-minute-ahead forecast of the system conditions. Those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder and the 10 percent cost adder. As a result, it is possible to decompose PJM system's load-weighted LMP using the components of unit offers and sensitivity factors.

The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal. Cost offers of marginal units are broken into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs were calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, fuel-specific emission rates for NO_x and unit-specific emission rates for SO_2.

The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland and New Jersey.[50]

Prior to the implementation of scarcity pricing on October 1, 2012, LMPs calculated based on SCED were modified ex-post (five minutes) to account for realized system conditions. This is sometimes referred to as an ex-post LMP calculation. The extent to which the ex-post LMP in a five-minute interval deviated from the LMP calculated by SCED (ex-ante LMP) reflected the change in system conditions between the time when the dispatch was solved, and the end of the five-minute interval. The contribution of this deviation to real-time LMPs is shown as the LPA-SCED differential. Starting with the October 1, 2012, implementation of scarcity pricing, PJM eliminated ex-post pricing and relies entirely on ex-ante pricing. After October 1, 2012, real-time LMPs are based solely on the interval's most recent SCED solution.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes energy and ancillary services. In periods when generators providing energy have to dispatched down from their economic operating level to meet reserve requirements, the cooptimization of energy and reserves takes into account the lost opportunity cost of the lowered generation and the associated incremental cost to maintain reserves. The cost of dispatching energy resources down to provide reserves are Ancillary Service Redispatch Cost.

The components of LMP are shown in Table 2-39, including markup using unadjusted cost offers.[51] (Numbers in parentheses in the table are negative.) Table 2-39 shows that for the first six months of 2013, 49.6 percent of the load-weighted LMP was the result of coal costs, 31.9 percent was the result of gas costs and 0.55 percent was the result of the cost of emission allowances. Markup was -$2.09 per MWh. In the first six months of 2012, 61.9 percent of the load-weighted LMP was the result of coal costs, 21.9 percent was the result of gas costs and 0.63 percent was the result of the cost of emission allowances. Markup was -$2.37. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP rather than all of the components of the offers of units burning that fuel.

Table 2-39 Components of PJM real-time (Unadjusted), annual, load-weighted, average LMP: January through June 2013 and 2012

Element	2012 (Jan – Jun) Contribution to LMP	Percent	2013 (Jan – Jun) Contribution to LMP	Percent
Coal	$19.32	61.9%	$18.81	49.6%
Gas	$6.82	21.9%	$12.11	31.9%
Ten Percent Adder	$0.00	0.0%	$3.75	9.9%
VOM	$2.37	7.6%	$2.30	6.1%
Oil	$0.95	3.0%	$0.86	2.3%
NA	$0.73	2.3%	$0.79	2.1%
LPA Rounding Difference	$0.00	0.0%	$0.67	1.8%
FMU Adder	$0.08	0.3%	$0.62	1.6%
Ancillary Service Redispatch cost	$0.00	0.0%	$0.26	0.7%
Increase Generation Adder	($0.00)	(0.0%)	$0.13	0.3%
CO_2 Cost	$0.08	0.2%	$0.10	0.3%
NO_X Cost	$0.10	0.3%	$0.09	0.2%
SO_2 Cost	$0.02	0.1%	$0.01	0.0%
Market-to-Market Adder	$0.03	0.1%	$0.00	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%
Other	$0.01	0.0%	$0.00	0.0%
Wind	($0.08)	(0.3%)	($0.00)	(0.0%)
Decrease Generation Adder	($0.25)	(0.8%)	($0.11)	(0.3%)
LPA-SCED Differential	$0.01	0.0%	($0.35)	(0.9%)
Markup	($2.37)	(7.6%)	($2.09)	(5.5%)
Total	$31.21	100.0%	$37.96	100.0%

All generating units, including coal units, are allowed to include a ten percent adder in their cost offer. The 10 percent adder was included in the definition of cost offers prior to the implementation of PJM markets in 1999, based on the uncertainty of calculating the hourly operating costs of CTs under changing ambient conditions.

In order to accurately assess the markup behavior of market participants, real-time and day-ahead LMPs are decomposed using two different approaches. In the first approach (Table 2-39 and Table 2-43), markup is simply the difference between the price offer and the cost offer. In the second approach (Table 2-40 and Table 2-44), the 10 percent markup is removed from the cost

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50 New Jersey withdrew from RGGI, effective January 1, 2012.
51 These components are explained in the *Technical Reference for PJM Markets*, Section 7 "Calculation and Use of Generator Sensitivity/Unit Participation Factors."

offers of coal units. Coal units do not face the same cost uncertainty as gas-fired CTs. Actual participant behavior supports this view, as the owners of coal units, facing competition, typically remove the 10 percent adder from their actual offers. The adjusted markup is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder. The unadjusted markup is calculated as the difference between the price offer and the cost offer including the 10 percent adder in the cost offer.

The components of LMP are shown in Table 2-40, including markup using adjusted cost offers.

Table 2-40 Components of PJM real-time (Adjusted), annual, load-weighted, average LMP: January through June 2013 and 2012

Element	2012 (Jan–Jun) Contribution to LMP	Percent	2013 (Jan–Jun) Contribution to LMP	Percent
Coal	$19.50	62.5%	$19.08	50.3%
Gas	$6.82	21.9%	$12.12	31.9%
VOM	$2.39	7.6%	$2.33	6.1%
Ten Percent Adder	$0.00	0.0%	$2.06	5.4%
Oil	$0.95	3.0%	$0.86	2.3%
NA	$0.73	2.3%	$0.79	2.1%
LPA Rounding Difference	$0.00	0.0%	$0.67	1.8%
FMU Adder	$0.08	0.3%	$0.51	1.3%
Ancillary Service Redispatch cost	$0.00	0.0%	$0.26	0.7%
Increase Generation Adder	($0.00)	(0.0%)	$0.13	0.3%
CO_2 Cost	$0.08	0.2%	$0.10	0.3%
NO_x Cost	$0.10	0.3%	$0.09	0.2%
SO_2 Cost	$0.02	0.1%	$0.01	0.0%
Market-to-Market Adder	$0.03	0.1%	$0.00	0.0%
Uranium	$0.00	0.0%	$0.00	0.0%
Other	$0.01	0.0%	$0.00	0.0%
Wind	($0.08)	(0.3%)	($0.00)	(0.0%)
Decrease Generation Adder	($0.25)	(0.8%)	($0.11)	(0.3%)
LPA-SCED Differential	$0.01	0.0%	($0.42)	(1.1%)
Markup	($0.49)	(1.6%)	($0.53)	(1.4%)
Total	$31.21	100.0%	$37.96	100.0%

Day-Ahead LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[52]

Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 2-21 shows the hourly distribution of PJM day-ahead average LMP for the first six months of 2012 and 2013.

Figure 2-21 Average LMP for the PJM Day-Ahead Energy Market: January through June of 2012 and 2013

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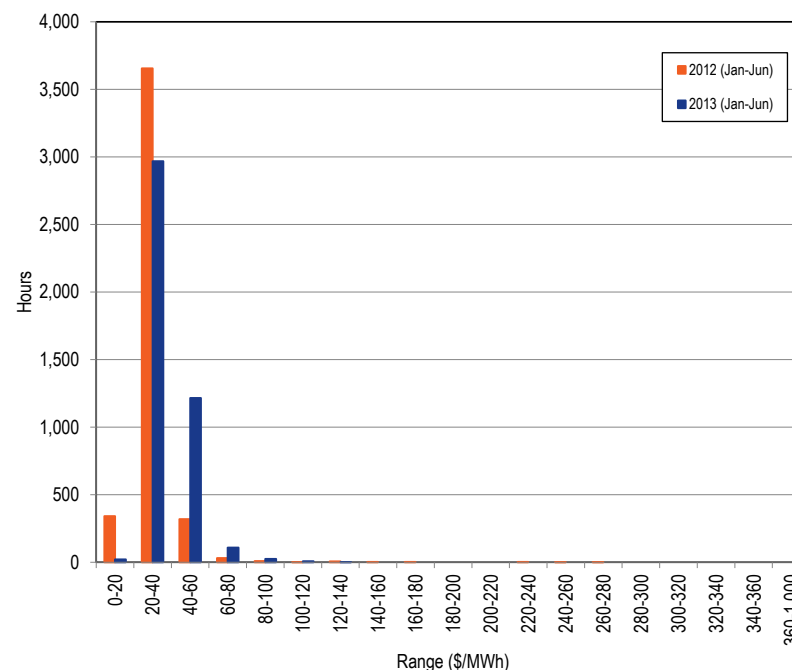
52 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for a detailed definition of Day-Ahead LMP.

PJM Day-Ahead, Average LMP

Table 2-41 shows the PJM day-ahead, average LMP for the first six months of each year of the 13-year period 2001 to 2013.

Table 2-41 PJM day-ahead, average LMP (Dollars per MWh): January through June of 2001 through 2013

	Day-Ahead LMP			Year-to-Year Change		
(Jan–Jun)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$35.02	$31.34	$17.43	NA	NA	NA
2002	$24.76	$21.28	$12.49	(29.3%)	(32.1%)	(28.4%)
2003	$42.83	$39.18	$23.52	73.0%	84.1%	88.3%
2004	$44.02	$43.14	$18.33	2.8%	10.1%	(22.0%)
2005	$45.63	$42.51	$18.35	3.7%	(1.5%)	0.1%
2006	$48.33	$47.07	$16.02	5.9%	10.7%	(12.7%)
2007	$53.03	$51.08	$22.91	9.7%	8.5%	43.0%
2008	$70.12	$66.09	$31.98	32.2%	29.4%	39.6%
2009	$40.01	$37.46	$15.38	(42.9%)	(43.3%)	(51.9%)
2010	$43.81	$40.64	$15.66	9.5%	8.5%	1.8%
2011	$44.75	$40.85	$19.53	2.1%	0.5%	24.8%
2012	$30.44	$29.64	$11.77	(32.0%)	(27.4%)	(39.8%)
2013	$37.11	$35.19	$10.42	21.9%	18.7%	(11.4%)

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 2-42 shows the PJM day-ahead, load-weighted, average LMP for the first six months of each year of the 13-year period 2001 to 2013.

Table 2-42 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through June of 2001 through 2013

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan–Jun)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$37.08	$33.91	$18.11	NA	NA	NA
2002	$26.88	$23.00	$14.36	(27.5%)	(32.2%)	(20.7%)
2003	$45.62	$42.01	$23.96	69.8%	82.6%	66.8%
2004	$46.12	$45.45	$18.62	1.1%	8.2%	(22.3%)
2005	$48.12	$44.88	$19.24	4.3%	(1.3%)	3.3%
2006	$50.21	$48.67	$16.23	4.3%	8.5%	(15.7%)
2007	$55.70	$54.26	$23.47	10.9%	11.5%	44.7%
2008	$73.71	$69.33	$33.95	32.3%	27.8%	44.7%
2009	$42.21	$38.83	$16.16	(42.7%)	(44.0%)	(52.4%)
2010	$46.12	$42.50	$16.54	9.3%	9.5%	2.3%
2011	$47.12	$42.58	$22.34	2.2%	0.2%	35.1%
2012	$31.84	$30.35	$13.94	(32.4%)	(28.7%)	(37.6%)
2013	$38.23	$36.19	$11.03	20.1%	19.3%	(20.8%)

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

Figure 2-22 shows the PJM day-ahead, monthly, load-weighted LMP from 2008 through the first six months of 2013.

Figure 2-22 Day-ahead, monthly, load-weighted, average LMP: January 2008 through June of 2013
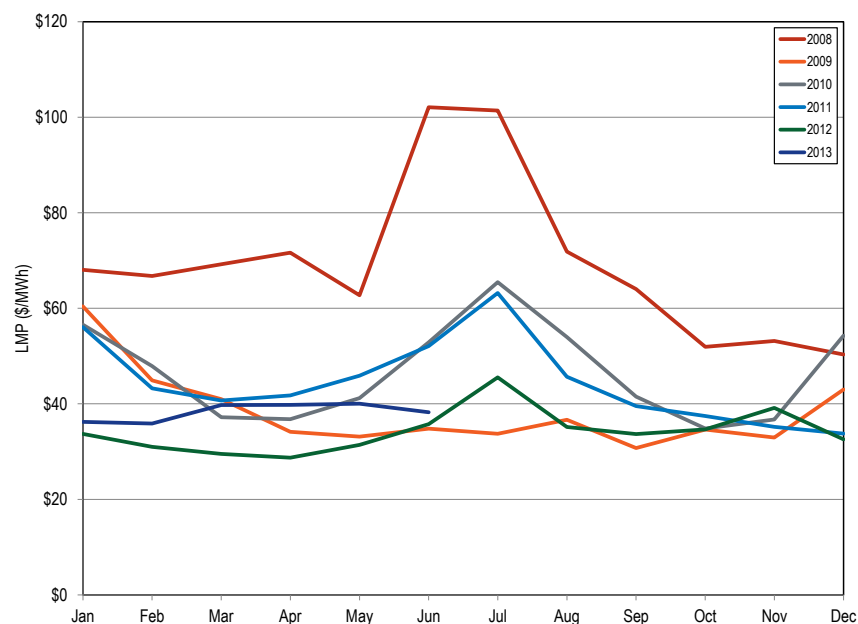
Components of Day-Ahead, Load-Weighted LMP

LMPs result from the operation of a market based on security-constrained, least-cost dispatch in which marginal resources determine system LMPs, based on their offers. For physical units, those offers can be decomposed into fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder, Day-Ahead Scheduling Reserve (DASR) adder and the 10 percent cost offer adder. INC offers, DEC bids and up-to congestion transactions are dispatchable injections and withdrawals in the Day-Ahead market. To the extent that INCs, DECs or up-to congestion transactions are the marginal resource, they either directly or indirectly set price via their offers and bids. Such financial offers cannot be decomposed. Using identified marginal resource offers and the components of unit offers, it is possible to decompose PJM system LMP using the components of unit offers and sensitivity factors.

The FMU adder is the calculated contribution of the FMU and AU adders to LMP that results when units with FMU or AU adders are marginal. Day-Ahead Scheduling Reserve (DASR) lost opportunity cost (LOC) and DASR offer adders are the calculated contribution to LMP when redispatch of resources is needed in order to satisfy DASR requirements. Cost offers of marginal units are broken into their component parts. The fuel related component is based on unit specific heat rates and spot fuel prices. Emission costs are calculated using spot prices for NO_x, SO_2 and CO_2 emission credits, fuel-specific emission rates for NO_x and unit-specific emission rates for SO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware, Maryland and New Jersey.[53]

The components of day ahead LMP are shown in Table 2-43, including markup using unadjusted cost offers. Table 2-43 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In the first six months of 2013, 48.7 percent of the load-weighted LMP was the result of up-to congestion transactions, 22.7 percent was the result of the cost of coal and 11.0 percent was the result of the cost of gas. In the first six month of 2012, 5.4 percent of the load-weighted LMP was the result of up-to congestion transactions, 42.8 percent was the result of the cost of coal and 12.2 percent was the result of the cost of gas.

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

Table 2-43 Components of PJM day-ahead, (unadjusted) annual, load-weighted, average LMP (Dollars per MWh): January through June 2012 and 2013[54]

	2012 (Jan - Jun)		2013 (Jan - Jun)	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$13.63	42.8%	$8.69	22.7%
DEC	$6.93	21.8%	$3.20	8.4%
Gas	$3.89	12.2%	$4.19	11.0%
INC	$2.99	9.4%	$1.94	5.1%
10% Cost Adder	$1.93	6.1%	$1.39	3.6%
Up-to Congestion Transaction	$1.72	5.4%	$18.61	48.7%
VOM	$1.47	4.6%	$0.95	2.5%
Price Sensitive Demand	$0.53	1.7%	$0.10	0.2%
Dispatchable Transaction	$0.43	1.3%	$0.25	0.6%
DASR LOC Adder	$0.23	0.7%	$0.00	0.0%
Oil	$0.22	0.7%	$0.01	0.0%
DASR Offer Adder	$0.10	0.3%	$0.00	0.0%
NO$_x$	$0.06	0.2%	$0.04	0.1%
CO$_2$	$0.05	0.2%	$0.04	0.1%
SO$_2$	$0.01	0.0%	$0.01	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%
Diesel	$0.00	0.0%	$0.00	0.0%
Wind	$0.00	0.0%	($0.00)	(0.0%)
Markup	($2.36)	(7.4%)	($1.47)	(3.8%)
FMU Adder	$0.00	0.0%	$0.07	0.2%
NA	$0.00	0.0%	$0.23	0.6%
Total	$31.84	100.0%	$38.23	100.0%

Table 2-44 Components of PJM day-ahead, (adjusted) annual, load-weighted, average LMP (Dollars per MWh): January through June 2012 and 2013

	2012 (Jan - Jun)		2013 (Jan - Jun)	
Element	Contribution to LMP	Percent	Contribution to LMP	Percent
Coal	$13.63	42.8%	$8.69	22.7%
DEC	$6.93	21.8%	$3.20	8.4%
Gas	$3.89	12.2%	$4.19	11.0%
INC	$2.99	9.4%	$1.94	5.1%
Up-to Congestion Transaction	$1.72	5.4%	$18.61	48.7%
VOM	$1.47	4.6%	$0.95	2.5%
10% Cost Adder	$0.85	2.7%	$0.92	2.4%
Price Sensitive Demand	$0.53	1.7%	$0.10	0.2%
Dispatchable Transaction	$0.43	1.3%	$0.25	0.6%
DASR LOC Adder	$0.23	0.7%	$0.00	0.0%
Oil	$0.22	0.7%	$0.01	0.0%
DASR Offer Adder	$0.10	0.3%	$0.00	0.0%
NO$_x$	$0.06	0.2%	$0.04	0.1%
CO$_2$	$0.05	0.2%	$0.04	0.1%
SO$_2$	$0.01	0.0%	$0.01	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%
Diesel	$0.00	0.0%	$0.00	0.0%
Wind	$0.00	0.0%	($0.00)	(0.0%)
Markup	($1.28)	(4.0%)	($1.00)	(2.6%)
FMU Adder	$0.00	0.0%	$0.07	0.2%
NA	$0.00	0.0%	$0.23	0.6%
Total	$31.84	100.0%	$38.23	100.0%

Table 2-44 shows the components of the PJM day ahead, annual, load-weighted average LMP.

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 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 and decrement bids may be submitted at any hub, transmission zone, aggregate, or single bus for which LMP is calculated.

Figure 2-23 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve without increment offers

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54 The NA in 2013 is $0.43. It is caused by bad savecase input files for March 5, 2013.

and the system aggregate supply curve with increment offers for an example day in March 2013.

Figure 2–23 PJM day–ahead aggregate supply curves: 2013 example day
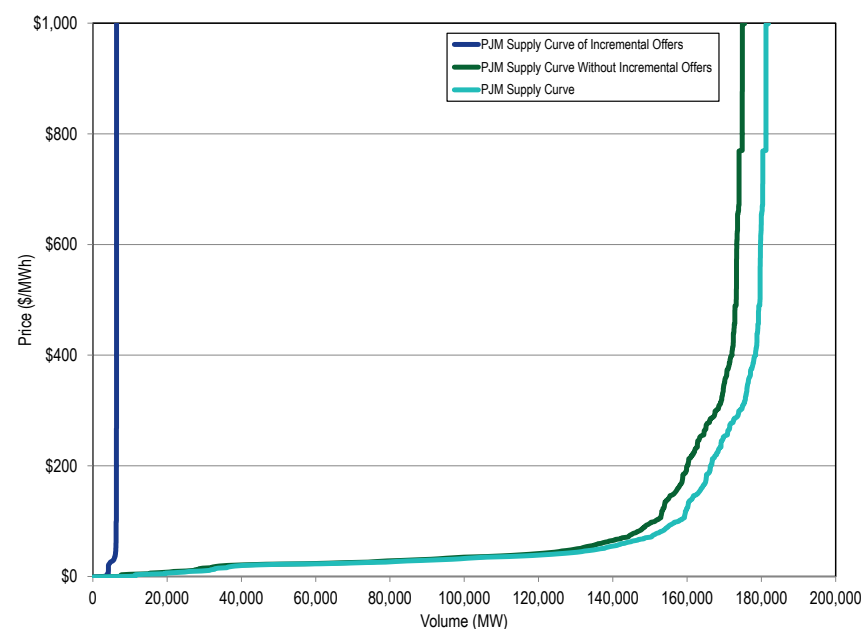
Table 2-45 shows the average volume of trading in increment offers and decrement bids per hour and the average total MW values of all bids per hour for 2012 through the first six months of 2013. Table 2-46 shows the average volume of up-to congestion transactions per hour and the average total MW values of all bids per hour for 2012 through the first six months of 2013. In the first six months of 2013, the average submitted and cleared increment bid MW decreased 28.2 and 12.8 percent, and the average submitted and cleared decrement bid MW decreased 21.6 and 11.4 percent, compared to the first six months of 2012. In the first six months of 2013, the average up-to congestion submitted MW increased 66.3 percent and cleared MW increased 36.6 percent, compared to the first six months of 2012. The increase in up-to congestion transactions displaced increment and decrement transactions.

Table 2–45 Hourly average volume of cleared and submitted INCs, DECs by month: January 2012 through June of 2013

Year		Increment Offers				Decrement Bids			
		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2012	Jan	6,781	10,341	91	455	9,031	12,562	111	428
2012	Feb	6,428	10,930	96	591	7,641	11,043	108	511
2012	Mar	5,969	9,051	90	347	7,193	10,654	112	362
2012	Apr	6,355	9,368	87	298	7,812	10,811	105	329
2012	May	6,224	8,447	80	271	8,785	11,141	109	316
2012	Jun	6,415	8,360	79	234	9,030	11,124	97	270
2012	Jul	6,485	8,270	81	285	8,981	11,121	112	349
2012	Aug	5,809	7,873	74	291	8,471	10,507	100	320
2012	Sep	5,274	7,509	78	313	8,192	10,814	109	381
2012	Oct	5,231	6,953	82	275	8,901	11,526	110	361
2012	Nov	5,423	6,944	67	190	8,678	11,758	102	289
2012	Dec	5,622	7,090	69	183	8,456	10,007	84	207
2012	Annual	6,001	8,428	81	311	8,431	11,089	105	343
2013	Jan	5,682	7,271	80	195	7,944	9,653	81	211
2013	Feb	5,949	7,246	61	130	7,689	8,942	75	165
2013	Mar	5,414	6,192	50	94	6,890	7,907	65	140
2013	Apr	5,329	6,179	56	108	6,597	7,732	63	145
2013	May	5,415	6,651	57	130	7,036	8,803	74	185
2013	Jun	5,489	7,031	64	187	7,671	9,768	88	258
2013	Annual	5,546	6,762	61	141	7,304	8,801	74	184

Table 2-46 Hourly average of cleared and submitted up-to congestion bids by month: January 2012 through June 2013[55]

Year		Up-to Congestion			
		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2012	Jan	37,469	102,762	805	1,950
2012	Feb	37,132	106,741	830	2,115
2012	Mar	35,921	105,222	865	2,224
2012	Apr	43,777	120,955	1,013	2,519
2012	May	43,468	119,374	1,052	2,541
2012	Jun	35,052	101,065	915	2,193
2012	Jul	35,179	118,294	981	2,710
2012	Aug	35,515	122,458	986	2,787
2012	Sep	35,199	112,731	946	2,801
2012	Oct	35,365	106,819	990	2,692
2012	Nov	40,499	143,853	1,329	3,934
2012	Dec	45,536	176,660	1,681	5,145
2012	Annual	38,343	119,744	1,033	2,801
2013	Jan	44,844	157,229	883	4,205
2013	Feb	46,351	144,066	893	3,862
2013	Mar	48,937	162,958	853	3,740
2013	Apr	57,938	193,366	1,683	4,229
2013	May	59,700	203,521	1,679	4,754
2013	Jun	60,210	229,912	1,984	5,997
2013	Annual	52,997	181,842	1,329	4,464

Table 2-47 shows the frequency with which generation offers, import or export transactions, up-to congestion transactions, decrement bids, increment offers and price-sensitive demand are marginal for each month.

Table 2-47 Type of day-ahead marginal units: January through June 2013

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	3.0%	0.1%	93.5%	2.0%	1.4%	0.0%
Feb	2.5%	0.1%	94.6%	1.4%	1.3%	0.0%
Mar	1.6%	0.1%	97.3%	0.5%	0.5%	0.0%
Apr	1.3%	0.1%	97.6%	0.4%	0.6%	0.0%
May	1.4%	0.1%	97.3%	0.8%	0.4%	0.0%
Jun	1.1%	0.1%	97.1%	1.0%	0.7%	0.0%
Annual	1.6%	0.1%	96.6%	0.9%	0.7%	0.0%

Figure 2-24 shows the hourly volume of bid and cleared INC, DEC and up-to congestion bids by month.

Figure 2-24 Hourly volume of bid and cleared INC, DEC and Up-to Congestion bids (MW) by month: January, 2005 through June, 2013

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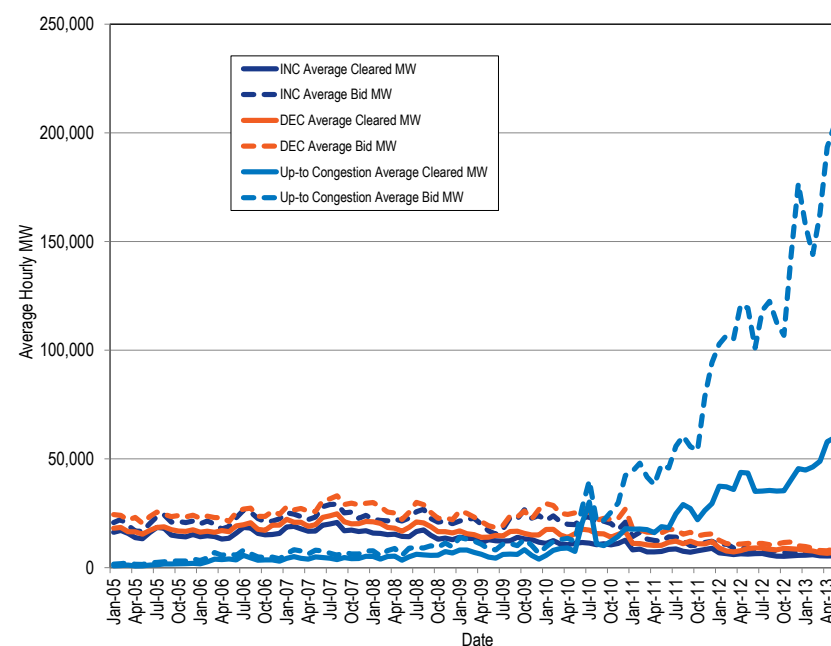
55 The version of this table in the *2013 State of the Market Report for PJM: January through March* reported only the internal up-to congestion transaction average submitted and cleared MW and volumes.

In order to evaluate the ownership of virtual bids, the MMU categorizes 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 2-48 shows, for the first six months of 2012 and 2013, the total increment offers and decrement bids by whether the parent organization is financial or physical. Table 2-49 shows for the first six months of 2012 and 2013, the total up-to congestion transactions by the type of parent organization.

The top five companies with cleared up-to congestion transactions are financial and account for 63.6 percent of all the cleared up-to congestion MW in PJM in the first six months of 2013.

Table 2-48 PJM INC and DEC bids by type of parent organization (MW): January through June of 2012 and 2013

Category	2012 (Jan – Jun)		2013 (Jan – Jun)	
	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	32,867,334	36.5%	16,564,288	24.5%
Physical	57,236,478	63.5%	50,975,729	75.5%
Total	90,103,812	100.0%	67,540,016	100.0%

Table 2-49 PJM up-to congestion transactions by type of parent organization (MW): January through June of 2012 and 2013

Category	2012 (Jan – Jun)		2013 (Jan – Jun)	
	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	161,702,500	95.4%	218,167,286	94.7%
Physical	7,840,068	4.6%	12,237,587	5.3%
Total	169,542,568	100.0%	230,404,873	100.0%

Table 2-50 shows increment offers and decrement bids bid by top ten locations for the first six months of 2012 and 2013.

Table 2-50 PJM virtual offers and bids by top ten locations (MW): January through June of 2012 and 2013

| | 2012 (Jan – Jun) | | | | | 2013 (Jan – Jun) | | | |
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	15,133,898	17,235,411	32,369,309	WESTERN HUB	HUB	12,988,250	14,451,505	27,439,756
AEP-DAYTON HUB	HUB	2,603,459	2,869,771	5,473,230	SOUTHIMP	INTERFACE	4,150,495	0	4,150,495
N ILLINOIS HUB	HUB	1,592,205	3,188,417	4,780,622	N ILLINOIS HUB	HUB	1,304,118	2,474,710	3,778,828
SOUTHIMP	INTERFACE	4,741,666	0	4,741,666	AEP-DAYTON HUB	HUB	1,777,832	1,879,048	3,656,880
MISO	INTERFACE	119,274	3,279,711	3,398,985	IMO	INTERFACE	2,955,529	38,609	2,994,138
PPL	ZONE	199,616	2,797,721	2,997,337	PPL	ZONE	37,395	2,672,426	2,709,821
PECO	ZONE	749,347	2,187,144	2,936,491	PECO	ZONE	48,706	1,718,713	1,767,419
IMO	INTERFACE	1,764,739	16,306	1,781,045	MISO	INTERFACE	207,554	1,526,580	1,734,134
BGE	ZONE	113,332	983,511	1,096,843	DOMINION HUB	HUB	199,382	918,597	1,117,979
PSEG	ZONE	339,399	525,698	865,097	NYIS	INTERFACE	325,738	657,086	982,824
Top ten total		27,356,934	33,083,689	60,440,623			23,995,000	26,337,276	50,332,275
PJM total		41,074,165	49,029,647	90,103,812			29,332,449	38,207,567	67,540,016
Top ten total as percent of PJM total		66.6%	67.5%	67.1%			81.8%	68.9%	74.5%

Table 2-51 shows up-to congestion transactions by import bids for the top ten locations for the first six months of 2012 and 2013.[56]

Table 2-52 shows up-to congestion transactions by export bids for the top ten locations for the first six months of 2012 and 2013.

Table 2-51 PJM cleared up-to congestion import bids by top ten source and sink pairs (MW): January through June of 2012 and 2013

Source	Source Type	Sink	Sink Type	MW
2012 (Jan – Jun)				
Imports				
MISO	INTERFACE	112 WILTON	EHVAGG	7,245,551
OVEC	INTERFACE	DEOK	ZONE	1,583,967
OVEC	INTERFACE	CONESVILLE 4	AGGREGATE	1,560,571
OVEC	INTERFACE	COOK	EHVAGG	1,487,704
OVEC	INTERFACE	MARYSVILLE	EHVAGG	1,486,388
MISO	INTERFACE	N ILLINOIS HUB	HUB	1,448,387
OVEC	INTERFACE	JEFFERSON	EHVAGG	1,441,163
OVEC	INTERFACE	DUMONT	EHVAGG	1,200,575
OVEC	INTERFACE	CONESVILLE 6	AGGREGATE	1,170,669
NYIS	INTERFACE	HUDSON BC	AGGREGATE	1,049,825
Top ten total				19,674,798
PJM total				84,966,083
Top ten total as percent of PJM total				23.2%
2013 (Jan – Jun)				
Imports				
OVEC	INTERFACE	DEOK	ZONE	747,582
OVEC	INTERFACE	STUART 1	AGGREGATE	638,710
NYIS	INTERFACE	HUDSON BC	AGGREGATE	633,803
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	632,639
NORTHWEST	INTERFACE	ZION 1	AGGREGATE	457,848
OVEC	INTERFACE	BECKJORD 6	AGGREGATE	367,838
MISO	INTERFACE	112 WILTON	EHVAGG	355,225
OVEC	INTERFACE	CONESVILLE 5	AGGREGATE	338,322
OVEC	INTERFACE	SPORN 2	AGGREGATE	324,940
NORTHWEST	INTERFACE	BYRON 1	AGGREGATE	319,915
Top ten total				4,816,821
PJM total				23,795,591
Top ten total as percent of PJM total				20.2%

Table 2-52 PJM cleared up-to congestion export bids by top ten source and sink pairs (MW): January through June of 2012 and 2013

Source	Source Type	Sink	Sink Type	MW
2012 (Jan – Jun)				
Exports				
ROCKPORT	EHVAGG	OVEC	INTERFACE	2,693,217
23 COLLINS	EHVAGG	MISO	INTERFACE	2,252,902
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	2,052,448
STUART 1	AGGREGATE	OVEC	INTERFACE	1,436,886
QUAD CITIES 1	AGGREGATE	NORTHWEST	INTERFACE	1,292,085
SPORN 3	AGGREGATE	OVEC	INTERFACE	1,278,055
WESTERN HUB	HUB	MISO	INTERFACE	1,194,255
167 PLANO	EHVAGG	MISO	INTERFACE	1,113,337
ROCKPORT	EHVAGG	MISO	INTERFACE	1,113,054
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	886,940
Top ten total				15,313,180
PJM total				83,675,782
Top ten total as percent of PJM total				18.3%
2013 (Jan – Jun)				
Exports				
JEFFERSON	EHVAGG	OVEC	INTERFACE	1,034,857
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	801,391
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	766,120
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	645,742
GAVIN	EHVAGG	OVEC	INTERFACE	614,094
TANNERS CRK 4	AGGREGATE	OVEC	INTERFACE	571,260
SPORN 3	AGGREGATE	OVEC	INTERFACE	450,427
F387 CHICAGOH	AGGREGATE	NIPSCO	INTERFACE	446,903
21 KINCA ATR24304	AGGREGATE	OVEC	INTERFACE	410,609
EAST BEND 2	AGGREGATE	OVEC	INTERFACE	364,120
Top ten total				6,105,523
PJM total				28,782,300
Top ten total as percent of PJM total				21.2%

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

Table 2-53 shows up-to congestion transactions by wheel bids for the top ten locations for the first six months of 2012 and 2013.

Table 2-53 PJM cleared up-to congestion wheel bids by top ten source and sink pairs (MW): January through June of 2012 and 2013

Source	Source Type	Sink	Sink Type	MW
		2012 (Jan – Jun)		
		Wheels		
NYIS	INTERFACE	IMO	INTERFACE	143,538
MISO	INTERFACE	NORTHWEST	INTERFACE	106,417
MISO	INTERFACE	NIPSCO	INTERFACE	63,951
NORTHWEST	INTERFACE	MISO	INTERFACE	60,546
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	46,108
SOUTHWEST	INTERFACE	OVEC	INTERFACE	40,090
MISO	INTERFACE	OVEC	INTERFACE	39,842
OVEC	INTERFACE	NIPSCO	INTERFACE	32,268
NIPSCO	INTERFACE	IMO	INTERFACE	30,013
NIPSCO	INTERFACE	NORTHWEST	INTERFACE	20,306
Top ten total				583,079
PJM total				900,702
Top ten total as percent of PJM total				64.7%
		2013 (Jan – Jun)		
		Wheels		
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	559,697
NORTHWEST	INTERFACE	MISO	INTERFACE	267,006
IMO	INTERFACE	NYIS	INTERFACE	225,339
MISO	INTERFACE	NIPSCO	INTERFACE	224,005
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	192,900
MISO	INTERFACE	SOUTHEXP	INTERFACE	85,854
LINDENVFT	INTERFACE	NYIS	INTERFACE	77,442
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	73,043
OVEC	INTERFACE	IMO	INTERFACE	57,734
MISO	INTERFACE	OVEC	INTERFACE	56,278
Top ten total				1,819,298
PJM total				2,303,956
Top ten total as percent of PJM total				79.0%

On November 1, 2012, PJM eliminated the requirement for market participants to specify an interface pricing point as either the source or sink of an up-to congestion transaction.[57] Up-to congestion transactions can now be made at internal buses. The top ten internal up-to congestion transaction locations were 7.2 percent of the PJM total internal up-to congestion transactions in the first six months of 2013.

Table 2-54 shows up-to congestion transactions by internal bids for the top ten locations for the first six months of 2013.

Table 2-54 PJM cleared up-to congestion internal bids by top ten source and sink pairs (MW): January through June of 2013

Source	Source Type	Sink	Sink Type	MW
		2013 (Jan – Jun)		
		Internal		
SUNBURY 1-3	AGGREGATE	CITIZENS	AGGREGATE	2,406,576
ATSI GEN HUB	HUB	ATSI	ZONE	1,597,254
CORDOVA	AGGREGATE	QUAD CITIES 2	AGGREGATE	1,491,949
FE GEN	AGGREGATE	ATSI	ZONE	1,116,651
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	1,090,748
MT STORM	EHVAGG	GREENLAND GAP	EHVAGG	1,079,954
YADKIN	EHVAGG	FENTRESS	EHVAGG	1,022,931
AEP-DAYTON HUB	HUB	WESTERN HUB	HUB	962,854
NAPERVILLE	AGGREGATE	WINNETKA	AGGREGATE	954,143
NAPERVILLE	AGGREGATE	CHICAGO HUB	HUB	921,123
Top ten total				12,644,184
PJM total				175,523,026
Top ten total as percent of PJM total				7.2%

Table 2-55 shows the number of source-sink pairs that were offered and cleared monthly in 2012 and the first six months of 2013. The increase in average offered and cleared source-sink pairs in November and December of 2012 and the first six months of 2013 illustrates that PJM's modification of the rules governing the location of up-to congestion transactions bids resulted in a significant increase in the number of offered and cleared up-to congestion transactions. The increase in source-sink pairs available for up-to congestion transactions has also led to increased dispersion in cleared up-to congestion transaction internal bids by location.

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57 For more information, see the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," Up-to Congestion.

Table 2-55 Number of PJM offered and cleared source and sink pairs: January 2012 through June of 2013

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
2012	Jan	1,771	2,182	1,126	1,568
2012	Feb	1,816	2,198	1,156	1,414
2012	Mar	1,746	2,004	1,128	1,353
2012	Apr	1,753	2,274	1,117	1,507
2012	May	1,866	2,257	1,257	1,491
2012	Jun	2,145	2,581	1,425	1,897
2012	Jul	2,168	2,800	1,578	2,078
2012	Aug	2,541	3,043	1,824	2,280
2012	Sep	2,140	3,032	1,518	2,411
2012	Oct	2,344	3,888	1,569	2,625
2012	Nov	4,102	8,142	2,829	5,811
2012	Dec	9,424	13,009	5,025	8,071
2012	Jan-Oct	2,031	3,888	1,371	2,625
2012	Nov-Dec	6,806	13,009	3,945	8,071
2012	Annual	2,818	3,951	1,796	2,709
2013	Jan	6,580	10,548	3,291	5,060
2013	Feb	4,891	7,415	2,755	3,907
2013	Mar	4,858	7,446	2,868	4,262
2013	Apr	6,426	9,094	3,464	4,827
2013	May	5,729	7,914	3,350	4,495
2013	Jun	6,014	8,437	3,490	4,775
2013	Annual	5,750	8,476	3,203	4,554

Table 2-56 and Figure 2-25 show total cleared up-to congestion transactions by type for the first six months of 2012 and 2013. Internal up-to congestion transactions in the first six months of 2013 were 76.2 percent of all up-to congestion transactions for the first six months of 2013.

Table 2-56 PJM cleared up-to congestion transactions by type (MW): January through June of 2012 and 2013

	2012 (Jan – Jun)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	19,674,798	15,313,180	583,079	NA	23,252,298
PJM total (MW)	84,966,083	83,675,782	900,702	NA	169,542,568
Top ten total as percent of PJM total	23.2%	18.3%	64.7%	NA	13.7%
PJM total as percent of all up-to congestion transactions	50.1%	49.4%	0.5%	NA	100.0%
	2013 (Jan – Jun)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	4,816,821	6,105,523	1,819,298	12,644,184	12,757,918
PJM total (MW)	23,795,591	28,782,300	2,303,956	175,523,026	230,404,873
Top ten total as percent of PJM total	20.2%	21.2%	79.0%	7.2%	5.5%
PJM total as percent of all up-to congestion transactions	10.3%	12.5%	1.0%	76.2%	100.0%

Figure 2-25 shows the initial increase and continued rise of internal up-to congestion transactions in November and December of 2012 and the first six months of 2013, following the November 1, 2012, rule change permitting such transactions.

Figure 2-25 PJM cleared up-to congestion transactions by type (MW): January 2005 through June of 2013

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. There may be substantial, persistent differences between day-ahead and real-time prices even on a monthly basis (Figure 2-27).

Table 2-57 shows that the difference between average day-ahead and real-time prices was $.69 per MWh in the first six months of 2012 and $.55 per MWh in the first six months of 2013. The difference between average on-peak day-ahead and real-time prices was $.05 per MWh in the first six months of 2012 and $.01 per MWh in the first six months of 2013.

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

Table 2-57 Day-ahead and real-time average LMP (Dollars per MWh): January through June of 2012 and 2013[58]

	2012 (Jan – Jun)				2013 (Jan – Jun)			
	Day Ahead	Real Time	Difference	Difference as Percent of Real Time	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
Average	$30.44	$29.74	($0.69)	(2.3%)	$37.11	$36.56	($0.55)	(1.5%)
Median	$29.64	$28.32	($1.31)	(4.6%)	$35.19	$32.79	($2.40)	(7.3%)
Standard deviation	$11.77	$16.10	$4.33	26.9%	$10.42	$17.18	$6.76	39.3%
Peak average	$35.02	$35.07	$0.05	0.1%	$42.68	$42.67	($0.01)	(0.0%)
Peak median	$32.27	$30.85	($1.42)	(4.6%)	$40.62	$37.38	($3.25)	(8.7%)
Peak standard deviation	$14.17	$18.61	$4.44	23.9%	$10.86	$20.38	$9.53	46.7%
Off peak average	$26.38	$25.04	($1.35)	(5.4%)	$32.21	$31.19	($1.02)	(3.3%)
Off peak median	$26.14	$24.96	($1.18)	(4.7%)	$31.01	$29.29	($1.72)	(5.9%)
Off peak standard deviation	$6.96	$11.62	$4.66	40.1%	$7.01	$11.29	$4.29	38.0%

The price difference between the Real-Time and the Day-Ahead Energy Markets results, in part, from conditions in the Real-Time Energy Market that are difficult, or impossible, to anticipate in the Day-Ahead Energy Market.

Table 2-58 shows the difference between the Real-Time and the Day-Ahead Energy Market Prices for the first six months of each year of the 13-year period 2001 to 2013.

Table 2-58 Day-ahead and real-time average LMP (Dollars per MWh): January through June of 2001 through 2013

(Jan – Jun)	Day Ahead	Real Time	Difference	Difference as Percent of Real Time
2001	$35.02	$33.10	($1.92)	(5.5%)
2002	$24.76	$24.10	($0.66)	(2.7%)
2003	$42.83	$41.31	($1.53)	(3.6%)
2004	$44.02	$44.99	$0.97	2.2%
2005	$45.63	$45.71	$0.07	0.2%
2006	$48.33	$49.36	$1.03	2.1%
2007	$53.03	$55.03	$2.00	3.8%
2008	$70.12	$70.19	$0.08	0.1%
2009	$40.01	$40.12	$0.11	0.3%
2010	$43.81	$43.27	($0.54)	(1.2%)
2011	$44.75	$45.51	$0.76	1.7%
2012	$30.44	$29.74	($0.69)	(2.3%)
2013	$37.11	$36.56	($0.55)	(1.5%)

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

Table 2-59 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 six months of the years 2007 through 2013.

Table 2-59 Frequency distribution by hours of PJM real-time and day-ahead load-weighted hourly LMP difference (Dollars per MWh): January through June of 2007 through 2013

	2007		2008		2009		2010		2011		2012		2013	
LMP	Frequency	Cumulative Percent	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%	4	0.09%	0	0.00%
($150) to ($100)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%	4	0.18%	0	0.00%
($100) to ($50)	17	0.39%	62	1.42%	3	0.07%	6	0.14%	27	0.64%	8	0.37%	0	0.00%
($50) to $0	2,365	54.85%	2,578	60.45%	2,541	58.58%	2,890	66.68%	2,773	64.49%	2,940	67.69%	3,018	69.49%
$0 to $50	1,832	97.03%	1,505	94.92%	1,772	99.38%	1,366	98.13%	1,414	97.05%	1,377	99.22%	1,281	98.99%
$50 to $100	118	99.75%	195	99.38%	25	99.95%	69	99.72%	105	99.47%	25	99.79%	34	99.77%
$100 to $150	7	99.91%	23	99.91%	2	100.00%	5	99.84%	16	99.84%	5	99.91%	4	99.86%
$150 to $200	0	99.91%	2	99.95%	0	100.00%	7	100.00%	2	99.88%	2	99.95%	5	99.98%
$200 to $250	1	99.93%	1	99.98%	0	100.00%	0	100.00%	2	99.93%	0	99.95%	0	99.98%
$250 to $300	1	99.95%	0	99.98%	0	100.00%	0	100.00%	0	99.93%	1	99.98%	1	100.00%
$300 to $350	2	100.00%	1	100.00%	0	100.00%	0	100.00%	0	99.93%	1	100.00%	0	100.00%
$350 to $400	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.93%	0	100.00%	0	100.00%
$400 to $450	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.93%	0	100.00%	0	100.00%
$450 to $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.93%	0	100.00%	0	100.00%
>= $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%	0	100.00%

Figure 2-26 shows the hourly differences between day-ahead and real-time load-weighted hourly LMP in the first six months of 2013.

Figure 2-27 shows the monthly average differences between the day-ahead and real-time LMP in the first six months of 2013.

Figure 2-26 Real-time load-weighted hourly LMP minus day-ahead load-weighted hourly LMP: January through June of 2013

Figure 2-27 Monthly average of real-time minus day-ahead LMP: January through June of 2013
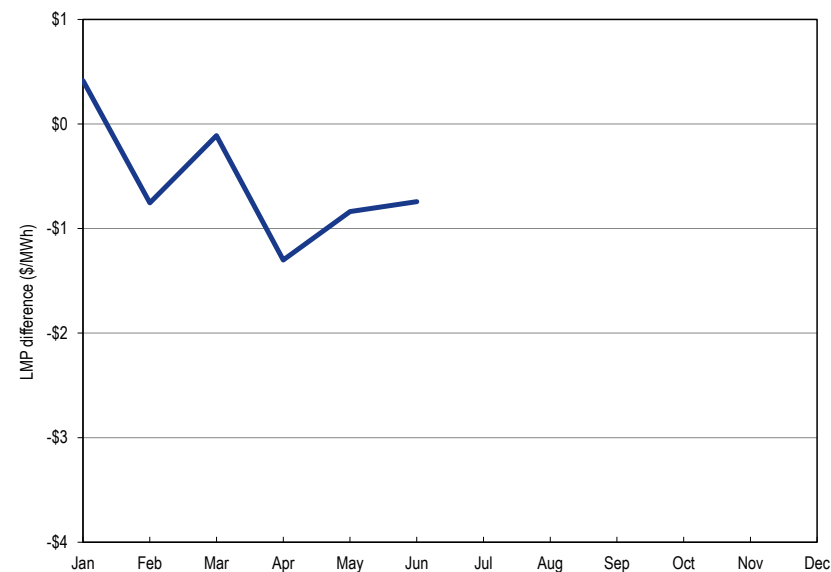
Figure 2-28 shows day-ahead and real-time LMP on an average hourly basis for the first six months of 2013.

Figure 2-28 PJM system hourly average LMP: January through June of 2013
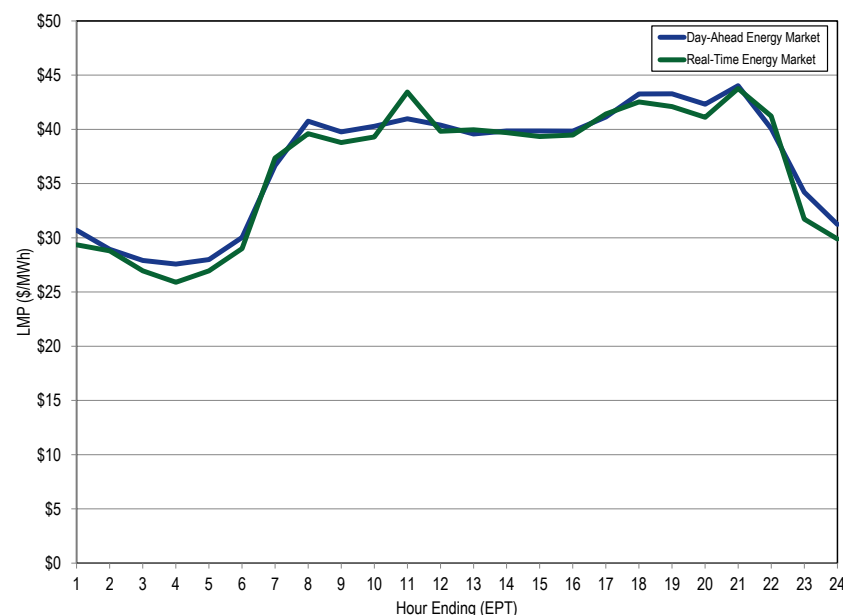
Load and Spot Market

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 generating less power from owned plants and/or purchasing less power under bilateral contracts than required 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 2-60 shows the monthly average share of real-time load served by self-supply, bilateral contracts and spot purchase in 2012 and 2013 based on parent company. For the first six months of 2013, 10.6 percent of real-time load was supplied by bilateral contracts, 23.8 percent by spot market purchase and 65.6 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased 1.6 percentage points, reliance on spot supply increased by 0.6 percentage points and reliance on self-supply decreased by 2.2 percentage points.

Table 2-60 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2012 through 2013

| | 2012 | | | 2013 | | | Difference in Percentage Points | | |
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	8.9%	22.0%	69.1%	10.4%	22.3%	67.3%	1.5%	0.2%	(1.8%)
Feb	8.8%	21.2%	70.0%	10.5%	22.0%	67.5%	1.7%	0.8%	(2.4%)
Mar	9.4%	23.6%	67.1%	10.4%	24.2%	65.4%	1.1%	0.6%	(1.6%)
Apr	9.4%	23.8%	66.8%	10.7%	24.2%	65.1%	1.3%	0.4%	(1.6%)
May	8.6%	23.5%	67.9%	10.9%	25.4%	63.6%	2.4%	1.9%	(4.3%)
Jun	8.7%	22.3%	69.0%	10.7%	25.0%	64.3%	2.0%	2.7%	(4.8%)
Jul	8.0%	22.7%	69.3%						
Aug	8.5%	23.6%	67.9%						
Sep	9.1%	24.4%	66.5%						
Oct	9.6%	25.5%	64.9%						
Nov	9.9%	23.9%	66.3%						
Dec	10.2%	22.6%	67.3%						
Annual	9.0%	23.2%	67.8%	10.6%	23.8%	65.6%	1.6%	0.6%	(2.2%)

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 2-61 shows the monthly average share of day-ahead load served by self-supply, bilateral contracts and spot purchases in 2012 and 2013, based on parent companies. For the first six months of 2013, 7.3 percent of day-ahead load was supplied by bilateral contracts, 23.0 percent by spot market purchases, and 69.7 percent by self-supply. Compared with 2012, reliance on bilateral contracts increased by 0.6 percentage points, reliance on

spot supply increased by 0.7 percentage points, and reliance on self-supply decreased by 1.4 percentage points.

Table 2-61 Monthly average percentage of day-ahead self-supply load, bilateral supply load, and spot-supply load based on parent companies: 2012 through 2013

| | 2012 | | | 2013 | | | Difference in Percentage Points | | |
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	6.6%	21.4%	72.0%	6.8%	22.1%	71.1%	0.2%	0.7%	(0.9%)
Feb	6.7%	20.0%	73.3%	7.0%	22.1%	71.0%	0.3%	2.1%	(2.3%)
Mar	6.7%	22.8%	70.5%	7.0%	23.6%	69.4%	0.3%	0.8%	(1.1%)
Apr	6.7%	22.8%	70.6%	7.1%	23.1%	69.8%	0.5%	0.3%	(0.8%)
May	6.6%	22.7%	70.7%	7.8%	23.5%	68.7%	1.2%	0.8%	(2.0%)
Jun	7.7%	20.7%	71.6%	8.2%	23.8%	68.0%	0.5%	3.1%	(3.5%)
Jul	5.9%	22.0%	72.0%						
Aug	6.4%	22.5%	71.0%						
Sep	6.5%	23.9%	69.6%						
Oct	6.6%	25.2%	68.2%						
Nov	6.9%	22.7%	70.5%						
Dec	7.0%	21.2%	71.8%						
Annual	6.7%	22.3%	71.0%	7.3%	23.0%	69.7%	0.6%	0.7%	(1.4%)

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.

Overview

Operating Reserve Results

- **Operating Reserve Charges.** Total operating reserve charges increased by 55.2 percent in the first six months of 2013 compared to the first six months of 2012, to a total of $433.6 million. Day-ahead operating reserve charges were 11.3 percent, balancing operating reserve charges were 52.6 percent, reactive services charges were 25.0 percent, synchronous condensing charges were 0.001 percent and black start services charges were 11.1 percent of total operating reserve charges.

- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.086 per MWh, the day-ahead operating reserve rate including unallocated congestion charges averaged $0.122 per MWh, the balancing operating reserve reliability rates averaged $0.050, $0.041 and $0.004 per MWh for the RTO, Eastern and Western Regions, and the balancing operating reserve deviation rates averaged $0.887, $3.302 and $0.117 per MWh for the RTO, Eastern and Western Regions. The lost opportunity cost rate averaged $0.729 per MWh and canceled resources rate averaged $0.0003 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 53.7 percent of all day-ahead generator credits and 61.7 percent of all balancing generator credits. Combustion turbines and diesels received 69.7 percent of the lost opportunity cost credits. Combined cycles and coal units received 87.5 percent of all reactive services credits.

- **Economic and Noneconomic Generation.** In the first six months of 2013, 81.8 percent of the day-ahead generation eligible for operating reserve credits was economic and 66.9 percent of the real-time generation eligible for operating reserve credits was economic.

Geography of Balancing Charges and Credits

- In the first six months of 2013, 80.7 percent of all charges allocated regionally were paid by transactions, demand and generators located in control zones, 6.4 percent by transactions at hubs and aggregates and 13.0 percent by transactions at interfaces.

- Generators in the Eastern Region paid 16.0 percent of all RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 80.2 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits. Generators in the Western Region paid 14.8 percent of all RTO and Western Region balancing generator charges, including lost opportunity cost and canceled resources charges, and received 19.7 percent of all balancing generator credits, including lost opportunity cost and canceled resources credits.

- Generators paid 10.7 percent of all operating reserve charges (excluding charges for resources controlling local transmission constraints) and received 99.99 percent of all credits.

Operating Reserve Issues

- **Concentration of Operating Reserve Credits:** The top 10 units receiving operating reserve credits received 40.3 percent of all credits. The top 10 organizations received 86.9 percent of all credits. Concentration indexes

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[1] See the *2012 State of the Market Report for PJM, Volume II*, Section 3, "Operating Reserve" at "Description of Operating Reserves" pp. 99–103 for a full description of how operating reserve credits and charges are calculated.

for the three largest operating reserve categories classify them as highly concentrated. Day-ahead operating reserves HHI was 5223, balancing operating reserves HHI was 4392 and lost opportunity cost HHI was 4753.

- **Day-Ahead Unit Commitment for Reliability:** In the first six months of 2013, 4.5 percent of the total day-ahead generation was scheduled as must run by PJM, of which 67.3 percent was made whole.

- **Lost Opportunity Cost Credits:** In the first six months of 2013, lost opportunity cost credits decreased by $23.7 million compared to the first six months of 2012. In the first six months of 2013, the top three control zones receiving lost opportunity cost credits, ATSI, AP and ComEd combined for 56.0 percent of all lost opportunity cost credits, 43.7 percent of the credits for day-ahead generation from pool-scheduled combustion turbines and diesels, 57.9 percent of the credits for day-ahead generation not called in real time by PJM from those unit types and 67.1 percent of the credits day-ahead generation not called in real time by PJM and receiving lost opportunity cost credits from those unit types.

- **Lost Opportunity Cost Calculation:** In the first six months of 2013, lost opportunity cost credits would have been reduced by $12.9 million, or 29.2 percent, if all changes proposed by the MMU had been implemented.

- **Black Start Service Units:** Certain units located in the AEP zone are relied on for their black start capability on a regular basis even during periods when the units are not economic. The relevant black start units provide black start service under the ALR option, which means that the units must be running even if not economic. In the first six months of 2013, the cost of the noneconomic operation of ALR units in the AEP control zone was $47.9 million.

- **Con Edison – PSEG Wheeling Contracts Support:** 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. These units are often run out of merit and received substantial balancing operating reserves credits.

- **Impact of Quantifiable Recommendations:** The impact of implementing the recommendations proposed by the MMU related to increasing the

pool of participants who pay operating reserve charges on operating reserve charge rates and on the payments by other participants would be significant. For example, in the first six months of 2013, the average rate paid by a DEC in the Eastern Region would have been $0.209 per MWh, $4.401 per MWh or 95.5 percent less than the actual average rate paid.

Recommendations

- The MMU recommends the reexamination of the allocation of operating reserve charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges.

- The MMU recommends four modifications to the energy lost opportunity cost calculations.

  - The MMU recommends that the lost opportunity cost in the Energy and Ancillary Services Markets be calculated using the schedule on which the unit was scheduled to run in the Energy Market.

  - The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not called in real time.

  - The MMU recommends eliminating the use of the day-ahead LMP to calculate lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not called in real time.

  - The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost.

- The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with operating reserve credits calculation

- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges.

- The MMU recommends that up-to congestion transactions be required to pay operating reserve charges.

- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts.

- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of information regarding the reasons for operating reserve payments in the PJM region.

Conclusion

Day-ahead and real-time operating reserve credits are paid to market participants under specified conditions in order to ensure that resources are not required to operate for the PJM system at a loss. Sometimes referred to as uplift or make whole, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market at marginal cost and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges.

From the perspective of those participants paying operating reserve charges, these costs are an unpredictable and unhedgeable component of the total cost of energy in PJM. While reasonable operating reserve charges are an appropriate part of the cost of energy, market efficiency would be improved by ensuring that the level and variability of operating reserve charges is as low as possible consistent with the reliable operation of the system and that the allocation of operating reserve charges reflects the reasons that the costs are incurred.

The goal should be to reflect the impact of physical constraints in market prices to the maximum extent possible and thus to reduce the necessity for out of market operating reserve payments. When units receive substantial revenues through operating reserve payments, these payments are not transparent to the market and other market participants do not have the opportunity to compete for them. As a result, substantial operating reserve payments to a concentrated group of units and organizations persists.

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, the details of the rules which define payments and the decisions of PJM operators. Operating reserve credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start units or to keep units operating even when hourly LMP is less than the offer price including energy, no load and startup costs. But these costs are collected as operating reserves rather than reflected in price as a result of the rules governing the determination of LMP in situations where something other than a simple thermal transmission constraint affects unit dispatch.

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, the MMU recommends that PJM take another step towards more precise definition and clearly identify and classify all reasons for incurring operating reserve charges in order to ensure a long term solution of the allocation issue of the costs of operating reserves. The MMU recommends that the goal should be to have dispatcher decisions reflected in transparent market outcomes, preferably LMP, to the maximum extent possible and to minimize the level and rate of operating reserve charges.

The MMU recommended and supports PJM in the reexamination of the allocation of operating reserve charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges.[2] For example, there has not been an analysis of the impact of up-to congestion transactions and their impact on the payment of operating reserve credits. Up-to congestion transactions continue to pay no operating reserve charges, which means that all others who pay operating reserve

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2   PJM presented a problem statement at the Markets and Reliability Committee (MRC) to perform a holistic review of operating reserves. See "Item 10 – Operating Reserves Problem Statement," <http://www.pjm.com/~/media/committees-groups/committees/mrc/20130425/20130425-item-10-operating-reserves-problem-statement.ashx> (Accessed April 26, 2013).

charges are paying too much. In addition, the issue of netting using internal bilateral transactions should be addressed.

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

Credits and Charges Categories

Operating reserves include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Total operating reserve credits paid to PJM participants equal the total operating reserve charges paid by PJM participants. Table 3-1 and Table 3-2 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

Table 3-1 Day-ahead and balancing operating reserve credits and charges

Credits received for:	Credits category:		Charges category:	Charges paid by:	
		Day-Ahead			
Day-Ahead Import Transactions and Generation Resources	Day-Ahead Operating Reserve Transaction Day-Ahead Operating Reserve Generator	→	Day-Ahead Operating Reserve	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Load Response Resources	Day-Ahead Operating Reserves for Load Response	→	Day-Ahead Operating Reserve for Load Response	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
Unallocated Negative Load Congestion Charges Unallocated Positive Generation Congestion Credits		→	Unallocated Congestion	Day-Ahead Load Day-Ahead Export Transactions Decrement Bids	in RTO Region
		Balancing			
Generation Resources	Balancing Operating Reserve Generator	→	Balancing Operating Reserve for Reliability	Real-Time Load plus Export Transactions	in RTO, Eastern or Western Region
			Balancing Operating Reserve for Deviations	Real-Time Deviations from Day-Ahead Schedule	
			Balancing Local Constraint	Applicable Requesting Party	
Canceled Resources	Balancing Operating Reserve Startup Cancellation				
Lost Opportunity Cost (LOC)	Balancing Operating Reserve LOC	→	Balancing Operating Reserve for Deviations	Real-Time Deviations from Day-Ahead Schedule	in RTO Region
Real-Time Import Transactions	Balancing Operating Reserve Transaction				
Resources Providing Quick Start Reserve	Balancing Operating Reserve Generator				
Load Response Resources	Balancing Operating Reserves for Load Response	→	Balancing Operating Reserve for Load Response	Real-Time Deviations from Day-Ahead Schedule by RTO, Eastern or Western Region	in RTO, Eastern or Western Region

Table 3-2 Reactive services, synchronous condensing and black start services credits and charges

Credits received for:	Credits category:		Charges category:	Charges paid by:
		Reactive		
Resources Providing Reactive Service	Reactive Services Generator Reactive Services LOC Reactive Services Condensing Reactive Services Synchronous Condensing LOC	→	Reactive Services Charge	Zonal Real-Time Load
			Reactive Services Local Constraint	Applicable Requesting Party
		Synchronous Condensing		
Resources Providing Synchronous Condensing	Synchronous Condensing Synchronous Condensing LOC	→	Synchronous Condensing	Real-Time Load Real-Time Export Transactions
		Black Start		
Resources Providing Black Start Service	Day-Ahead Operating Reserve Balancing Operating Reserve Black Start Testing	→	Black Start Service Charge	Zone and Non-zone Peak Transmission Use

Total operating reserve charges in the first six months of 2013 were $433.6 million, up from the total of $279.4 million in the first six months of 2012. Table 3-4 compares monthly operating reserve charges by category for 2012 and 2013. The increase of 55.2 percent in the first six months of 2013 is comprised of a 36.3 percent increase in day-ahead operating reserve charges, an 11.0 percent increase in balancing operating reserve charges, a 186.9 percent increase in reactive services charges, a 94.0 percent decrease in synchronous condensing charges and $47.9 million of the new black start services charges. Black start services operating reserve charges accounted for 11.1 percent of all operating reserve charges.

Operating Reserve Results

Operating Reserve Charges

Table 3-3 shows total operating reserve charges for the first six months of 2012 and 2013.[3] Total operating reserve charges increased by 55.2 percent in the first six months of 2013 compared to the first six months of 2012, to a total of $433.6 million.

Table 3-3 Total operating reserve charges: January through June 2012 and 2013

	Jan – Jun 2012	Jan – Jun 2013	Change	Percentage Change
Total Operating Reserve Charges	$279,407,268	$433,571,760	$154,164,492	55.2%
Operating Reserve as a Percent of Total PJM Billing	2.0%	2.8%	0.8%	39.4%

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3 Table 3-3 includes all categories of charges as defined in Table 3-1 and Table 3-2 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 July 9, 2013.

Table 3-4 Monthly operating reserve charges: 2012 and 2013

	2012						2013					
	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start	Total	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total
Jan	$8,311,574	$27,341,331	$2,934,337	$27,037	$0	$38,614,279	$11,161,579	$79,186,346	$23,604,234	$1,873	$8,453,397	$122,407,430
Feb	$5,858,308	$24,877,526	$13,108,017	$18,592	$0	$43,862,444	$5,071,156	$67,100,983	$17,624,984	$0	$6,988,632	$96,785,754
Mar	$3,852,873	$29,758,387	$6,731,994	$1,648	$0	$40,344,903	$7,003,778	$17,485,557	$14,350,138	$0	$6,768,618	$45,608,091
Apr	$2,967,302	$34,172,651	$4,521,280	$0	$0	$41,661,233	$5,712,618	$23,636,368	$13,670,581	$0	$9,242,815	$52,262,382
May	$7,956,965	$43,761,595	$5,392,428	$0	$0	$57,110,987	$10,613,963	$22,962,726	$17,189,489	$959	$8,645,457	$59,412,594
Jun	$6,973,548	$45,706,864	$5,133,009	$0	$0	$57,813,421	$9,413,019	$17,804,992	$22,055,476	$0	$7,822,022	$57,095,510
Jul	$11,773,179	$66,592,698	$2,960,922	$0	$0	$81,326,798						
Aug	$8,692,702	$47,698,841	$4,112,186	$0	$0	$60,503,728						
Sep	$28,877,736	$32,849,356	$4,458,891	$24,366	$0	$66,210,349						
Oct	$23,382,961	$26,884,798	$1,253,642	$38,762	$0	$51,560,164						
Nov	$18,077,440	$24,494,474	$120,820	$0	$0	$42,692,735						
Dec	$7,878,203	$27,874,133	$25,282,650	$37,845	$8,384,651	$69,457,482						
Total (Jan – Jun)	$35,920,569	$205,618,356	$37,821,064	$47,278	$0	$279,407,268	$48,976,113	$228,176,971	$108,494,903	$2,832	$47,920,941	$433,571,760
Share (Jan – Jun)	12.9%	73.6%	13.5%	0.0%	0.0%	100.0%	11.3%	52.6%	25.0%	0.0%	11.1%	100.0%
Total	$134,602,791	$432,012,655	$76,010,175	$148,250	$8,384,651	$651,158,522						
Share	20.7%	66.3%	11.7%	0.0%	1.3%	100.0%						

Table 3-5 shows the composition of the day-ahead operating reserve charges. Day-ahead operating reserve charges consist of day-ahead operating reserve charges attributable to generators and import transactions, day-ahead operating reserve charges for load response and unallocated congestion charges.[4] Day-ahead operating reserve charges increased 36.3 percent or $13.1 million in the first six months of 2013 compared to the first six months of 2012 as a result of unallocated congestion charges.[5,6] Day-ahead operating reserve charges attributable to generators and imports decreased by $0.9 million in the first six months of 2013 compared to the first six months of 2012, but unallocated congestion charges increased from zero in the first six months of 2012 to $14.0 million in the first six months of 2013. These charges are paid by day-ahead demand, day-ahead exports and decrement bids.

Table 3-5 Day-ahead operating reserve charges: January through June 2012 and 2013

Type	Jan – Jun 2012	Jan – Jun 2013	Change	Jan – Jun 2012 Share	Jan – Jun 2013 Share
Day-Ahead Operating Reserve Charges	$35,920,569	$35,001,966	($918,603)	100.0%	71.5%
Day-Ahead Operating Reserve Charges for Load Response	$0	$0	$0	0.0%	0.0%
Unallocated Congestion Charges	$0	$13,974,147	$13,974,147	0.0%	28.5%
Total	$35,920,569	$48,976,113	$13,055,544	100.0%	100.0%

Table 3-6 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (attributable to generators), balancing operating reserve deviation charges (attributable to generators and import transactions), balancing operating reserve charges for load response and balancing local constraint charges. In the first six months of 2013, balancing operating reserve deviation charges accounted for 87.8 percent of all balancing operating reserve charges, 13.4 percentage points higher compared to the share in the first six months of 2012.

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4 Attributable means that these charges are the result of credits paid to the identified resources.
5 See OATT Attachment K - Appendix § 3.2.3 (c). Unallocated congestion charges are added to the total costs of day-ahead operating reserves. Congestion charges have been allocated to day-ahead operating reserves nine times, totaling $21.0 million, of which 66.7 percent was charged in the first six months of 2013.
6 See Section 12, "Financial Transmission Rights and Auction Revenue Rights" at "Unallocated Congestion Charges" for an explanation of the source of these charges.

Table 3-6 Balancing operating reserve charges: January through June 2012 and 2013

Type	Jan – Jun 2012	Jan – Jun 2013	Change	Jan – Jun 2012 Share	Jan – Jun 2013 Share
Balancing Operating Reserve Reliability Charges	$46,989,524	$27,725,175	($19,264,349)	22.9%	12.2%
Balancing Operating Reserve Deviation Charges	$153,094,228	$200,428,631	$47,334,403	74.5%	87.8%
Balancing Operating Reserve Charges for Load Response	$112,755	$1,247	($111,508)	0.1%	0.0%
Balancing Local Constraint Charges	$5,421,848	$21,918	($5,399,930)	2.6%	0.0%
Total	$205,618,356	$228,176,971	$22,558,615	100.0%	100.0%

Table 3-7 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve charges consist of charges attributable to make whole payments to generators and import transactions, energy lost opportunity costs paid to generators and payments to resources canceled by PJM before coming online. In the first six months of 2013, 77.9 percent of all balancing operating reserve deviation charges were attributable to make whole payments to generators and import transactions, an increase of 24.4 percentage points compared to the share in the first six months of 2012.

Table 3-7 Balancing operating reserve deviation charges: January through June 2012 and 2013

Charge attributable to	Jan – Jun 2012	Jan – Jun 2013	Change	Jan – Jun 2012 Share	Jan – Jun 2013 Share
Make Whole Payments to Generators and Imports	$81,932,713	$156,198,004	$74,265,290	53.5%	77.9%
Energy Lost Opportunity Cost	$67,871,182	$44,211,377	($23,659,805)	44.3%	22.1%
Canceled Resources	$3,290,332	$19,250	($3,271,082)	2.1%	0.0%
Total	$153,094,228	$200,428,631	$47,334,403	100.0%	100.0%

Table 3-8 shows reactive services, synchronous condensing and black start services charges. Black start services charges were introduced in December 2012.

Table 3-8 Additional operating reserve charges: January through June 2012 and 2013

Type	Jan – Jun 2012	Jan – Jun 2013	Change	Jan – Jun 2012 Share	Jan – Jun 2013 Share
Reactive Services Charges	$37,821,064	$108,494,903	$70,673,838	99.9%	69.4%
Synchronous Condensing Charges	$47,278	$2,832	($44,446)	0.1%	0.0%
Black Start Services Charges	$0	$47,920,941	$47,920,941	0.0%	30.6%
Total	$37,868,342	$156,418,676	$118,550,333	100.0%	100.0%

Table 3-9 and Table 3-10 show the amount and percentages of regional balancing charges allocation for the first six months of 2012 and 2013. Regional balancing operating reserve charges consist of the balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. The largest share of regional charges was paid by demand deviations in the RTO region. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints and resources providing quick start reserve.

In the first six months of 2013, regional balancing operating reserve charges increased by $28.1 million compared to the first six months of 2012. Balancing operating reserve reliability charges decreased by $19.3 million or 41.0 percent and balancing operating reserve deviation charges increased by $47.3 million or 30.9 percent. In the first six months of 2013, deviation charges in the Eastern Region increased by $88.9 million compared to the first six months of 2012, as a result of payments to units providing relief to transmission constraints in north/central New Jersey and units providing support to the Con Edison – PSEG wheeling contracts.[7,8] The remaining two deviation categories decreased by $41.6 million.

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7 See "Selected MMU Market Issues," MMU Presentation to the Members Committee (February 25, 2013) <http://www.pjm.com/~/media/committees-groups/committees/mc/20130225-webinar/20130225-item-08-imm-flowchart.ashx>.

8 See "Winter 2012-2013: Balancing Operating Reserve Rates," PJM Presentation at the Market Implementation Committee (MIC) (March 6, 2013) <http://www.pjm.com/~/media/committees-groups/committees/mic/20130306/20130306-item-10-winter-2012-2013-bor-rates.ashx>.

Table 3-9 Regional balancing charges allocation: January through June 2012

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$7,512,359	3.8%	$1,002,489	0.5%	$36,755,592	18.4%	$45,270,440	22.6%
	Real-Time Exports	$209,312	0.1%	$17,392	0.0%	$1,492,381	0.7%	$1,719,085	0.9%
	Total	$7,721,671	3.9%	$1,019,881	0.5%	$38,247,973	19.1%	$46,989,524	23.5%
Deviation Charges	Demand	$81,786,179	40.9%	$6,159,396	3.1%	$1,673,696	0.8%	$89,619,271	44.8%
	Supply	$27,395,821	13.7%	$2,240,403	1.1%	$467,607	0.2%	$30,103,831	15.0%
	Generator	$30,876,942	15.4%	$1,678,735	0.8%	$815,450	0.4%	$33,371,126	16.7%
	Total	$140,058,941	70.0%	$10,078,534	5.0%	$2,956,753	1.5%	$153,094,228	76.5%
Total Regional Balancing Charges		$147,780,612	73.9%	$11,098,415	5.5%	$41,204,726	20.6%	$200,083,752	100%

Table 3-10 Regional balancing charges allocation: January through June 2013

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$18,936,105	8.3%	$7,255,936	3.2%	$895,300	0.4%	$27,087,342	11.9%
	Real-Time Exports	$425,122	0.2%	$195,789	0.1%	$16,923	0.0%	$637,834	0.3%
	Total	$19,361,227	8.5%	$7,451,726	3.3%	$912,223	0.4%	$27,725,175	12.2%
Deviation Charges	Demand	$57,594,740	25.2%	$61,549,043	27.0%	$1,891,916	0.8%	$121,035,700	53.1%
	Supply	$15,742,850	6.9%	$16,667,890	7.3%	$514,610	0.2%	$32,925,350	14.4%
	Generator	$24,717,457	10.8%	$20,766,356	9.1%	$983,768	0.4%	$46,467,581	20.4%
	Total	$98,055,048	43.0%	$98,983,289	43.4%	$3,390,294	1.5%	$200,428,631	87.8%
Total Regional Balancing Charges		$117,416,275	51.5%	$106,435,015	46.7%	$4,302,517	1.9%	$228,153,806	100%

Operating Reserve Rates

Under the operating reserves cost allocation rules, PJM calculates nine separate rates, a day-ahead operating reserve rate, a reliability rate for each region, a deviation rate for each region, a lost opportunity cost rate and a canceled resources rate for the entire RTO region. See Table 3-1 for how these charges are allocated.[9]

Figure 3-1 shows the weekly weighted average day-ahead operating reserve rate for 2012 and the first six months of 2013. The average rate in the first six months of 2013 was $0.086 per MWh, $0.003 per MWh lower than the average in the first six months of 2012. The highest rate occurred on April 21, when the rate reached $0.262 per MWh, 28.4 percent lower than the $0.366 per MWh reached during the first six months of 2012, on June 20.

Figure 3-1 also shows the weekly weighted average day-ahead operating reserve rates including the congestion charges allocated to day-ahead operating reserves. The average rate in the first six months of 2013, including unallocated congestion charges, was $0.122 per MWh, 40.6 percent higher than the day-ahead operating reserve rate without unallocated congestion charges.

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9   The lost opportunity cost and canceled resources rates are not posted separately by PJM. PJM adds the lost opportunity cost rates and the canceled resources rate to the deviation rate for the RTO region since these three charges are allocated following the same rules.

Figure 3-1 Weekly weighted average day-ahead operating reserve rate ($/MWh): 2012 and 2013[10]
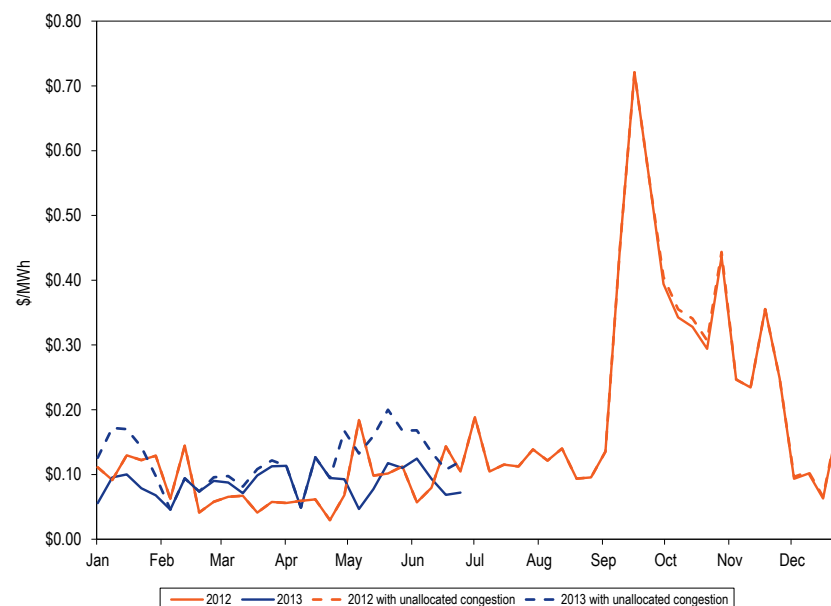
Figure 3-2 shows the RTO and the regional reliability rates for 2012 and the first six months of 2013. The average daily RTO reliability rate was $0.050 per MWh. The highest RTO reliability rate of the first six months of 2013 occurred on January 23, when the rate reached $0.802 per MWh. The average daily Eastern Region reliability rate was $0.041 per MWh. The highest Eastern Region reliability rate of the first six months of 2013 occurred on January 23, when the rate reached $2.887 per MWh. The spikes on both rates was a result of a combination of transmission constraints in central and northeastern New Jersey and high natural gas prices in the area. The transmission constraints were the result of issues with the 500 kV system in the area which resulted in overloads on the 230 kV system. The issues on the 500 kV system were a combination of unplanned outages and unforeseen outages resulting from

damage due to Hurricane Sandy. Cold weather in the region resulted in an increase in the Transco Zone 6 NY natural gas price index in January and February 2013 compared to previous months and compared to January and February 2012. The units committed to provide relief for the transmission constraints only set the LMP during short periods of time in comparison to their minimum run times, which increased the costs of operating reserves during periods when the units continue operating out of merit as a result of their operating parameters.[11]

Figure 3-2 Daily balancing operating reserve reliability rates ($/MWh): 2012 and 2013
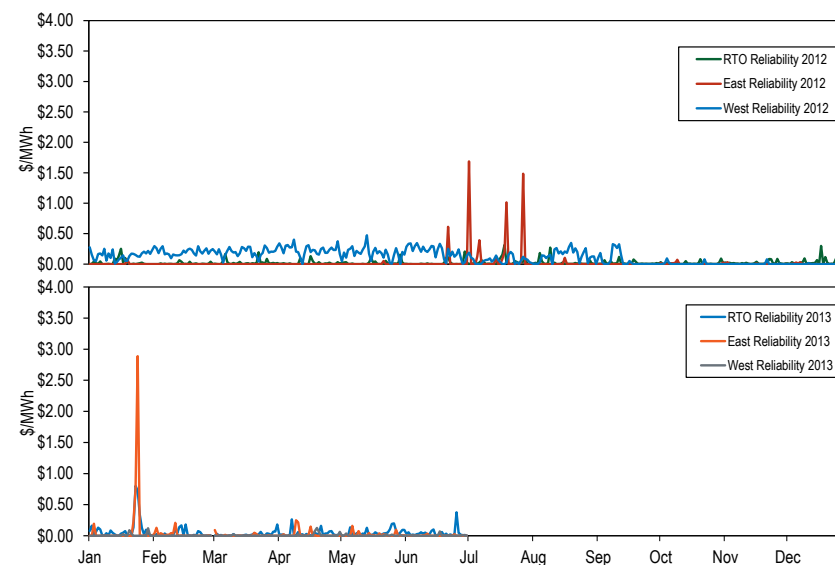
Figure 3-3 shows the RTO and the regional deviation rates for 2012 and the first six months of 2013. The average daily RTO deviation rate was $0.887 per MWh. The highest daily rate in the first six months of 2013 occurred

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10 On September 13, 2012, PJM increased the amount of generation scheduled in the Day-Ahead Energy Market for reliability purposes. This change shifted the allocation of certain operating reserve charges from the Real-Time Energy Market to the Day-Ahead Energy Market. See *2012 State of the Market Report for PJM*, Volume II, Section 3, "Operating Reserve" at "Day-Ahead Unit Commitment for Reliability" for further details on the September 13 day-ahead scheduling process change.

11 The relevant parameters are minimum run time, minimum down time, maximum daily starts and maximum weekly starts.

on January 23, when the RTO deviation rate reached $10.202 per MWh. Between January 1 and February 21, 2013, the Eastern Region deviation rate averaged $10.045 per MWh, reaching its highest rate on February 9, when it reached $32.767 per MWh. Prior to the 2012 – 2013 winter, the highest daily Eastern Region deviation rate had been $5.739 per MWh. The spikes in the Eastern deviation rate in early January and from mid-January until the end of February were caused by the same issues that caused the RTO and Eastern reliability rates to spike on January 25, a combination of transmission constraints in central and northeastern New Jersey and high natural gas prices in the area. Current balancing operating reserve rules allocate the costs of operating reserves in real time for reliability or deviations according to when the units are committed (before or during the operating day) and the number of intervals the units were operating noneconomic (more or less than four intervals).[12]

Figure 3-3 Daily balancing operating reserve deviation rates ($/MWh): 2012 and 2013

Figure 3-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2012 and the first six months of 2013. The lost opportunity rate averaged $0.729 per MWh. The highest lost opportunity cost rate occurred on January 25, when it reached $4.862 per MWh.

Figure 3-4 Daily lost opportunity cost and canceled resources rates ($/MWh): 2012 and 2013
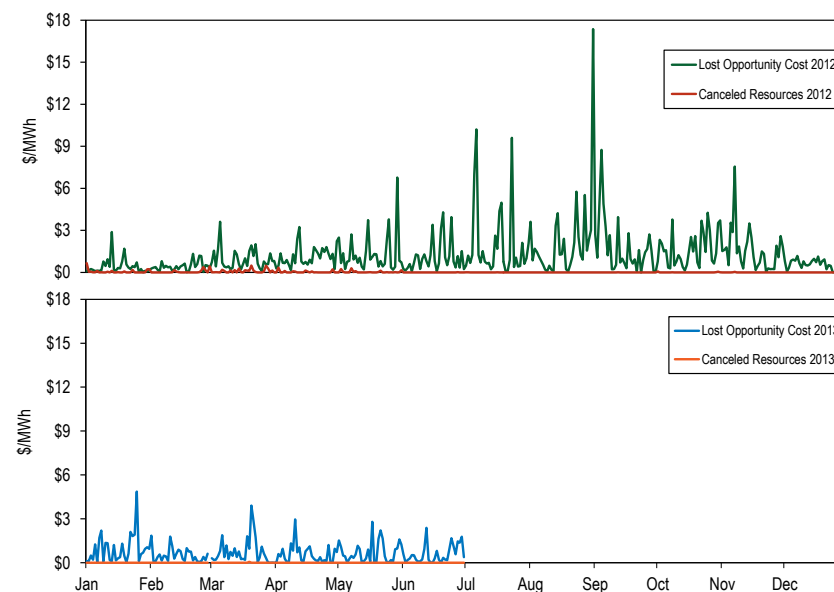
Table 3-11 shows the average rates for each region in each category for the first six months of 2012 and 2013.

12 See the *2012 State of the Market Report for PJM,* Volume II, Section 3, "Operating Reserve" at "Balancing Operating Reserve Cost Allocation" p.101 for a more detailed description of how the cost of balancing operating reserves are allocated.

Table 3-11 Operating reserve rates ($/MWh): January through June 2012 and 2013

Rate	Jan – Jun 2012 ($/MWh)	Jan – Jun 2013 ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.089	0.086	(0.003)	(3.1%)
Day-Ahead with Unallocated Congestion	0.089	0.122	0.032	36.3%
RTO Reliability	0.020	0.050	0.030	148.4%
East Reliability	0.006	0.041	0.035	611.3%
West Reliability	0.187	0.004	(0.183)	(97.6%)
RTO Deviation	0.951	0.887	(0.064)	(6.7%)
East Deviation	0.252	3.302	3.050	1,208.1%
West Deviation	0.091	0.117	0.025	27.7%
Lost Opportunity Cost	0.937	0.729	(0.208)	(22.2%)
Canceled Resources	0.045	0.000	(0.045)	(99.3%)

Table 3-12 shows the operating reserve cost of a 1 MW transaction during the first six months of 2013. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $4.610 per MWh with a maximum rate of $32.946 per MWh, a minimum rate of $0.231 per MWh and a standard deviation of $6.554 per MWh. The rates in the table include all operating reserve charges including RTO deviation charges and unallocated congestion charges. Table 3-12 illustrates both the average level of operating reserve charges to transaction types but also the uncertainty reflected in the maximum, minimum and standard deviation levels.

Table 3-12 Operating reserve rates statistics ($/MWh): January through June 2013

Region	Transaction	Rates Charged ($/MWh) Maximum	Average	Minimum	Standard Deviation
East	INC	32.914	4.488	0.024	6.572
	DEC	32.946	4.610	0.231	6.554
	DA Load	0.283	0.122	0.000	0.059
	RT Load	3.610	0.082	0.000	0.295
	Deviation	32.914	4.488	0.024	6.572
West	INC	12.986	1.616	0.024	1.741
	DEC	13.063	1.738	0.130	1.745
	DA Load	0.283	0.122	0.000	0.059
	RT Load	0.802	0.053	0.000	0.096
	Deviation	12.986	1.616	0.024	1.741

Operating Reserve Determinants

Table 3-13 shows the determinants used to allocate the regional balancing operating reserve charges for the first six months of 2012 and 2013. Total real-time load and real-time exports were 3,560,867 MWh or 0.9 percent higher in the first six months of 2013 compared to the first six months of 2012. Total deviations summed across the demand, supply, and generator categories were lower in the six months of 2013 compared to the first six months of 2012 by 11,787,580 MWh or 16.3 percent.

Table 3-13 Balancing operating reserve determinants (MWh): January through June 2012 and 2013

		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
Jan – Jun 2012	RTO	370,906,527	12,356,482	383,263,009	41,711,347	14,528,729	16,203,453	72,443,529
	East	174,227,592	4,760,895	178,988,487	24,298,611	8,657,629	6,966,562	39,922,802
	West	196,678,935	7,595,587	204,274,522	17,249,341	5,841,974	9,236,891	32,328,206
Jan – Jun 2013	RTO	377,392,067	9,431,808	386,823,876	35,858,091	9,370,458	15,427,399	60,655,949
	East	179,030,981	4,816,411	183,847,393	18,823,201	4,619,592	6,531,961	29,974,754
	West	198,361,086	4,615,397	202,976,483	15,713,418	4,416,251	8,895,438	29,025,107
Difference	RTO	6,485,540	(2,924,673)	3,560,867	(5,853,256)	(5,158,271)	(776,053)	(11,787,580)
	East	4,803,389	55,517	4,858,906	(5,475,410)	(4,038,037)	(434,601)	(9,948,048)
	West	1,682,151	(2,980,190)	(1,298,039)	(1,535,923)	(1,425,724)	(341,452)	(3,303,099)

Deviations fall into three categories, demand, supply and generator deviations. Table 3-14 shows the different categories by the type of transactions that incur deviations. For example, 38.2 percent of all RTO deviations in the first six months of 2013 were from participants that only had load transactions. In the first six months of 2013, 19.0 percent of all RTO deviations were incurred by participants that deviated due to INCs and DECs or due to combinations of INCs and DECs with other transactions, the remaining 81.0 percent of all RTO deviations were incurred by participants that deviated due to other transaction types or due to combinations of other transaction types.

Table 3-14 Deviations by transaction type: January through June 2013

Deviation Category	Transaction	Deviation (MWh)			Share		
		RTO	East	West	RTO	East	West
Demand	Bilateral Sales Only	565,758	174,725	391,033	0.9%	0.6%	1.3%
	DECs Only	4,072,880	1,324,394	1,427,014	6.7%	4.4%	4.9%
	Exports Only	2,571,553	1,384,042	1,187,512	4.2%	4.6%	4.1%
	Load Only	23,146,133	13,650,405	9,495,728	38.2%	45.5%	32.7%
	Combination with DECs	2,817,166	1,527,234	1,289,932	4.6%	5.1%	4.4%
	Combination without DECs	2,684,600	762,402	1,922,198	4.4%	2.5%	6.6%
Supply	Bilateral Purchases Only	757,756	592,387	165,369	1.2%	2.0%	0.6%
	Imports Only	3,950,032	2,078,608	1,871,424	6.5%	6.9%	6.4%
	INCs Only	2,661,638	653,662	1,673,360	4.4%	2.2%	5.8%
	Combination with INCs	1,961,149	1,259,902	701,248	3.2%	4.2%	2.4%
	Combination without INCs	39,884	35,034	4,850	0.1%	0.1%	0.0%
Generators		15,427,399	6,531,961	8,895,438	25.4%	21.8%	30.6%
Total		60,655,949	29,974,754	29,025,107	100.0%	100.0%	100.0%

Table 3-15 shows the totals for each credit category for the first six months of 2012 and 2013. During the first six months of 2013, 54.4 percent of total operating reserve credits were in the balancing category. This percentage decreased 19.2 percentage points from the 73.6 percent in the first six months of 2012. This decrease was in part due to the reallocation of operating reserve credits paid to units providing black start services and reactive services.

Operating Reserve Credits

Table 3-15 Credits by operating reserve category: January through June 2012 and 2013

Category	Type	Jan – Jun 2012	Jan – Jun 2013	Change	Percentage Change	Jan – Jun 2012 Share	Jan – Jun 2013 Share
Day-Ahead	Generators	$35,920,014	$35,001,959	($918,055)	(2.6%)	12.9%	8.3%
	Imports	$554	$7	($548)	(98.8%)	0.0%	0.0%
	Load Response	$0	$0	$0	NA	0.0%	0.0%
Balancing	Canceled Resources	$3,290,334	$19,250	($3,271,084)	(99.4%)	1.2%	0.0%
	Generators	$128,881,015	$183,973,690	$55,092,675	42.7%	46.1%	43.8%
	Imports	$41,223	$33,964	($7,259)	(17.6%)	0.0%	0.0%
	Load Response	$112,731	$1,179	($111,551)	(99.0%)	0.0%	0.0%
	Local Constraints Control	$5,421,848	$21,918	($5,399,930)	(99.6%)	1.9%	0.0%
	Lost Opportunity Cost	$67,871,180	$44,213,815	($23,657,365)	(34.9%)	24.3%	10.5%
Reactive Services	Day-Ahead	$0	$94,526,380	$94,526,380	NA	0.0%	22.5%
	Local Constraints Control	$0	$90,590	$90,590	NA	0.0%	0.0%
	Lost Opportunity Cost	$1,490,586	$202,165	($1,288,421)	(86.4%)	0.5%	0.0%
	Reactive Services	$36,209,408	$13,458,799	($22,750,608)	(62.8%)	13.0%	3.2%
	Synchronous Condensing	$121,071	$216,968	$95,897	79.2%	0.0%	0.1%
Synchronous Condensing		$47,278	$2,832	($44,445)	(94.0%)	0.0%	0.0%
Black Start Services	Day-Ahead	$0	$46,162,349	$46,162,349	NA	0.0%	11.0%
	Balancing	$0	$1,687,134	$1,687,134	NA	0.0%	0.4%
	Testing	$0	$125,050	$125,050	NA	0.0%	0.0%
Total		$279,407,241	$419,738,049	$140,330,807	50.2%	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 3-16 Operating reserve credits by unit type: January through June 2012 and 2013

Unit Type	Jan – Jun 2012	Jan – Jun 2013	Change	Percentage Change	Jan – Jun 2012 Share	Jan – Jun 2013 Share
Battery	$0	$0	$0	0.0%	0.0%	0.0%
Combined Cycle	$37,730,691	$147,123,296	$109,392,606	289.9%	13.5%	35.1%
Combustion Turbine	$91,152,820	$71,090,645	($20,062,174)	(22.0%)	32.6%	16.9%
Diesel	$3,107,162	$5,545,504	$2,438,341	78.5%	1.1%	1.3%
Fuel Cell	$0	$0	$0	0.0%	0.0%	0.0%
Hydro	$267,183	$85,191	($181,992)	(68.1%)	0.1%	0.0%
Nuclear	$337,984	$126,510	($211,473)	(62.6%)	0.1%	0.0%
Solar	$0	$0	$0	0.0%	0.0%	0.0%
Steam - Coal	$131,581,366	$170,429,709	$38,848,344	29.5%	47.1%	40.6%
Steam - Other	$11,695,687	$16,262,952	$4,567,266	39.1%	4.2%	3.9%
Wind	$3,379,842	$9,039,091	$5,659,249	167.4%	1.2%	2.2%
Total	$279,252,734	$419,702,899	$140,450,165	50.3%	100.0%	100.0%

Table 3-17 Operating reserve credits by unit type: January through June 2013

Unit Type	Day–Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Battery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Combined Cycle	53.7%	61.7%	0.0%	0.0%	4.1%	11.9%	0.0%	0.0%
Combustion Turbine	8.8%	16.3%	100.0%	99.8%	69.7%	6.5%	100.0%	0.3%
Diesel	0.0%	0.1%	0.0%	0.0%	0.1%	4.9%	0.0%	0.0%
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Hydro	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Steam - Coal	36.7%	13.7%	0.0%	0.2%	5.4%	75.6%	0.0%	99.7%
Steam - Others	0.7%	8.1%	0.0%	0.0%	0.1%	1.0%	0.0%	0.0%
Wind	0.0%	0.0%	0.0%	0.0%	20.4%	0.0%	0.0%	0.0%
Total	$35,001,959	$183,973,690	$19,250	$21,918	$44,213,815	$108,494,903	$2,832	$47,974,532

Table 3-16 shows the distribution of total operating reserve credits by unit type for the first six months of 2012 and 2013. Credits paid to all unit types using fossil fuels increased in the first six months of 2013 compared to the first six months of 2012. Credits paid to combined cycle units increased 289.9

percent or $109.4 million, mainly due to units providing relief for transmission constraints and supporting the Con Edison – PSEG wheeling contracts during days with high natural gas prices. In the first six months of 2013, 35.1 percent of all operating reserve credits paid to units were paid to combined cycle units, 21.5 percentage points more than the share in the first six months of 2012.

Table 3-17 shows the distribution of operating reserve credits by category and by unit type in the first six months of 2013. Combined cycle units received 53.7 percent of the day-ahead generator credits in the first six months of 2013, 22.7 percentage points higher than the share received in the first six months of 2012. Combined cycle units received 61.7 percent of the balancing generator credits in the first six months of 2013, 48.6 percentage points higher than the share received in the first six months of 2012. Combustion turbines and diesels received 69.7 percent of the lost opportunity cost credits, 21.4 percentage points lower than the share received in the first six months of 2012.

Table 3-17 also shows the distribution of reactive service credits, synchronous condensing and black start services credits by unit type. In the first six months of 2013, combined cycle and coal units received 87.5 percent of all reactive services credits, 3.0 percentage points higher than the share received in the first six months of 2012. Synchronous condensing was only provided by combustion turbines. Coal units received 99.7 percent of all black start services credits.

Economic and Noneconomic Generation[13]

Economic dispatch generation includes units scheduled day ahead or producing energy in real time at an incremental offer less than or equal to the LMP at the unit's bus. Noneconomic generation includes units that are scheduled or producing energy at an incremental offer higher than the

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13 The analysis of economic and noneconomic generation is based on the units' incremental offer, the value used by PJM to calculate LMP. The analysis does not include no load or startup cost.

LMP at the unit's bus. Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing generator operating reserve credits are paid on a segmented basis for each period defined by the greater of the day-ahead schedule and minimum run time. Table 3-18 shows PJM's day-ahead and real-time total generation and the amount of generation eligible for operating reserve credits. In the Day-Ahead Energy Market only pool-scheduled resources are eligible for day-ahead operating reserve credits. In the Real-Time Energy Market only pool-scheduled resources that follow PJM's dispatch instructions are eligible for balancing operating reserve credits.

The MMU analyzed PJM's day-ahead and real-time generation eligible for operating reserve credits to determine the shares of economic and noneconomic generation. Each unit's hourly generation was determined to be economic or noneconomic based solely on the unit's hourly incremental offer, excluding the hourly no load cost and any applicable startup cost. A unit could be economic for every hour during a day or segment, but still receive operating reserve credits because the energy revenues did not cover the additional hourly no load and startup costs. A unit could be noneconomic for an hour or multiple hours and not receive operating reserve credits because total energy revenues covered total hourly costs for the day or segment. In the first six months of 2013, 32.4 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 31.3 percent of the real-time generation was eligible for balancing operating reserve credits.[14]

Table 3-18 Day-ahead and real-time generation (GWh): January through June 2013

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percentage
Day-Ahead	393,443	127,632	32.4%
Real-Time	387,313	121,273	31.3%

Table 3-19 shows PJM's economic and noneconomic generation by hour eligible for operating reserve credits. In the first six months of 2013, 81.8 percent of the day-ahead generation eligible for operating reserve credits was

economic and 66.9 percent of the real-time generation eligible for operating reserve credits was economic. A unit's generation may be noneconomic for a portion of their daily generation and economic for the rest. Table 3-19 shows the separate amounts of economic and noneconomic generation even if the daily generation was economic.

Table 3-19 Day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits (GWh): January through June 2013

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percentage	Noneconomic Generation Percentage
Day-Ahead	104,459	23,173	81.8%	18.2%
Real-Time	81,130	40,143	66.9%	33.1%

Noneconomic generation only leads to operating reserve credits when units' generation for the day or segment scheduled or committed is noneconomic, including no load and startup costs. Table 3-20 shows the generation receiving day-ahead and balancing operating reserve credits. In the first six months of 2013, 6.1 percent of the day-ahead generation eligible for operating reserve credits received credits and 9.1 percent of the real-time generation eligible for operating reserve credits was made whole.

Table 3-20 Day-ahead and real-time generation receiving operating reserve credits (GWh): January through June 2013

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percentage
Day-Ahead	127,632	7,756	6.1%
Real-Time	121,273	11,030	9.1%

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14 In the Day-Ahead Energy Market only pool-scheduled resources are eligible for day-ahead operating reserve credits. In the Real-Time Energy Market only pool-scheduled resources that operate as requested by PJM are eligible for balancing operating reserve credits.

Geography of Charges and Credits

Table 3-21 shows the geography of charges and credits in the first six months of 2013. Table 3-21 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub, aggregate 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, transactions in the AECO Control Zone paid 1.4 percent of all operating reserve charges allocated regionally, and resources in the AECO Control Zone were paid 0.7 percent of the corresponding credits. The AECO Control Zone received less operating reserve credits than operating reserve charges paid and had an 1.6 percent share of the deficit. The deficit is the sum of the negative entries in the balance column. Transactions in the PSEG Control Zone paid 7.0 percent of all operating reserve charges allocated regionally, and resources in the PSEG Control Zone were paid 47.8 percent of the corresponding credits. The PSEG Control Zone received more operating reserve credits than operating reserve charges paid and had an 92.5 percent share of the surplus. The surplus is the sum of the positive entries in the balance column. Table 3-21 also shows that 80.7 percent of all charges were allocated in control zones, 6.4 percent in hubs and aggregates and 13.0 percent in interfaces.

Table 3-21 Geography of regional charges and credits: January through June 2013[15,16]

Location		Charges	Credits	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$3,648,908	$1,848,234	($1,800,674)	1.4%	0.7%	1.6%	0.0%
	AEP	$21,000,877	$14,749,503	($6,251,374)	8.0%	5.6%	5.4%	0.0%
	AP – DLCO	$12,253,987	$10,325,934	($1,928,053)	4.7%	3.9%	1.7%	0.0%
	ATSI	$10,171,999	$11,479,646	$1,307,646	3.9%	4.4%	0.0%	1.1%
	BGE – Pepco	$26,124,556	$16,383,040	($9,741,517)	9.9%	6.2%	8.4%	0.0%
	ComEd – External	$17,374,014	$11,941,934	($5,432,080)	6.6%	4.5%	4.7%	0.0%
	DAY – DEOK	$7,847,211	$458,223	($7,388,988)	3.0%	0.2%	6.4%	0.0%
	Dominion	$26,080,164	$23,020,434	($3,059,730)	9.9%	8.7%	2.6%	0.0%
	DPL	$7,731,039	$7,296,481	($434,557)	2.9%	2.8%	0.4%	0.0%
	JCPL	$8,262,859	$11,735,242	$3,472,383	3.1%	4.5%	0.0%	3.0%
	Met-Ed	$6,603,429	$2,155,535	($4,447,893)	2.5%	0.8%	3.8%	0.0%
	PECO	$16,525,629	$2,369,852	($14,155,777)	6.3%	0.9%	12.2%	0.0%
	PENELEC	$12,159,062	$2,226,700	($9,932,362)	4.6%	0.8%	8.6%	0.0%
	PPL	$17,380,745	$21,369,925	$3,989,180	6.6%	8.1%	0.0%	3.4%
	PSEG	$18,430,747	$125,848,031	$107,417,284	7.0%	47.8%	0.0%	92.5%
	RECO	$704,446	$0	($704,446)	0.3%	0.0%	0.6%	0.0%
	All Zones	$212,299,672	$263,208,714	$50,909,042	80.7%	100.0%	56.2%	100.0%
Hubs and Aggregates	AEP – Dayton	$1,484,226	$0	($1,484,226)	0.6%	0.0%	1.3%	0.0%
	Dominion	$1,805,815	$0	($1,805,815)	0.7%	0.0%	1.6%	0.0%
	Eastern	$162,894	$0	($162,894)	0.1%	0.0%	0.1%	0.0%
	New Jersey	$558,587	$0	($558,587)	0.2%	0.0%	0.5%	0.0%
	Ohio	$50,544	$0	($50,544)	0.0%	0.0%	0.0%	0.0%
	Western Interface	$993,731	$0	($993,731)	0.4%	0.0%	0.9%	0.0%
	Western	$11,720,839	$0	($11,720,839)	4.5%	0.0%	10.1%	0.0%
	RTEP B0328 Source	$32	$0	($32)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$16,776,668	$0	($16,776,668)	6.4%	0.0%	14.5%	0.0%
Interfaces	CPLE Imp	$3,992	$0	($3,992)	0.0%	0.0%	0.0%	0.0%
	Hudson	$143,878	$0	($143,878)	0.1%	0.0%	0.1%	0.0%
	IMO	$3,169,649	$0	($3,169,649)	1.2%	0.0%	2.7%	0.0%
	Linden	$1,304,628	$0	($1,304,628)	0.5%	0.0%	1.1%	0.0%
	MISO	$2,961,975	$0	($2,961,975)	1.1%	0.0%	2.6%	0.0%
	Neptune	$642,606	$0	($642,606)	0.2%	0.0%	0.6%	0.0%
	NIPSCO	$8,432	$0	($8,432)	0.0%	0.0%	0.0%	0.0%
	Northwest	$102,293	$0	($102,293)	0.0%	0.0%	0.1%	0.0%
	NYIS	$6,410,643	$0	($6,410,643)	2.4%	0.0%	5.5%	0.0%
	OVEC	$753,991	$0	($753,991)	0.3%	0.0%	0.6%	0.0%
	South Exp	$4,380,862	$0	($4,380,862)	1.7%	0.0%	3.8%	0.0%
	South Imp	$14,196,484	$0	($14,196,484)	5.4%	0.0%	12.2%	0.0%
	All Interfaces	$34,079,433	$33,970	($34,045,462)	13.0%	0.0%	29.4%	0.0%
	Total	$263,155,772	$263,242,684	$86,912	100.0%	100.0%	100.0%	100.0%

15 Zonal information in each zonal table has been aggregated to ensure that market sensitive data is not revealed. Table 3-21 does not include synchronous condensing and local constraint control charges and credits since these are allocated zonally.
16 The total balance should be zero but due to resettlements performed while this report was been developed, total operating reserve charges do not match total operating reserve credits.

Table 3-22 and Table 3-23 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 3-22 Monthly balancing operating reserve charges and credits to generators (Eastern Region): January through June 2013

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$2,096,513	$7,281,329	$1,253,875	$10,631,718	$67,207,246
Feb	$556,817	$11,003,414	$508,995	$12,069,225	$62,194,877
Mar	$580,462	$576,344	$746,430	$1,903,236	$10,847,015
Apr	$999,408	$1,469,523	$575,474	$3,044,405	$18,664,201
May	$972,766	$288,017	$954,400	$2,215,183	$12,090,561
Jun	$685,563	$147,729	$755,561	$1,588,853	$12,129,734
East Generators Total	$5,891,530	$20,766,356	$4,794,734	$31,452,620	$183,133,633
PJM Total	$53,824,421	$98,983,289	$44,230,627	$197,038,337	$228,240,719
Share	10.9%	21.0%	10.8%	16.0%	80.2%

Table 3-23 Monthly balancing operating reserve charges and credits to generators (Western Region): January through June 2013

	Generators RTO Deviation Charges	Generators Regional Deviation Charges	Generators LOC and Canceled Resources Charges	Total Charges	Balancing, LOC and Canceled Resources Credits
Jan	$2,538,766	$156,268	$1,705,694	$4,400,728	$11,986,551
Feb	$856,451	$54,981	$611,030	$1,522,462	$4,905,889
Mar	$858,010	$59,092	$1,007,397	$1,924,499	$6,606,397
Apr	$1,405,584	$18,514	$928,440	$2,352,538	$4,972,019
May	$1,151,568	$470,712	$1,243,513	$2,865,793	$10,905,805
Jun	$825,670	$224,200	$899,070	$1,948,941	$5,641,175
West Generators Total	$7,636,049	$983,768	$6,395,144	$15,014,960	$45,017,838
PJM Total	$53,824,421	$3,390,294	$44,230,627	$101,445,341	$228,240,719
Share	14.2%	29.0%	14.5%	14.8%	19.7%

Table 3-22 shows that on average, 16.0 percent of the RTO and Eastern Region balancing generator charges, including lost opportunity cost and canceled resources charges were paid by generators deviating in the Eastern Region

while these generators received 80.2 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 3-23 also shows that generators in the Western Region paid 14.8 percent of the RTO and Western Region balancing generator charges including lost opportunity cost and canceled resources charges while these generators received 19.7 percent of all balancing generator credits including lost opportunity cost and canceled resources credits.

Table 3-24 shows that on average in the first six months of 2013, operating reserve charges paid by generators were 10.7 percent of all operating reserve charges, excluding local constraints control charges which are allocated to the requesting transmission owner, 1.5 percentage points lower than the average in the first six months of 2012. Generators received 99.99 percent of all operating reserve credits, while the remaining 0.01 percent were credits paid to import transactions, load response resources and unallocated congestion charges.

Table 3-24 Percentage of unit credits and charges of total credits and charges: 2012 and 2013

	2012		2013	
	Generators Share of Total Operating Reserve Charges	Generators Share of Total Operating Reserve Credits	Generators Share of Total Operating Reserve Charges	Generators Share of Total Operating Reserve Credits
Jan	10.8%	99.9%	12.3%	100.0%
Feb	8.2%	100.0%	14.0%	100.0%
Mar	11.7%	99.8%	8.4%	99.9%
Apr	13.6%	100.0%	10.3%	100.0%
May	14.0%	100.0%	8.6%	100.0%
Jun	13.6%	99.9%	6.2%	100.0%
Jul	15.6%	99.8%		
Aug	14.6%	100.0%		
Sep	9.4%	100.0%		
Oct	12.6%	99.9%		
Nov	12.7%	99.8%		
Dec	8.8%	100.0%		
Average (Jan - Jun)	12.2%	99.9%	10.7%	100.0%
Average	12.3%	99.9%		

Reactive services charges are allocated by zone or zones where the service is provided, and charged to real-time load of the zone or zones. The costs of running units that provide reactive services to the entire RTO Region are allocated to the entire RTO real-time load. Table 3-25 shows the geography of reactive services charges. In the first six months of 2013, 55.9 percent of all reactive service charges were paid by real-time load in the single zone where the service was provided, 7.5 percent were paid by real-time load in multiple zones and 36.6 percent were paid by real-time load across the entire RTO. In the first six months of 2013, resources in two control zones accounted for 99.5 percent of all reactive services costs allocated across the entire RTO.

Table 3-25 Geography of reactive services charges: January through June, 2013[17]

Location	Charges	Share of Charges
Single Zone	$60,604,689	55.9%
Multiple Zones	$8,089,031	7.5%
Entire RTO	$39,710,593	36.6%
Total	$108,404,313	100.0%

In the first six months of 2013, the top three zones accounted for 80.5 percent of all the reactive services charges allocated to single zones.

Black start services charges are allocated to zone and non-zone peak transmission use. Resources in one zone accounted for 99.7 percent of all the black start services costs in the first six months of 2013. These costs resulted from noneconomic operation of units providing black start service under the Automatic Load Rejection (ALR) option in the AEP Control Zone.

Synchronous condensing charges are allocated by zone. Resources in two control zones accounted for all synchronous condensing costs in the first six months of 2013.[18]

Operating Reserve Issues
Concentration of Operating Reserve Credits

There is a continuing 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, PJM's persistent need for operating reserves in particular locations and the fact that the lack of transparency makes it impossible for competition to affect operating reserve credit payments.

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17 PJM and the MMU cannot publish more detailed information about the location of the costs of reactive services because of confidentiality requirements. See "Manual 33: Administrative Services for the PJM Interconnection Agreement," Revision 09 (July 22, 2010).

18 PJM and the MMU cannot publish more detailed information about the location of the costs of synchronous condensing because of confidentiality requirements. See "Manual 33: Administrative Services for the PJM Interconnection Agreement," Revision 09 (July 22, 2010).

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 in the top 10 units remains high and it increased in the first six months of 2013 compared to the first six months of 2012. Table 3-26 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 40.3 percent of total operating reserve credits in the first six months of 2013, compared to 26.0 percent in the first six months of 2012.

Table 3-26 Top 10 operating reserve credits units (By percent of total system): January through June 2012 and 2013

	Top 10 Units Credit Share	Percent of Total PJM Units
Jan – Jun 2012	26.0%	0.7%
Jan – Jun 2013	40.3%	0.7%

Table 3-27 shows the credits received by the top 10 units and top 10 organizations in each of the operating reserve categories paid to generators. The shares of the top 10 organizations in all categories separately were above 86.0 percent.

Table 3-27 Top 10 units and organizations operating reserve credits: January through June 2013

Category	Type	Top 10 units Credits	Credits Share	Top 10 organizations Credits	Credits Share
Day-Ahead	Generators	$22,740,843	65.0%	$31,810,259	90.9%
	Canceled Resources	$19,250	100.0%	$19,250	100.0%
Balancing	Generators	$121,648,095	66.1%	$168,269,095	91.5%
	Local Constraints Control	$21,918	100.0%	$21,918	100.0%
	Lost Opportunity Cost	$15,827,266	35.8%	$38,454,671	87.0%
Reactive Services		$61,271,723	56.5%	$105,525,959	97.3%
Synchronous Condensing		$2,832	100.0%	$2,832	100.0%
Black Start Services		$40,419,076	84.3%	$47,971,015	100.0%
Total		$168,976,634	40.3%	$364,785,718	86.9%

Table 3-28 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In the first six months of 2013, 91.1 percent of all credits paid to these units were allocated to deviations while the remaining 8.9 percent were paid for reliability reasons.

Table 3-28 Identification of balancing operating reserve credits received by the top 10 units by category and region: January through June 2013

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits	$7,339,152	$3,535,441	$0	$25,643,479	$85,130,023	$0	$121,648,095
Share	6.0%	2.9%	0.0%	21.1%	70.0%	0.0%	100.0%

In the first six months of 2013, concentration in all operating reserve credits categories was high.[19,20] Operating reserve credits HHI was calculated based on each organization's daily credits for each category. Table 3-29 shows the average HHI for each category. HHI for day-ahead operating reserve credits was 5223, for balancing operating reserve generator credits was 4392 and for lost opportunity cost credits was 4753.

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19 See Section 2, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
20 Table 3-29 excludes the local constraints control categories.

Table 3-29 Daily operating reserve credits HHI: January through June 2013

Category	Type	Average	Minimum	Maximum	Highest market share (One day)	Highest market share (All days)
Day-Ahead	Generators	5223	1254	10000	100.0%	59.2%
	Imports	10000	10000	10000	100.0%	53.3%
	Load Response	NA	NA	NA	NA	NA
Balancing	Canceled Resources	10000	10000	10000	100.0%	100.0%
	Generators	4392	1438	9888	99.4%	55.8%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	10000	10000	10000	100.0%	68.9%
	Lost Opportunity Cost	4753	862	10000	100.0%	34.6%
Reactive Services		4475	1852	10000	100.0%	43.2%
Synchronous Condesing		10000	10000	10000	100.0%	66.1%
Black Start Services		9947	8650	10000	100.0%	99.7%
Total		9947	8650	10000	85.1%	30.0%

Day-Ahead Unit Commitment for Reliability

PJM may schedule units as must run in the Day-Ahead Energy Market when needed in real time to address reliability issues of various types. PJM puts such reliability issues in four categories: voltage issues (high and low); black start requirement (from automatic load rejection units); local contingencies not seen in the Day-Ahead Energy Market; and long lead time units not able to be scheduled in the Day-Ahead Energy Market.[21] Participants can submit units as self-scheduled (must run), meaning that the unit must be committed but a unit submitted as must run by a participant cannot set LMP and is not eligible for day-ahead operating reserve credits.[22] Units scheduled as must run by PJM may set LMP if raised above economic minimum and are eligible for day-ahead operating reserve credits.

Table 3-30 shows the total day-ahead generation and the subset of that generation scheduled as must run by PJM. In the first six months of 2013, 4.5 percent of the total day-ahead generation was scheduled as must run by PJM, 2.3 percentage points higher than the first six months of 2012.[23]

Table 3-30 Day-ahead generation scheduled as must run by PJM: 2012 and 2013

	2012			2013		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	71,152	1,312	1.8%	72,681	2,907	4.0%
Feb	63,642	1,191	1.9%	65,632	2,474	3.8%
Mar	60,513	1,109	1.8%	67,940	3,178	4.7%
Apr	55,999	1,099	2.0%	57,570	2,522	4.4%
May	62,986	1,944	3.1%	61,169	2,848	4.7%
Jun	69,190	1,841	2.7%	68,452	3,724	5.4%
Jul	82,984	3,618	4.4%			
Aug	76,161	2,438	3.2%			
Sep	63,535	2,902	4.6%			
Oct	60,656	3,509	5.8%			
Nov	62,985	3,542	5.6%			
Dec	68,759	2,347	3.4%			
Total (Jan – Jun)	383,481	8,495	2.2%	393,443	17,654	4.5%
Total	798,561	26,851	3.4%			

Pool-scheduled units are made whole in the Day-Ahead Energy Market if their total offer (including no load and startup costs) is greater than the revenues from the Day-Ahead Energy Market. Such units are paid day-ahead operating reserve credits. Pool-scheduled units scheduled as must run by PJM are only paid day-ahead operating reserve credits when their total offer is greater than the revenues from the Day-Ahead Energy Market. Table 3-31 shows the total day-ahead generation scheduled as must run by PJM by category. In the first six months of 2013, 67.3 percent of the day-ahead generation scheduled as must run by PJM received operating reserve credits, of which, 15.0 percent were credits paid to units scheduled to provide black start services, 39.8 percent were credits paid to units scheduled to provide reactive services and 12.4 percent were normal day-ahead operating reserve credits paid to units scheduled noneconomic. The remaining 32.7 percent of the day-ahead generation scheduled as must run by PJM did not need to be made whole.

Table 3-31 Day-ahead generation scheduled as must run by PJM by category (GWh): 2013

	Black Start Services	Reactive Services	Day-Ahead Operating Reserves	Economic	Total
Jan	433	1,271	250	954	2,907
Feb	430	1,356	206	481	2,474
Mar	424	909	490	1,354	3,178
Apr	451	840	439	792	2,522
May	429	1,058	346	1,016	2,848
Jun	484	1,601	459	1,181	3,724
Total	2,652	7,035	2,190	5,777	17,654
Share	15.0%	39.8%	12.4%	32.7%	100.0%

Total day-ahead operating reserve credits in the first six months of 2013 were $35.0 million, 56.9 percent of that total was paid to units scheduled as must run by PJM, not scheduled to provide black start or reactive services.

The MMU recommends PJM clearly identify and classify all reasons for incurring operating reserves in the Day-Ahead and the Real-Time Energy Markets in order to help ensure a long term solution to the issue of how to allocate the costs of operating reserves. The overall 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.

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost credits are paid to units under two scenarios. If a combustion turbine or a diesel is scheduled to operate in day-ahead but is not requested by PJM in real time, the unit will receive a credit which covers the day-ahead financial position of the unit plus balancing spot energy market charges that the unit will have to pay. For purposes of this report, this lost opportunity cost will be referred to as day-ahead lost opportunity cost.[24] If a unit generating in

[24] A unit's day-ahead financial position equals the revenues from the Day-Ahead Energy Market subtracted by the expected costs (valued at the unit's offer curve cleared in day ahead). A unit scheduled in the Day-Ahead Energy Market and not called in real time incurs in balancing spot energy charges since it has to cover its day-ahead scheduled energy position in real time.

real time with an offer price lower than the LMP at the unit's bus is reduced or suspended by PJM due to a transmission constraint or other reliability issue, the unit will receive a credit for lost opportunity cost based on the desired output. For purposes of this report, this lost opportunity cost will be referred as real-time lost opportunity cost.

In the first six months of 2013, lost opportunity cost credits decreased by $23.7 million or 34.9 percent compared to the first six months of 2012. The decrease of $23.7 million is comprised of a decrease of $30.6 million in day-ahead lost opportunity cost and an increase of $6.9 million in real-time lost opportunity cost. Table 3-34 shows the monthly composition of lost opportunity cost credits in 2012 and 2013.

Table 3-32 Monthly lost opportunity cost credits: 2012 and 2013

	2012			2013		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$5,116,947	$332,282	$5,449,229	$8,862,207	$2,752,980	$11,615,188
Feb	$4,277,162	$366,971	$4,644,133	$2,050,724	$2,681,143	$4,731,868
Mar	$10,327,361	$450,299	$10,777,660	$4,854,970	$2,350,261	$7,205,230
Apr	$11,814,780	$692,309	$12,507,090	$3,893,834	$1,548,469	$5,442,303
May	$15,806,150	$3,502,912	$19,309,062	$5,357,701	$2,876,609	$8,234,310
Jun	$14,502,682	$677,375	$15,180,057	$6,211,445	$746,748	$6,958,193
Jul	$27,875,651	$3,066,115	$30,941,767			
Aug	$25,573,420	$1,202,079	$26,775,499			
Sep	$19,723,184	$1,825,454	$21,548,638			
Oct	$12,391,362	$7,619,940	$20,011,303			
Nov	$14,547,688	$4,073,072	$18,620,760			
Dec	$5,177,551	$987,447	$6,164,998			
Total (Jan – Jun)	$61,845,083	$6,022,149	$67,867,232	$31,230,882	$12,956,210	$44,187,093
Share (Jan – Jun)	91.1%	8.9%	100.0%	70.7%	29.3%	100.0%
Total	$167,133,940	$24,796,257	$191,930,196			
Share	87.1%	12.9%	100.0%			

Day-ahead lost opportunity cost (payments to combustion turbines and diesels scheduled in the Day-Ahead Market and not requested in real time) continue to receive the majority of all lost opportunity cost credits. In the first six months of 2013, day-ahead lost opportunity cost were 70.7 percent of all lost opportunity cost credits. Combustion turbines and diesels are only eligible

for day-ahead lost opportunity cost if the units are scheduled in day ahead and follow PJM instructions in real time.[25] Table 3-33 shows, for combustion turbines and diesels scheduled day ahead, the total day-ahead generation, the day-ahead generation from units that were not requested by PJM in real time and the subset of that generation that received lost opportunity costs credits. In the first six months of 2013, PJM scheduled 5,125 GWh from combustion turbines and diesels, of which 51.8 percent was not requested by PJM in real time and of which 38.7 percent received lost opportunity cost credits, 20.2 percentage points lower than the first six months of 2012.

all day-ahead generation not called in real time by PJM and receiving lost opportunity cost credits from those unit types.

Combustion turbines and diesels receive lost opportunity cost credits on an hourly basis. For example, if a combustion turbine is scheduled to run from hour 10 to hour 18 and the unit only runs from hour 12 to hour 16, the unit is eligible for lost opportunity cost credits for hours 10, 11, 17 and 18. Table 3-34 shows the lost opportunity costs credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market for units that did not run in real time and units that ran in real time for at least one hour of their day-ahead schedule. Table 3-34 shows that in the first six months of 2013, $24.0 million or 76.8 percent of all lost opportunity cost credits were paid to combustion turbines and diesels that did not run for any hour in real time, 11.4 percentage points lower than the first six months of 2012.

Table 3–33 Day-ahead generation from combustion turbines and diesels (GWh): 2012 and 2013

	2012			2013		
	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits	Day-Ahead Generation	Day-Ahead Generation Not Requested in Real Time	Day-Ahead Generation Not Requested in Real Time Receiving LOC Credits
Jan	572	435	373	886	638	565
Feb	753	590	546	430	206	173
Mar	1,408	1,076	921	809	397	283
Apr	1,870	1,431	1,249	684	325	256
May	1,926	1,250	1,046	1,031	389	262
Jun	2,586	1,624	1,235	1,284	699	442
Jul	3,898	1,424	988			
Aug	2,356	1,383	1,122			
Sep	1,635	1,169	1,032			
Oct	1,079	895	797			
Nov	1,319	1,018	823			
Dec	851	678	625			
Total (Jan – Jun)	9,116	6,406	5,370	5,125	2,655	1,981
Share (Jan – Jun)	100.0%	70.3%	58.9%	100.0%	51.8%	38.7%
Total	20,254	12,973	10,757			
Share	100.0%	64.1%	53.1%			

In the first six months of 2013, the top three control zones in which generation received lost opportunity cost credits, ATSI, AP and ComEd accounted for 56.0 percent of all lost opportunity cost credits, 43.7 percent of all the day-ahead generation from combustion turbines and diesels and 67.1 percent of

25 Combustion turbines and diesels with lead times of two hours or less are automatically eligible for lost opportunity cost credits. Combustion turbines and diesels with lead times greater than two hours are assumed to be committed in real time for the duration of their day-ahead schedule unless instructed not to run by PJM.

Table 3-34 Lost opportunity cost credits paid to combustion turbines and diesels by scenario: 2012 and 2013

	2012			2013		
	Units That Did Not Run in Real Time	Units That Ran in Real Time for At Least One Hour of Their Day-Ahead Schedule	Total	Units That Did Not Run in Real Time	Units That Ran in Real Time for At Least One Hour of Their Day-Ahead Schedule	Total
Jan	$4,857,442	$355,007	$5,212,449	$8,166,901	$695,307	$8,862,207
Feb	$4,382,996	$154,019	$4,537,015	$1,860,546	$190,178	$2,050,724
Mar	$9,661,923	$894,042	$10,555,965	$3,031,710	$1,823,260	$4,854,970
Apr	$10,846,998	$1,028,201	$11,875,199	$2,476,452	$1,417,382	$3,893,834
May	$12,925,885	$2,775,886	$15,701,771	$3,686,814	$1,670,887	$5,357,701
Jun	$12,550,655	$2,163,079	$14,713,734	$4,762,210	$1,449,235	$6,211,445
Jul	$13,911,706	$13,967,989	$27,879,694			
Aug	$22,219,006	$3,415,961	$25,634,967			
Sep	$17,783,763	$2,196,639	$19,980,402			
Oct	$11,185,166	$1,296,974	$12,482,141			
Nov	$12,704,380	$2,130,370	$14,834,749			
Dec	$4,979,204	$364,570	$5,343,774			
Total (Jan - Jun)	$55,225,900	$7,370,233	$62,596,133	$23,984,633	$7,246,249	$31,230,882
Share (Jan - Jun)	88.2%	11.8%	100.0%	76.8%	23.2%	100.0%
Total	$138,009,125	$30,742,736	$168,751,861			
Share	81.8%	18.2%	100.0%			

PJM may not run units in real time if the real-time value of that energy (generation multiplied by the real-time LMP) is lower than the units' total offer (including no load and startup costs). Table 3-35 shows the total day-ahead generation from combustion turbines and diesels that were not called in real time by PJM and received lost opportunity cost credit. Table 3-35 shows the scheduled generation that had a total offer (including no load and startup costs) lower than its real-time value (generation multiplied by the real-time LMP) or economic scheduled generation, and the scheduled generation that had a total offer greater than its real-time value or noneconomic scheduled generation. In the first six months of 2013, 69.0 percent of the scheduled generation not called by PJM from units receiving lost opportunity cost credits was economic and the remaining 31.0 percent was noneconomic.

Table 3-35 Day-ahead generation (GWh) from combustion turbines and diesels receiving lost opportunity cost credits by value: 2012 and 2013[26]

	2012			2013		
	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)
Jan	309	136	445	548	121	669
Feb	422	248	670	171	53	224
Mar	805	287	1,092	272	145	417
Apr	1,126	329	1,455	225	93	318
May	875	363	1,237	229	130	359
Jun	835	667	1,501	364	272	635
Jul	826	402	1,228			
Aug	946	397	1,343			
Sep	880	305	1,185			
Oct	710	193	903			
Nov	782	280	1,062			
Dec	434	298	732			
Total (Jan – Jun)	4,372	2,030	6,401	1,809	814	2,622
Share (Jan – Jun)	68.3%	31.7%	100.0%	69.0%	31.0%	100.0%
Total	8,950	3,904	12,853			
Share	69.6%	30.4%	100.0%			

The MMU recommends that PJM initiate an analysis of the reasons why some combustion turbines and diesels scheduled in the Day-Ahead Energy Market are not called in real time when they are economic.

Lost Opportunity Cost Calculation

On February 17, 2012, the PJM Market Implementation Committee (MIC) endorsed the charge to prepare a proposal to make all energy related lost opportunity costs calculations consistent throughout the PJM rules.[27] PJM and the MMU jointly proposed two specific modifications. The MMU also believes that two additional modifications would be appropriate but the MMU did not formally recommend these to the MIC for consideration although they were brought to the attention of the MIC.

- **Unit Schedule Used:** Current rules require the use of the higher of a unit's price-based and cost-based schedules to calculate the lost opportunity cost in the energy market. The MMU recommends that the lost opportunity cost in the energy and ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market.

- **No load and startup costs:** Current rules do not include in the calculation of lost opportunity cost credits all of the costs not incurred by a scheduled unit not running in real time. Generating units do not incur no load or startup costs if they are not dispatched in real time. As a result, no load and startup costs should be subtracted from the real time LMP in the same way that the incremental energy offer is subtracted to calculate the actual value of the opportunity lost by the unit. The MMU recommends including no load and startup costs as part of the total avoided costs in the calculation of lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not called in real time.

- **Day-Ahead LMP:** Current rules require the use of the day-ahead LMP as part of the lost opportunity cost calculation logic when a unit is scheduled on a noneconomic basis day ahead, meaning that the unit's offer is greater than the day-ahead LMP. In the Day-Ahead Energy Market, such units receive operating reserve credits equal to the difference between the unit's offer (including no load and startup costs) and the day-ahead LMP. If such a unit is not dispatched in real time, under the current rules the unit receives lost opportunity cost credits equal to the difference between the real-time LMP and the day-ahead LMP. This calculation results in double counting because the unit has already been made whole to its day-ahead offer in the Day-Ahead Energy Market through day-ahead operating reserve credits

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26 The total generation in Table 3-35 is lower than the Day-Ahead Generation not requested in Real Time in Table 3-33 because the former only includes generation from units that received lost opportunity costs during at least one hour of the day. Table 3-35 includes all generation, including generation from units that were not called in real time and did not receive lost opportunity cost credits.

27 See "Meeting Minutes," from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20120217/20120217-minutes.ashx>. (February 17, 2012)

if necessary. If the unit is not dispatched in real time, it should receive only the difference between real-time LMP and the unit's offer, which is the actual lost opportunity cost. The MMU recommends eliminating the use of the day-ahead LMP to calculate lost opportunity cost credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not called in real time.

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

These four modifications are consistent with the inputs used by PJM's software to commit combustion turbines in real time. PJM's commitment process is based on the forecasted LMPs, the reliability requirements, reserve requirement and the total cost of the units. The total cost of the units includes no load costs and startup costs and is based on the units' schedule on which it is committed.

Table 3-36 shows the impact that each of these changes would have had on the lost opportunity cost credits in the energy market for the first six months of 2013, for the two categories of lost opportunity cost credits. Energy lost opportunity cost credits would have been reduced by a net of $12.9 million, or 29.2 percent, if all these changes had been implemented.[28]

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

Table 3-36 Impact on energy market lost opportunity cost credits of rule changes: January through June 2013

	LOC when output reduced in RT	LOC when scheduled DA not called RT	Total
Current Credits	$12,956,210	$31,230,882	$44,187,093
Impact 1: Committed Schedule	$548,482	$5,444,941	$5,993,423
Impact 2: Eliminating DA LMP	NA	($202,740)	($202,740)
Impact 3: Using Offer Curve	($630,673)	$2,602,845	$1,972,172
Impact 4: Including No Load Cost	NA	($16,282,944)	($16,282,944)
Impact 5: Including Startup Cost	NA	($4,361,730)	($4,361,730)
Net Impact	($82,191)	($12,799,628)	($12,881,819)
Credits After Changes	$12,874,020	$18,431,254	$31,305,274

Black Start Service Units

Certain units located in the AEP control zone are relied on for their black start capability on a regular basis even during periods when the units are not economic. The relevant black start units provide black start service under the Automatic Load Rejection (ALR) option, which means that the units must be running even if not economic. Units providing black start service under the ALR option could remain running at a minimum level, disconnected from the grid. The costs of the noneconomic operation of these units results in make whole payments in the form of operating reserve credits. The MMU recommended that these costs be allocated as black start charges. This recommendation was made effective on December 1, 2012.[29]

In the first six months of 2013, the cost of the noneconomic operation of ALR units in the AEP control zone was $47.8 million, 94.8 percent of these costs was paid by peak transmission use in the AEP control zone while the remaining 5.2 percent was paid by non-zone peak transmission use (exports from PJM).

PJM and AEP have issued two requests for proposal (RFP) seeking additional black start capability for the AEP control zone. PJM awarded all viable solutions from the last RFP.[30] PJM has approved new rules concerning black

29 See PJM Interconnection, L.L.C., Docket No. ER13-481-000 (November 30, 2012).
30 See "Item 3: Black Start RFP Status," from the PJM's System Restoration Strategy Task Force June 14, 2013 meeting. <http://www.pjm.com/~/media/committees-groups/task-forces/srstf/20130614/20130614-item-03-srstf-bs-rfp-status.ashx>.

start service procurement, and the new selection process will be effective on April 1, 2015.[31,32]

Con Edison – 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.[33] These units are often run out-of-merit and received substantial balancing operating reserve 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.

Reactive / Voltage Support Units

Certain units located in the BGE and Pepco control zones are committed to provide reactive support to the AP-South interface. The AP-South interface consists of four 500 kV transmission lines that connected the Western and Eastern regions of PJM. PJM approved in the 2012 Regional Transmission Expansion Planning (RTEP) seven reactive upgrades to solve identified N-1-1 low voltage NERC criteria violations, and five of the seven upgrades are located in substations at or near the AP-South interface. These upgrades should reduce the need for noneconomic operation of units to provide reactive support to the AP-South interface.

Reactive Service Credits and Operating Reserve Credits

Credits to resources providing reactive services are separate from operating reserve credits.[34] Under the rules providing for credits for reactive service, units are not assured recovery of the entire offer including no load and startup costs as they are under the operating reserve credits rules. Units providing reactive services at the request of PJM are made whole through reactive service credits. But when the reactive service credits do not cover a unit's entire offer, the unit is paid through balancing operating reserves. The result

is a misallocation of the costs of providing reactive service. Reactive service credits are paid by real-time load in the control zone or zones where the service is provided while balancing operating reserve are paid by deviations from day-ahead or real-time load plus exports depending on the allocation process rather than by zone.

In the first six months of 2013, units providing reactive services were paid $4.8 million in balancing operating reserve credits in order to cover their total energy offer.

On October 10, 2012 and November 7, 2012 the MMU presented this issue at PJM's Market Implementation Committee (MIC).[35,36] The MIC endorsed the issue charge and approved merging this issue with the long term solution for the allocation of the cost of day-ahead operating reserves for reliability.[37]

The MMU recommends that the total cost of providing reactive support be categorized and allocated as reactive services. Reactive services credits should be calculated consistent with operating reserve credits calculation.

Internal Bilateral Transactions

Market participants are allocated a portion of the costs of operating reserves based on their deviations. Deviations are calculated in three categories, demand, supply and generation. Generators deviate when their real-time output is different than the desired output or their day-ahead scheduled output.[38] Load, interchange transactions, internal bilateral transactions, demand response, increment offers and decrement bids also incur deviations. These transactions are grouped in the demand and supply categories.

Generators are allowed to offset their deviations with other generators at the same bus if all generators have the same electrical impact on the transmission

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31 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at "Black Start Service".

32 See "Manual 14D: Generator Operational Requirement" Revision 23 (April 1, 2013) at "Section 10: Black Start Generation Procurement".

33 See the *2012 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.

34 OATT Attachment K - Appendix § 3.2.3B (f).

35 See "Item 7: Reactive Service and Operating Reserve Credits Problem Statement and Issue Charge," from the PJM's MIC October 10, 2012 meeting. <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-07-reactive-service-and-operating-reserve-credits-problem-statement-and-issue-charge.ashx>.

36 See "Minutes," from PJM's MIC November 7, 2012 meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20121212/20121212-draft-minutes-mic-20121107.ashx>.

37 PJM created the MIC sub group Day Ahead (DA) Reliability and Reactive Cost Allocation (DARRCA) to address the allocation of the cost of reactive services in day ahead and real time. <http://www.pjm.com/committees-and-groups/issue-tracking/issue-tracking-details.aspx?Issue={323CE736-A41E-49D4-A8AF-687BB3697AE9}> (Accessed January 11, 2013).

38 See OATT 3.2.3 (o) for a complete description of how generators deviate.

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system. Load, interchange transactions, internal bilateral transactions, demand response, increment offers and decrement bids are also allowed to offset their deviations. These transactions are grouped into two categories, demand and supply and aggregated by location. A negative deviation from one transaction can offset a positive deviation from another transaction in the same category, as long as both transactions are in the same location at the same hour.[39] Demand transactions such as load, exports, internal bilateral sales and decrement bids may offset each other's deviations. The same applies to supply transactions such as imports, internal bilateral purchases and increment offers. Unlike all other transaction types, internal bilateral sales and purchases do not impact dispatch or market prices. Internal bilateral transactions are used by participants to transfer the financial responsibility or right of the energy withdrawn or injected into the system in the Day-Ahead and Real-Time Energy Markets.

The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. IBTs should not pay for balancing operating reserves and should not be used to offset other transactions that deviate. IBTs shift the responsibility for an injection or withdrawal in PJM from one participant to another but IBTs are not part of the day-ahead unit commitment process, do not set energy prices and do not impact the energy flows in either the Day-Ahead or the Real-Time Energy Market, therefore IBTs should not be consider in the allocation of balancing operating reserve charges. The use of IBTs has been extended to offset deviations that other transactions that do impact the Energy Market may have. The elimination of the use of IBTs in the deviation calculation would eliminate the balancing operating reserve charges to participants that use IBTs only in real time. Such elimination would increase the balancing operating reserve charges to participants that use IBTs to offset deviations from day-ahead transactions.

The impact of eliminating the use of internal bilateral transactions in the calculation of deviations use to allocated balancing operating reserve charges has been aggregated with the impacts of other recommendations.[40]

Up-to Congestion Transactions

Up-to congestion transactions do not pay operating reserve charges. The MMU calculated the impact on 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 six months of 2013, 52.9 percent of all up-to congestion transactions were profitable.[41]

The MMU calculated the up-to congestion transactions that would have remained if operating reserve charges had been applied and the other identified quantifiable recommendations had been implemented. It was assumed that up-to congestion transactions would have maintained the same shares of profitable and unprofitable transactions after paying operating reserve charges as when no operating reserve charges were paid. If up-to congestion transactions were allocated operating reserve charges, 69.2 percent of all up-to congestion transactions would have been made. Even with this reduction in the level of up-to congestion transactions, the contribution to total operating reserve charges and the impact on other participants who pay those charges would have been significant.[42]

The MMU recommends that up-to congestion transactions be required to pay operating reserve charges. Up-to congestion transactions would have paid an average rate between $0.265 and $0.392 per MWh in the first six months of 2013.[43]

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39 Locations can be control zones, hubs, aggregates and interfaces. See the *2012 State of the Market Report for PJM, Volume II*, Section 3, "Operating Reserve" at "Description of Operating Reserves" pp. 102-103 for a full description of balancing operating reserve locations.

40 See "Quantifiable Recommendations Impact" on "Operating Reserve Issues" for the impact of this and other Operating Reserve recommendations.

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

42 See "Quantifiable Recommendations Impact" on "Operating Reserve Issues" for the impact of this and other Operating Reserve recommendations.

43 The range of operating reserve rates paid by up-to congestion transactions depends on the location of the transactions' source and sink.

Quantifiable Recommendations Impact

The MMU calculated the impact that all quantifiable recommendations would have had on the operating reserve rates paid by participants in the RTO, Eastern and Western Region. For reasons of confidentiality, these impacts cannot be disaggregated by issue. Five recommendations have been aggregated in this analysis: reallocation of operating reserve credits paid to units supporting the Con Edison – PSEG wheeling contracts; reallocation of no load and startup costs of units providing reactive services; implementation of the proposed changes to lost opportunity cost calculations; elimination of internal bilateral transactions from the deviations calculation; and the allocation of operating reserve charges to up-to congestion transactions.

Table 3-37 shows the combined impact that these recommendations would have had on all operating reserve rates for the first six months of 2013. The reduction in the rates is due to a decrease of 51.9 percent of the credits used to calculate these rates and a weighted average increase of 677.6 percent in the denominators used to calculate these rates.[44]

Table 3-37 MMU Recommendations Impact on Operating Reserve Rates: January through June 2013

	Current Rates ($/MWh)	Proposed Rates ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.086	0.026	(0.060)	(69.8%)
RTO Reliability	0.050	0.032	(0.018)	(36.1%)
East Reliability	0.041	0.041	0.000	0.0%
West Reliability	0.004	0.004	0.000	0.0%
RTO Deviations	0.887	0.054	(0.834)	(93.9%)
East Deviations	3.302	0.073	(3.229)	(97.8%)
West Deviations	0.117	0.011	(0.106)	(90.7%)
Lost Opportunity Cost	0.729	0.050	(0.679)	(93.1%)
Canceled Resources	0.000	0.000	(0.000)	(90.3%)

Table 3-38 shows the operating reserve cost of a 1 MW transaction had these recommendations been implemented in the first six months of 2013. For example, a decrement bid in the Eastern Region (if not offset by other transactions) would have paid an average rate of $0.209 per MWh, $4.401

per MWh or 95.5 percent less than the actual average rate paid. An up-to congestion transactions sourced in the Eastern Region and sinking at the Western Region would have been charged an average rate of $0.329 per MWh. Table 3-38 illustrates the current and proposed averages operating reserve rates for all transactions.

Table 3-38 Current and Proposed Average Operating Reserve Rate by Transaction: January through June 2013

Transaction		Rates Charged ($/MWh)		
		Current	Proposed	Change
East	INC	4.488	0.183	(4.305)
	DEC	4.610	0.209	(4.401)
	DA Load	0.122	0.026	(0.096)
	RT Load	0.082	0.062	(0.019)
	Deviation	4.488	0.183	(4.305)
West	INC	1.616	0.119	(1.497)
	DEC	1.738	0.145	(1.593)
	DA Load	0.122	0.026	(0.096)
	RT Load	0.053	0.033	(0.019)
	Deviation	1.616	0.119	(1.497)
UTC	East to East	NA	0.392	
	West to West	NA	0.265	
	East to/from West	NA	0.329	

Confidentiality of Operating Reserves Information

PJM rules require all data posted publicly by PJM or the MMU to comply with existing confidentiality rules. Current rules do not appear to allow posting data containing three or fewer PJM participants and cannot be aggregated in a geographic area smaller than a control zone.[45]

Operating reserves are out of market, non-transparent payments made to resources operating on the behalf of PJM to provide transmission constraint relief or other reliability services. Operating reserve charges are highly concentrated in a small number of zones and paid to a small number of PJM participants. These costs are not reflected in PJM market prices. Current confidentiality rules prevent the publication of detailed data concerning the reasons and locations of these payments, making it difficult for other

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44 The weighted average was calculated based on the total charges by rate.

45 See "Manual 33 Administrative Services for the PJM Interconnection Operating Agreement," Revision 9 (July 22, 2012), Market Data Posting.

participants to compete with the units receiving operating reserve payments. The confidentiality rules were implemented in order to protect competition. The application of confidentiality rules in the case of operating reserves information does exactly the opposite. There is no market in operating reserves and the absence of relevant information creates a very effective barrier to entry. The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of information regarding the reasons for operating reserve payments in the PJM region. This information would include the publication of operating reserve information by zone, by owner and by unit.

Capacity Market

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

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for the first six months of calendar year 2013, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1]

Table 4-1 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	Competitive	
Market Performance	Competitive	Mixed

- The aggregate market structure was evaluated as not competitive. For almost all auctions held from 2007 to the present, the PJM region failed the Three Pivotal Supplier Test (TPS), which is conducted at the time of the auction.[2]

- The local market structure was evaluated as not competitive. For almost every auction held, all LDAs have failed the TPS test, which is conducted at the time of the auction.[3]

- Participant behavior was evaluated as competitive. Market power mitigation measures were applied when the Capacity Market Seller failed the market power test for the auction, the submitted sell offer exceeded

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

- Market performance was evaluated as competitive. Although structural market power exists in the Capacity Market, a competitive outcome resulted from the application of market power mitigation rules.

- Market design was evaluated as mixed because while there are many positive features of the Reliability Pricing Model (RPM) design, there are several features of the RPM design which threaten competitive outcomes. These include the 2.5 percent reduction in demand in Base Residual Auctions and the definition of DR which permits inferior products to substitute for capacity.

Overview

RPM Capacity Market

Market Design

The Reliability Pricing Model (RPM) Capacity Market 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.[4]

Under RPM, capacity obligations are annual. Base Residual Auctions (BRA) are held for delivery years that are three years in the future. Effective with the 2012/2013 Delivery Year, First, Second and Third Incremental Auctions (IA) are held for each delivery year.[5] Prior to the 2012/2013 Delivery Year, the Second Incremental Auction was conducted if PJM determined that an unforced capacity resource shortage exceeded 100 MW of unforced capacity due to a load forecast increase. Effective January 31, 2010, First, Second,

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1 The values stated in this report for the RTO and LDAs refer to the aggregate level including all nested LDAs unless otherwise specified. For example, RTO values include the entire PJM market and all LDAs. Rest of RTO values are RTO values net of nested LDA values.
2 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.
3 In the 2012/2013 RPM Base Residual Auction, six participants included in the incremental supply of EMAAC passed the TPS test. In the 2014/2015 RPM Base Residual Auction, seven participants in the incremental supply in MAAC passed the TPS test.

4 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2013 Quarterly State of the Market Report for PJM*, Section 4, "Capacity Market" and include all capacity within the PJM footprint.
5 See 126 FERC ¶ 61,275 (2009) at P 86.

and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[6] Also effective for the 2012/2013 Delivery Year, a conditional incremental auction may be held if there is a need to procure additional capacity resulting from a delay in a planned large transmission upgrade that was modeled in the BRA for the relevant delivery year.[7]

RPM prices are locational and may vary depending on transmission constraints.[8] Existing generation capable of qualifying as a capacity resource must be offered into RPM Auctions, except for resources owned by entities that elect the fixed resource requirement (FRR) option. Participation by LSEs is mandatory, except for those entities that elect the FRR option. There is an administratively determined demand curve that defines scarcity pricing levels and that, with the supply curve derived from capacity offers, determines market prices in each BRA. RPM rules provide performance incentives for generation, including the requirement to submit generator outage data and the linking of capacity payments to the level of unforced capacity. Under RPM there are explicit market power mitigation rules that define the must offer requirement, that define structural market power, that define offer caps based on the marginal cost of capacity, that define the minimum offer price, and that have flexible criteria for competitive offers by new entrants. Demand-side resources and Energy Efficiency resources may be offered directly into RPM Auctions and receive the clearing price without mitigation.

Market Structure

- **PJM Installed Capacity.** During the period January 1 through June 30, 2013, PJM installed capacity increased 3,549.2 MW or 1.9 percent from 182,011.1 MW on January 1 to 185,560.3 MW on June 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.

- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity on June 30, 2013, 42.0 percent was coal; 28.8 percent was gas; 17.8 percent

was nuclear; 6.1 percent was oil; 4.4 percent was hydroelectric; 0.4 percent was solid waste; 0.5 percent was wind, and 0.0 percent was solar.

- **Market Concentration.** In the 2016/2017 RPM Base Residual Auction, all participants in the total PJM market as well as the LDA RPM markets failed the Three Pivotal Supplier (TPS) test. 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.[9,10,11]

- **Imports and Exports.** Of the 7,493.7 MW of imports offered in the 2016/2017 RPM Base Residual Auction, 7,482.7 MW cleared. Of the cleared imports, 4,723.1 MW (63.1 percent) were from MISO.

- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 8,490.0 MW for June 1, 2013 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2013/2014 Delivery Year (11,683.8 MW) less replacement capacity (3,193.8 MW).

Market Conduct

- **2016/2017 RPM Base Residual Auction.** Of the 1,199 generation resources which submitted offers, unit-specific offer caps were calculated for 139 generation resources (11.6 percent). The MMU calculated offer caps for 638 generation resources (53.2 percent), of which 491 were based on the technology specific default (proxy) ACR values.

Market Performance

- The 2016/2017 RPM Base Residual Auction was conducted in the second quarter of 2013. In the 2016/2017 RPM Base Residual Auction, the

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6 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
7 See 126 FERC ¶ 61,275 (2009) at P 88.
8 Transmission constraints are local capacity import capability limitations (low capacity emergency transfer limit (CETL) margin over capacity emergency transfer objective (CETO)) caused by transmission facility limitations, voltage limitations or stability limitations.

9 See OATT Attachment DD § 6.5.
10 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.
11 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).

RTO clearing price for Annual Resources was $59.37 per MW-day. The weighted average capacity price for the 2016/2017 BRA was $89.29.

- The delivery year weighted average capacity price was $70.46 per MW-day in 2012/2013 and $161.62 per MW-day in 2015/2016.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for January through June was 8.4 percent, an increase from the 7.5 percent average PJM EFORd for 2012.[12]

- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for January through June was 81.4 percent, a decrease from the 84.1 percent PJM aggregate equivalent availability factor for 2012.

- **Outages Deemed Outside Management Control (OMC).** In the first six months of 2013, 15.6 percent of forced outages were classified as OMC outages. OMC outages are excluded from the calculation of the forced outage rate used to calculate the unforced capacity that must be offered in the PJM Capacity Market.

Conclusion

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, but no exercise of market power in the PJM Capacity Market in the first six months of 2013. 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 six months of 2013.[13]

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[14,15,16,17] In 2011, 2012, and 2013, the MMU prepared a number of RPM-related reports and testimony, shown in Table 4-2.

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12 The generator performance analysis includes all PJM capacity resources for which there are data in the PJM Generator Availability Data Systems (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. Data is for the twelve months ending December 31 or the six months ending June 30, as downloaded from the PJM GADS database on August 5, 2013. 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.

13 For more complete conclusions, see *2012 State of the Market Report for PJM*, Volume II, Section 4, "Capacity Market."

14 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).

15 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).

16 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).

17 See "IMM Response to Maryland PSC re: Reliability Pricing Model and the 2013/2014 Delivery Year Base Residual Auction Results," <http://www.monitoringanalytics.com/reports/Reports/2010/IMM_Response_to_MDPSC_RPM_and_2013-2014_BRA_Results.pdf> (October 4, 2010).

Table 4‑2 RPM related MMU reports

Date	Name
January 6, 2011	Analysis of the 2011/2012 RPM First Incremental Auction http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_RPM_First_Incremental_Auction_20110106.pdf
January 6, 2011	Impact of New Jersey Assembly Bill 3442 on the PJM Capacity Market http://www.monitoringanalytics.com/reports/Reports/2011/NJ_Assembly_3442_Impact_on_PJM_Capacity_Market.pdf
January 14, 2011	Analysis of the 2011/2012 and 2012/2013 ATSI Integration Auctions http://www.monitoringanalytics.com/reports/Reports/2011/Analysis_of_2011_2012_and_2012_2013_ATSI_Integration_Auctions_20110114.pdf
January 28, 2011	Impact of Maryland PSC's Proposed RFP on the PJM Capacity Market http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_to_MDPSC_Case_No_9214_20110128.pdf
February 1, 2011	Preliminary Market Structure Screen results for the 2014/2015 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2011/PMSS_Results_20142015_20110201.pdf
March 4, 2011	IMM Comments re MOPR Filing Nos. EL11‑20, ER11‑2875 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_EL11-20-000_ER11-2875-000_20110304.pdf
March 21, 2011	IMM Answer and Motion for Leave to Answer re: MOPR Filing Nos. EL11‑20, ER11‑2875 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Answer_and_Motion_for_Leave_to_Answer_EL11-20-000_ER11-2875-000_20110321.pdf
June 2, 2011	IMM Protest re: PJM Filing in Response to FERC Order Regarding MOPR No. ER11‑2875‑002 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Protest_ER11-2875-002.pdf
June 17, 2011	IMM Comments re: In the Matter of the Board's Investigation of Capacity Procurement and Transmission Planning No. EO11050309 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_NJ_EO_11050309_20110617.pdf
June 27, 2011	Units Subject to RPM Must Offer Obligation http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Units_Subject_to_RPM_Must_Offer_Obligation_20110627.pdf
August 29, 2011	Post Technical Conference Comments re: PJM's Minimum Offer Price Rule Nos. ER11‑2875‑001, 002, and EL11‑20‑001 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Post_Technical_Conference_Comments_ER11-2875_20110829.pdf
September 15, 2011	IMM Motion for Leave to Answer and Answer re: MMU Role in MOPR Review No. ER11‑2875‑002 http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Motion_for_Leave_to_Answer_and_Answer_ER11-2875-002_20110915.pdf
November 22, 2011	Generator Capacity Resources in PJM Region Subject to "Must Offer" Obligatrion for the 2012/2013, 2013/2014 and 2014/2015 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20111123.pdf
January 9, 2012	IMM Comments re:MOPR Compliance No. ER11‑2875‑003 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER11-2875-003_20120109.pdf
January 20, 2012	IMM Testimony re: Review of the Potential Impact of the Proposed Capacity Additions in the State of Maryland's Joint Petition for Approval of Settlement MD PSC Case No. 9271 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Testimony_MD_PSC_9271.pdf
January 20, 2012	IMM Comments re: Capacity Procurement RFP MD PSC Case No. 9214 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_MD_PSC_9214.pdf
February 7, 2012	Preliminary Market Structure Screen results for the 2015/2016 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2012/PMSS_Results_20152016_20120207.pdf
February 15, 2012	RPM‑ACR and RPM Must Offer Obligation FAQs http://www.monitoringanalytics.com/Tools/docs/RPM-ACR_FAQ_RPM_Must_Offer_Obligation_20120215.pdf
February 17, 2012	IMM Motion for Clarification re: Minimum Offer Price Rule Revision Nos.ER11‑2871‑000, ‑001 and ‑002, EL11‑20‑000 and ‑001 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Motion_for_Clarification_ER11-2875_EL-20_20120217.pdf
April 9, 2012	Analysis of the 2014/2015 RPM Base Residual Auction www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf
May 1, 2012	IMM Complaint and Request for Fast Track Treatment and Shortened Comment Period re Complaint v. Unnamed Participant No. EL12‑63 www.monitoringanalytics.com/report/Report/2012/IMM_Complaint_and_Fast_Track_Treatment_and_Shortened_Comment_Period_EL12-63-000_20120501.pdf
May 17, 2012	IMM Notice of Withdrawal re Complaint v. Unnamed Participant No. EL12‑63 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Notice_of_Withdrawal_EL12-63-000_20120517.pdf
July 3, 2012	Generator Capacity Resources in PJM Region Subject to "Must Offer" Obligation for the 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20120703.pdf
August 10, 2012	IMM Comments re Capacity Portability AD12‑16 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_AD12-16_20120810.pdf
August 20, 2012	IMM and PJM Capacity White Papers on OPSI Issues http://www.monitoringanalytics.com/reports/Reports/2012/IMM_And_PJM_Capacity_White_Papers_On_OPSI_Issues_20120820.pdf
August 29, 2012	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20120829.pdf
November 29, 2012	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2013/2014, 2014/2015 and 2015/2016 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20121129.pdf
December 11, 2012	Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2012 http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Report_Replacement_Capacity_Activity_20121211.pdf
March 29, 2013	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2014/2015, 2015/2016 and 2016/2017 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20130329.pdf
April 19, 2013	IMM Answer and Motion for Leave to Answer re: MOPR No. ER13‑535‑001 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Answer_and_Motion_for_Leave_to_Answer_ER13-535-001_20130419.pdf
June 19, 2013	Unit Specific MOPR Review Modeling Assumptions http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_Unit_Specific_MOPR_Review_Modeling_Assumptions_20130619.pdf
June 20, 2013	Capacity Deliverability, Docket No. AD12‑16 http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_FERC_Capacity_Deliverability_20130620.pdf
June 28, 2013	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2014/2015, 2015/2016 and 2016/2017 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20130628.pdf

Installed Capacity

On January 1, 2013, PJM installed capacity was 182,011.1 MW (Table 4-3).[18] Over the next six months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in PJM installed capacity of 185,560.3 MW on June 30, 2013, an increase of 3,549.2 MW or 1.9 percent over the January 1 level.[19,20] The 3,549.2 MW increase was the result of the integration of the East Kentucky Power Cooperative (EKPC) Zone (2,680.0 MW), new or reactivated generation (274.4 MW), an increase in imports (594.1 MW) capacity modifications (337.3 MW), and a decrease in exports (148.3 MW), offset by deactivations (217.1 MW) and derates (267.8 MW).

Table 4-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and June 30, 2013

	1-Jan-13		31-May-13		1-Jun-13		30-Jun-13	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	75,989.2	41.7%	76,055.6	41.8%	77,981.5	42.0%	77,981.5	42.0%
Gas	52,003.2	28.6%	52,106.1	28.6%	53,420.2	28.8%	53,412.6	28.8%
Hydroelectric	7,879.8	4.3%	7,880.4	4.3%	8,091.4	4.4%	8,091.4	4.4%
Nuclear	33,024.0	18.1%	33,024.0	18.1%	33,072.8	17.8%	33,072.8	17.8%
Oil	11,531.2	6.3%	11,361.2	6.2%	11,339.5	6.1%	11,339.5	6.1%
Solar	47.0	0.0%	47.0	0.0%	80.7	0.0%	80.7	0.0%
Solid waste	757.1	0.4%	756.4	0.4%	709.4	0.4%	709.4	0.4%
Wind	779.6	0.4%	805.6	0.4%	872.4	0.5%	872.4	0.5%
Total	182,011.1	100.0%	182,036.3	100.0%	185,567.9	100.0%	185,560.3	100.0%

Table 4-4 Generation capacity changes: 2007/2008 through 2012/2013

	ICAP (MW)									
	Total at June 1	New	Reactivations	Uprates	Integration	Net Change in Capacity Imports	Net Change in Capacity Exports	Deactivations	Derates	Net Change
2007/2008	163,659.4	372.8	156.8	1,238.1	0.0	(96.7)	143.9	389.5	617.8	519.8
2008/2009	164,179.2	812.9	6.3	1,108.9	0.0	871.1	(1,702.9)	615.0	612.4	3,274.7
2009/2010	167,453.9	188.1	13.0	370.4	0.0	68.6	735.9	472.4	171.2	(739.4)
2010/2011	166,714.5	1,751.2	16.0	587.3	11,821.6	187.2	(427.0)	1,439.2	286.9	13,064.2
2011/2012	179,778.7	3,095.0	138.0	553.8	3,607.4	262.7	(1,374.5)	2,758.5	313.0	5,959.9
2012/2013	185,738.6	266.4	79.0	364.5	2,680.0	841.8	(17.3)	4,152.1	267.6	(170.7)

18 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.
19 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.
20 Wind resources accounted for 872.4 MW of installed capacity in PJM on June 30, 2013. This value represents approximately 13 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 13 percent of nameplate capacity when determining the system installed capacity because wind resources cannot be assumed to be available on peak and cannot respond to dispatch requests. As data become available, unforced capability of wind resources will be calculated using actual data. There are additional wind resources not reflected in total capacity because they are energy only resources and do not participate in the PJM Capacity Market.

At the beginning of the new delivery year on June 1, 2013, PJM installed capacity was 185,567.9 MW, an increase of 3,531.6 MW or 1.9 percent over the May 31 level.

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. Effective January 31, 2010, First, Second, and Third Incremental Auctions are conducted 20, 10, and three months prior to the delivery year.[21] In the second quarter of 2013, a Base Residual Auction was held in May for the 2016/2017 Delivery Year.

Market Structure

Supply

Offered MW in the 2013/2014 RPM Third Incremental Auction totaled 5,526.4 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 2013/2014 RPM Third Incremental Auction were 1,099.2 MW.

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

Demand

On June 1, 2013, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 72.0 percent (Table 4-5), up slightly from 71.9 percent on June 1, 2012. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 28.0 percent, down slightly from 28.1 percent on June 1, 2012. Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make-whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM Auctions for the delivery year.

Table 4-6 presents the results of the TPS test. A generation owner or owners are pivotal if the capacity of the owners' generation facilities is needed to meet the demand for capacity.

Table 4–5 Capacity Market load obligations served: June 1, 2013

	Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non–PJM EDC Generating Affiliates	Non–PJM EDC Marketing Affiliates	Non–EDC Generating Affiliates	Non–EDC Marketing Affiliates	Total
Obligation	69,846.4	38,979.5	18,589.5	4,117.3	14,441.1	5,420.6	25,628.2	177,022.6
Percent of total obligation	39.5%	22.0%	10.5%	2.3%	8.2%	3.1%	14.5%	100.0%

Market Concentration

Auction Market Structure

As shown in Table 4-6, all participants in the total PJM market as well as the LDA RPM markets failed the Three Pivotal Supplier (TPS) test in the 2016/2017 RPM Base Residual Auction.[22] 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.[23,24,25]

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22 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.
23 See OATT Attachment DD § 6.5.
24 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.
25 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 4-6 RSI results: 2013/2014 through 2016/2017 RPM Auctions[26]

RPM Markets	RSI$_{1,1.05}$	RSI$_3$	Total Participants	Failed RSI$_3$ Participants
2013/2014 BRA				
RTO	0.80	0.59	87	87
MAAC/SWMAAC	0.42	0.23	9	9
EMAAC/PSEG/PSEG North/DPL South	0.25	0.00	2	2
Pepco	0.00	0.00	1	1
2013/2014 First Incremental Auction				
RTO/MAAC	0.24	0.28	33	33
EMAAC/PSEG/PSEG North/DPL South	0.34	0.00	3	3
SWMAAC/Pepco	0.00	0.00	0	0
2013/2014 Second Incremental Auction				
RTO	0.44	0.27	32	32
MAAC/SWMAAC/Pepco	0.00	0.00	0	0
EMAAC/PSEG/PSEG North/DPL South	0.00	0.00	0	0
2013/2014 Third Incremental Auction				
RTO	0.60	0.38	60	60
MAAC/SWMAAC/Pepco	0.01	0.02	4	4
EMAAC/PSEG/PSEG North/DPL South	0.38	0.22	7	7
2014/2015 BRA				
RTO	0.76	0.58	93	93
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	1.40	1.03	7	0
PSEG North	0.00	0.00	1	1
2014/2015 First Incremental Auction				
RTO	0.45	0.14	36	36
MAAC/SWMAAC/EMAAC/PSEG/DPL South/Pepco	0.00	0.00	1	1
PSEG North	0.00	0.00	1	1
2015/2016 BRA				
RTO	0.75	0.57	99	99
MAAC/EMAAC/SWMAAC/PSEG/PSEG North/DPL South/Pepco	0.49	0.63	12	12
ATSI	0.01	0.00	3	3
2016/2017 BRA				
RTO	0.78	0.59	110	110
MAAC/EMAAC/SWMAAC/DPL South/Pepco	0.56	0.38	6	6
PSEG/PSEG North	0.00	0.00	1	1
ATSI/ATSI Cleveland	0.00	0.00	1	1

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 delivery year, an LDA will be modeled as a potentially constrained LDA for a delivery year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 delivery year, EMAAC, SWMAAC, and MAAC LDAs will be modeled as potentially constrained LDAs regardless of the results of the above three tests.[27] In addition, PJM may establish a constrained LDA even if it does not qualify under the above tests if PJM finds that "such is required to achieve an acceptable level of reliability."[28] A reliability requirement, a Variable Resource Requirement (VRR) curve, a Minimum Annual Resource Requirement, and a Minimum Extended Summer Resource Requirement are established for each modeled LDA.

Locational Deliverability Areas are shown in Figure 4-1, Figure 4-2 and Figure 4-3.

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

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

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

Figure 4-1 Map of PJM Locational Deliverability Areas
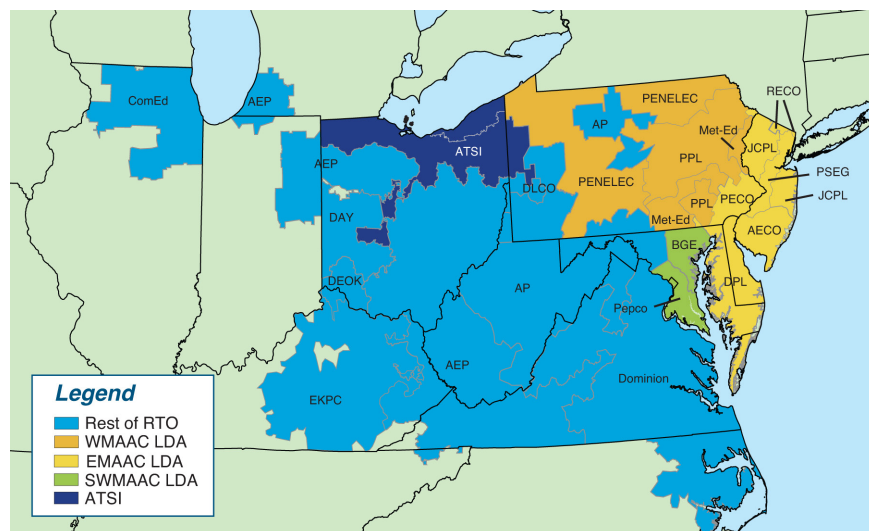
Figure 4-2 Map of PJM RPM EMAAC subzonal LDAs
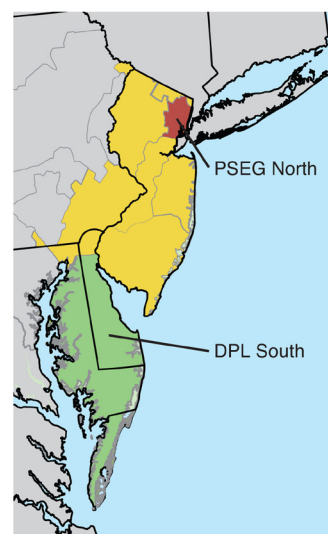
Figure 4-3 Map of PJM RPM ATSI subzonal LDA
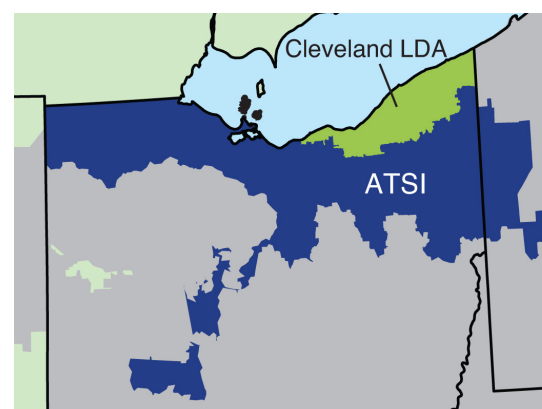
Imports and Exports

Units external to the metered boundaries of PJM can qualify as PJM capacity resources if they meet the requirements to be 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 from PJM.[29] As shown in Table 4-7, a total of 7,482.7 MW of imports cleared in the 2016/2017 RPM Base Residual Auction. Of these cleared imports, 4,723.1 MW (63.1 percent) were from MISO.

Table 4-7 RPM imports: 2007/2008 through 2016/2017 RPM Base Residual Auctions

| | UCAP (MW) | | | | | |
| | MISO | | Non-MISO | | Total Imports | |
Base Residual Auction	**Offered**	**Cleared**	**Offered**	**Cleared**	**Offered**	**Cleared**
2007/2008	1,073.0	1,072.9	547.9	547.9	1,620.9	1,620.8
2008/2009	1,149.4	1,109.0	517.6	516.8	1,667.0	1,625.8
2009/2010	1,189.2	1,151.0	518.8	518.1	1,708.0	1,669.1
2010/2011	1,194.2	1,186.6	539.8	539.5	1,734.0	1,726.1
2011/2012	1,862.7	1,198.6	3,560.0	3,557.5	5,422.7	4,756.1
2012/2013	1,415.9	1,298.8	1,036.7	1,036.7	2,452.6	2,335.5
2013/2014	1,895.1	1,895.1	1,358.9	1,358.9	3,254.0	3,254.0
2014/2015	1,067.7	1,067.7	1,948.8	1,948.8	3,016.5	3,016.5
2015/2016	1,538.7	1,538.7	2,396.6	2,396.6	3,935.3	3,935.3
2016/2017	4,723.1	4,723.1	2,770.6	2,759.6	7,493.7	7,482.7

29 OATT Attachment DD § 5.6.6(b).

Demand-Side Resources

As shown in Table 4-8 and Table 4-10, capacity in the RPM load management programs was 8,490.0 MW for June 1, 2013 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2013/2014 Delivery Year (11,683.8 MW) less replacement capacity (3,193.8 MW). Table 4-9 shows RPM commitments for DR and EE resources as the result of RPM Auctions prior to adjustments for replacement capacity transactions and certified ILR.

Table 4-8 RPM load management statistics by LDA: June 1, 2012 to June 1, 2016[30,31,32]

	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland
					UCAP (MW)					
DR cleared	8,740.9	5,193.6	1,971.8	1,794.4	71.0	517.8	97.9			
EE cleared	666.1	253.6	48.1	160.1	0.0	15.9	7.8			
DR net replacements	(2,253.6)	(1,848.6)	(761.5)	(645.5)	(30.6)	(182.9)	10.1			
EE net replacements	(34.9)	(32.4)	(16.2)	(16.5)	0.0	(3.0)	(1.0)			
RPM load management @ 01-Jun-12	7,118.5	3,566.2	1,242.2	1,292.5	40.4	347.8	114.8			
DR cleared	10,779.6	6,466.6	2,735.7	1,788.8	155.4	1,185.0	534.8	661.9		
EE cleared	904.2	289.9	65.2	149.5	10.7	26.2	9.4	72.7		
DR net replacements	(3,318.8)	(3,016.9)	(1,434.3)	(745.7)	(53.3)	(819.7)	(388.6)	(272.4)		
EE net replacements	125.0	121.8	(11.1)	124.2	2.2	(2.1)	1.4	4.8		
RPM load management @ 01-Jun-13	8,490.0	3,861.4	1,355.5	1,316.8	115.0	389.4	157.0	467.0		
DR cleared	14,226.8	7,320.0	2,923.5	2,250.3	220.9	989.5	468.0	908.5		
EE cleared	956.4	276.9	35.2	169.8	8.1	14.9	7.6	51.4		
DR net replacements	(5.9)	(5.4)	(2.4)	(0.3)	0.0	(0.6)	0.0	0.0		
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		
RPM load management @ 01-Jun-14	15,177.3	7,591.5	2,956.3	2,419.8	229.0	1,003.8	475.6	959.9		
DR cleared	14,832.8	6,648.7	2,610.4	2,009.1	86.3	796.1	263.3	867.4	1,763.7	
EE cleared	922.5	222.6	42.2	159.4	0.0	10.7	3.1	55.8	44.9	
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
RPM load management @ 01-Jun-15	15,755.3	6,871.3	2,652.6	2,168.5	86.3	806.8	266.4	923.2	1,808.6	
DR cleared	12,408.1	5,350.2	2,006.4	1,600.5	105.7	630.7	226.6	663.9	1,811.9	468.7
EE cleared	1,117.3	310.1	51.2	208.4	0.6	11.9	3.1	83.5	196.6	52.6
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RPM load management @ 01-Jun-16	13,525.4	5,660.3	2,057.6	1,808.9	106.3	642.6	229.7	747.4	2,008.5	521.3

30 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.
31 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.
32 Pursuant to PJM Operating Agreement § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The replacement transactions reported for the 2014/2015 Delivery Year are associated with RTP Controls, Inc. which was declared in collateral default on March 9, 2012.

Table 4-9 RPM load management cleared capacity and ILR: 2007/2008 through 2016/2017[33,34]

	DR Cleared		EE Cleared		ILR	
Delivery Year	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
2007/2008	123.5	127.6	0.0	0.0	1,584.6	1,636.3
2008/2009	540.9	559.4	0.0	0.0	3,488.5	3,608.1
2009/2010	864.5	892.9	0.0	0.0	6,273.8	6,481.5
2010/2011	930.9	962.9	0.0	0.0	7,961.3	8,236.4
2011/2012	1,766.0	1,826.6	74.0	76.4	8,730.7	9,032.6
2012/2013	8,429.7	8,740.9	643.4	666.1	0.0	0.0
2013/2014	10,345.6	10,779.6	871.0	904.2	0.0	0.0
2014/2015	13,667.2	14,226.8	920.3	956.4	0.0	0.0
2015/2016	14,303.2	14,832.8	890.8	922.5	0.0	0.0
2016/2017	11,918.7	12,408.1	1,074.7	1,117.3	0.0	0.0

Table 4-10 RPM load management statistics: June 1, 2007 to June 1, 2016[35,36]

	DR and EE Cleared Plus ILR		DR Net Replacements		EE Net Replacements		Total RPM LM	
	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)	ICAP (MW)	UCAP (MW)
01-Jun-07	1,708.1	1,763.9	0.0	0.0	0.0	0.0	1,708.1	1,763.9
01-Jun-08	4,029.4	4,167.5	(38.7)	(40.0)	0.0	0.0	3,990.7	4,127.5
01-Jun-09	7,138.3	7,374.4	(459.5)	(474.7)	0.0	0.0	6,678.8	6,899.7
01-Jun-10	8,892.2	9,199.3	(499.1)	(516.3)	0.0	0.0	8,393.1	8,683.0
01-Jun-11	10,570.7	10,935.6	(1,017.3)	(1,052.4)	0.2	0.2	9,553.6	9,883.4
01-Jun-12	9,073.1	9,407.0	(2,173.4)	(2,253.6)	(33.7)	(34.9)	6,866.0	7,118.5
01-Jun-13	11,216.6	11,683.8	(3,184.8)	(3,318.8)	120.0	125.0	8,151.8	8,490.0
01-Jun-14	14,587.5	15,183.2	(5.7)	(5.9)	0.0	0.0	14,581.8	15,177.3
01-Jun-15	15,194.0	15,755.3	0.0	0.0	0.0	0.0	15,194.0	15,755.3
01-Jun-16	12,993.4	13,525.4	0.0	0.0	0.0	0.0	12,993.4	13,525.4

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33 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.

34 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.

35 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.

36 Pursuant to PJM Operating Agreement § 15.1.6(c), PJM Settlement shall attempt to close out and liquidate forward capacity commitments for PJM Members that are declared in collateral default. The replacement transactions reported for the 2014/2015 Delivery Year are associated with RTP Controls, Inc. which was declared in collateral default on March 9, 2012.

Market Conduct

Offer Caps and Offer Floors

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.[37,38,39]

Table 4-11 ACR statistics: 2016/2017 RPM Base Residual Auction

	2016/2017 Base Residual Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	471	39.3%
ACR data input (APIR)	138	11.5%
ACR data input (non-APIR)	1	0.1%
Opportunity cost input	8	0.7%
Default ACR and opportunity cost	5	0.4%
Offer cap of 1.1 times BRA clearing price elected	NA	NA
Uncapped planned uprate and default ACR	15	1.3%
Uncapped planned uprate and opportunity cost	0	0.0%
Uncapped planned uprate and price taker	11	0.9%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA
Uncapped planned generation resources	31	2.6%
Price takers	519	43.3%
Total Generation Capacity Resources offered	1,199	100.0%

2016/2017 RPM Base Residual Auction

As shown in Table 4-11, 1,199 generation resources submitted offers in the 2016/2017 RPM Base Residual Auction. Unit-specific offer caps were calculated for 139 generation resources (11.6 percent), including 138 generation resources (11.5 percent) with an Avoidable Project Investment Recovery Rate (APIR) and one generation resource (0.1 percent) without an APIR component. The MMU calculated offer caps for 638 generation resources (53.2 percent),

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37 See OATT Attachment DD § 6.5.

38 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.

39 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).

of which 491 (41.0 percent) were based on the technology specific default (proxy) ACR values. Of the 1,199 generation resources, 31 Planned Generation Capacity Resources had uncapped offers (2.6 percent), 15 generation resources had uncapped planned uprates along with default ACR based offer caps calculated for the existing portion (1.3 percent), and 11 generation resources had uncapped planned uprates along with price taker status for the existing portion (0.9 percent), while the remaining 519 generation resources were price takers (43.3 percent). Market power mitigation was applied to the sell offers for 50 generation resources.

Market Performance[40]

Figure 4-4 presents cleared MW weighted average capacity market prices on a delivery year basis for the entire history of the PJM capacity markets. Table 4-12 shows RPM clearing prices for all RPM Auctions held through the first six months of 2013.

Figure 4-5 illustrates the RPM cleared MW weighted average prices for each LDA for the current delivery year and all results for future delivery years that have been held through the first six months of 2013.

Table 4-13 shows RPM revenue by resource type for all RPM Auctions held through the first six months of 2013 with $2.1 billion for new/repower/reactivated generation resources based on the unforced MW cleared and the resource clearing prices.

Table 4-14 shows RPM revenue by calendar year for all RPM Auctions held through the first six months of 2013.

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

Table 4-12 Capacity prices: 2007/2008 through 2016/2017 RPM Auctions

	Product Type	RPM Clearing Price ($ per MW-day)									
		RTO	MAAC	APS	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI
2007/2008 BRA		$40.80	$40.80	$40.80	$197.67	$188.54	$197.67	$197.67	$197.67	$188.54	
2008/2009 BRA		$111.92	$111.92	$111.92	$148.80	$210.11	$148.80	$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	$10.00	$223.85	
2009/2010 BRA		$102.04	$191.32	$191.32	$191.32	$237.33	$191.32	$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	$86.00	
2010/2011 BRA		$174.29	$174.29	$174.29	$174.29	$174.29	$186.12	$174.29	$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	$50.00	
2011/2012 BRA		$110.00	$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	$55.00	
2011/2012 ATSI FRR Integration Auction		$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89	$108.89
2011/2012 Third Incremental Auction		$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00	$5.00
2012/2013 BRA		$16.46	$133.37	$16.46	$139.73	$133.37	$222.30	$139.73	$185.00	$133.37	
2012/2013 ATSI FRR Integration Auction		$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46	$20.46
2012/2013 First Incremental Auction		$16.46	$16.46	$16.46	$153.67	$16.46	$153.67	$153.67	$153.67	$16.46	$16.46
2012/2013 Second Incremental Auction		$13.01	$13.01	$13.01	$48.91	$13.01	$48.91	$48.91	$48.91	$13.01	$13.01
2012/2013 Third Incremental Auction		$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51	$2.51
2013/2014 BRA		$27.73	$226.15	$27.73	$245.00	$226.15	$245.00	$245.00	$245.00	$247.14	$27.73
2013/2014 First Incremental Auction		$20.00	$20.00	$20.00	$178.85	$54.82	$178.85	$178.85	$178.85	$54.82	$20.00
2013/2014 Second Incremental Auction		$7.01	$10.00	$7.01	$40.00	$10.00	$40.00	$40.00	$40.00	$10.00	$7.01
2013/2014 Third Incremental Auction		$4.05	$30.00	$4.05	$188.44	$30.00	$188.44	$188.44	$188.44	$30.00	$4.05
2014/2015 BRA	Limited	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$125.47	$213.97	$125.47	$125.47
2014/2015 BRA	Extended Summer	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99
2014/2015 BRA	Annual	$125.99	$136.50	$125.99	$136.50	$136.50	$136.50	$136.50	$225.00	$136.50	$125.99
2014/2015 First Incremental Auction	Limited	$0.03	$5.23	$0.03	$5.23	$5.23	$5.23	$5.23	$399.62	$5.23	$0.03
2014/2015 First Incremental Auction	Extended Summer	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54
2014/2015 First Incremental Auction	Annual	$5.54	$16.56	$5.54	$16.56	$16.56	$16.56	$16.56	$410.95	$16.56	$5.54
2015/2016 BRA	Limited	$118.54	$150.00	$118.54	$150.00	$150.00	$150.00	$150.00	$150.00	$150.00	$304.62
2015/2016 BRA	Extended Summer	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$322.08
2015/2016 BRA	Annual	$136.00	$167.46	$136.00	$167.46	$167.46	$167.46	$167.46	$167.46	$167.46	$357.00
2016/2017 BRA	Limited	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$94.45
2016/2017 BRA	Extended Summer	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23
2016/2017 BRA	Annual	$59.37	$119.13	$59.37	$119.13	$119.13	$119.13	$219.00	$219.00	$119.13	$114.23

Table 4–13 RPM revenue by type: 2007/2008 through 2016/2017[41,42]

| | | Energy | | Coal | | Gas | | Hydroelectric | | Nuclear | | Oil | | Solar | | Solid waste | | Wind | | |
| | Demand | Efficiency | | | New/ | | New/ | | New/ | | New/ | | New/ | | New/ | | New/ | | New/ | |
	Resources	Resources	Imports	Existing	repower/ reactivated	Existing	repower/ reactivated	Existing	repower/ reactivated	Existing	repower/ reactivated	Existing	repower/ reactivated	Existing	repower/ reactivated	Existing	repower/ reactivated	Existing	repower/ reactivated	Total revenue
2007/2008	$5,537,085	$0	$22,225,980	$1,022,372,301	$0	$1,458,989,006	$3,472,667	$209,490,444	$0	$996,085,233	$0	$502,172,373	$0	$0	$0	$31,512,230	$0	$430,065	$0	$4,252,287,381
2008/2009	$35,349,116	$0	$60,918,903	$1,844,120,476	$0	$1,910,349,518	$9,751,112	$287,850,403	$0	$1,322,601,837	$0	$572,259,505	$4,837,523	$0	$0	$35,011,991	$0	$1,180,153	$2,917,048	$6,087,147,586
2009/2010	$65,762,003	$0	$56,517,793	$2,417,576,805	$1,854,781	$2,275,446,414	$30,168,831	$364,742,517	$0	$1,517,723,628	$0	$715,618,319	$5,676,582	$0	$0	$42,758,762	$523,739	$2,011,156	$6,836,827	$7,503,218,157
2010/2011	$60,235,796	$0	$106,046,871	$2,662,434,386	$3,168,069	$2,586,971,699	$58,065,964	$442,429,815	$0	$1,799,258,125	$0	$668,505,533	$4,339,539	$0	$0	$40,731,606	$413,503	$1,819,413	$15,232,177	$8,449,652,496
2011/2012	$55,795,785	$139,812	$185,421,273	$1,595,707,479	$28,330,047	$1,607,317,731	$98,448,693	$278,529,660	$0	$1,079,386,338	$0	$368,084,004	$967,887	$0	$66,978	$25,636,836	$261,690	$1,072,929	$9,919,881	$5,335,087,023
2012/2013	$264,387,897	$11,408,552	$13,260,822	$1,016,194,603	$7,568,127	$1,079,413,451	$76,633,409	$179,117,975	$11,397	$762,719,550	$0	$423,957,756	$2,772,987	$0	$1,246,337	$26,840,670	$316,420	$812,644	$5,052,036	$3,871,714,635
2013/2014	$558,715,114	$21,598,174	$31,804,645	$1,745,438,458	$12,950,135	$1,846,432,716	$167,844,235	$308,853,673	$25,708	$1,346,223,419	$0	$689,864,789	$5,670,399	$0	$3,523,555	$43,943,130	$1,977,705	$1,373,205	$13,538,988	$6,799,778,047
2014/2015	$670,147,703	$40,247,604	$130,795,180	$1,901,021,346	$56,917,305	$1,969,525,871	$184,293,676	$328,974,881	$6,591,114	$1,460,152,259	$0	$469,738,966	$3,896,120	$0	$3,152,447	$34,529,651	$1,297,139	$1,493,377	$31,173,865	$7,293,948,503
2015/2016	$880,020,384	$52,113,238	$186,311,568	$2,656,149,396	$62,882,021	$2,473,484,871	$527,114,537	$384,329,997	$14,880,302	$1,846,030,461	$0	$562,402,530	$5,166,777	$0	$3,403,067	$35,405,293	$3,324,459	$1,768,330	$39,549,396	$9,734,336,627
2016/2017	$437,607,477	$35,346,456	$157,012,514	$1,259,270,875	$42,487,007	$1,461,069,582	$498,909,311	$218,627,999	$10,031,353	$1,002,422,494	$0	$327,077,318	$4,026,475	$0	$4,868,047	$28,668,947	$3,780,862	$1,144,873	$20,886,259	$5,513,237,849

Table 4–14 RPM revenue by calendar year: 2007 through 2017[43]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	129,409.2	214	$2,486,310,108
2008	$111.93	130,223.2	366	$5,334,880,241
2009	$142.74	132,772.0	365	$6,917,391,702
2010	$164.71	134,033.9	365	$8,058,113,907
2011	$135.14	134,105.2	365	$6,615,032,130
2012	$89.01	137,684.7	366	$4,485,656,150
2013	$99.39	154,044.3	365	$5,588,442,225
2014	$124.13	156,470.1	365	$7,089,510,863
2015	$148.33	160,866.8	365	$8,709,157,810
2016	$119.33	166,574.7	366	$7,275,094,223
2017	$89.29	169,159.7	151	$2,280,818,946

Figure 4–4 History of PJM capacity prices: 1999/2000 through 2016/2017[44]
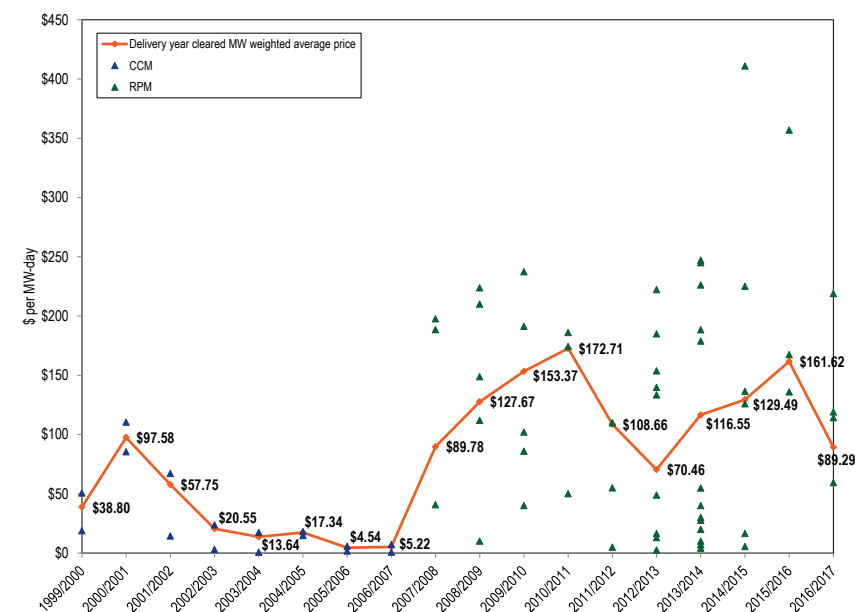
41 A resource classified as "new/repower/reactivated" is a capacity resource addition since the implementation of RPM and is considered "new/repower/reactivated" for its initial offer and all its subsequent offers in RPM Auctions.
42 The results for the ATSI Integration Auctions are not included in this table.
43 The results for the ATSI Integration Auctions are not included in this table.

44 1999/2000-2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008-2016/2017 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. For the 2014/2015 Delivery Year and forward, only the prices for Annual Resources are plotted.

Figure 4-5 Map of RPM capacity prices: 2013/2014 through 2016/2017
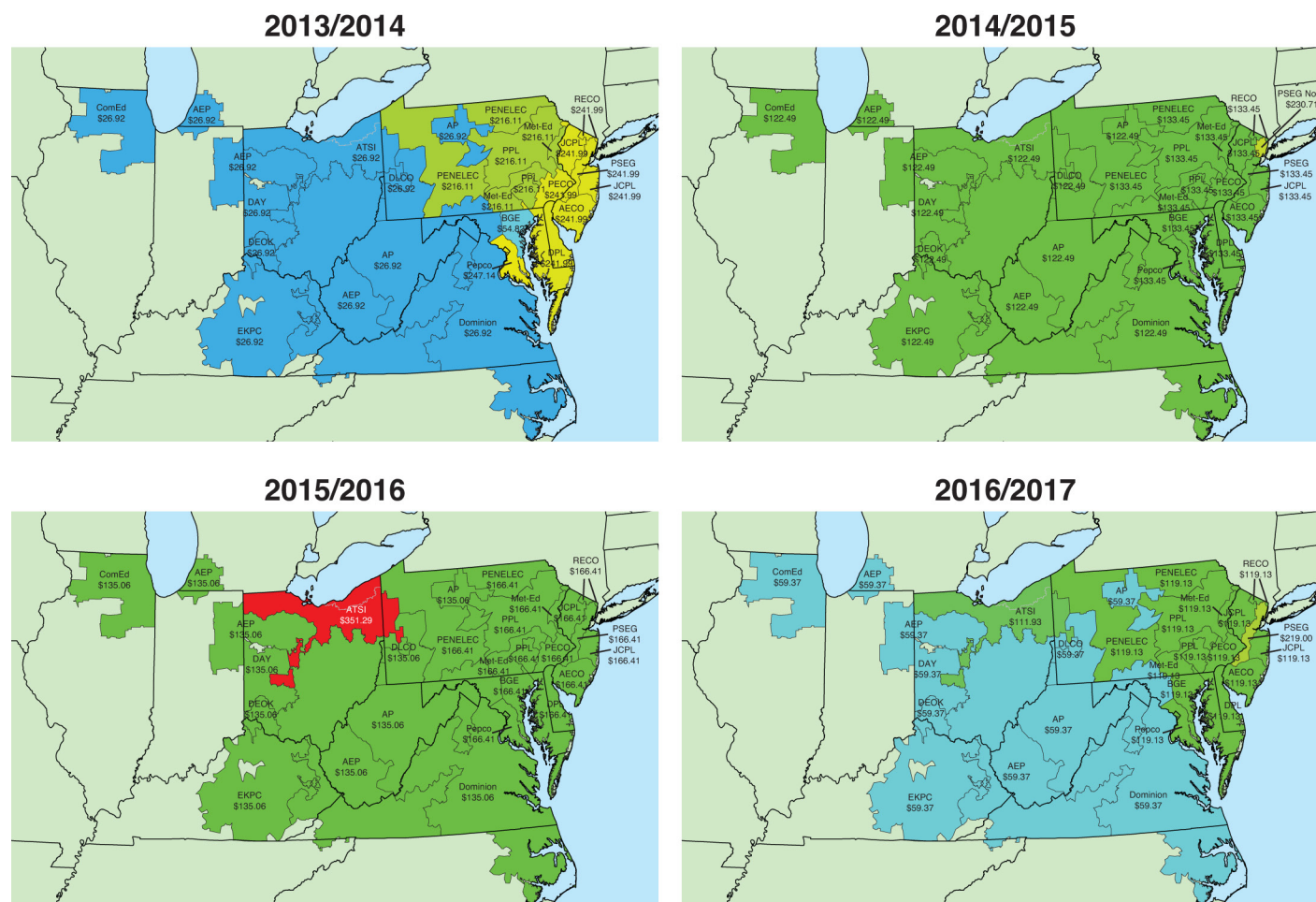
Table 4-15 RPM cost to load: 2012/2013 through 2016/2017 RPM Auctions[45,46,47]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
2012/2013			
Rest of RTO	$16.74	65,495.4	$400,296,161
Rest of MAAC	$133.42	30,107.9	$1,466,181,230
Rest of EMAAC	$143.06	19,954.6	$1,041,932,095
DPL	$171.27	4,523.9	$282,806,394
PSEG	$157.73	11,645.3	$670,441,158
Total		131,727.1	$3,861,657,038
2013/2014			
Rest of RTO	$28.45	80,012.1	$830,802,258
Rest of MAAC	$232.55	14,623.8	$1,241,276,219
EMAAC	$248.30	36,094.7	$3,271,227,460
Rest of SWMAAC	$231.58	7,925.5	$669,900,300
Pepco	$244.94	7,525.2	$672,777,842
Total		146,181.3	$6,685,984,079
2014/2015			
Rest of RTO	$128.17	82,577.4	$3,863,199,144
Rest of MAAC	$137.60	30,833.8	$1,548,586,169
Rest of EMAAC	$137.61	20,460.8	$1,027,667,647
DPL	$145.32	4,625.7	$245,357,435
PSEG	$170.24	11,833.5	$735,288,837
Total		150,331.2	$7,420,099,231
2015/2016			
Rest of RTO	$134.62	84,948.0	$4,185,534,909
MAAC	$165.78	68,742.2	$4,170,968,816
ATSI	$294.03	14,940.4	$1,607,805,047
Total		168,630.6	$9,964,308,771
2016/2017			
Rest of RTO	$59.37	88,722.2	$1,922,615,128
Rest of MAAC	$118.89	57,413.6	$2,491,443,430
PSEG	$177.61	12,055.9	$781,575,871
ATSI	$90.54	15,121.1	$499,720,114
Total		173,312.9	$5,695,354,543

45 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM Base Residual Auction results.
46 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.
47 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 2014/2015, 2015/2016, and 2016/2017 Net Load Prices are not finalized. The 2014/2015, 2015/2016, and 2016/2017 Obligation MW are not finalized.

Table 4-15 shows the RPM annual charges to load. For the 2013/2014 planning year, RPM annual charges to load total approximately $6.7 billion.

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 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).[48]

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity during that period. In the first six months of 2013, nuclear units had a capacity factor of 92.8 percent, compared to 91.6 percent in the first six months of 2012. Combined cycle units ran less often, decreasing from a percent capacity factor of 61.0 percent in the first six months of 2012 to 51.5 in the first six months of 2013. The capacity factor for steam units, which are primarily coal fired, increased from 41.4 percent in the first six months of 2012 to 48.5 percent in the first six months of 2013.

48 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.

Table 4-16 PJM capacity factor (By unit type (GWh)): January through June 2012 and 2013[49]

	Jan-Jun 2012		Jan-Jun 2013	
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
Battery	0.1	0.1%	0.2	0.2%
Combined Cycle	69,465.8	61.0%	56,946.4	50.5%
Combustion Turbine	2,771.5	2.1%	2,523.4	1.9%
Diesel	325.1	16.6%	297.9	16.1%
Diesel (Landfill gas)	608.3	42.7%	663.2	41.5%
Fuel Cell	0.7	92.8%	32.0	24.5%
Nuclear	134,802.4	91.6%	135,858.8	92.8%
Pumped Storage Hydro	2,922.1	12.2%	3,206.1	13.4%
Run of River Hydro	3,893.8	37.0%	4,296.1	40.8%
Solar	117.7	16.4%	175.9	16.3%
Steam	159,802.4	41.4%	174,751.0	48.5%
Wind	7,305.5	31.3%	8,561.5	31.7%
Total	382,015.4	45.5%	387,312.7	47.4%

Generator Performance Factors

Generator outages fall into three categories: planned, maintenance, and forced. The amount of MW on outages varies throughout the year. For example, the MW on planned outages are generally highest in the spring and fall, as shown in Figure 4-6. The effect of seasonal variation in outages can be seen in the monthly generator performance metrics in "Performance By Month."

Figure 4-6 PJM outages (MW): January 2012 to June 2013
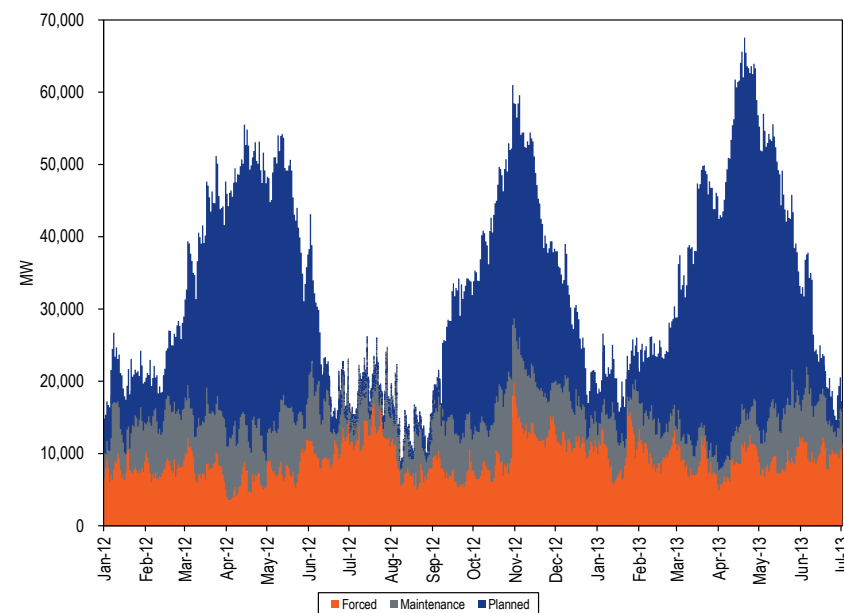
Performance factors include the equivalent availability factor (EAF), the equivalent maintenance outage factor (EMOF), the equivalent planned outage factor (EPOF) and the equivalent forced outage factor (EFOF). These four factors add to 100 percent for any generating unit. The EAF is the proportion of 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, EFOF, EPOF, and EMOF are shown in Figure 4-7. Metrics by unit type are shown in Table 4-17 through Table 4-20.

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

Figure 4–7 PJM equivalent outage and availability factors: 2007 to 2013
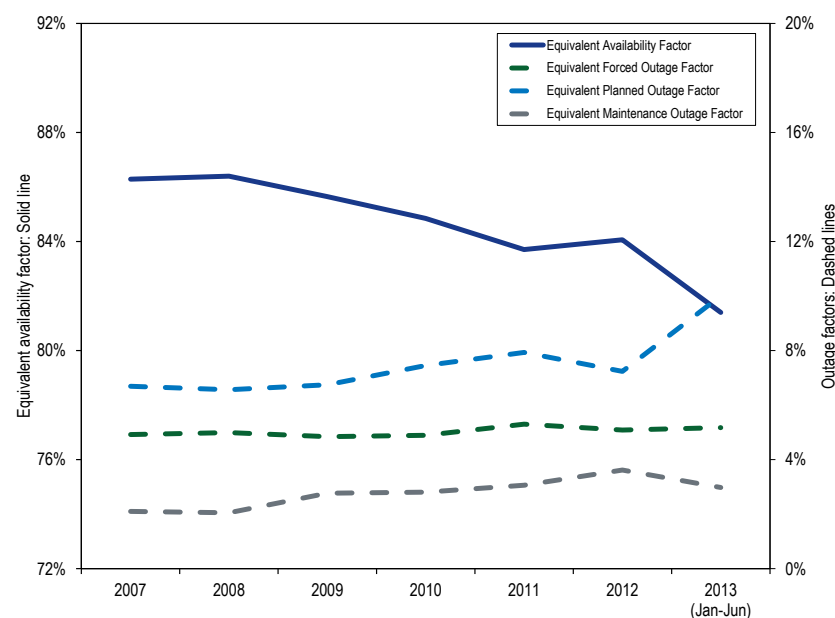
Table 4–17 EAF by unit type: 2007 through June 2013

	2007	2008	2009	2010	2011	2012	2013 (Jan–Jun)
Combined Cycle	89.7%	90.2%	87.8%	85.9%	85.4%	85.4%	82.4%
Combustion Turbine	90.5%	91.1%	93.2%	93.1%	91.8%	92.4%	87.4%
Diesel	86.4%	87.8%	91.2%	94.1%	94.8%	92.5%	93.0%
Hydroelectric	90.1%	88.8%	86.9%	88.8%	84.6%	88.8%	90.1%
Nuclear	93.1%	92.3%	90.1%	91.8%	90.1%	91.1%	90.0%
Steam	81.3%	81.6%	80.9%	79.0%	78.2%	77.9%	74.7%
Total	86.3%	86.4%	85.6%	84.8%	83.7%	84.1%	81.4%

Table 4–18 EMOF by unit type: 2007 through June 2013

	2007	2008	2009	2010	2011	2012	2013 (Jan–Jun)
Combined Cycle	2.0%	1.6%	3.0%	3.1%	2.4%	2.7%	3.2%
Combustion Turbine	2.5%	2.2%	2.3%	2.0%	2.4%	1.7%	1.6%
Diesel	1.8%	1.2%	1.2%	1.5%	2.0%	2.6%	1.7%
Hydroelectric	1.4%	2.1%	2.3%	1.9%	1.9%	2.1%	2.1%
Nuclear	0.3%	0.8%	0.6%	0.5%	1.2%	1.1%	0.6%
Steam	2.7%	2.6%	3.7%	3.9%	4.2%	5.6%	4.5%
Total	2.1%	2.1%	2.8%	2.8%	3.1%	3.6%	3.0%

Table 4–19 EPOF by unit type: 2007 through June 2013

	2007	2008	2009	2010	2011	2012	2013 (Jan–Jun)
Combined Cycle	5.9%	6.0%	6.3%	8.2%	9.6%	8.3%	11.4%
Combustion Turbine	2.5%	4.0%	2.8%	3.0%	3.8%	3.2%	3.6%
Diesel	0.7%	1.1%	0.6%	0.5%	0.1%	0.7%	0.5%
Hydroelectric	7.2%	7.8%	8.6%	8.6%	11.8%	6.3%	7.3%
Nuclear	5.3%	5.1%	5.2%	5.4%	6.1%	6.4%	7.5%
Steam	8.6%	8.0%	8.6%	9.4%	9.2%	8.7%	13.2%
Total	6.7%	6.6%	6.7%	7.5%	7.9%	7.2%	10.0%

Table 4–20 EFOF by unit type: 2007 through June 2013

	2007	2008	2009	2010	2011	2012	2013 (Jan–Jun)
Combined Cycle	2.3%	2.3%	2.9%	2.7%	2.6%	3.6%	3.1%
Combustion Turbine	4.5%	2.7%	1.6%	1.9%	2.0%	2.8%	4.8%
Diesel	11.2%	9.9%	7.0%	3.8%	3.2%	4.2%	3.6%
Hydroelectric	1.3%	1.3%	2.3%	0.7%	1.7%	2.8%	0.4%
Nuclear	1.3%	1.8%	4.1%	2.3%	2.6%	1.5%	1.9%
Steam	7.3%	7.9%	6.8%	7.7%	8.3%	7.8%	7.6%
Total	4.9%	5.0%	4.8%	4.9%	5.3%	5.1%	5.2%

Generator Forced Outage Rates

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

The unadjusted forced outage rate of a generating unit is measured as the equivalent demand forced outage rate (EFORd). EFORd is a measure of the probability that a generating unit will fail, either partially or totally, to perform when it is needed to operate. EFORd measures the forced outage rate during periods of demand, and does not include planned or maintenance outages. A period of demand is a period during which a generator is running or needed to run. EFORd calculations use historical performance data, including equivalent forced outage hours,[50] service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours. The EFORd metric includes all forced outages, regardless of the reason for those outages.

Figure 4-8 shows the average EFORd since 2007 for all units in PJM.

Figure 4-8 Trends in the PJM equivalent demand forced outage rate (EFORd): 2007 through 2013

Table 4-21 shows the class average EFORd by unit type.

Table 4-21 PJM EFORd data for different unit types: 2007 through June 2013

	2007	2008	2009	2010	2011	2012	2013 (Jan-Jun)
Combined Cycle	3.8%	3.9%	4.3%	3.9%	3.5%	4.3%	3.9%
Combustion Turbine	11.1%	11.1%	9.8%	8.9%	8.0%	8.2%	14.3%
Diesel	12.9%	11.2%	9.9%	5.9%	9.6%	5.5%	3.8%
Hydroelectric	2.0%	2.0%	3.2%	1.2%	2.9%	4.4%	0.7%
Nuclear	1.4%	1.9%	4.1%	2.5%	2.8%	1.6%	2.2%
Steam	9.2%	10.1%	9.4%	9.8%	11.3%	10.6%	10.9%
Total	7.1%	7.7%	7.6%	7.2%	7.9%	7.5%	8.4%

Distribution of EFORd

The average EFORd results do not show the underlying pattern of EFORd rates within each unit type. The distribution of EFORd by unit type is shown in Figure 4-9. Each generating unit is represented by a single point, and the capacity weighted unit average is represented by a solid square. Combustion turbine units had the greatest variance of EFORd, while nuclear units had the lowest variance in EFORd values in the first six months of 2013.

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50 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.

Figure 4-9 PJM distribution of EFORd data by unit type: January through June 2013
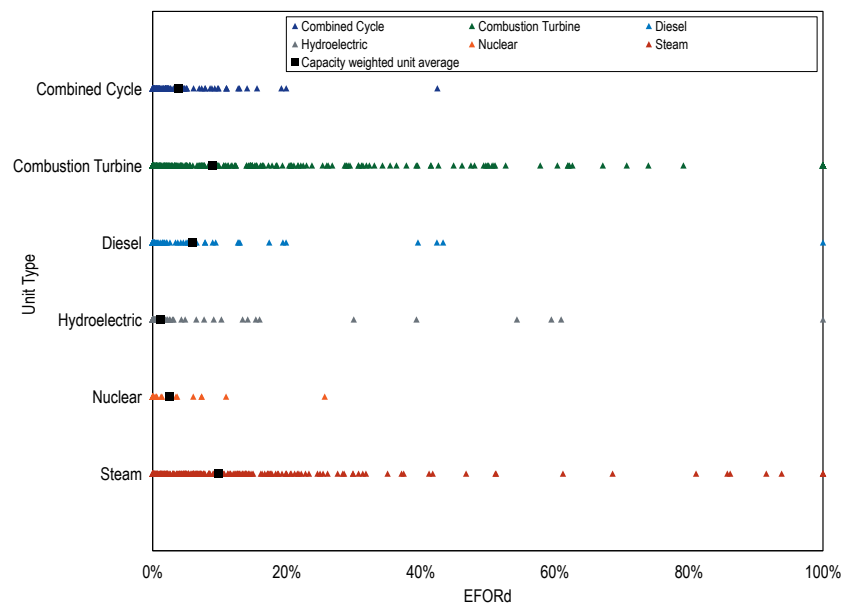
Other Forced Outage Rate Metrics

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

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

All outages, including OMC outages, are included in the EFORd that is used for planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations of XEFORd, which are used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market.

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

Outages Deemed Outside Management Control

In 2006, NERC created specifications for certain types of outages deemed to be Outside Management Control (OMC).[51] For NERC, an outage can be classified as an OMC outage only if the outage meets the requirements outlined in Appendix K of the "Generator Availability Data System Data Reporting Instructions." Appendix K of the "Generator Availability Data Systems Data Reporting Instructions" also lists specific cause codes (codes that are standardized for specific outage causes) that would be considered OMC outages.[52] Not all outages caused by the factors in these specific OMC cause codes are OMC outages. For example, according to the NERC specifications, fuel quality issues (codes 9200 to 9299) may be within the control of the owner or outside management control. Each outage must be considered separately per the NERC directive.

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51 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>.

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

Nothing in NERC's classification of outages requires that PJM exclude OMC outages from the forced outage rate metric used in the Capacity Market.[53] That choice was made by PJM and can be modified without violating any NERC requirements.[54] It is possible to have an OMC outage under the NERC definition, which PJM does not define as OMC for purposes of calculating XEFORd. That is the current PJM practice. The actual implementation of the OMC outages and their impact on XEFORd is and has been within the control of PJM. PJM has chosen to exclude only some of the OMC outages from the XEFORd metric.

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

All outages, including OMC outages, are included in the EFORd that is used for PJM planning studies that determine the reserve requirement. However, OMC outages are excluded from the calculations used to determine the level of unforced capacity for specific units that must be offered in PJM's Capacity Market. This modified EFORd is termed the XEFORd. Table 4-22 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages account for 15.6 percent of all forced outages. The second-largest contributor to OMC outages, lack of fuel, was the cause in of 32.1 percent of OMC outages and 5.0 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."

Table 4–22 OMC Outages: January through June 2013

OMC Cause Code	Percent of OMC Forced Outages	Percent of all Forced Outages
Hurricane	42.8%	6.7%
Lack of fuel	32.1%	5.0%
Flood	12.5%	1.9%
Lightning	3.4%	0.5%
Transmission system problems other than catastrophes	2.5%	0.4%
Switchyard circuit breakers external	1.6%	0.2%
Other switchyard equipment external	1.3%	0.2%
Other miscellaneous external problems	0.8%	0.1%
Transmission line	0.7%	0.1%
Transmission equipment beyond the 1st substation	0.6%	0.1%
Storms	0.5%	0.1%
Lack of water	0.5%	0.1%
Transmission equipment at the 1st substation	0.3%	0.1%
Switchyard system protection devices external	0.1%	0.0%
Switchyard transformers and associated cooling systems	0.1%	0.0%
Other fuel quality problems	0.1%	0.0%
Tornados	0.1%	0.0%
Total	100.0%	15.6%

An outage is an outage, regardless of the cause. Lack of fuel is especially noteworthy because, even if the OMC concept were accepted, the lack of fuel reasons are not outside the control of management. Virtually any issue with fuel supply can be addressed by additional expenditures. These are economic issues within the control of management and the resultant tradeoffs should be reflected in actual forced outage rates rather than ignored by designation as OMC. It is significant that some OMC outages are classified as economic. Firm gas contracts could be used in place of interruptible gas contracts. Alternative fuels could be used as a supplement to primary fuels. Improved fuel management practices including additional investment could eliminate wet coal as a reason. Better diversification in supplies could eliminate interruptions from individual suppliers. But regardless of the reason, an outage is an outage. If a particular unit or set of units have outages on a regular basis for one of the OMC reasons, that is a real feature of the units that should be reflected in overall PJM system planning as well as in the economic fundamentals of the capacity market and the capacity market outcomes. Permitting OMC outages to be excluded from the forced outage metric skews the results of the capacity

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

54 It is unclear whether there were member votes taken on this issue prior to PJM's implementation of its approach to OMC outages. It does not appear that PJM has consulted with members for the subsequent changes to its application of OMC outages.

market towards less reliable units and away from more reliable units. This is exactly the wrong incentive. Paying for capacity from units using the EFORd, not the XEFORd, metric would provide a market incentive for unit owners to address all their outage issues in an efficient manner. Pretending that some outages simply do not exist distorts market outcomes. That is exactly the result of using OMC outages to reduce EFORd.[55]

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

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

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

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

Table 4-23 shows the impact of OMC outages on EFORd. The difference is especially noticeable for steam units and combustion turbine units.

Table 4-23 PJM EFORd vs. XEFORd: January through June 2013

	EFORd	XEFORd	Difference
Combined Cycle	3.9%	3.2%	0.6%
Combustion Turbine	14.3%	9.3%	5.0%
Diesel	3.8%	3.3%	0.5%
Hydroelectric	0.7%	0.6%	0.1%
Nuclear	2.2%	1.8%	0.4%
Steam	10.9%	9.1%	1.8%
Total	8.4%	6.6%	1.8%

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

PJM EFOF was 5.2 percent in 2013. This means there was 5.2 percent lost availability because of forced outages. Table 4-24 shows that forced outages for boiler tube leaks, at 17.5 percent of the systemwide EFOF, were the largest single contributor to EFOF.

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

56 For any unit, lost generation can be converted to lost equivalent availability by dividing lost generation by the product of the generating units' capacity and period hours. This can also be done on a systemwide basis.

Table 4-24 Contribution to EFOF by unit type by cause: January through June 2013

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	2.1%	0.0%	0.0%	0.0%	0.0%	23.7%	17.5%
Catastrophe	17.7%	44.7%	10.0%	1.6%	9.8%	3.3%	9.2%
Boiler Piping System	4.1%	0.0%	0.0%	0.0%	0.0%	7.7%	6.0%
Economic	0.5%	3.5%	2.0%	4.7%	0.0%	6.7%	5.3%
Electrical	3.0%	5.8%	3.7%	8.7%	17.5%	4.0%	4.9%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	6.6%	4.8%
Feedwater System	2.4%	0.0%	0.0%	0.0%	4.8%	5.6%	4.6%
High Pressure Turbine	11.6%	0.0%	0.0%	0.0%	0.0%	4.0%	4.0%
Miscellaneous (Generator)	3.5%	3.1%	1.3%	52.1%	0.0%	1.7%	2.7%
Boiler Fuel Supply from Bunkers to Boiler	0.8%	0.0%	0.0%	0.0%	0.0%	3.6%	2.7%
Reserve Shutdown	1.6%	8.3%	20.2%	2.0%	0.8%	2.0%	2.6%
Controls	2.5%	4.4%	0.5%	0.2%	3.8%	1.5%	2.0%
Valves	2.6%	0.0%	0.0%	0.0%	2.3%	2.2%	2.0%
Fuel, Ignition and Combustion Systems	16.2%	3.0%	0.0%	0.0%	0.0%	0.0%	1.9%
Circulating Water Systems	1.1%	0.0%	0.0%	0.0%	7.1%	1.7%	1.8%
Miscellaneous (Steam Turbine)	1.1%	0.0%	0.0%	0.0%	0.2%	1.9%	1.5%
Low Pressure Turbine	0.0%	0.0%	0.0%	0.0%	2.2%	1.6%	1.3%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	22.5%	0.0%	1.2%
Condensing System	1.1%	0.0%	0.0%	0.0%	2.3%	1.3%	1.2%
All Other Causes	28.0%	27.2%	62.3%	30.6%	26.7%	20.9%	22.8%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 4-25 shows the categories which are included in the economic category.[57] Lack of fuel that is considered Outside Management Control accounted for 93.5 percent of all economic reasons while lack of fuel that was not Outside Management Control accounted for only 4.9 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."[58] Only a handful of units use other economic problems to describe outages. Other economic problems are not defined by NERC GADS and are best described as economic problems that cannot be classified by the other NERC GADS economic problem cause codes. Lack of water events occur when a hydroelectric plant does not have sufficient fuel (water) to operate.

Table 4-25 Contributions to Economic Outages: January through June 2013

	Contribution to Economic Reasons
Lack of fuel (OMC)	93.5%
Lack of fuel (Non-OMC)	4.9%
Lack of water (Hydro)	1.4%
Fuel conservation	0.1%
Problems with Primary Fuel for Units with Secondary Fuel Operation	0.0%
Other economic problems	0.0%
Ground water or other water supply problems	0.0%
Total	100.0%

57 The definitions of these outages are defined by NERC GADS.
58 The definitions of these outages are defined by NERC GADS.

EFORd, XEFORd and EFORp

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

EFORd, XEFORd and EFORp are designed to measure the rate of forced outages, which are defined as outages that cannot be postponed beyond the end of the next weekend.[59] 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 ability to do so. That is consistent with the incentives created by the PJM Capacity Market.

Table 4-26 shows the capacity-weighted class average of EFORd, XEFORd and EFORp. The impact of OMC outages is especially noticeable in the difference between EFORd and XEFORd for steam units and combustion turbine units.

Table 4-26 PJM EFORd, XEFORd and EFORp data by unit type: January through June 2013[60]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	3.9%	3.2%	1.3%	0.6%	2.6%
Combustion Turbine	14.3%	9.3%	3.7%	5.0%	10.5%
Diesel	3.8%	3.3%	1.2%	0.5%	2.6%
Hydroelectric	0.7%	0.6%	0.5%	0.1%	0.2%
Nuclear	2.2%	1.8%	1.4%	0.4%	0.7%
Steam	10.9%	9.1%	5.5%	1.8%	5.4%
Total	8.4%	6.6%	3.7%	1.8%	4.8%

Performance By Month

On a monthly basis, EFORp values were significantly less than EFORd and XEFORd values as shown in Figure 4-10, demonstrating that units had fewer outages during peak hours than would have been expected based on EFORd.

Figure 4-10 PJM EFORd, XEFORd and EFORp: January through June 2013
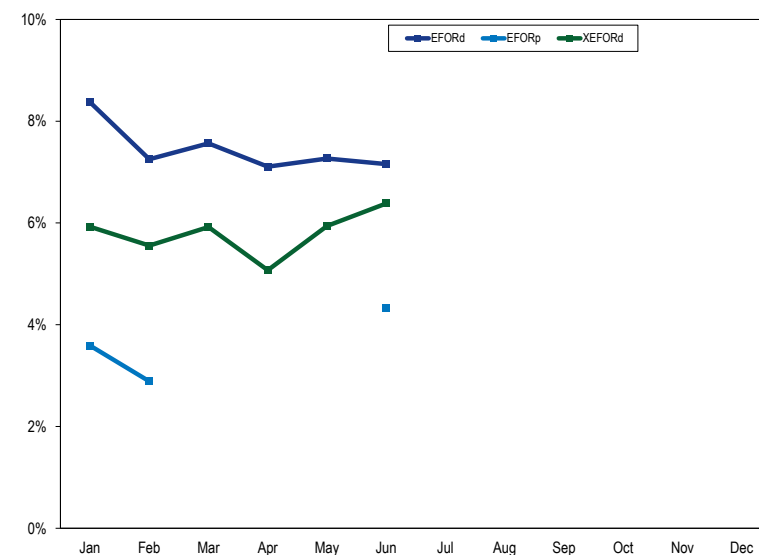
59 See PJM. "Manual 22: Generator Resource Performance Indices," Revision 16 (November 16, 2011), Definitions.

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

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On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 4-11.

Figure 4–11 PJM monthly generator performance factors: January through June 2013
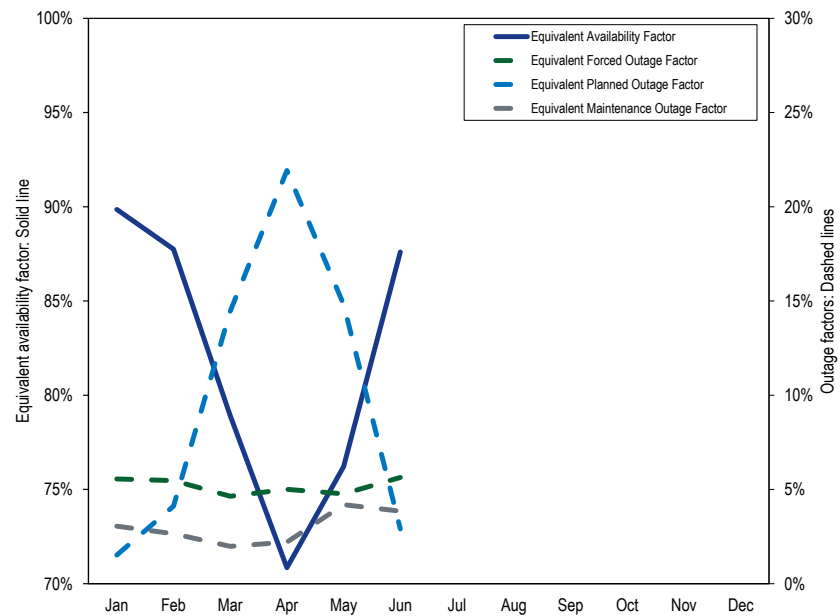
Demand-Side Response (DSR)

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 without depending on special programs.

Overview

- **Demand-Side Response Activity.** In the first six months of 2013, total load reduction under the Economic Load Response Program decreased by 3,773 MWh compared to the same period in 2012, from 38,692 MWh in the first six months of 2012 to 34,919 MWh in the first six months of 2013, a 10 percent decrease. Total credits under the Economic Program decreased by $321,417, from $2,172,454 in the first six months of 2012 to $1,851,037 in the same period of 2013, a 15 percent decrease. However, total credits increased by 516 percent from the first four months of 2012 to the first four months of 2013. May and June, 2013 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.

  The capacity market is the primary source of revenue to participants in PJM demand side programs. In the first six months of 2013, Load Management (LM) Program revenue decreased $39.6 million, or 20.2 percent, from $196.2 million to $156.6 million. Through the first six months of 2013, Synchronized Reserve credits for demand side resources decreased by $1.4 million compared to the same period in 2012, from $2.5 million to $1.4 million in 2013.

Conclusion

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.

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 are not adequate to determine and quantify deliberate actions taken to reduce consumption. The MMU recommends that actual meter load data should be provided in order to measure and verify actual demand resource behavior.

The MMU recommends that demand side measurement and verification be further modified to more accurately reflect compliance. Increases in load by load management resources during event hours should not be considered zero response or ignored, but should be included for reporting and determining compliance. Load management testing does not adequately reflect actual resource performance during event days. Testing should be initiated by PJM with limited warning to CSPs in order to more accurately reflect the conditions of an emergency event.[1] The MMU recommends that load management resources whose load drop method is designated as "Other" explicitly record the method of load drop.

The load management product is currently defined as an emergency product. In fact, the load management product is an economic product and it is treated as an economic product in the PJM capacity market design where it competes directly with generation capacity, affects market clearing prices and

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1 For additional conclusions see the *2012 State of the Market Report for PJM*, Volume 2: Section 5, "Demand Response."

receives the market clearing price. The load management product should also be treated as an economic product in PJM dispatch meaning that demand resources should be called when the resources are required and prior to the declaration of an emergency. For these reasons, the MMU recommends that the DR program be classified as an economic program and not an emergency program.[2]

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.[3]

Table 5-1 Overview of Demand Side Programs[4]

Emergency Load Response Program			Economic Load Response Program
Load Management (LM)			
Capacity Only	Capacity and Energy	Energy Only	Energy Only
DR cleared in RPM;	DR cleared in RPM	Not included in RPM	Not included in RPM
Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment
RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA
Capacity payments based on RPM clearing price	Capacity payments based on RPM price	NA	NA
No energy payment.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment during PJM declared Emergency Event mandatory curtailments.	Energy payment based on submitted higher of "minimum dispatch price" and LMP. Energy payment only for voluntary curtailments.	Energy payment based on full LMP. Energy payment for hours of dispatched curtailment.

Participation in Demand Side Programs

On April 1, 2012, FERC Order No. 745 was implemented in the PJM Economic Program, mandating payment of full LMP for dispatched demand resources. In the first six months of 2013, in the Economic Program, participation decreased compared to the same period in 2012. There were fewer settlements submitted and active registrations in 2013 compared to the same period in 2012, and credits decreased. However, May and June 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.

Figure 5-1 shows all revenue from PJM Demand Side Response Programs by market for the period 2002 through the first six months of 2013. Since the implementation of the RPM design on June 1, 2007, the capacity market has been the primary source of revenue to demand side participants, representing 98.2 percent of all revenue received through demand response programs in the first six months of 2013. In the first six months of 2013, total credits under the Economic Program decreased by $321,417, from $2,172,454 in the first six months of 2012 to $1,851,037 in the same period of 2013. This represents a 15 percent decrease in credits, but only 1.2 percent of all revenue received through PJM demand response programs. The total MWh reductions increased by 325 percent for the first four months of 2013 compared to the first four months of 2012. In the first six months of 2013, capacity revenue represents 98.2 percent of all revenue received by demand response providers, emergency energy revenue represented 0.0 percent, revenue from the economic program represented 1.2 percent and revenue from Synchronized Reserve represented 0.7 percent.

Capacity revenue decreased by $39.6 million, or 20.2 percent, from $196.2 million to $156.6 million in the first six months of 2013, primarily due to lower clearing prices in the RPM market. Synchronized Reserve credits for demand side resources decreased by $1.4 million, from $2.5 million to $1.0 million in the first six months 2013, due to lower clearing prices in the Synchronized Reserve market.

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2   This issue is currently being discussed in the Capacity Senior Task Force (CSTF) with an expected resolution by summer 2014.
3   For more detail on the historical development of PJM Load Response Programs see the *2011 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market," <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2011.shtml>.
4   Prior to April 1, 2012, payment for the Economic Load Response Program was based on LMP minus the generation and transmission components of the retail rate.

Figure 5-1 Demand Response revenue by market: 2002 through June 2013
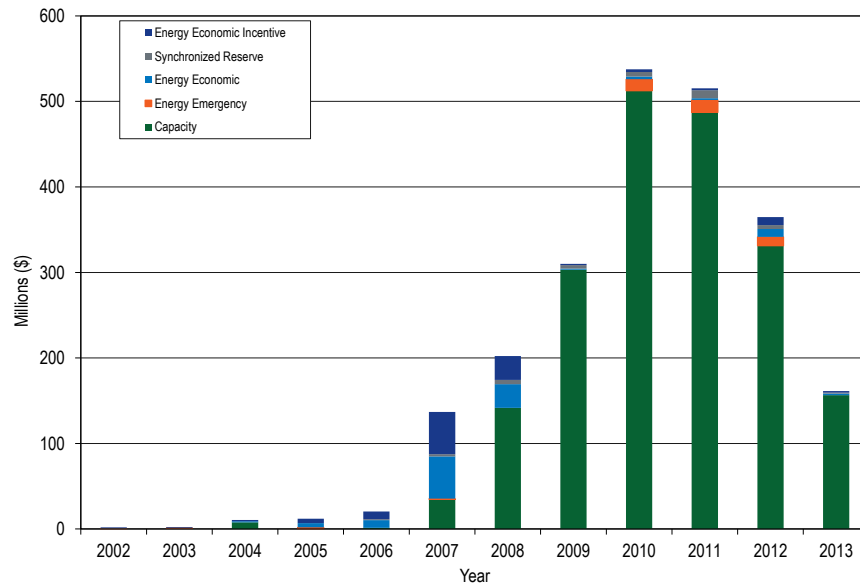
Economic Program

Table 5-2 shows registered sites and MW for the last day of each month for the period 2010 through the first six months of 2013. The average registered MW for the first six months increased by 241 MW from 2,077 in 2012 to 2,318 registered MW in 2013. Historically, registered MW have declined in June but increased in August, which is likely the result of expirations and renewals. Registration in the Economic Program means that customers have been signed up and can participate if they choose. Registrations in January through June 2013 were 1,228 less than 2012. Although registrations decreased, total registered MW were higher by 1,446 MW in the first six months of 2013 compared to the same period of 2012. The registered MW per registration increased in the first six months of 2013 compared to the first six months of 2012. The average number of active registrations was 1,225 in the first six months of 2012 and 1,020 in the same period in 2013.

Table 5-2 Economic Program registrations on the last day of the month: 2010 through June 2013

Month	2010		2011		2012		2013	
	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	1,841	2,623	1,609	2,432	1,993	2,385	841	2,332
Feb	1,842	2,624	1,612	2,435	1,995	2,384	843	2,345
Mar	1,845	2,623	1,612	2,519	1,996	2,356	788	2,302
Apr	1,849	2,587	1,611	2,534	189	1,318	970	2,352
May	1,875	2,819	1,687	3,166	371	1,669	1,375	2,424
Jun	813	1,608	1,143	1,912	803	2,347	1,302	2,150
Jul	1,192	2,159	1,228	2,062	942	2,323		
Aug	1,616	2,398	1,987	2,194	1,013	2,373		
Sep	1,609	2,447	1,962	2,183	1,052	2,421		
Oct	1,606	2,444	1,954	2,179	828	2,269		
Nov	1,605	2,444	1,988	2,255	824	2,267		
Dec	1,598	2,439	1,992	2,259	846	2,283		
Avg.	1,608	2,435	1,699	2,344	1,071	2,200	1,020	2,318

Total credits in Table 5-3 exclude incentive credits in the Economic Program for the years 2006 and 2007. The economic incentive program expired in December of 2007.[5]

Table 5-3 Performance of PJM Economic Program participants excluding incentive credits: 2003 through June 2013

	Total MWh	Total Credits	$/MWh
2003	19,518	$833,530	$42.71
2004	58,352	$1,917,202	$32.86
2005	157,421	$13,036,482	$82.81
2006	258,468	$10,213,828	$39.52
2007	714,148	$31,600,046	$44.25
2008	452,222	$27,087,495	$59.90
2009	57,157	$1,389,136	$24.30
2010	74,070	$3,088,049	$41.69
2011	17,398	$2,052,996	$118.00
2012	145,019	$9,284,118	$64.02
2013	34,919	$1,851,037	$53.01

Figure 5-2 shows monthly economic program credits, excluding incentive credits, for 2009 through June 2013. Higher energy prices and FERC Order 745 increased incentives to participate during the first six months of 2013. January through April, 2013, had greater economic credits than the same period since 2009. May and June of 2013 do not yet reflect complete economic program activity results as participants have up to 60 days to submit data for settlement.

Figure 5-2 Economic Program credits by month: 2009 through June 2013

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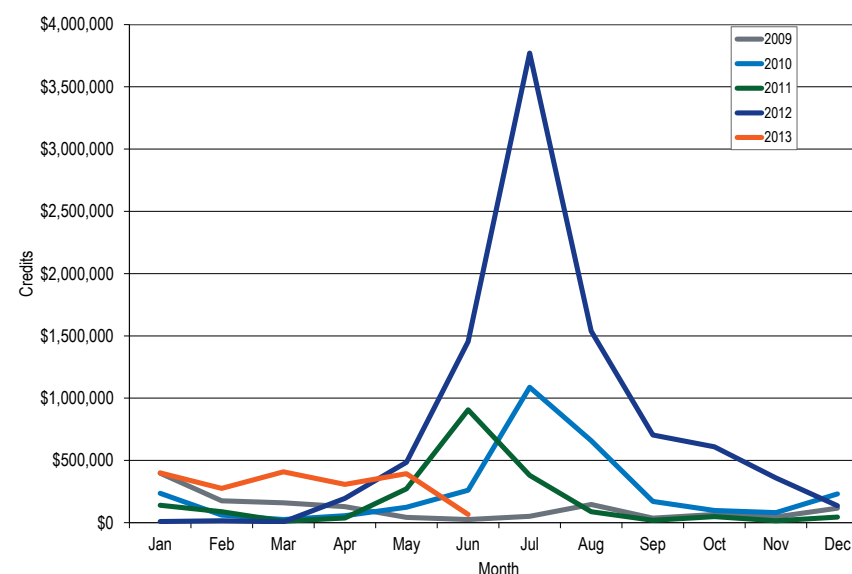
5 In 2006 and 2007, when LMP was greater than, or equal to, $75 per MWh, customers were paid the full LMP and the amount not paid by the LSE, equal to the generation and transmission components of the applicable retail rate (recoverable charges), was charged to all LSEs in the zone of the load reduction.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

Table 5-4 shows the first six months of 2012 and 2013 performance in the Economic Program by control zone and participation type. Curtailed energy for the Economic Program was 34,919 MWh and the total payment amount was $1,851,037. The Dominion Control Zone accounted for $1,545,699 or 84 percent of all Economic Program credits, associated with 29,442 MWh or 84 percent of total program reductions. Table 5-4 shows the average participation in the Economic Program by zone and amount of customers in each zone. The Dominion Control Zone has the highest average MW reductions per customer and average credits per customer. Credits for the first six months of 2013 decreased by $321,417, or 15 percent, compared to the same time period of 2012. However, this does not fully account for data lag in May and June settlements by demand response providers that have up to 60 days to submit data after a demand response event. The total credits increased by 516 percent for the first four months of 2012 compared to the first four months of 2013.

Table 5-4 PJM Economic Program participation by zone: January through June 2012 and 2013

	Credits			MWh Reductions		
	2012	2013	Percentage Change	2012	2013	Percentage Change
AECO	$0	$0	NA	0	0	NA
AEP	$1,469	$1,073	(27%)	21	22	6%
AP	$195,858	$33,319	(83%)	3,399	822	(76%)
ATSI	$2,514	$107	(96%)	68	3	(95%)
BGE	$4,225	$24,717	485%	20	134	578%
ComEd	$64,473	$63,921	(1%)	1,854	1,464	(21%)
DAY	$0	$0	NA	0	0	NA
DEOK	$0	$0	NA	0	0	NA
DLCO	$2,793	$0	(100%)	40	0	(100%)
Dominion	$1,230,715	$1,545,699	26%	20,916	29,442	41%
DPL	$10,037	$0	(100%)	99	0	(100%)
EKPC	$0	$0	NA	0	0	NA
JCPL	$39,398	$57,732	47%	324	678	109%
Met-Ed	$36,138	$1,177	(97%)	378	22	(94%)
PECO	$91,898	$19,963	(78%)	1,467	392	(73%)
PENELEC	$166,506	$78,760	(53%)	3,507	1,420	(60%)
Pepco	$27,127	$0	(100%)	359	0	(100%)
PPL	$71,374	$19,377	(73%)	839	360	(57%)
PSEG	$227,930	$5,194	(98%)	5,400	160	(97%)
RECO	$0	$0	NA	0	0	NA
Total	$2,172,454	$1,851,037	(15%)	38,692	34,919	(10%)

Table 5-5 shows total settlements submitted by month for 2008 through June 2013.

Table 5-5 Settlement days submitted by month in the Economic Program: 2008 through June 2013

Month	2008	2009	2010	2011	2012	2013
Jan	2,916	1,264	1,415	562	62	192
Feb	2,811	654	546	148	30	92
Mar	2,818	574	411	82	46	126
Apr	3,406	337	338	102	93	160
May	3,336	918	673	298	144	188
Jun	3,184	2,727	1,221	743	1,480	402
Jul	3,339	2,879	3,010	1,412	2,906	
Aug	3,848	3,760	2,158	793	1,693	
Sep	3,264	2,570	660	294	555	
Oct	1,977	2,361	699	66	481	
Nov	1,105	2,321	672	51	280	
Dec	986	1,240	894	40	124	
Total	32,990	21,605	12,697	4,591	7,894	1,160

Table 5-6 shows the number of distinct Curtailment Service Providers (CSPs) and distinct customers actively submitting settlements by month for the period 2009 through June 2013.[6] The number of active customers during the first six months of 2013 decreased by 281 compared to the same period in 2012. The smaller number of active customers in 2013 responded more frequently compared to customers in the same period of 2012.

Table 5-7 shows a frequency distribution of MWh reductions and credits in each hour for the first six months of 2012 and 2013. In the first six months of 2013, 56.6 percent of the reductions occurred between hour ending 7 and hour ending 12, while in the first six months of 2012, 53.8 percent of hourly reductions occurred from hour ending 15 to hour ending 18.

Table 5-6 Distinct customers and CSPs submitting settlements in the Economic Program by month: 2009 through June 2013

Month	2009 Active CSPs	2009 Active Customers	2010 Active CSPs	2010 Active Customers	2011 Active CSPs	2011 Active Customers	2012 Active CSPs	2012 Active Customers	2013 Active CSPs	2013 Active Customers
Jan	17	257	11	153	5	40	5	15	8	47
Feb	12	129	9	92	6	29	3	9	5	14
Mar	11	149	7	124	3	15	3	12	5	19
Apr	9	76	5	77	3	15	3	8	5	16
May	9	201	6	140	6	144	5	20	6	33
Jun	20	231	11	152	10	304	16	338	9	53
Jul	21	183	18	267	15	214	21	383		
Aug	15	400	14	317	14	186	17	361		
Sep	11	181	11	96	7	47	11	127		
Oct	11	93	8	37	3	9	9	50		
Nov	9	143	7	38	3	13	5	63		
Dec	10	160	7	44	5	12	3	10		
Total Distinct Active	25	747	24	438	20	610	24	520	12	89

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6 May and June 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.

Table 5-7 Hourly frequency distribution of Economic Program MWh reductions and credits: January through June 2012 and 2013

Hour Ending (EPT)	MWh Reductions			Program Credits		
	2012	2013	Percentage Change	2012	2013	Percentage Change
1	31	3	(89%)	$678	($191)	(128%)
2	25	10	(59%)	$623	$1	(100%)
3	25	19	(21%)	$113	$324	188%
4	14	21	52%	($48)	$423	NA
5	14	20	47%	($49)	$353	NA
6	45	29	(36%)	$499	$927	86%
7	732	3,480	376%	$25,721	$187,640	630%
8	1,261	3,990	216%	$35,834	$253,007	606%
9	1,212	3,829	216%	$41,182	$191,511	365%
10	1,032	3,527	242%	$39,495	$159,021	303%
11	1,142	2,677	134%	$45,868	$125,228	173%
12	1,227	2,276	86%	$53,705	$99,058	84%
13	2,031	1,819	(10%)	$99,687	$79,964	(20%)
14	3,124	1,349	(57%)	$166,059	$69,813	(58%)
15	4,674	1,878	(60%)	$262,884	$104,038	(60%)
16	5,376	1,887	(65%)	$347,751	$110,413	(68%)
17	5,474	2,016	(63%)	$409,258	$125,482	(69%)
18	5,304	2,065	(61%)	$363,264	$119,948	(67%)
19	2,262	1,898	(16%)	$139,264	$101,821	(27%)
20	1,737	1,512	(13%)	$71,728	$83,766	17%
21	1,105	415	(62%)	$48,233	$28,659	(41%)
22	502	156	(69%)	$16,155	$7,756	(52%)
23	218	28	(87%)	$3,491	$977	(72%)
24	127	14	(89%)	$1,060	$1,098	4%
Total	38,692	34,919	(10%)	2,172,454	1,851,037	(15%)

Following the implementation of Order 745 on April 1, 2012, demand resources were paid full LMP for any load reductions during hours they were dispatched, provided that LMP was greater than the Net Benefits Test (NBT) threshold. The NBT is used to define a price point above which the net benefits of DR are deemed to exceed the cost to load. When the LMP is above the NBT threshold, the demand response resource receives credit for the full LMP. The Net Benefits Test defined an average price of $26.79 from January through June 2013. Demand resources are not paid for any load reductions during hours where the LMP is below the Net Benefits Test price.

Table 5-8 shows the frequency distribution of Economic Program MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP. MWh reductions in the $0 to $25 bracket decreased from 754 MWh in 2012 to 111 MWh in the first six months of 2013. Since these reductions occurred when LMP was below the Net Benefits Test, they did not receive any credits for their reduction from the economic program. MWh reductions in the $50 to $75 LMP bracket increased 37.4 percent from 7,542 MWh to 10,365 MWh in the first six months of 2013.

Total Economic Program reductions decreased by 3,773 MWh, from 38,692 MWh in the first six months of 2012 to 34,919 MWh in the same time period of 2013. Reductions occurred at all price levels. Approximately 89.0 percent of MWh reductions and 78.5 percent of program credits are associated with hours when the applicable zonal LMP was between $25 and $75. MWh reductions in the first six months of 2013 decreased 9.8 percent compared to the same period in 2012. However, the 2013 data is not fully representative of activity in May and June due to the lag in settlements by demand response providers that have up to 60 days to submit data after a demand response event. The total MWh reductions increased by 325 percent for the first four months of 2013 compared to the first four months of 2012.

Table 5-8 Frequency distribution of Economic Program zonal, load-weighted, average LMP (By hours): January through June 2012 and 2013

LMP	MWh Reductions			Program Credits		
	2012	2013	Percentage Change	2012	2013	Percentage Change
$0 to $25	754	111	(85.34%)	$7,583	$0	(100.00%)
$25 to $50	23,552	20,694	(12.13%)	$853,597	$828,110	(2.99%)
$50 to $75	7,542	10,365	37.44%	$440,713	$625,376	41.90%
$75 to $100	2,699	2,174	(19.47%)	$222,779	$187,546	(15.82%)
$100 to $125	1,336	885	(33.80%)	$149,017	$97,988	(34.24%)
$125 to $150	1,103	385	(65.10%)	$141,919	$51,033	(64.04%)
$150 to $200	427	263	(38.46%)	$59,234	$49,761	(15.99%)
$200 to $250	806	29	(96.43%)	$153,014	$6,191	(95.95%)
$250 to $300	281	2	(99.13%)	$61,185	$628	(98.97%)
> $300	191	12	(93.85%)	$83,413	$4,403	(94.72%)
Total	38,692	34,919	(9.75%)	$2,172,454	$1,851,037	(14.80%)

Load Management Program

Table 5-9 shows zonal monthly capacity credits to DR resources for the period January through June of 2013. Capacity revenue decreased in the first six months of 2013 by $39.6 million, or 20.2 percent, compared to the first six months of 2012; from $196.2 million to $156.6 million in the same time period of 2013. The decrease in capacity credits in 2013 is the result of a decrease in RPM clearing prices for the 2012/2013 Delivery Year. RPM prices increased for the 2013/2014 Delivery Year resulting in higher capacity credits in June 2013 by $23.2 million compared to May 2013.[7]

Table 5-9 Zonal monthly capacity credits: January through June 2013

Zone	January	February	March	April	May	June	Total
AECO	$411,097	$371,313	$411,097	$397,836	$411,097	$1,002,307	$3,004,747
AEP	$425,101	$383,962	$425,101	$411,388	$425,101	$749,663	$2,820,314
AP	$185,478	$167,528	$185,478	$179,495	$185,478	$477,348	$1,380,805
ATSI	$19,859	$17,937	$19,859	$19,218	$19,859	$365,564	$462,295
BGE	$5,430,108	$4,904,613	$5,430,108	$5,254,943	$5,430,108	$7,487,232	$33,937,111
ComEd	$405,926	$366,643	$405,926	$392,831	$405,926	$782,114	$2,759,366
DAY	$63,670	$57,508	$63,670	$61,616	$63,670	$42,849	$352,984
DEOK	$8,185	$7,393	$8,185	$7,921	$8,185	$16,115	$55,982
DLCO	$49,718	$44,907	$49,718	$48,114	$49,718	$143,269	$385,445
Dominion	$306,929	$277,226	$306,929	$297,028	$306,929	$585,863	$2,080,903
DPL	$1,547,049	$1,397,335	$1,547,049	$1,497,145	$1,547,049	$1,915,174	$9,450,802
EKPC	$0	$0	$0	$0	$0	$1,495	$1,495
JCPL	$1,495,628	$1,350,890	$1,495,628	$1,447,382	$1,495,628	$2,215,048	$9,500,203
Met-Ed	$1,044,281	$943,222	$1,044,281	$1,010,595	$1,044,281	$2,174,111	$7,260,771
PECO	$2,660,069	$2,402,643	$2,660,069	$2,574,260	$2,660,069	$5,142,792	$18,099,901
PENELEC	$1,144,857	$1,034,064	$1,144,857	$1,107,926	$1,144,857	$2,884,571	$8,461,131
Pepco	$1,906,591	$1,722,082	$1,906,591	$1,845,088	$1,906,591	$4,092,964	$13,379,905
PPL	$3,247,272	$2,933,020	$3,247,272	$3,142,521	$3,247,272	$7,019,745	$22,837,102
PSEG	$2,354,400	$2,126,555	$2,354,400	$2,278,452	$2,354,400	$8,574,172	$20,042,381
RECO	$14,896	$13,454	$14,896	$14,415	$14,896	$249,408	$321,963
Total	$22,721,111	$20,522,294	$22,721,111	$21,988,172	$22,721,111	$45,921,805	$156,595,604

Table 5-10 shows the amount of Energy Efficiency resources in each LDA for the 2012/2013 and 2013/2014 Delivery Year. The total MW of Energy Efficiency resources increased by 63 percent from 631.2 MW in 2012/2013 to 1,029.2 MW in 2013/2014 delivery year.

Table 5-10 LDA Energy Efficiency resources by MW: 2012/2013 and 2013/2014 Delivery Year

	EE ICAP (MW)			EE UCAP (MW)		
LDA Name	2012/2013	2013/2014	Percentage Change	2012/2013	2013/2014	Percentage Change
DPL-SOUTH	0.0	12.4	NA	0.0	12.9	NA
EMAAC	18.7	17.3	(7%)	19.0	17.1	(10%)
MAAC	44.3	81.1	83%	45.7	83.9	84%
PEPCO	0.0	74.6	NA	0.0	77.5	NA
PS-NORTH	6.6	10.4	58%	6.8	10.8	59%
PSEG	6.1	13.1	115%	6.1	13.3	118%
RTO	395.5	593.5	50%	410.0	617.5	51%
SWMAAC	138.6	188.5	36%	143.6	196.2	37%
Total	609.8	990.9	62%	631.2	1,029.2	63%

Table 5-11 shows the MW registered by load drop method and by measurement and verification method. Of the DR MW committed, 3.5 percent use the Guaranteed Load Drop method, 87.0 percent use the Firm Service Level method and 9.5 percent use the Direct Load Control method as the measurement and verification method.

There is a lack of transparency in the load drop method for demand response resources. The load drop method of 20.3 percent of committed MW is labeled as "Other." The MMU recommends that any MW designated as "Other" explicitly record the method of load drop. DR has 30.2 percent of registered MW as reduced by applications at manufacturing facilities, 22.0 percent of registered MW by applications using HVAC units, 20.3 percent of registered MW as reduced by non-specified other applications, 18.0 percent of registered MW as reduced by on-site generation, 6.2 percent of registered MW as reduced by lighting applications, 1.9 percent of registered MW as reduced by refrigeration applications and 1.3 percent of registered MW as reduced by water heater applications.

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7   For more detail on the historical RPM prices of PJM Load Response Programs see the *2012 State of the Market Report for PJM*, Volume II, Section 4, "Capacity Market," <http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012.shtml>.

Table 5-11 Reduction MW by each demand response method: 2013/2014 Delivery Year

Program Type	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating MW	Other MW	Total	Percentage by type
Firm Service Level	1,550.0	1,042.2	171.4	535.9	2,678.6	77.4	1,743.9	7,799.3	87.0%
Guaranteed Load Drop	61.3	157.6	1.9	19.8	31.0	0.4	41.4	313.4	3.5%
Non hourly metered sites (DLC)	0.0	775.6	0.0	0.0	0.0	40.0	37.0	852.7	9.5%
Total	1,611.3	1,975.4	173.2	555.7	2,709.6	117.9	1,822.3	8,965.3	100.0%
Percentage by method	18.0%	22.0%	1.9%	6.2%	30.2%	1.3%	20.3%	100.0%	

Table 5-12 shows the fuel type used in the on-site generators identified in Table 5-11. Of the load management resources identified as using on-site generation, 92.5 percent of MW are diesel, 6.2 percent are natural gas and 1.3 percent is coal, oil, other or no fuel source. The Other category in Table 5-11 could also include on-site generation, but there is no detailed information about the Other category at present.

Table 5-12 On-site generation fuel type by MW: 2013/2014 Delivery Year

Fuel Type	MW	Percentage
Coal	1.0	0.1%
Diesel	1,489.7	92.5%
Gas	100.7	6.2%
None	4.3	0.3%
Oil	8.7	0.5%
Other	6.8	0.4%
Total	1,611.3	100.00%

Limited Demand Resource Penalty Charge

Limited Demand Response Resources are required to be available for only 10 times during the months of June through September in a Delivery Year on weekdays other than PJM holidays from 12:00pm to 8:00pm EPT and be capable of maintaining an interruption for 6 hours. Limited demand response resources have one or two hours to reduce load once PJM initiates an event. When a provider under complies based on their registered MW, the penalty is based on the amount of under compliance, the number of events called during the DY and the cost per MW day for that provider. DR penalties are only assessed for PJM initiated events, after a compliance review is complete. The penalties are assessed daily and have increased by $842,993.74 since December 31, 2012. Table 5-13 shows penalty charges by zone for the 2012/2013 DY. Met-Ed was the only zone that was called for an event that had no penalty charges.

Table 5-13 Penalty Charges per Zone: Delivery Year 2012/2013[8]

	Penalty Charge
AECO	$91.25
AEP	$143,499.75
AP	$0.00
ATSI	$0.00
BGE	$133,849.15
ComEd	$0.00
DAY	$0.00
DEOK	$0.00
Dominion	$59,020.50
DPL	$740,756.55
DLCO	$0.00
JCPL	$5,332.65
Met-Ed	$0.00
PECO	$399,404.90
PENELEC	$44,066.45
Pepco	$500,904.10
PPL	$594.95
PSEG	$10,179.85
RECO	$0.00
Total	$2,037,700.10

8   EKPC was not integrated until June 1, 2013, during the 2013/2014 Delivery Year.

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 turbine (CT), combined cycle (CC), coal plant (CP), integrated gasification combined cycle (IGCC), diesel (DS), nuclear (NU), solar, and wind generating units.

Overview

Net Revenue

- In the first six months of 2013, energy market net revenues for a new entrant coal plant exceeded 2012 annual energy market net revenues in nine zones. This increase in net revenues was a result of the change in the relative prices of coal and gas and higher energy market prices.

- In the first six months of 2013, average energy market net revenues for a new entrant CT were 43 percent of 2012 annual energy market net revenues. In the first six months of 2013, average energy market net revenues for a new entrant CC were 40 percent of 2012 annual energy market net revenues.

- In the first six months of 2013, average energy market net revenues for a new entrant wind plant were over 69 percent and for a new entrant solar plant were over 77 percent of 2012 annual net revenues.

Conclusion

Wholesale electric power markets are affected by externally imposed reliability requirements. A regulatory authority external to the market makes a determination as to the acceptable level of reliability which is enforced through a requirement to maintain a target level of installed or unforced capacity. The requirement to maintain a target level of installed capacity can be enforced via a variety of mechanisms, including government construction of generation, full-requirement contracts with developers to construct and operate generation, state utility commission mandates to construct

capacity, or capacity markets of various types. Regardless of the enforcement mechanism, the exogenous requirement to construct capacity in excess of what is constructed in response to energy market signals has an impact on energy markets. The reliability requirement results in maintaining a level of capacity in excess of the level that would result from the operation of an energy market alone. The result of that additional capacity is to reduce the level and volatility of energy market prices and to reduce the duration of high energy market prices. This, in turn, reduces net revenue to generation owners which reduces the incentive to invest. The exact level of both aggregate and locational excess capacity is a function of the calculation methods used by RTOs and ISOs.

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

The historical level of net revenues in PJM markets was not the result of the $1,000-per-MWh offer cap, of local market power mitigation, or of a basic incompatibility between wholesale electricity markets and competition. Competitive markets can, and do, signal scarcity and surplus conditions through market clearing prices. Nonetheless, in PJM as in other wholesale electric power markets, the application of reliability standards means that scarcity conditions in the Energy Market occur with reduced frequency. Traditional levels of reliability require units that are only directly used and priced under relatively unusual load conditions. Thus, the Energy Market alone frequently does not directly compensate the resources needed to provide for reliability.

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

Energy Market. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. CTs are generally the highest incremental cost units and therefore tend to be marginal in the energy market and set prices when they run. When this occurs, CT energy market net revenues tend to be low and there is little contribution to fixed costs. High demand hours result in less efficient CTs setting prices, which results in higher net revenues for more efficient CTs and other inframarginal units.

The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. In the PJM design, the capacity market provides a significant stream of revenue that contributes to the recovery of total costs for new and existing peaking units that may be needed for reliability during years in which energy net revenues are not sufficient. The capacity market is also a significant source of net revenue to cover the fixed costs of investing in new intermediate and base load units, although capacity revenues are a larger part of net revenue for peaking units. However, when the actual fixed costs of capacity increase rapidly, or, when the energy net revenues used as the offset in determining capacity market prices are higher than actual energy net revenues, there is a corresponding lag in capacity market prices which will tend to lead to an under recovery of the fixed costs of CTs. The reverse can also happen, leading to an over recovery of the fixed costs of CTs, although it has happened less frequently in PJM markets.

Net Revenue

When compared to annualized fixed costs, net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Net revenue equals total revenue received by generators from PJM Energy, Capacity and Ancillary Service Markets and from the provision of black start and reactive services less the variable costs of energy production. In other words, net revenue is the amount that remains, after

short run variable costs of energy production have been subtracted from gross revenue, to cover fixed costs, which include a return on investment, depreciation, taxes and fixed operation and maintenance expenses. Net revenue is the contribution to total fixed costs received by generators from all PJM markets.

In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all annualized fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute to the payment of fixed costs. In PJM, the Energy, Capacity and Ancillary Service Markets are all significant sources of revenue to cover fixed costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long-run equilibrium, with energy, capacity and ancillary service payments, net revenue from all sources would be expected to equal the annualized fixed costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to encourage entry of new capacity. In actual wholesale power markets, where equilibrium seldom occurs, net revenue is expected to fluctuate above and below the equilibrium level based on actual conditions in all relevant markets.

Operating reserve payments are included when the analysis is based on the peak-hour, economic dispatch model and actual net revenues.[1]

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The real-time load-weighted average LMP was 21.6 percent higher in the first six months of 2013 than in the first six months of 2012, $37.96 per MWh versus $31.21 per MWh. Comparing fuel prices in the first six months of 2013 to fuel prices in the first six months of 2012, the price of Northern Appalachian coal was 0.5 percent lower; the price of Central Appalachian coal was 4.1 percent higher; the price of Powder River Basin

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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.

coal was 18.0 percent higher; the price of eastern natural gas was 52.7 percent higher; and the price of western natural gas was 35.4 percent higher.

Figure 6-1 Energy Market net revenue factor trends: December 2008 through June 2013
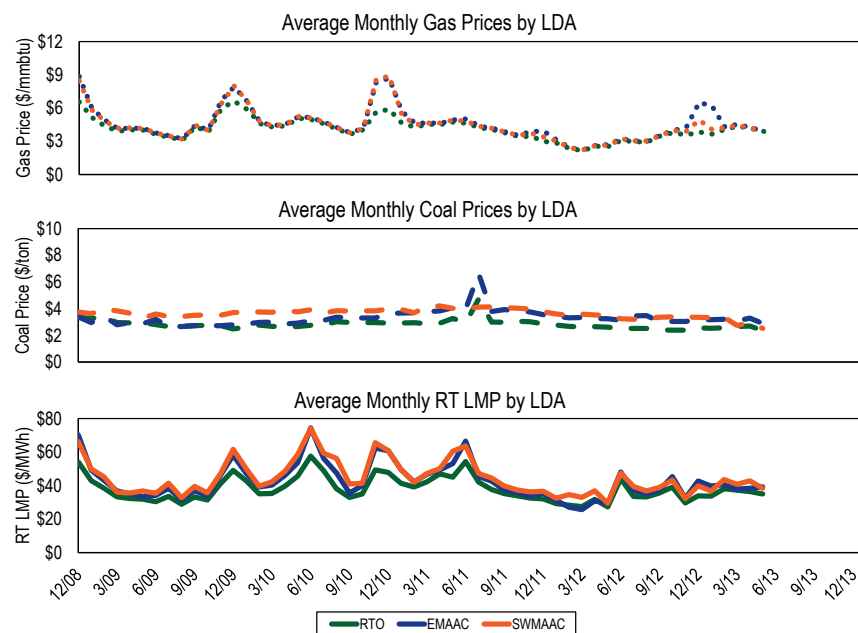
Theoretical Energy Market Net Revenue

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 this economic dispatch scenario.

Analysis of Energy Market net revenues for a new entrant includes eight power plant configurations:

- 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 CP is a sub-critical steam unit, 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.

- The IGCC plant consists of a coal gasification plant producing a low BTU gas product which is fired in two modified GE Frame 7FA CTs in CC configuration.

- The DS plant consists of one oil fired CAT 2 MW unit using ultra low sulfur fuel.

- The nuclear plant consists of two nuclear power units and related facilities using the Westinghouse AP1000 technology.

- The wind installation consists of twenty GE 2.5 MW wind turbines totaling 50 MW installed capacity.

- The solar installation consists of a 60 acre ground mounted solar farm totaling 10 MW of AC capacity.

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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.

Net revenue calculations for the CT, CC, CP and IGCC include the hourly effect of actual 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 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 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 CT, CC, CP and IGCC 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 the CT, CC and IGCC plant are also set to zero since these plant types typically do not provide regulation service in PJM. No black start service capability is assumed for any of the unit types.

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.

CT generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CT generators with 20 or fewer operating years. CC generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CC generators with 20 or fewer operating years. CP generators receive revenues for the provision of reactive services based on the average reactive revenue per MW-year received by all CP generators with 30 or fewer operating years. IGCC generators are assumed to receive reactive revenues equal to the CP plant.

Zonal net revenues reflect zonal fuel costs based on 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]

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.

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3   Hourly ambient conditions supplied by Schneider Electric.
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. The CC outage rate was used for the IGCC plant.

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.

New Entrant Combustion Turbine

Energy market net revenue was calculated for a CT plant dispatched by PJM. For this economic dispatch, 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 costs. If the unit was not already committed day ahead, it was then run in real time in standalone profitable blocks of at least four hours, or any profitable hours bordering the profitable day ahead or real time block.

Table 6-1 Energy Market net revenue[10] for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): 2009 through June 2013

Zone	2009	2010	2011	2012	2013 (Jan–Jun)
AECO	$12,421	$40,037	$46,157	$24,993	$10,208
AEP	$3,696	$11,575	$20,839	$16,263	$6,682
AP	$11,136	$32,494	$32,958	$21,029	$8,850
ATSI	NA	NA	NA	$18,296	$7,266
BGE	$15,126	$52,411	$48,642	$36,307	$15,983
ComEd	$2,445	$9,446	$15,081	$13,780	$5,474
DAY	$3,313	$11,701	$21,705	$18,573	$6,602
DEOK	NA	NA	NA	$16,004	$6,095
DLCO	$4,471	$17,525	$24,179	$18,773	$6,813
Dominion	$15,253	$42,922	$38,945	$25,375	$10,935
DPL	$13,886	$40,530	$44,339	$32,587	$11,566
JCPL	$11,994	$39,409	$44,968	$24,117	$13,124
Met-Ed	$11,083	$39,409	$40,802	$25,396	$10,523
PECO	$10,611	$38,311	$45,853	$25,884	$10,119
PENELEC	$6,986	$24,309	$32,090	$22,463	$10,013
Pepco	$17,798	$50,906	$44,233	$32,011	$14,892
PPL	$10,045	$33,649	$42,872	$22,817	$10,284
PSEG	$10,079	$37,626	$37,929	$24,081	$10,313
RECO	$8,717	$35,022	$32,178	$22,808	$12,999
PJM	$9,945	$32,781	$36,104	$23,240	$9,934

New Entrant Combined Cycle

Energy market net revenue was calculated for a CC plant dispatched by PJM. 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 costs.[11] If the unit was not already committed day ahead, it was then run in real time in standalone profitable blocks of at least eight hours, or any profitable hours bordering the profitable day ahead or real time block.

Table 6-2 PJM Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): 2009 through June 2013

Zone	2009	2010	2011	2012	2013 (Jan–Jun)
AECO	$62,063	$106,643	$126,869	$101,124	$38,503
AEP	$29,759	$47,591	$82,324	$87,908	$35,217
AP	$59,052	$91,032	$113,561	$100,499	$40,373
ATSI	NA	NA	NA	$94,387	$38,277
BGE	$70,571	$124,665	$130,806	$123,367	$50,227
ComEd	$20,613	$33,906	$46,293	$61,754	$21,377
DAY	$27,904	$46,647	$82,067	$93,517	$36,665
DEOK	NA	NA	NA	$82,044	$32,335
DLCO	$27,649	$51,180	$81,642	$89,180	$30,905
Dominion	$68,932	$116,873	$114,530	$103,610	$41,871
DPL	$64,321	$106,245	$123,599	$114,808	$42,306
JCPL	$61,477	$105,474	$124,878	$100,386	$43,173
Met-Ed	$55,400	$97,665	$111,653	$96,018	$37,344
PECO	$57,843	$99,951	$121,804	$98,151	$35,912
PENELEC	$48,876	$80,773	$109,048	$106,236	$47,926
Pepco	$71,959	$121,952	$121,143	$115,691	$48,146
PPL	$52,285	$87,314	$111,111	$91,727	$36,335
PSEG	$57,910	$101,819	$114,951	$96,617	$39,180
RECO	$51,808	$93,724	$96,235	$90,924	$44,060
PJM	$52,260	$89,027	$106,618	$97,260	$38,954

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10 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

11 All starts associated with combined cycle units are assumed to be hot starts.

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 day ahead by PJM for all available plant hours. The calculations include operating reserve credits based on PJM rules, when applicable, since the assumed operation is under the direction of PJM. 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 (Dollars per installed MW-year): 2009 through June 2013

Zone	2009	2010	2011	2012	2013 (Jan–Jun)
AECO	$87,901	$149,022	$75,325	$23,301	$23,595
AEP	$19,251	$56,227	$72,858	$41,244	$28,182
AP	$49,303	$98,671	$99,020	$54,552	$47,966
ATSI	NA	NA	NA	$47,274	$42,740
BGE	$46,299	$80,689	$56,940	$23,390	$29,167
ComEd	$42,738	$106,599	$94,493	$53,813	$39,249
DAY	$27,905	$77,082	$65,842	$43,027	$50,368
DEOK	NA	NA	NA	$36,519	$44,665
DLCO	$22,971	$76,395	$47,075	$43,904	$25,078
Dominion	$46,756	$144,290	$77,310	$17,547	$23,681
DPL	$38,833	$147,279	$94,908	$29,102	$27,020
JCPL	$74,389	$147,559	$71,437	$30,517	$22,961
Met-Ed	$57,888	$139,228	$61,703	$38,561	$16,821
PECO	$78,602	$142,542	$74,834	$24,474	$21,617
PENELEC	$77,650	$122,426	$95,440	$52,897	$52,597
Pepco	$70,058	$160,627	$73,476	$23,706	$45,091
PPL	$71,601	$114,549	$76,697	$18,079	$20,572
PSEG	$171,879	$124,533	$47,550	$22,590	$44,767
RECO	$71,025	$143,410	$59,111	$29,258	$41,783
PJM	$62,062	$119,478	$73,178	$34,408	$34,101

New Entrant Integrated Gasification Combined Cycle

Energy market net revenue was calculated for an IGCC plant located in the Dominion zone assuming that the IGCC plant had a 24-hour minimum run time and was dispatched day ahead by PJM for all available plant hours. The calculations include operating reserve credits based on PJM rules,

when applicable, since the assumed operation is under the direction of PJM operations.

Table 6-4 PJM Energy Market net revenue for a new entrant IGCC (Dollars per installed MW-year): 2012 through June 2013

Zone	2012	2013 (Jan–Jun)
Dominion	$13,130	$5,583

New Entrant Diesel

Energy market net revenue was calculated assuming that the DS plant was economically dispatched on an hourly basis based on the real-time LMP.

Table 6-5 PJM Energy Market net revenue for a new entrant DS (Dollars per installed MW-year): January through June 2013

Zone	2013 (Jan–Jun)
AECO	$6,840
AEP	$4,542
AP	$4,970
ATSI	$4,706
BGE	$7,250
ComEd	$4,347
DAY	$4,651
DEOK	$4,288
DLCO	$4,241
Dominion	$5,953
DPL	$7,101
JCPL	$6,991
Met-Ed	$6,527
PECO	$6,612
PENELEC	$5,066
Pepco	$6,531
PPL	$6,192
PSEG	$6,831
RECO	$6,690
PJM	$5,807

New Entrant Nuclear Plant

Energy market net revenue for a nuclear plant located in the AEP zone was calculated by assuming the unit was dispatched day ahead by PJM. The unit runs for all hours of the year.

Table 6-6 PJM Energy Market net revenue for a new entrant nuclear plant (Dollars per installed MW-year): 2012 through June 2013

Zone	2012	2013 (Jan–Jun)
AEP	$201,658	$116,873

New Entrant Wind Installation

Energy market net revenues for a wind installation located in the ComEd and PENELEC zones were calculated hourly by assuming the unit was generating at the average capacity factor if 75 percent of existing wind units in the zone were generating power. Capacity revenue was calculated using a 13 percent capacity factor. Wind net revenues include both production tax credits and RECs.

Table 6-7 PJM Energy Market net revenue for a new entrant wind installation (Dollars per installed MW-year): 2012 through June 2013

Zone	2012	2013 (Jan–Jun)
ComEd	$125,004	$82,626
PENELEC	$127,364	$90,644

New Entrant Solar Installation

Energy market net revenue for a solar installation located in the PSEG zone was calculated hourly by assuming the unit was generating at the average capacity factor if 75 percent of existing solar units in the zone were generating power. Capacity revenue was calculated using a 38 percent capacity factor. Solar net revenues include SRECs.

Table 6-8 PJM Energy Market net revenue for a new entrant solar installation (Dollars per installed MW-year): 2012 through June 2013

Zone	2012	2013 (Jan–Jun)
PSEG	$364,893	$282,086

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) requires significant investments for some fossil-fired power plants in the PJM footprint in order to reduce heavy metal emissions. The Cross-State Air Pollution Rule (CSAPR), would if implemented, potentially also require investments for some fossil-fired power plants in the PJM footprint in order to reduce SO_2 and NO_X emissions. New Jersey's High Electric Demand Day (HEDD) Rule limits NO_X emissions on peak energy demand days and requires investments for noncompliant units. CO_2 costs resulting from RGGI affect unit offers in the PJM energy market. The investments required for environmental compliance have resulted in higher offers in the capacity market, and when units do not clear, in the retirement of 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 potentially significant impacts on PJM wholesale markets.[1]

Overview

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.**[2] On December 16, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel,

selenium and cyanide.[3] The rule establishes a compliance deadline of April 16, 2015.

In addition, in a related EPA rule issued on the same date regarding utility New Source Performance Standards (NSPS), the EPA requires new coal and oil fired electric utility generating units constructed after May 3, 2011, to comply with amended emission standards for SO_2, NO_X and filterable particulate matter. On March 28, 2013, EPA issued a rule that raised the new source limits for new coal- and oil-fired power plants based on new information and analysis.[4]

- **Cross-State Air Pollution Rule.** On August 21, 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR, which previously had been subject to a stay.[5] The Supreme Court granted EPA's petition for certiorari on June 24, 2013, and its review of CSAPR is pending. Meanwhile, the Clean Air Interstate Rule (CAIR) remains in effect. The EPA continues to process a number of pending requests under CAIR, including State Implementation Plans (SIPs), originally submitted under CSAPR.

- **National Emission Standards for Reciprocating Internal Combustion Engines.** On January 14, 2013, EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[6] RICE includes certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE includes facilities located behind the meter. The rule exempts from its requirements one hundred hours of RICE operation in emergency demand response programs, provided that RICE uses ultra low sulfur diesel fuel (ULSD). Otherwise, a 15-hour exception applies. Emergency demand response programs include Demand Resources in RPM.

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1 For quantification of the economics of new entrant wind and solar installations, see the *2012 State of the Market Report for PJM*, Volume 2: Section 6, "Net Revenue."

2 MATS replaces the Clean Air Mercury Rule (CAMR). It has been widely known previously as the "HAP" or "Utility MACT" rule.

3 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).

4 *Reconsideration of Certain New Source Issues: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR 2009-0234, 78 Fed. Reg. 24073 (April 24, 2013).

5 *See* EME Homer City Generations, L.P. v. EPA, NO. 11-1302.

6 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 9403 (January 30, 2013).

- **Greenhouse Gas Emissions Rule.** On June 13, 2013, pursuant to a Climate Action Plan, the President issued a memorandum directing that EPA propose a rule to replace the rule that had been proposed on April 13, 2012, entitled "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units." The President directed that EPA issue the new proposal no later than September 20, 2013, and that it issue a final rule "in a timely fashion." [7]

State Environmental Regulation

- **NJ High Electric Demand Day (HEDD) Rule.** New Jersey addressed the issue of NO_X emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as High Electric Demand Days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_X emissions on such high energy demand days. [8] New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_X emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies. [9]

- **Regional Greenhouse Gas Initiative (RGGI).** The Regional Greenhouse Gas Initiative (RGGI) is a cooperative effort by Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities. Auction prices in 2013 for the 2012-2014 compliance period were $2.80 per ton, above the price floor for 2013.

Emissions Controls in PJM Markets

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. On June 30, 2013, 69.4 percent of coal steam MW had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units, while 97.6 percent of coal steam MW had some type of particulate control, and 91.3 percent of fossil fuel fired capacity in PJM had NO_X emission control technology in place.

State 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 June 30, 2013, Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 2015.

Renewable energy credits provide out of market payments to qualifying resources, primarily wind and solar. 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 LMP is equal to the marginal cost of producing minus the credit received for each MWh. As the net of LMP and credits can be negative, the credits can provide an incentive to make negative energy offers. These subsidies affect the offer behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

Conclusion

Environmental requirements and renewable energy mandates at both the Federal and state levels have a significant impact on the cost of energy and capacity in PJM markets. 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 formally recognized as part of PJM markets.

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7 77 Fed. Reg. 22392.
8 N.J.A.C. § 7:27–19.
9 CTs must have either water injection or Selective Catalytic Reduction (SCR) controls; steam units must have either an SCR or and Selective Non-Catalytic Reduction (SNCR).

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 incorporates renewable resources and renewable energy credit markets, and ensures that renewable resources have access to a broad market. PJM markets provide efficient price signals that permit valuation of resources with very different characteristics when they provide the same product.

Federal Environmental Regulation

The U.S. Environmental Protection Agency (EPA) administers the Clean Air Act (CAA), which, among other things, comprehensively regulates air emissions by establishing acceptable levels of and regulating emissions of hazardous air pollutants. EPA issues technology based standards for major sources and certain area sources of emissions.[10,11] EPA actions have and are expected to continue to affect the cost to build and operate generating units in PJM which in turn affects wholesale energy prices and capacity prices.

The EPA also regulates water pollution, and its regulation of cooling water intakes under section 316(b) of the CAA affects generating plants that rely on water drawn from jurisdictional water bodies.

Control of Mercury and Other Hazardous Air Pollutants

Section 112 of the CAA requires the EPA to promulgate emissions control standards, known as the National Emission Standards for Hazardous Air Pollutants (NESHAP), from both new and existing area and major sources. There are at least three NESHAP rulemakings in progress that will impact operations at various classes of generating units.[12]

On December 21, 2011, the U.S. Environmental Protection Agency (EPA) issued its Mercury and Air Toxics Standards rule (MATS), which applies the Clean Air Act (CAA) maximum achievable control technology (MACT) requirement to new or modified sources of emissions of mercury and arsenic, acid gas, nickel, selenium and cyanide.[13] The rule establishes a compliance deadline of April 16, 2015.

In addition, in a related EPA rule issued on the same date regarding utility New Source Performance Standards (NSPS), the EPA requires new coal and oil fired electric utility generating units constructed after May 3, 2011, to comply with amended emission standards for SO_2, NO_x and filterable particulate matter. On March 28, 2013, EPA issued a rule that raised the new source limits for new coal- and oil-fired power plants based on new information and analysis.[14]

Control of NO_x and SO_2 Emissions Allowances

The CAA requires States to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). The CAA requires each State to prohibit emissions that significantly interfere with the ability of another State to meet NAAQS.[15] The EPA has sought to promulgate default Federal rules to achieve this objective.[16]

On August 21, 2012, the U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR, which previously had been subject to a stay.[17] The Supreme Court granted EPA's petition for certiorari on June 24, 2013, and its review of CSAPR is pending. Meanwhile, the Clean Air Interstate Rule (CAIR) remains in effect. The EPA continues to process a number of pending requests under CAIR, including State Implementation Plans (SIPs), originally submitted under CSAPR.

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10 42 U.S.C. § 7401 et seq. (2000).
11 EPA defines "major sources" as a stationary source or group of stationary sources that emit or have the potential to emit 10 tons per year or more of a hazardous air pollutant or 25 tons per year or more of a combination of hazardous air pollutants. An "area source" is any stationary source that is not a major source.
12 For more details see the *2012 State of the Market Report for PJM*, Volume 2; Section 7, "Environmental and Renewables."

13 *National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR-2009-0234, 77 Fed. Reg. 9304 (February 16, 2012).
14 *Reconsideration of Certain New Source Issues: National Emission Standards for Hazardous Air Pollutants From Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units*, EPA Docket No. EPA-HQ-OAR 2009-0234, 78 Fed. Reg. 24073 (April 24, 2013).
15 CAA § 110(a)(2)(D)(i)(I).
16 For more details see the *2012 State of the Market Report for PJM*, Volume 2: Section 7, "Environmental and Renewables."
17 *See* EME Homer City Generations, L.P. v. EPA, NO. 11-1302.

Emission Standards for Reciprocating Internal Combustion Engines

On January 14, 2013, EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[18] RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE include facilities located behind the meter. These rules include: National Emission Standard for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE); New Source Performance Standards (NSPS)–Standards of Performance for Stationary Spark Ignition Internal Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively "RICE Rules").[19]

The RICE rules apply to emissions such as formaldehyde, acrolein, acetaldehyde, methanol, CO, NO_X, volatile organic compounds (VOCs), and PM. The regulatory regime for RICE is complicated, and the applicable requirements turn on the location of the engine (area source or major source), and the starter mechanism for the engine (compression ignition or spark ignition).

On May 22, 2012, the EPA proposed amendments to the RICE NESHAP Rule.[20] The proposed rule allowed owners and operators of emergency stationary internal combustion engines to operate them in emergency conditions, as defined in those regulations, as part of an emergency demand response program for 100 hours per year or the minimum hours required by an Independent System Operator's tariff, whichever is less. The Market Monitoring Unit objected to the proposed rule, as it had to similar provisions in a related proposed settlement released for comment, explaining that it was not required for participation by demand side resources in the PJM markets nor for reliability.[21] The final rule approves the proposed 100 hours per year exception, provided that RICE uses ultra low sulfur diesel fuel (ULSD).[22]

Otherwise a 15-hour exception applies.[23] The exempted emergency demand response programs include Demand Resources in RPM.

Regulation of Greenhouse Gas Emissions

On April 2, 2007, the U.S. Supreme Court overruled the EPA's determination that it was not authorized to regulate greenhouse gas emissions under the CAA and remanded the matter to EPA to determine whether greenhouse gases endanger public health and welfare.[24] 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.[25] In a decision dated June 26, 2012, the U.S. Court of Appeals for the D.C. Circuit upheld the endangerment finding, rejecting challenges brought by industry groups and a number of states.[26, 27]

On June 13, 2013, the President released a Climate Action Plan including a number of initiatives to address climate change. In a memorandum to the EPA pursuant to the plan,[28] the President directed that the EPA issue a notice of proposed rulemaking to replace the rule proposed on April 13, 2012, entitled "Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units."[29] The President directed that the EPA issue the new proposal no later than September 20, 2013, and that it issue a final rule "in a timely fashion."[30] The memorandum also directs that the EPA use its authority under section 111(b) and 111(d) of the CAA to "issue standards, regulations, or guidelines, as appropriate, that address carbon pollution from modified, reconstructed, and existing power plants and build on State efforts to move toward a cleaner power sector."[31] The President requested that guidelines for modified, reconstructed, and existing plants be issued by June 1, 2014, and that such guidelines require states to submit implementation plans to the EPA by no later than June 30, 2016.[32]

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18 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Final Rule, EPA Docket No. EPA-HQ-OAR-2008-0708, 78 Fed. Reg. 6674 (January 30, 2013) ("Final NESHAP RICE Rule").

19 EPA Docket No. EPA-H-OAR-2009-0234 & -2011-0044, codified at 40 CFR Part 63, Subpart ZZZZ; EPA Dockets Nos. EPA-HQ-OAR-2005-0030 & EPA-HQ-OAR-2005-0029, -2010-0295 , codified at 40 CFR Part 60 Subpart JJJJ.

20 *National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines; New Source Performance Standards for Stationary Internal Combustion Engines*, Proposed Rule, EPA Docket No. EPA-HQ-OAR-2008-0708.

21 *See* Comments of the Independent Market Monitor for PJM, Docket No. EPA-HQ-OAR-2008-0708 (August 9, 2012); *In the Matter of: EnerNOC, Inc., et al.*, Comments of the Independent Market Monitor for PJM, Docket No. EPA–HQ–OGC–2011–1030 (February 16, 2012).

22 Final NESHAP RICE Rule at 31–24.

23 *Id.* at 31.

24 Massachusetts v. EPA, 549 U.S. 497.

25 *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).

26 Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.

27 For more details see the *2012 State of the Market Report for PJM*, Volume 2: Section 7, "Environmental and Renewables."

28 Presidential Memorandum–Power Sector Carbon Pollution Standards, Environmental Protection Agency (June 25, 2013).

29 77 Fed. Reg. 22392.

30 *Id.*

31 *Id.*

32 *Id.*

Federal Regulation of Environmental Impacts on Water

On March 28, 2011, the EPA issued a proposed rule intended to ensure that the location, design, construction, and capacity of cooling water intake structures reflects the best technology available (BTA) for minimizing adverse environmental impacts, as required under Section 316(b) of the Clean Water Act (CWA).[33] A settlement in a Federal Court, as modified, obligates the EPA to issue a final rule no later than November 4, 2013.[34, 35]

State Environmental Regulation

New Jersey High Electric Demand Day (HEDD) Rules

The EPA's transport rules apply to total annual and seasonal emissions. Units that run only during peak demand periods have relatively low annual emissions, and have less incentive to make such investments under the EPA transport rules.

New Jersey addressed the issue of NO_x emissions on peak energy demand days with a rule that defines peak energy usage days, referred to as High Electric Demand Days or HEDD, and imposes operational restrictions and emissions control requirements on units responsible for significant NO_x emissions on such high energy demand days.[36] New Jersey's HEDD rule, which became effective May 19, 2009, applies to HEDD units, which include units that have a NO_x emissions rate on HEDD equal to or exceeding 0.15 lbs/MMBtu and lack identified emission control technologies.[37, 38]

Table 7-1 shows the HEDD emissions limits applicable to each unit type. Emissions limits for coal units became effective December 15, 2012.[39] Emissions limits for other unit types will become effective May 1, 2015.[40]

Table 7-1 HEDD maximum NOx emission rates[41]

Fuel and Unit Type	Emission Limit (lbs/MWh)
Coal Steam Unit	1.50
Heavier than No. 2 Fuel Oil Steam Unit	2.00
Simple cycle gas CT	1.00
Simple cycle oil CT	1.60
Combined cycle gas CT	0.75
Combined cycle oil CT	1.20
Regenerative cycle gas CT	0.75
Regenerative cycle oil CT	1.20

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 York, Rhode Island, and Vermont to cap CO_2 emissions from power generation facilities.[42, 43]

Table 7-2 shows the RGGI CO_2 auction clearing prices and quantities for the 14 2009-2011 compliance period auctions and additional 17 auctions for the 2012-2014 compliance period held as of June 30, 2013. Prices for auctions held in the first six months of 2013 for the 2012-2014 compliance period were from $2.80 to $3.21 per allowance (equal to one ton of CO_2), which is above the current price floor for RGGI auctions. The average spot price the first six months of 2013 for a 2012-2014 compliance period allowance was $2.95 per ton. Monthly average spot prices for the 2012-2014 compliance period ranged from $1.99 per ton in February to $3.35 per ton in June.

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33 EPA, *National Pollutant Discharge Elimination System—Cooling Water Intake Structures at Existing Facilities and Phase I Facilities, Proposed Rule*, Docket No. EPA-HQ-OW-2008-0667, 76 Fed. Reg. 22174 (April 20, 2011) (Cooling Water Proposed Rule).

34 Settlement Agreement among the United States Environmental Protection Agency, Plaintiffs in Cronin, et al. v. Reilly, 93 Civ. 314 (LTS) (SDNY), and Plaintiffs in Riverkeeper, et al. v. EPA, 06 CIV. 12987 (PKC) (SDNY), dated November 22, 2010, *modified*, Second Amendment to Settlement Agreement among the Environmental Protection Agency, Plaintiffs in Cronin, et al. v. Reilly, dated July 17, 2012; Third Amendment to Settlement Agreement among the Environmental Protection Agency, the Plantiffs in Conin, et al. v. Reilly, 93 Civ. 314 (LTS) (SDNY), and the Plantiffs in Riverkeeper, et al. v. EPA, 06 Civ. 12987 (PKC) (SDNY).

35 For more details see the *2012 State of the Market Report for PJM*, Volume 2: Section 7, "Environmental and Renewables."

36 N.J.A.C. § 7:27–19.

37 CTs must have either water injection or Selective Catalytic Reduction (SCR) controls; steam units must have either an SCR or and Selective Non-Catalytic Reduction (SNCR).

38 For more details see the *2012 State of the Market Report for PJM*, Volume 2: Section 7, "Environmental and Renewables."

39 N.J.A.C. § 7:27-19.4.

40 N.J.A.C. § 7:27-19.5.

41 Regenerative cycle CTs are combustion turbines that recover heat from its exhaust gases and uses that heat to preheat the inlet combustion air which is fed into the combustion turbine.

42 RGGI provides a link on its website to state statutes and regulations authorizing its activities, which can be accessed at: <http://www.rggi.org/design/regulations>.

43 For more details see the *2012 State of the Market Report for PJM*, Volume 2: Section 7, "Environmental and Renewables."

Figure 7-1 shows average, daily settled prices for NO_x and SO_2 emissions within PJM. In the first six months of 2013, NO_x prices were 3.6 percent higher than in 2012. SO_2 prices were 12.4 percent lower in the first six months of 2013 than in 2012. Figure 7-1 also shows the average, daily settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances. RGGI allowances are required by generation in participating RGGI states. This includes PJM generation located in Delaware and Maryland.

Figure 7-1 Spot monthly average emission price comparison: 2012 and 2013
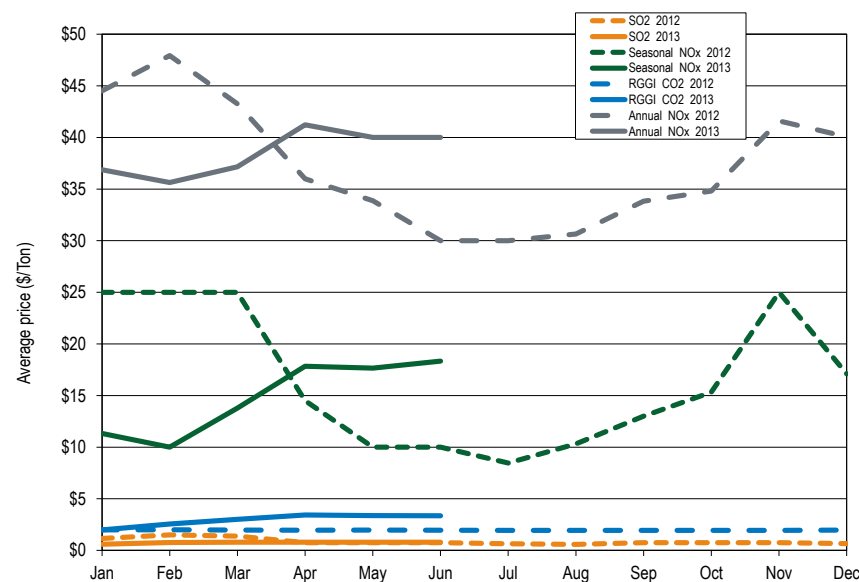
Table 7-2 RGGI CO_2 allowance auction prices and quantities (tons): 2009-2011 and 2012-2014 Compliance Periods[44]

Auction Date	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387
December 17, 2008	$3.38	31,505,898	31,505,898
March 18, 2009	$3.51	31,513,765	31,513,765
June 17, 2009	$3.23	30,887,620	30,887,620
September 9, 2009	$2.19	28,408,945	28,408,945
December 2, 2009	$2.05	28,591,698	28,591,698
March 10, 2010	$2.07	40,612,408	40,612,408
June 9, 2010	$1.88	40,685,585	40,685,585
September 10, 2010	$1.86	45,595,968	34,407,000
December 1, 2010	$1.86	43,173,648	24,755,000
March 9, 2011	$1.89	41,995,813	41,995,813
June 8, 2011	$1.89	42,034,184	12,537,000
September 7, 2011	$1.89	42,189,685	7,847,000
December 7, 2011	$1.89	42,983,482	27,293,000
March 14, 2012	$1.93	34,843,858	21,559,000
June 6, 2012	$1.93	36,426,008	20,941,000
September 5, 2012	$1.93	37,949,558	24,589,000
December 5, 2012	$1.93	37,563,083	19,774,000
March 13, 2013	$2.80	37,835,405	37,835,405
June 5, 2013	$3.21	38,782,076	38,782,076

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 June 30, 2013, Delaware, Illinois, Indiana, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington D.C. had renewable portfolio standards. Virginia has enacted a voluntary renewable portfolio standard. Kentucky and Tennessee have enacted no renewable portfolio standards. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 2015.

Under the proposed standards, a substantial amount of load in PJM is required to be served by renewable resources by 2023. As shown in Table 7-3, New Jersey will require 22.5 percent of load to be served by renewable resources in 2023, the most stringent standard of all PJM jurisdictions. Typically, renewable

44 See "Regional Greenhouse Gas Initiative: Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed July 15, 2013).

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 only requires utilities to purchase renewable energy credits, while Pennsylvania requires all load serving entities to purchase renewable energy credits (known as alternative energy credits in Pennsylvania).

Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation or 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 formally recognized as part of PJM markets. Revenues from RECs markets are out of market revenues for PJM resources and are in addition to revenues earned from the sale of the same MWh in PJM markets. Many jurisdictions allow various types of renewable resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, West Virginia allows one credit per MWh from generation from "alternative

energy resources" including waste coal and pumped-storage hydroelectric, and allows two credits per MWh of electricity generated by "renewable energy resources," which include 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.

Many PJM jurisdictions have also added specific requirements for the purchase of solar resources. These solar requirements are included in the standards shown in Table 7-3 but must be met by solar RECs (SRECs) only. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C., all have requirements for the proportion of load served by solar units by 2023.[45] Indiana, Michigan, Virginia, and West Virginia have no specific solar standards. In 2013, the most stringent standard in PJM was New Jersey's, requiring that 0.75 percent of load be served by solar resources. As Table 7-4 shows, by 2023, the most stringent standard will be New Jersey's which requires that at least 3.65 percent of load be served by solar.

Table 7–3 Renewable standards of PJM jurisdictions to 2023[46,47]

Jurisdiction	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Delaware	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.00%	21.00%	22.00%	23.00%
Illinois	7.00%	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.50%
Indiana	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Kentucky	No Standard										
Maryland	10.70%	12.80%	13.00%	15.20%	15.60%	18.30%	17.70%	18.00%	18.70%	20.00%	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	10.14%	11.10%	12.07%	13.08%	14.10%	16.16%	18.25%	20.37%	22.50%	22.50%	22.50%
North Carolina	3.00%	3.00%	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%	12.50%	12.50%	12.50%
Ohio	2.00%	2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%	10.50%	11.50%
Pennsylvania	10.20%	10.70%	11.20%	13.70%	14.20%	14.70%	15.20%	15.70%	18.00%	18.00%	18.00%
Tennessee	No Standard										
Virginia	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	12.00%	12.00%
Washington, D.C.	9.00%	10.50%	12.00%	13.50%	15.00%	16.50%	18.00%	20.00%	20.00%	20.00%	20.00%
West Virginia			10.00%	10.00%	10.00%	10.00%	10.00%	15.00%	15.00%	15.00%	15.00%

46 This shows the total standard of renewable resources in all PJM jurisdictions, including Tier I and Tier II resources.
47 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.

45 Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill the solar requirement.

Table 7-4 Solar renewable standards of PJM jurisdictions to 2023

Jurisdiction	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Delaware	0.60%	0.80%	1.00%	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%	2.75%	3.00%
Illinois	0.00%	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%	1.23%
Indiana	No Solar Standard										
Kentucky	No Standard										
Maryland	0.25%	0.35%	0.50%	0.70%	0.95%	1.40%	1.75%	2.00%	2.00%	2.00%	2.00%
Michigan	No Solar Standard										
New Jersey	0.75%	2.05%	2.45%	2.75%	3.00%	3.20%	3.29%	3.38%	3.47%	3.56%	3.65%
North Carolina	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio	0.09%	0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%	0.42%	0.46%
Pennsylvania	0.05%	0.08%	0.14%	0.25%	0.29%	0.34%	0.39%	0.44%	0.50%	0.50%	0.50%
Tennessee	No Standard										
Virginia	No Solar Standard										
Washington, D.C.	0.50%	0.60%	0.70%	0.83%	0.98%	1.15%	1.35%	1.58%	1.85%	2.18%	2.50%
West Virginia	No Solar Standard										

Some PJM jurisdictions have also added other specific requirements to their renewable portfolio standards for other technologies. The standards shown in Table 7-5 are also included in the base standards. Illinois requires that a percentage of utility load be served by wind farms, with 5.25 percent of load served in 2013 escalating to 15.38 percent in 2023. Maryland, New Jersey, Pennsylvania, and Washington D.C. all have "Tier 2" or "Class 2" standards, which allow specific technology types, such as waste coal units in Pennsylvania, to qualify for renewable energy credits. [48] North Carolina also requires a certain amount of power generated using swine waste and poultry waste to fulfill their renewable portfolio standards (Table 7-5).

PJM jurisdictions include various methods for complying 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. These alternative compliance payments are a way to make up any shortfall between the RECs required by the state and those the LSE actually purchased. In New Jersey,

solar alternative compliance payments are $641 per MWh. [49] Pennsylvania requires that the alternative compliance payment for solar credits be 200 percent of the average market value of solar RECs sold in the RTO. Compliance methods differ from jurisdiction to jurisdiction. For example, Illinois requires that 50 percent of the renewable portfolio standard be met through alternative compliance payments. Table 7-6 shows the alternative compliance standards in PJM jurisdictions, where such standards exist. These alternative compliance methods can have a significant impact on the traded price of RECs.

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48 Pennsylvania Tier II credits includes energy derived from waste coal, distributed generation systems, demand-side management, large-scale hydropower, municipal solid waste, generation from wood pulping process, and integrated combined coal gasification technology.

49 See "New Jersey Renewables Portfolio Standard," <*http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NJ05R&re=0&ee=0*> (Accessed July 1, 2013).

Table 7–5 Additional renewable standards of PJM jurisdictions to 2023

Jurisdiction		2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Illinois	Wind Requirement	5.25%	6.00%	6.75%	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%	14.25%	15.38%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	0.00%	0.00%	0.00%	0.00%	0.00%
New Jersey	Class II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
New Jersey	Solar Carve-Out (in GWh)	596	772	965	1,150	1,357	1,591	1,858	2,164	2,518	2,928	3,433
North Carolina	Swine Waste	0.07%	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)	700	900	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	6.20%	6.20%	6.20%	8.20%	8.20%	8.20%	8.20%	8.20%	10.00%	10.00%	10.00%
Washington, D.C.	Tier 2 Standard	2.50%	2.50%	2.50%	2.00%	1.50%	1.00%	0.50%	0.00%	0.00%	0.00%	0.00%

Table 7–6 Renewable alternative compliance payments in PJM jurisdictions: 2013

Jurisdiction	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Illinois	$2.16		
Indiana	Voluntary standard		
Kentucky	No standard		
Maryland	$40.00	$15.00	$400.00
Michigan	No specific penalties		
New Jersey	$50.00		$641.00
North Carolina	No specific penalties		
Ohio	$45.00		$350.00
Pennsylvania	$45.00	$45.00	200% market value
Tennessee	No standard		
Virginia	Voluntary standard		
Washington, D.C.	$50.00	$10.00	$500.00
West Virginia	$50.00		

Table 7-7 shows renewable generation by jurisdiction and resource type in the first six months of 2013. This includes only units that would qualify for REC credits by primary fuel type, including waste coal, battery, and pumped-storage hydroelectric, which can qualify for Pennsylvania Tier II credits if they are located in the PJM footprint. Wind units account for 8,561.5 GWh of 14,155.0 Tier I GWh, or 60.4 percent, in the PJM footprint. As shown in Table 7-7, 24,659.3 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 57.4 percent.

Table 7–7 Renewable generation by jurisdiction and renewable resource type (GWh): January through June, 2013

Jurisdiction	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	29.8	0.0	0.0	0.0	0.0	0.0	0.0	29.8	59.6
Illinois	77.7	0.0	0.0	0.0	0.0	0.0	3,251.5	3,329.2	3,329.2
Indiana	0.0	0.0	24.9	0.0	0.0	0.0	1,699.4	1,724.4	1,724.4
Kentucky	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Maryland	52.3	0.0	1,071.0	31.2	305.4	0.0	195.9	1,350.4	1,655.8
Michigan	11.2	0.0	34.6	0.0	0.0	0.0	0.0	45.8	45.8
New Jersey	165.7	235.7	14.7	125.8	697.7	0.0	5.4	311.6	1,245.0
North Carolina	0.0	0.0	371.0	0.0	0.0	0.0	0.0	371.0	371.0
Ohio	176.6	0.0	255.7	0.7	0.0	0.0	612.1	1,045.1	1,045.1
Pennsylvania	415.2	825.7	1,313.0	13.1	682.8	4,369.3	1,868.4	3,609.7	9,487.5
Tennessee	0.0	0.0	0.0	0.0	163.1	0.0	0.0	0.0	163.1
Virginia	192.1	2,144.7	529.4	5.2	550.2	0.0	0.0	726.6	3,421.6
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	679.5	0.0	0.0	529.6	928.7	1,611.4	2,141.0
Total	1,123.7	3,206.1	4,293.8	175.9	2,399.3	4,898.9	8,561.5	14,155.0	24,659.3

Table 7-8 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary or alternative fuel types.[50] This capacity 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. West Virginia has the largest amount of renewable capacity in PJM, 10,027.6 MW, or 26.7 percent of the total renewable capacity. New Jersey has the largest amount of solar capacity in PJM, 186.8 MW, or 75.4 percent of the total solar capacity. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 3,707.6 MW, or 56.6 percent of the total wind capacity.

Table 7-8 PJM renewable capacity by jurisdiction (MW), on June 30, 2013

Jurisdiction	Coal	Landfill Gas	Natural Gas	Oil	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Total
Delaware	0.0	8.1	1,835.3	13.8	0.0	0.0	0.0	0.0	0.0	0.0	1,857.2
Illinois	0.0	78.9	0.0	0.0	0.0	0.0	0.0	20.0	0.0	2,454.4	2,553.3
Indiana	0.0	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	1,253.2	1,261.4
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0	185.0
Kentucky	600.0	0.0	0.0	0.0	0.0	70.0	0.0	0.0	0.0	0.0	670.0
Maryland	60.0	28.7	129.0	31.9	0.0	581.0	40.1	109.0	0.0	120.0	1,099.8
Michigan	0.0	4.8	0.0	0.0	0.0	11.8	0.0	0.0	0.0	0.0	16.6
New Jersey	0.0	85.5	0.0	0.0	400.0	5.0	186.8	189.1	0.0	7.5	873.9
North Carolina	0.0	0.0	0.0	0.0	0.0	315.0	0.0	94.0	0.0	0.0	409.0
Ohio	5,021.8	52.3	125.5	225.0	0.0	178.0	0.0	0.0	0.0	500.0	6,102.6
Pennsylvania	35.0	222.0	2,370.7	0.0	1,505.0	682.3	18.0	247.0	1,422.2	1,365.6	7,867.7
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
Virginia	63.0	121.6	80.0	7.0	3,588.0	457.1	2.7	215.0	0.0	0.0	4,534.4
West Virginia	8,539.0	2.0	450.0	0.0	0.0	243.1	0.0	0.0	130.0	663.5	10,027.6
PJM Total	14,318.8	603.9	4,990.5	277.7	5,493.0	2,551.5	247.6	924.1	1,552.2	6,549.2	37,508.5

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

Table 7-9 shows renewable capacity registered in the PJM Generation Attribute Tracking System (GATS), a system operated by PJM EIS, that are not resources offered into PJM wholesale markets. This includes solar capacity of 1,354.3 MW of which 895.8 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 7-9 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.

Table 7-9 Renewable capacity by jurisdiction, non-PJM units registered in GATS[51,52] (MW), on June 30, 2013

Jurisdiction	Coal	Hydroelectric	Landfill Gas	Natural Gas	Other Gas	Other Source	Solar	Solid Waste	Wind	Total
Delaware	0.0	0.0	0.0	0.0	0.0	0.0	46.7	0.0	2.1	48.8
Georgia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	60.0	0.0	60.0
Illinois	0.0	6.6	91.8	0.0	0.0	0.0	34.5	0.0	302.5	435.4
Indiana	0.0	0.0	49.7	0.0	679.1	0.0	1.2	0.0	0.0	730.0
Kentucky	0.0	2.0	16.0	0.0	0.0	0.0	0.6	88.0	0.0	106.6
Maryland	0.0	0.0	7.0	0.0	0.0	0.0	95.2	1.2	0.3	103.7
Michigan	55.0	0.0	1.6	0.0	0.0	0.0	0.3	0.0	0.0	56.9
Minnesota	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Missouri	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	146.0	146.0
New Jersey	0.0	0.0	39.9	0.0	0.0	23.3	895.8	0.0	0.4	959.4
New York	0.0	146.7	0.0	0.0	0.0	0.0	0.4	0.0	0.0	147.1
North Carolina	0.0	0.0	0.0	0.0	0.0	0.0	8.0	0.0	0.0	8.0
Ohio	0.0	1.0	39.8	52.6	67.0	1.0	85.1	109.3	17.4	373.2
Pennsylvania	0.0	37.0	41.3	4.8	86.2	0.3	170.9	0.0	3.2	343.7
Virginia	0.0	12.5	14.8	0.0	0.0	0.0	5.9	318.1	0.0	351.4
West Virginia	0.0	0.0	0.0	0.0	0.0	0.0	1.7	0.0	0.0	1.7
Wisconsin	0.0	9.0	0.0	0.0	0.0	0.0	0.4	44.6	0.0	54.0
District of Columbia	0.0	0.0	0.0	0.0	0.0	0.0	7.7	0.0	0.0	7.7
Total	55.0	214.8	301.9	57.4	832.4	24.6	1,354.3	621.2	472.0	3,933.6

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51 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.
52 See "Renewable Generators Registered in GATS," <*https://gats.pjm-eis.com/myModule/rpt/myrpt.asp?r=228*> (Accessed July 15, 2013).

Emissions Controlled Capacity and Renewables in PJM Markets

Emission Controlled Capacity in the PJM Region

Environmental regulations may affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls. Many PJM units burning fossil fuels have installed emission control technology.

Coal and heavy oil have the highest SO_2 emission rates, while natural gas and light oil have low to negligible SO_2 emission rates. Many coal steam units in PJM have installed FGD (flue-gas desulfurization) technology to reduce SO_2 emissions from coal steam units. Of the current 78,856.4 MW of coal steam capacity in PJM, 54,749.3 MW of capacity, 69.4 percent, has some form of FGD technology. Table 7-10 shows SO_2 emission controls by unit type, of fossil fuel units in PJM.[53]

Table 7–10 SO_2 emission controls (FGD) by unit type (MW), as of June 30, 2013

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal Steam	54,759.3	24,097.1	78,856.4	69.4%
Combined Cycle	0.0	26,069.5	26,069.5	0.0%
Combustion Turbine	0.0	31,332.6	31,332.6	0.0%
Diesel	0.0	371.1	371.1	0.0%
Non-Coal Steam	0.0	8,735.4	8,735.4	0.0%
Total	54,759.3	90,605.7	145,365.0	37.7%

NO_x emission control technology is used by nearly all fossil fuel unit types. Coal steam, combined cycle, combustion turbine, and non-coal steam units in PJM have NO_x controls. Of current fossil fuel units in PJM, 132,740.3 MW, 91.3 percent, of 145,365.0 MW of capacity in PJM, have emission controls for NO_x. Table 7-11 shows NO_x emission controls by unit type 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

53 See "Air Market Programs Data," <*http://ampd.epa.gov/ampd/*> (Accessed July 15, 2013)

units, as well as SCRs or water injection technology for HEDD combustion turbine units.

Table 7–11 NO_x emission controls by unit type (MW), as of June 30, 2013

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal Steam	76,425.8	2,430.6	78,856.4	96.9%
Combined Cycle	25,868.5	201.0	26,069.5	99.2%
Combustion Turbine	26,075.2	5,257.4	31,332.6	83.2%
Diesel	0.0	371.1	371.1	0.0%
Non-Coal Steam	4,370.8	4,364.6	8,735.4	50.0%
Total	132,740.3	12,624.7	145,365.0	91.3%

Most coal steam units in PJM have particulate controls. Typically, technologies such as electrostatic precipitators (ESP) or baghouses are used to reduce particulate matter in coal steam units. In PJM, 76,972.4 MW, 97.6 percent, of all coal steam unit MW, have some type of particulate emissions control technology. Table 7-12 shows particulate emission controls by unit type 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 7–12 Particulate emission controls by unit type (MW), as of June 30, 2013

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal Steam	76,972.4	1,884.0	78,856.4	97.6%
Combined Cycle	0.0	26,069.5	26,069.5	0.0%
Combustion Turbine	0.0	31,332.6	31,332.6	0.0%
Diesel	0.0	371.1	371.1	0.0%
Non-Coal Steam	3,047.0	5,688.4	8,735.4	34.9%
Total	80,019.4	65,345.6	145,365.0	55.0%

Fossil fuel fired units in PJM emit multiple pollutants, including CO_2, SO_2, and NO_x. Table 7-13 shows the amount of emissions generated by units in PJM in

the first six months of 2013. Over 203 million tons of CO_2, 729 thousand tons of SO_2, and 380 thousand tons of NO_x were emitted in the first six months of 2013 by PJM units.

Table 7-13 CO_2, SO_2, NO_x emissions by month (tons), by PJM units, January through June 2013

	Tons of CO_2	Tons of SO_2	Tons of NO_x
January	37,228,376.7	134,864.3	70,223.1
February	34,317,735.4	111,597.2	64,239.8
March	35,200,726.6	124,634.2	65,349.6
April	29,610,745.7	117,490.4	55,329.0
May	31,545,055.3	104,075.3	58,052.1
June	35,739,426.9	136,733.2	67,752.9
Total	203,642,066.6	729,394.6	380,946.6

Wind Units

Table 7-14 shows the capacity factor of wind units in PJM. In the first six months of 2013, the capacity factor of wind units in PJM was 31.7 percent. Wind units that were capacity resources had a capacity factor of 31.5 percent and an installed capacity of 4,888 MW. Wind units that were classified as energy only had a capacity factor of 32.4 percent and an installed capacity of 1,476 MW. Wind capacity in RPM is derated to 13 percent of nameplate capacity for the Capacity Market, and energy only resources are not included in the Capacity Market.[54]

Table 7-14 Capacity factor of wind units in PJM: January through June 2013[55]

Type of Resource	Capacity Factor	Capacity Factor by Cleared MW	Installed Capacity (MW)
Energy-Only Resource	32.4%	NA	1,476
Capacity Resource	31.5%	199.4%	4,888
All Units	31.7%	199.4%	6,364

Figure 7-2 shows the average hourly real time generation of wind units in PJM, by month. The highest average hour, 2,688.8 MW, occurred in January, and the lowest average hour, 921.0 MW, occurred in June. 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 June 2013

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54 Wind resources are derated to 13 percent unless demonstrating higher availability during peak periods.

55 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. 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.
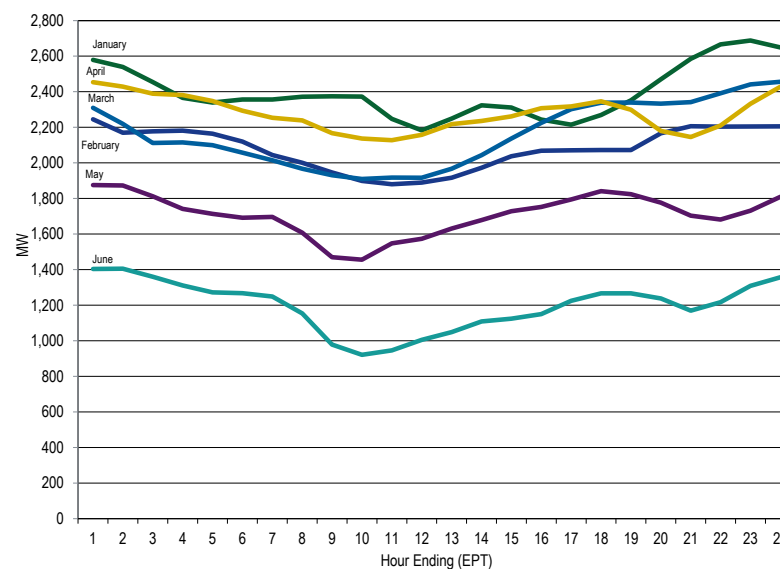
Table 7-15 shows the generation and capacity factor of wind units in each month of 2012 and the first six months of 2013.

Table 7-15 Capacity factor of wind units in PJM by month, 2012 and January through June 2013

| Month | 2012 | | 2013 | |
	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	1,608,349.8	41.9%	1,784,359.3	37.7%
February	1,167,011.9	32.4%	1,397,468.3	32.7%
March	1,416,278.0	35.6%	1,606,248.3	34.0%
April	1,345,643.3	34.7%	1,639,590.9	36.8%
May	885,583.1	21.6%	1,271,272.4	27.5%
June	882,597.0	22.2%	862,532.1	18.8%
July	546,676.9	13.3%		
August	415,544.2	10.1%		
September	677,039.5	16.9%		
October	1,213,664.0	27.7%		
November	1,022,628.8	22.9%		
December	1,452,588.7	31.1%		
Annual	12,633,605.2	25.7%	8,561,471.4	31.7%

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 generation offers of wind units in PJM, by month.

Figure 7-3 Average hourly day-ahead generation of wind units in PJM: January through June 2013
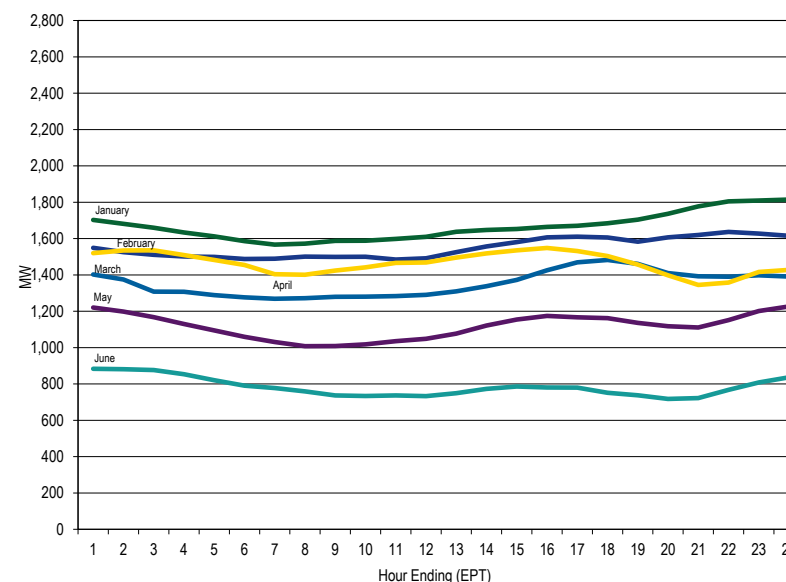
Output from wind turbines displaces output from other generation types. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output depends on the level of the wind turbine output, its location, time and duration. One measure of this displacement 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 through the first six months of 2013. This provides, on an hourly average basis, potentially displaced marginal unit MW by fuel type in January through June 2013. This is not an exact measure of displacement because it is not based on a redispatch of the system without wind resources. When wind appears as the displaced fuel at times when wind resources were on the margin this means that there was no displacement for those hours.

Figure 7-4 Marginal fuel at time of wind generation in PJM: January through June 2013
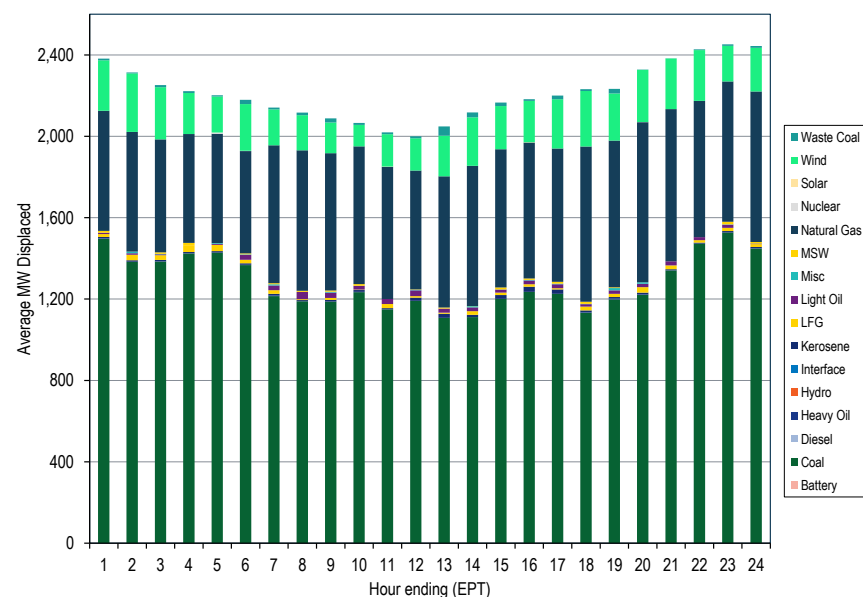
Solar Units

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 April, the month with the highest average hour, 117.2 MW, compared to 248.8 MW of solar installed capacity in PJM. 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 June 2013
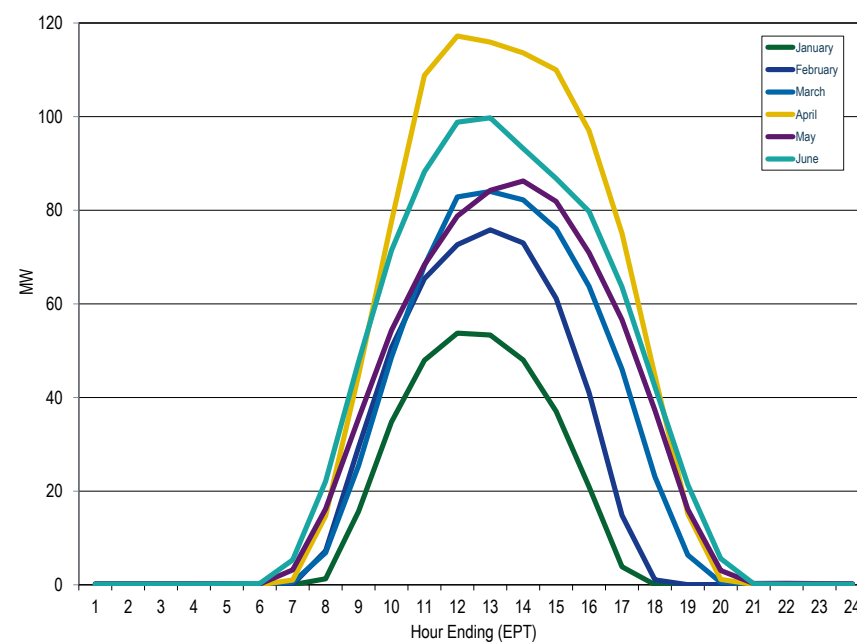
Interchange Transactions

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 respond to price differentials. The external regions include both market and non-market balancing authorities.

Overview

Interchange Transaction Activity

- **East Kentucky Power Cooperative (EKPC).** On June 1, 2013, East Kentucky Power Cooperative was integrated into PJM. This integration eliminated the EKPC Interface. The integration did not result in any changes to interface pricing points.

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first six months of 2013, PJM was a monthly net importer of energy in the Real-Time Energy Market.[1] During the first six months of 2013, the real-time net interchange of 4,023.3 GWh was greater than net interchange of 2,351.1 GWh in the first six months of 2012.

- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first six months of 2013, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market. During the first six months of 2013, the total day-ahead net interchange of -9,161.6 GWh was greater than net interchange of -1,947.9 GWh during the first six months of 2012.

- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first six months of 2013, gross imports in the Day-Ahead Energy Market were 158.0 percent of gross imports in the Real-Time Energy Market (427.8 percent during the first six months of 2012), gross exports in the Day-Ahead Energy Market were 242.0 percent of the gross exports in the Real-Time Energy Market (487.3 percent during the first six months of 2012).

- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first six months of 2013, there were net scheduled exports at ten of PJM's 21 interfaces.

- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first six months of 2013, there were net scheduled exports at eleven of PJM's 17 interface pricing points eligible for real-time transactions.[2]

- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first six months of 2013, there were net scheduled exports at ten of PJM's 21 interfaces.

- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first six months of 2013, there were net scheduled exports at nine of PJM's 19 interface pricing points eligible for day-ahead.

- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Market, for the first six months of 2013, up-to congestion transactions had net exports at five of PJM's 19 interface pricing points eligible for day-ahead transactions.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first six months of 2013, the direction of the average hourly flow was inconsistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. The direction of flow was consistent with price differentials in only 46.5 percent of hours in the first six months of 2013.

- **PJM and New York ISO Interface Prices.** In the first six months of 2013, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. The direction of flow was consistent with price differentials in 55.9 percent of the hours in the first six months of 2013.

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1 Calculated values shown in Section 8, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

2 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

- **Neptune Underwater Transmission Line to Long Island, New York.** In the first six months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus.[3] The average hourly flow during the first six months of 2013 was -293 MW.[4] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 78.3 percent of the hours in the first six months of 2013.

- **Linden Variable Frequency Transformer (VFT) Facility.** In the first six months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO LMP Linden Bus.[5] The average hourly flow during the first six months of 2013 was -139 MW.[6] The direction of flows was consistent with price differentials in 70.6 percent of the hours in the first six months of 2013.

- **Hudson DC Line.** The Hudson direct current (DC) line began commercial operation on June 3, 2013. The Hudson direct current (DC) line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM and NYISO. While the Hudson DC line is a bidirectional line, power flows will only be from PJM to New York. In the first month of operations, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO LMP Hudson Bus.[7] The average hourly flow during the first month of operation was -17 MW.[8] The direction of flows was consistent with price differentials in 60.9 percent of the hours during June, 2013.

Interchange Transaction Issues

- **Loop Flows.** Actual flows are the metered power flows at an interface for a defined period. Scheduled flows are the power 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 the difference between actual and scheduled power flows at one or more specific interfaces.

  For the first six months of 2013, net scheduled interchange was 2,989 GWh and net actual interchange was 3,058 GWh, a difference of 69 GWh. For the first six months of 2012, net scheduled interchange was 1,666 GWh and net actual interchange was 1,480 GWh, a difference of 185 GWh. This difference is inadvertent interchange.

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued 23 TLRs of level 3a or higher in the first six months of 2013, compared to eight TLRs issued in the first six months of 2012.

- **Up-To Congestion.** Following elimination of the requirement to procure transmission service for up-to congestion transactions in 2010, the volume of transactions increased significantly. The volumes of submitted and cleared up-to congestion bids continued to increase following the business rule change on November 1, 2012, which eliminated the requirement for either the source or sink of an up-to congestion transaction to be at an interface. The average number of up-to congestion bids submitted in the Day-Ahead Market increased to 107,215 bids per day, with an average cleared volume of 1,272,955 MWh per day, in the first six months of 2013, compared to an average of 54,180 bids per day, with an average cleared volume of 931,553 MWh per day, in the first six months of 2012. (Figure 8-13).

- **Elimination of Sources and Sinks.** The MMU recommended that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets. On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink

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3   In the first six months of 2013, there were 833 hours where there was no flow on the Neptune DC Tie line. The PJM average hourly LMP at the Neptune Interface during non-zero flows was $40.03 while the NYISO LMP at the Neptune Bus during non-zero flows was $71.87, a difference of $31.84.
4   The average hourly flow during the first six months of 2013, ignoring hours with no flow, on the Neptune DC Tie line was -363 MW.
5   In the first six months of 2013, there were 841 hours where there was no flow on the Linden VFT line. The PJM average hourly LMP at the Linden Interface during non-zero flows was $41.32 while the NYISO LMP at the Neptune Bus during non-zero flows was $51.64, a difference of $10.32.
6   The average hourly flow during the first six months of 2013, ignoring hours with no flow, on the Linden VFT line was -173 MW.
7   In its first month of operation, there were 550 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $37.17 while the NYISO LMP at the Hudson Bus during non-zero flows was $39.26, a difference of $2.09.
8   The average hourly flow during the first months of operations, ignoring hours with no flow, on the Hudson line was -147 MW.

designations in both the Day-Ahead and Real-Time Energy Markets.[9] On April 22, 2013, PJM implemented changes to its OASIS eliminating the internal source and sink designations on transmission reservations.

- **Spot Import.** Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. However, PJM interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction. The result was that the availability of spot import service was limited by ATC and not all spot transactions were approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all non-firm point-to-point willing to pay congestion imports and exports) at all PJM Interfaces in order to improve the efficiency of the market.

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 offsets (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 six months of 2013, including evolving

9   See "Meeting Minutes, " Minutes from PJM's MIC meeting, <http://www.pjm.com/~/media/committees-groups/committees/mic/20110412/20110412-mic-minutes.ashx>.

transaction patterns, economics and issues. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Markets, coincident with the expansion of the PJM footprint. In January, 2012, the direction of real-time power flows started to fluctuate between net imports and exports. The net direction of power flows is generally a function of price differences net of transactions costs. Since the modification of the up-to congestion product in September 2010, up-to congestion transactions have played a significant role in power flows between PJM and external balancing authorities in the Day-Ahead Market. On November 1, 2012, PJM eliminated the requirement that market participants specify an interface pricing point as either the source or sink of an up-to congestion transaction. As a result, the volume of import and export up-to congestion transactions decreased, and the volume of internal up-to congestion transactions increased, reducing the day-ahead gross import and export volumes. While the gross import and export volumes in the Day-Ahead Market have decreased, the net direction of power flows has remained predominantly in the export direction.

In the first six months of 2013, 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 53.5 percent of the hours for transactions between PJM and MISO and for 44.1 percent of the hours for transactions between PJM and NYISO. The MMU recommends that PJM continue to work with both MISO and NYISO to improve the ways in which interface flows and prices are established in order to help ensure that interface prices are closer to the efficient levels that would result if the interface between balancing authorities were entirely internal to an LMP market. In an LMP market, redispatch based on LMP and generator offers would result in an efficient dispatch and efficient prices. Price differences at the seams continue to be determined by relying on market participants to see the prices and react to the prices by scheduling transactions with both an internal lag and an RTO administrative lag.

Loop flows remain a significant concern for the efficiency of the PJM market. Loop flows can have negative impacts on the efficiency of markets with explicit locational pricing, including impacts on locational prices, on

FTR revenue adequacy and on system operations, and can be evidence of attempts to game such markets. The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on market paths that reflect the expected actual flow. This validation method would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices. This validation method would provide PJM with a more accurate forecast of where actual energy flows are expected. This validation method would reduce the unscheduled power flows across neighboring balancing authorities that result in increased production costs caused by the increase of generation to control for the unscheduled loop flows without compensating transmission revenues associated with those flows. Requiring market paths to match as closely as possible to the expected actual power flows would result in a more economic dispatch of the entire Eastern Interconnection.

The MMU recommends that PJM perform a comprehensive evaluation of the up-to congestion product in coordination with the MMU and provide a joint report to PJM stakeholders to ensure that all market participants are aware of how these transactions impact the operation of the PJM Day-Ahead Market and charges and credits to market participants in all other areas of the PJM Energy Market. The MMU recommends that during the period of study, up-to congestion transactions be required to pay a fee in lieu of operating reserve charges equal to $0.50 per MWh. This rate is intended to reflect the lowest operating reserve rates charged to other virtual transactions in 2012.

Sham scheduling refers to a scheduling method under which a market participant breaks a single transaction, from generation balancing authority (source) to load balancing authority (sink), into multiple segments. Sham scheduling hides the actual source of generation from the load balancing authority. When unable to identify the source of the energy, the load balancing authority lacks a complete picture of how the power will flow to the load. This can create loop flows and inaccurate pricing for transactions. The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU also recommends that PJM, NYISO, MISO and Ontario work together to create

business rules that prevent sham scheduling among and between the RTO/ISO markets.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies plan to operate separately for a period of time, they have a Joint Dispatch Agreement, and a Joint Open Access Transmission Tariff.[10] The MMU has confirmed that the rules governing the assignment of interface pricing under the PJM/PEC JOA related to simultaneous imports or exports have been maintained. The MMU recommends the termination of the existing PJM/PEC JOA, as some of the assumptions used in the development of the JOA were based on explicit assumptions about the Progress generation fleet and the dispatch of that generation.

The MMU continues to recommend that PJM permit unlimited spot market imports as well as unlimited non-firm point-to-point willing to pay congestion imports and exports at all PJM Interfaces in order to improve the efficiency of the market.

Interchange Transaction Activity
Aggregate Imports and Exports

During the first six months of 2013, PJM was a monthly net importer of energy in the Real-Time Energy Market in all months (Figure 8-1).[11] During the first six months of 2013, the total real-time net interchange of 4,023.3 GWh was greater than the net interchange of 2,351.1 GWh during the first six months of 2012. During the first six months of 2013, the peak month for net importing interchange was May, 846.7 GWh; in 2012 it was May, 798.4 GWh. Gross monthly export volumes during the first six months of 2013 averaged 3,078.5 GWh compared to 3,362.9 GWh for the first six months of 2012, while gross monthly imports during the first six months of 2013 averaged 3,749.1 GWh compared to 3,754.7 GWh during the first six months of 2012.

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10 See Docket Nos. ER12-1338-000 and ER12-1343-000.
11 Calculated values shown in Section 8, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

During the first six months of 2013, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months (Figure 8-1). During the first six months of 2013, the total day-ahead net interchange of -9,161.6 GWh was greater than the net interchange of -1,947.9 GWh during the first six months of 2012. During the first six months of 2013, the peak month for net exporting interchange was January, -2,602.8 GWh; in 2012 it was January, -1,847.5 GWh. Gross monthly export volumes during the first six months of 2013 averaged 7,449.5 GWh compared to 16,387.7 GWh for the first six months of 2012, while gross monthly imports during the first six months of 2013 averaged 5,922.6 GWh compared to 16,063.0 GWh during the first six months of 2012.

The large decreases in gross import and export volumes in the Day-Ahead Energy Market were the result of the rule change on November 1, 2012, which permitted up-to congestion transactions to be submitted between two internal buses. Prior to the rule change, up-to congestion transactions were required to have the source at an interface (modeled as an import) or the sink at an interface (modeled as an export).[12]

Figure 8-1 shows the impact of net import and export up-to congestion transactions on the overall net Day-Ahead Market interchange. The import, export and net interchange volumes include fixed, dispatchable and up-to congestion transaction totals. The up-to congestion net volume (as represented by the line on the chart) shows the net up-to congestion transaction volume. The net interchange volume under the line in Figure 8-1 represents the net interchange for fixed and dispatchable day-ahead transactions only.

In the first six months of 2013, import up-to congestion transactions accounted for 73.4 percent of all scheduled import MW transactions, export up-to congestion transactions accounted 69.5 percent of all scheduled export MW transactions and net up-to congestion transactions accounted for 54.4 percent of the net interchange volume in the Day-Ahead Market. The average number of import and export up-to congestion bids that had approved MWh in the Day-Ahead Market decreased to 10,548 bids per day, with an average cleared volume of 303,215 MWh per day, in the first six months of 2013, compared to an average of 21,929 bids per day, with an average cleared volume of 931,553 MWh per day, in the first six months of 2012.

The average number of up-to congestion bids, including internal up-to congestion transactions, that had approved MWh in the Day-Ahead Market increased to 38,471 bids per day, with an average cleared volume of 1,272,955 MWh per day, in the first six months of 2013, compared to an average of 21,929 bids per day, with an average cleared volume of 931,553 MWh per day, in the first six months of 2012.

In the first six months of 2013, gross imports in the Day-Ahead Energy Market were 158.0 percent of gross imports in the Real-Time Energy Market (427.8 percent during the first six months of 2012), gross exports in the Day-Ahead Energy Market were 242.0 percent of gross exports in the Real-Time Energy Market (487.3 percent during the first six months of 2012). In the first six months of 2013, net interchange was -9,161.6 GWh in the Day-Ahead Energy Market and 4,023.3 GWh in the Real-Time Energy Market compared to -1,947.9 GWh in the Day-Ahead Energy Market and 2,351.1 GWh in the Real-Time Energy Market for the first six months of 2012.

Transactions in the Day-Ahead Energy Market create financial obligations to deliver in the Real-Time Energy Market and to pay operating reserve charges based on differences between the transaction MW and price differences in the Day-Ahead and Real-Time Energy Markets.[13] For the first six months of 2013, while the total day-ahead imports and exports were greater than the real-time imports and exports, the day-ahead imports net of up-to congestion transactions were less than the real-time imports, and the day-ahead exports net of up-to congestion transactions were less than real-time exports. In addition, day-ahead transactions can be offset by increment offers, decrement bids and internal bilateral transactions.

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12 See "*Up-To Congestion Transaction Enhancements,*" (October 10, 2012) <https://pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-11-up-to-congestion-transactions.ashx> (Accessed August 7, 2013).

13 Up-to congestion transactions create financial obligations to deliver in real time, but do not pay operating reserve charges.

Figure 8-1 PJM real-time and day-ahead scheduled imports and exports: January through June, 2013

up-to congestion transactions increased, reducing the day-ahead gross import and export volumes. While the gross import and export volumes in the Day-Ahead Market have decreased, the net direction of power flows has remained predominantly in the export direction.

Figure 8-2 PJM real-time and day-ahead scheduled import and export transaction volume history: January, 1999 through June, 2013

Figure 8-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through June, 2013. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Markets, coincident with the expansion of the PJM footprint. In January, 2012, the direction of real-time power flows started to fluctuate between net imports and exports. The net direction of power flows is generally a function of price differences net of transactions costs. Since the modification of the up-to congestion product in September 2010, up-to congestion transactions have played a significant role in power flows between PJM and external balancing authorities in the Day-Ahead Market. On November 1, 2012, PJM eliminated the requirement that market participants specify an interface pricing point as either the source or sink of an up-to congestion transaction. As a result, the volume of import and export up-to congestion transactions decreased, and the volume of internal

Real-Time Interface Imports and Exports

In the Real-Time Energy Market, scheduled imports and exports are determined by the scheduled market path, which is the transmission path a market participant selects from the original source to the final sink. These scheduled flows are measured at each of PJM's interfaces with neighboring balancing authorities. See Table 8-16 for a list of active interfaces during the first six months of 2013. Figure 8-3 shows the approximate geographic location of the interfaces. In the first six months of 2013, PJM had 21 interfaces with

neighboring balancing authorities. While the Linden (LIND) Interface, the Hudson (HUDS) Interface and the Neptune (NEPT) Interface are separate from the NYIS Interface, all four are interfaces between PJM and the NYISO. Similarly, there are nine separate interfaces that make up the MISO Interface between the PJM and MISO balancing authorities. Table 8-1 through Table 8-3 show the Real-Time Market interchange totals at the individual NYISO interfaces, as well as with the NYISO as a whole. Similarly, the interchange totals at the individual interfaces between PJM and MISO are shown, as well as with MISO as a whole. Net interchange in the Real-Time Energy Market is shown by interface for the first six months of 2013 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 six months of 2013, there were net scheduled exports at ten of PJM's 21 interfaces.[14] The top three net exporting interfaces in the Real-Time Energy Market accounted for 65.5 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 23.9 percent, PJM/New York Independent System Operator, Inc. (NYIS) with 23.6 percent, and PJM/Eastern Alliant Energy Corporation (ALTE) with 18.1 percent of the net export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 42.3 percent of the total net PJM exports in the Real-Time Energy Market. Nine PJM interfaces had net scheduled imports, with three importing interfaces accounting for 62.9 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 29.9 percent, PJM/Tennessee Valley Authority (TVA) with 17.5 percent and PJM/Michigan Electric Coordinated System (MECS) with 15.4 percent of the net import volume.[15]

Eleven shareholders own OVEC and share OVEC's generation output. Approximately 70 percent of OVEC is owned by load serving entities or their affiliates within the PJM footprint. The Inter-Company Power Agreement (ICPA), signed by OVEC's shareholders, requires delivery of approximately 70 percent of the generation output into the PJM footprint.[16] OVEC itself does not

serve load, and therefore does not generally import energy. OVEC accounts for a large percentage of PJM's net interchange import volume.

Table 8-1 Real-time scheduled net interchange volume by interface (GWh): January through June, 2013

		Jan	Feb	Mar	Apr	May	Jun	Total
CPLE		(30.6)	(38.3)	(48.4)	(33.1)	(25.3)	188.1	12.4
CPLW		0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK		175.2	122.7	148.1	80.9	294.6	221.9	1,043.4
EKPC		(149.7)	(139.9)	(152.7)	(152.2)	(108.8)		(703.3)
LGEE		281.5	272.0	302.2	182.9	204.3	253.5	1,496.4
MEC		(484.1)	(390.8)	(158.9)	(421.4)	(509.1)	(464.2)	(2,428.5)
MISO		283.1	518.3	572.6	622.4	103.4	62.0	2,161.9
	ALTE	(306.7)	(176.9)	(239.3)	(214.3)	(454.5)	(449.7)	(1,841.6)
	ALTW	(9.0)	(4.5)	(3.0)	(3.8)	(25.3)	(40.2)	(85.7)
	AMIL	181.7	153.6	181.5	150.2	170.1	12.0	849.1
	CIN	253.3	285.4	349.7	272.0	129.6	350.0	1,640.0
	CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	IPL	(43.4)	48.1	63.8	74.5	(29.2)	128.7	242.5
	MECS	322.3	298.9	322.5	433.4	529.0	291.8	2,197.8
	NIPS	(22.9)	(12.5)	(22.0)	(25.6)	(71.6)	(5.0)	(159.5)
	WEC	(92.1)	(73.8)	(80.5)	(64.0)	(144.7)	(225.6)	(680.7)
NYISO		(1,047.1)	(1,018.0)	(1,100.9)	(313.3)	(216.5)	(609.2)	(4,305.0)
	HUDS						(25.6)	(25.6)
	LIND	(165.2)	(149.8)	(91.6)	(64.9)	(77.0)	(55.8)	(604.5)
	NEPT	(270.9)	(245.9)	(239.2)	(247.1)	(102.5)	(167.8)	(1,273.4)
	NYIS	(611.0)	(622.3)	(770.1)	(1.3)	(37.0)	(360.0)	(2,401.6)
OVEC		798.2	713.5	585.0	542.8	712.0	908.3	4,259.8
TVA		643.8	600.0	383.6	249.0	392.2	217.6	2,486.2
Total		470.4	639.5	530.6	757.9	846.7	778.1	4,023.3

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14 In June, 2013, the EKPC Interface was eliminated, and the HUDS Interface was added. While there are 21 total interfaces with PJM during 2013, only 20 were active at any given time.

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

16 See "Ohio Valley Electric Corporation: Company Background," <http://www.ovec.com/OVECHistory.pdf> (Accessed July 17, 2013).

Table 8-2 Real-time scheduled gross import volume by interface (GWh): January through June, 2013

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	1.4	0.1	1.6	0.0	2.0	219.4	224.4
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	225.0	190.6	157.0	137.4	320.4	265.8	1,296.3
EKPC	4.4	1.5	25.6	21.8	33.0		86.3
LGEE	299.0	272.4	302.2	186.0	205.0	255.4	1,519.9
MEC	0.2	48.2	320.6	6.2	0.0	0.0	375.4
MISO	1,026.7	971.1	1,110.5	1,199.0	1,264.4	1,193.4	6,765.1
ALTE	0.0	1.1	0.0	0.0	0.0	0.0	1.1
ALTW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AMIL	207.0	177.1	215.1	198.2	213.8	79.0	1,090.3
CIN	374.5	394.7	455.5	438.9	358.2	519.7	2,541.6
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	95.9	76.5	101.6	101.3	70.4	176.3	622.1
MECS	349.1	321.6	338.3	458.2	621.9	418.4	2,507.5
NIPS	0.2	0.0	0.0	2.4	0.0	0.0	2.6
WEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	871.0	782.0	820.7	1,037.6	857.5	895.0	5,263.9
HUDS						0.0	0.0
LIND	0.6	10.4	7.5	13.5	7.8	10.2	50.1
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	870.5	771.6	813.2	1,024.1	849.7	884.8	5,213.8
OVEC	798.3	713.5	585.1	543.8	728.4	916.1	4,285.2
TVA	689.8	630.0	399.1	261.5	431.9	265.9	2,678.2
Total	3,915.7	3,609.5	3,722.4	3,393.4	3,842.5	4,010.9	22,494.5

Table 8-3 Real-time scheduled gross export volume by interface (GWh): January through June, 2013

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	31.9	38.4	50.0	33.1	27.3	31.3	212.0
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	49.8	67.9	8.9	56.5	25.8	43.9	252.9
EKPC	154.0	141.4	178.3	174.0	141.8		789.6
LGEE	17.5	0.4	0.0	3.1	0.7	1.8	23.5
MEC	484.4	439.0	479.6	427.6	509.1	464.2	2,803.8
MISO	743.5	452.8	537.9	576.7	1,161.0	1,131.4	4,603.2
ALTE	306.7	178.0	239.3	214.3	454.5	449.7	1,842.6
ALTW	9.0	4.5	3.0	3.8	25.3	40.2	85.7
AMIL	25.3	23.5	33.6	48.0	43.7	67.0	241.2
CIN	121.2	109.3	105.8	166.9	228.6	169.7	901.6
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	139.3	28.4	37.8	26.8	99.7	47.6	379.6
MECS	26.8	22.7	15.8	24.8	93.0	126.6	309.7
NIPS	23.0	12.5	22.0	28.0	71.6	5.0	162.1
WEC	92.1	73.8	80.5	64.0	144.7	225.6	680.7
NYISO	1,918.1	1,800.1	1,921.6	1,351.0	1,074.0	1,504.2	9,568.9
HUDS						25.6	25.6
LIND	165.8	160.3	99.1	78.5	84.8	66.1	654.5
NEPT	270.9	245.9	239.2	247.1	102.5	167.8	1,273.4
NYIS	1,481.5	1,393.9	1,583.3	1,025.4	886.6	1,244.7	7,615.4
OVEC	0.1	0.0	0.0	1.1	16.4	7.8	25.3
TVA	46.0	30.0	15.6	12.5	39.7	48.3	192.0
Total	3,445.3	2,970.0	3,191.9	2,635.5	2,995.8	3,232.8	18,471.2

Real-Time Interface Pricing Point Imports and Exports

Interfaces differ from interface pricing points. An interface is a point of interconnection between PJM and a neighboring balancing authority which market participants may designate as a market path on which scheduled imports or exports will flow.[17] An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled market path from a generation control area (GCA) to a load control area (LCA), this market path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the

17 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.

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 MISO/PJM Interface based on the scheduled market path of the transaction. However, the physical flow of energy does not enter the PJM footprint at the MISO/PJM Interface, but enters PJM at the southern boundary. For this reason, PJM prices an import with the GCA of LGEE at the SouthIMP interface pricing point rather than the MISO pricing point.

Interfaces differ from interface pricing points. The challenge is to create interface prices, composed of external pricing points, which accurately represent flows between PJM and external sources of energy. The result is price signals that embody the underlying economic fundamentals across balancing authority borders.[18]

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.[19] 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.[20] The weighting factors are determined in such a manner that the interface reflects actual system conditions. However, this analysis is an approximation given the complexity of the transmission network outside PJM and the dynamic nature of power flows. Transactions between PJM and external balancing authorities need to be priced at the PJM border. Table 8-17 presents the interface pricing points used for the first six months of 2013.

The interface pricing methodology implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are generally static, and are modified by PJM only occasionally.

While the OASIS has a path component, this path only reflects the path of energy into or out of PJM to one neighboring balancing authority. The NERC Tag requires the complete path to be specified from the Generation Control Area (GCA) to the Load Control Area (LCA). This complete path is utilized by PJM to determine the interface pricing point which PJM will associate with the transaction. This approach will correctly identify the interface pricing point only if the market participant provides the complete path in the Tag. This approach will not correctly identify the interface pricing point if the market participant breaks the transaction into portions, each with a separate Tag. The result of such behavior can be incorrect pricing of transactions.

There are several pricing points mapped to the region south of PJM. The SouthIMP and SouthEXP pricing points serve as the default pricing point for transactions at the southern border of PJM. The CPLEEXP, CPLEIMP, DUKEXP, DUKIMP, NCMPAEXP and NCMPAIMP were also established to account for various special agreements with neighboring balancing areas, and PJM continued to use the Southwest pricing point for certain grandfathered transactions.[21]

In the Real-Time Energy Market, for the first six months of 2013, there were net scheduled exports at eleven of PJM's 17 interface pricing points eligible for real-time transactions.[22] The top two net exporting interface pricing points in the Real-Time Energy Market accounted for 70.4 percent of the total net exports: PJM/MISO with 52.8 percent, and PJM/NYIS with 17.6 percent of the net export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 34.1 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 71.4 percent of the total

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18 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.

19 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed July 17, 2013). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

20 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 July 17, 2013)

21 The MMU does not believe that it is appropriate to allow the use of the Southwest pricing point for the grandfathered transactions, and suggests that no further such agreements be entered into.

22 There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).

net imports: PJM/SouthIMP with 44.0 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 27.4 percent of the net import volume.

Table 8-4 Real-time scheduled net interchange volume by interface pricing point (GWh): January through June, 2013

	Jan	Feb	Mar	Apr	May	Jun	Total
HUDS						(25.6)	(25.6)
IMO	592.6	395.0	556.4	547.2	668.7	584.3	3,344.1
LINDENVFT	(165.2)	(149.8)	(91.6)	(64.9)	(77.0)	(55.8)	(604.5)
MISO	(1,015.3)	(686.3)	(699.3)	(709.9)	(1,444.8)	(1,513.8)	(6,069.4)
NEPTUNE	(270.9)	(245.9)	(239.2)	(247.1)	(102.5)	(167.8)	(1,273.4)
NORTHWEST	(3.6)	(3.3)	(5.9)	(5.0)	(5.5)	(2.7)	(26.0)
NYIS	(603.2)	(572.1)	(706.3)	62.9	28.4	(230.2)	(2,020.7)
OVEC	798.2	713.5	585.0	542.8	712.0	908.3	4,259.8
SOUTHIMP	1,441.6	1,472.4	1,387.4	923.1	1,306.5	1,411.2	7,942.1
CPLEIMP	0.0	0.0	0.0	0.0	0.0	219.4	219.4
DUKIMP	107.2	105.3	83.8	46.7	110.6	129.7	583.3
NCMPAIMP	68.6	31.3	19.5	22.6	95.1	61.7	298.9
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	1,265.7	1,335.8	1,284.0	853.8	1,100.9	1,000.4	6,840.6
SOUTHEXP	(303.9)	(283.9)	(255.9)	(291.0)	(238.9)	(129.7)	(1,503.3)
CPLEEXP	(31.3)	(33.4)	(47.6)	(32.0)	(26.7)	(30.8)	(201.7)
DUKEXP	(27.1)	(45.2)	(0.9)	(32.9)	(11.8)	(29.9)	(147.7)
NCMPAEXP	0.0	(0.1)	0.0	(0.2)	0.0	(1.5)	(1.7)
SOUTHWEST	(4.5)	(5.7)	(3.0)	(11.7)	(3.6)	(4.4)	(32.8)
SOUTHEXP	(241.0)	(199.6)	(204.5)	(214.2)	(196.9)	(63.1)	(1,119.3)
Total	470.4	639.5	530.6	757.9	846.7	778.1	4,023.3

Table 8-5 Real-time scheduled gross import volume by interface pricing point (GWh): January through June, 2013

	Jan	Feb	Mar	Apr	May	Jun	Total
HUDS						0.0	0.0
IMO	594.6	403.2	562.5	549.8	669.9	584.7	3,364.7
LINDENVFT	0.6	10.4	7.5	13.5	7.8	10.2	50.1
MISO	204.4	196.3	309.1	277.5	215.9	74.6	1,277.8
NEPTUNE	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NORTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	876.3	813.6	870.9	1,085.7	914.0	1,014.1	5,574.6
OVEC	798.3	713.5	585.1	543.8	728.4	916.1	4,285.2
SOUTHIMP	1,441.6	1,472.4	1,387.4	923.1	1,306.5	1,411.2	7,942.1
CPLEIMP	0.0	0.0	0.0	0.0	0.0	219.4	219.4
DUKIMP	107.2	105.3	83.8	46.7	110.6	129.7	583.3
NCMPAIMP	68.6	31.3	19.5	22.6	95.1	61.7	298.9
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	1,265.7	1,335.8	1,284.0	853.8	1,100.9	1,000.4	6,840.6
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	3,915.7	3,609.5	3,722.4	3,393.4	3,842.5	4,010.9	22,494.5

Table 8-6 Real-time scheduled gross export volume by interface pricing point (GWh): January through June, 2013

	Jan	Feb	Mar	Apr	May	Jun	Total
HUDS						25.6	25.6
IMO	2.0	8.2	6.1	2.6	1.3	0.4	20.6
LINDENVFT	165.8	160.3	99.1	78.5	84.8	66.1	654.5
MISO	1,219.7	882.6	1,008.4	987.4	1,660.7	1,588.4	7,347.2
NEPTUNE	270.9	245.9	239.2	247.1	102.5	167.8	1,273.4
NORTHWEST	3.6	3.3	5.9	5.0	5.5	2.7	26.0
NYIS	1,479.5	1,385.8	1,577.2	1,022.8	885.6	1,244.3	7,595.2
OVEC	0.1	0.0	0.0	1.1	16.4	7.8	25.3
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	303.9	283.9	255.9	291.0	238.9	129.7	1,503.3
CPLEEXP	31.3	33.4	47.6	32.0	26.7	30.8	201.7
DUKEXP	27.1	45.2	0.9	32.9	11.8	29.9	147.7
NCMPAEXP	0.0	0.1	0.0	0.2	0.0	1.5	1.7
SOUTHWEST	4.5	5.7	3.0	11.7	3.6	4.4	32.8
SOUTHEXP	241.0	199.6	204.5	214.2	196.9	63.1	1,119.3
Total	3,445.3	2,970.0	3,191.9	2,635.5	2,995.8	3,232.8	18,471.2

Day-Ahead Interface Imports and Exports

In the Day-Ahead Energy Market, as in the Real-Time Energy Market, scheduled imports and exports are determined by the scheduled market path, which is the transmission path a market participant selects from the original source to the final sink. Entering external energy transactions in the Day-Ahead Energy Market requires fewer steps than the Real-Time Energy Market. Market participants need to acquire a valid, willing to pay congestion (WPC) OASIS reservation to prove that their day-ahead schedule could be supported in the Real-Time Energy Market.[23] 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 unless they are also submitted in the Real-Time Energy Market. 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.[24]

In the Day-Ahead Energy Market, transaction sources and sinks are determined solely by the market participants. 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 bear any necessary relationship to 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 Day-Ahead Market. In the interface tables, the import transaction would appear as scheduled through the MISO Interface, and in the interface pricing point tables, the import transaction would appear 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 six months of 2013 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 six months of 2013, there were net scheduled exports at ten of PJM's 21 interfaces.[25] The top three net exporting interfaces in the Real-Time Energy Market accounted for 78.5 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 31.7 percent, PJM/MidAmerican Energy Company (MEC) with 31.6 percent, and PJM/NEPT with 15.2 percent of the net export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS,

[23] 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.

[24] See the *2010 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for details.
[25] In June, 2013, the EKPC Interface was eliminated, and the HUDS Interface was added. While there are 21 total interfaces with PJM during 2013, only 20 were active at any given time.

PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 48.1 percent of the total net PJM exports in the Day-Ahead Energy Market. The nine separate interfaces that connect PJM to MISO together represented 11.5 percent of the total net PJM exports in the Day-Ahead Energy Market. Nine PJM interfaces had net scheduled imports, with three importing interfaces accounting for 84.7 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 63.6 percent, PJM/DUK with 12.5 percent and PJM/Michigan Electric Coordinated Systems (MECS) with 8.6 percent of the net import volume.[26]

Table 8-7 Day-Ahead scheduled net interchange volume by interface (GWh): January through June, 2013

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	(33.4)	(28.5)	(41.2)	(30.5)	(24.1)	172.0	14.2
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	78.0	70.1	75.8	82.3	145.7	127.5	579.5
EKPC	(36.6)	(33.6)	(37.2)	(36.0)	(37.2)		(180.5)
LGEE	58.3	65.8	81.8	40.3	2.3	0.0	248.5
MEC	(483.0)	(435.7)	(477.7)	(423.0)	(484.7)	(462.9)	(2,767.0)
MISO	(242.1)	(52.6)	(48.7)	(34.3)	(324.7)	(302.2)	(1,004.7)
ALTE	(177.8)	(79.5)	(119.1)	(99.9)	(238.2)	(267.3)	(981.6)
ALTW	(7.6)	(2.5)	0.0	0.0	(2.5)	(35.8)	(48.3)
AMIL	8.7	5.2	26.3	13.5	(0.9)	(1.2)	51.6
CIN	7.9	45.9	37.1	32.3	18.3	44.4	185.9
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	(0.9)	(5.9)	(1.6)	0.0	0.0	33.9	25.5
MECS	23.4	45.8	102.9	93.1	97.9	36.9	400.2
NIPS	(22.2)	(12.5)	(21.5)	(27.8)	(70.7)	0.0	(154.7)
WEC	(73.7)	(49.2)	(72.8)	(45.5)	(128.8)	(113.1)	(483.1)
NYISO	(833.6)	(874.4)	(944.3)	(459.5)	(386.6)	(707.5)	(4,205.9)
HUDS					(32.5)	(36.6)	(69.1)
LIND	(15.3)	(14.3)	(2.6)	0.1	0.0	0.1	(32.1)
NEPT	(278.5)	(255.2)	(248.7)	(253.1)	(101.5)	(193.7)	(1,330.7)
NYIS	(539.7)	(604.9)	(693.0)	(206.5)	(252.6)	(477.2)	(2,774.0)
OVEC	561.5	494.4	408.0	324.6	522.8	644.8	2,956.0
TVA	32.7	3.6	(3.6)	41.2	92.4	18.6	185.0
Total without Up-To Congestion	(898.1)	(790.9)	(987.2)	(494.9)	(494.1)	(509.7)	(4,174.9)
Up-To Congestion	(1,704.8)	(1,336.7)	(875.0)	(421.3)	(191.6)	(457.4)	(4,986.7)
Total	(2,602.8)	(2,127.7)	(1,862.2)	(916.1)	(685.7)	(967.1)	(9,161.6)

Table 8-8 Day-Ahead scheduled gross import volume by interface (GWh): January through June, 2013

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	0.0	0.0	0.0	0.0	0.0	202.5	202.5
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	78.0	70.1	75.8	82.3	145.7	127.5	579.5
EKPC	0.0	0.0	0.0	0.0	0.0		0.0
LGEE	58.3	65.8	81.8	40.3	2.3	0.0	248.5
MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MISO	75.2	115.2	196.6	184.4	231.6	229.4	1,032.5
ALTE	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ALTW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AMIL	8.7	5.2	26.3	13.5	3.9	1.9	59.6
CIN	21.5	64.2	58.4	77.7	61.9	52.0	335.7
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	5.6	0.0	0.0	0.0	0.0	33.9	39.6
MECS	39.3	45.8	111.9	93.1	165.8	141.6	597.6
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYISO	726.2	650.4	717.7	768.3	601.6	726.7	4,190.9
HUDS					0.0	0.0	0.0
LIND	0.1	9.3	2.9	0.1	0.0	0.1	12.4
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	726.2	641.1	714.8	768.2	601.6	726.6	4,178.5
OVEC	561.5	494.4	408.0	324.6	522.8	644.8	2,956.0
TVA	41.7	13.6	3.6	42.7	102.8	21.5	225.9
Total without Up-To Congestion	1,540.9	1,409.5	1,483.5	1,442.6	1,606.8	1,952.4	9,435.8
Up-To Congestion	4,637.9	3,481.0	4,226.5	4,728.9	4,890.0	4,135.3	26,099.5
Total	6,178.8	4,890.5	5,710.0	6,171.5	6,496.8	6,087.8	35,535.3

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26 In the Day-Ahead Market, two PJM interfaces had a net interchange of zero (PJM/Carolina Power and Light – Western (CPLW) and PJM/City Water Light & Power (CWLP)).

Table 8-9 Day-Ahead scheduled gross export volume by interface (GWh): January through June, 2013

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	33.4	28.5	41.2	30.5	24.1	30.5	188.3
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EKPC	36.6	33.6	37.2	36.0	37.2		180.5
LGEE	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	483.0	435.7	477.7	423.0	484.7	462.9	2,767.0
MISO	317.3	167.9	245.4	218.6	556.4	531.6	2,037.1
ALTE	177.8	79.5	119.1	99.9	238.2	267.3	981.6
ALTW	7.6	2.5	0.0	0.0	2.5	35.8	48.3
AMIL	0.0	0.0	0.0	0.0	4.8	3.2	8.0
CIN	13.7	18.3	21.3	45.5	43.5	7.6	149.8
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	6.5	5.9	1.6	0.0	0.0	0.0	14.0
MECS	15.9	0.0	9.1	0.0	67.9	104.7	197.5
NIPS	22.2	12.5	21.5	27.8	70.7	0.0	154.7
WEC	73.7	49.2	72.8	45.5	128.8	113.1	483.1
NYISO	1,559.8	1,524.8	1,662.1	1,227.8	988.2	1,434.2	8,396.8
HUDS					32.5	36.6	69.1
LIND	15.4	23.6	5.5	0.0	0.0	0.0	44.5
NEPT	278.5	255.2	248.7	253.1	101.5	193.7	1,330.7
NYIS	1,265.9	1,246.0	1,407.8	974.7	854.2	1,203.9	6,952.5
OVEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TVA	9.0	10.0	7.2	1.5	10.4	2.9	40.9
Total without Up-To Congestion	2,439.0	2,200.5	2,470.7	1,937.5	2,100.9	2,462.2	13,610.7
Up-To Congestion	6,342.6	4,817.7	5,101.5	5,150.2	5,081.6	4,592.7	31,086.3
Total	8,781.6	7,018.2	7,572.2	7,087.7	7,182.4	7,054.9	44,697.0

Day-Ahead Interface Pricing Point Imports and Exports

Table 8-10 through Table 8-15 show the Day-Ahead Market interchange totals at the individual interface pricing points. In the first six months of 2013, up-to congestion transactions accounted for 73.4 percent of all scheduled import MW transactions, 69.5 percent of all scheduled export MW transactions and 54.4 percent of the net interchange volume in the Day-Ahead Market. Net interchange in the Day-Ahead Market, including up-to congestion transactions, is shown by interface pricing point for the first six months of 2013 in Table 8-10. Up-to congestion transactions by interface pricing point for the first six

months of 2013 are shown in Table 8-11. Gross imports and exports, including up-to congestion transactions, for the Day-Ahead Market are shown in Table 8-12 and Table 8-14, while gross import up-to congestion transactions are show in Table 8-13 and gross export up-to congestion transactions are shown in Table 8-15.

In the Day-Ahead Energy Market, for the first six months of 2013, there were net scheduled exports at nine of PJM's 19 interface pricing points eligible for day-ahead.[27] The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 63.7 percent of the total net exports: PJM/SouthEXP with 24.2 percent, PJM/NIPSCO with 21.8 percent and PJM/Southwest with 17.7 percent of the net export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 26.5 percent of the total net PJM exports in the Day-Ahead Energy Market. Nine PJM interface pricing points had net imports, with three importing interface pricing points accounting for 75.1 percent of the total net imports: PJM/SouthIMP with 33.9 percent, PJM/Ohio Valley Electric Corporation (OVEC) with 21.7 percent and PJM/Southeast with 19.5 percent of the net import volume.[28]

In the Day-Ahead Market, for the first six months of 2013, up-to congestion transactions had net exports at five of PJM's 19 interface pricing points eligible for day-ahead transactions. The top two net exporting interface pricing points for up-to congestion transactions accounted for 57.2 percent of the total net up-to congestion exports: PJM/SouthEXP with 29.2 percent and PJM/NIPSCO with 28.0 percent of the net export up-to congestion volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 7.4 percent of the net up-to congestion PJM exports in the Day-Ahead Energy Market (PJM/NEPTUNE with 7.4 percent). The PJM/NYIS and the PJM/LINDEN interface pricing points had net imports in the Day-Ahead Energy Market and the PJM/HUDS interface pricing point had a net interchange of zero. Seven PJM interface pricing points had net up-to congestion imports, with two importing

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[27] There are two interface pricing points eligible for day-ahead transaction scheduling only (NIPSCO and Southeast).
[28] In the Day-Ahead Market, one PJM interface pricing points had a net interchange of zero (PJM/DUKEXP).

interface pricing points accounting for 51.8 percent of the total net up-to congestion imports: PJM/MISO with 32.1 percent and PJM/Northwest with 19.6 percent of the net import volume.[29]

Table 8-10 Day–Ahead scheduled net interchange volume by interface pricing point (GWh): January through June, 2013

	Jan	Feb	Mar	Apr	May	Jun	Total
HUDS					(32.5)	(36.6)	(69.1)
IMO	27.4	235.1	206.5	104.5	100.1	37.8	711.3
LINDENVFT	102.2	14.5	(14.6)	(16.8)	(68.7)	(13.6)	3.0
MISO	192.7	130.5	453.0	228.8	(434.9)	(207.4)	362.8
NEPTUNE	(335.1)	(381.7)	(398.9)	(473.6)	(341.6)	(302.0)	(2,232.9)
NIPSCO	(927.2)	(757.5)	(743.5)	(591.9)	(121.5)	(269.9)	(3,411.6)
NORTHWEST	(744.5)	(810.7)	(646.6)	199.5	520.7	128.3	(1,353.3)
NYIS	(662.2)	(576.6)	(506.4)	208.5	10.8	(312.0)	(1,837.9)
OVEC	254.6	210.5	438.4	269.4	92.5	142.3	1,407.7
SOUTHIMP	1,255.6	902.5	877.1	965.4	1,108.3	1,236.1	6,345.2
CPLEIMP	0.0	0.0	0.0	0.0	0.0	202.5	202.5
DUKIMP	22.5	22.0	9.0	7.0	17.5	46.8	124.8
NCMPAIMP	18.3	15.4	14.9	19.1	84.6	53.9	206.1
SOUTHEAST	488.4	326.9	366.3	268.4	188.8	182.9	1,821.8
SOUTHWEST	283.6	231.0	184.8	321.0	394.2	376.6	1,791.2
SOUTHIMP	442.8	307.4	302.0	349.9	423.2	373.5	2,198.8
SOUTHEXP	(1,766.4)	(1,094.4)	(1,527.3)	(1,809.8)	(1,518.9)	(1,370.0)	(9,086.8)
CPLEEXP	(32.4)	(27.8)	(40.7)	(29.6)	(22.8)	(29.5)	(182.7)
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	(1.0)	(0.8)	(0.5)	(0.9)	(1.3)	(1.1)	(5.6)
SOUTHEAST	(49.3)	(28.8)	(26.5)	(123.4)	(213.1)	(118.9)	(560.0)
SOUTHWEST	(912.1)	(535.5)	(800.2)	(1,017.5)	(653.5)	(638.6)	(4,557.3)
SOUTHEXP	(771.5)	(501.6)	(659.5)	(638.4)	(628.2)	(582.0)	(3,781.2)
Total	(2,602.8)	(2,127.7)	(1,862.2)	(916.1)	(685.7)	(967.1)	(9,161.6)

Table 8-11 Up-to Congestion scheduled net interchange volume by interface pricing point (GWh): January through June, 2013

	Jan	Feb	Mar	Apr	May	Jun	Total
HUDS					0.0	0.0	0.0
IMO	(11.9)	189.4	94.5	18.0	(62.6)	(92.8)	134.6
LINDENVFT	117.5	28.8	(12.0)	(16.9)	(68.7)	(13.7)	35.0
MISO	500.7	288.8	660.8	422.2	117.7	323.4	2,313.5
NEPTUNE	(56.5)	(126.5)	(150.2)	(220.6)	(240.1)	(108.3)	(902.1)
NIPSCO	(927.2)	(757.5)	(743.5)	(591.9)	(121.5)	(269.9)	(3,411.6)
NORTHWEST	(261.6)	(375.0)	(168.9)	622.5	1,004.7	591.2	1,413.0
NYIS	(121.9)	25.3	185.7	415.0	264.0	165.2	933.3
OVEC	(306.9)	(281.8)	31.4	(55.2)	(430.3)	(502.5)	(1,545.3)
SOUTHIMP	1,050.5	694.0	668.9	727.3	792.5	786.7	4,719.8
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	488.4	326.9	366.3	268.4	188.8	181.0	1,819.9
SOUTHWEST	283.6	231.0	184.8	321.0	394.2	376.6	1,791.2
SOUTHIMP	278.5	136.1	117.7	137.9	209.4	229.0	1,108.7
SOUTHEXP	(1,687.4)	(1,022.2)	(1,441.8)	(1,741.8)	(1,447.2)	(1,336.7)	(8,677.1)
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	(49.3)	(28.8)	(26.5)	(123.4)	(213.1)	(118.9)	(560.0)
SOUTHWEST	(912.1)	(535.5)	(800.2)	(1,017.5)	(653.5)	(638.6)	(4,557.3)
SOUTHEXP	(725.9)	(457.9)	(615.1)	(600.9)	(580.6)	(579.2)	(3,559.8)
Total Interfaces	(1,704.8)	(1,336.7)	(875.0)	(421.3)	(191.6)	(457.4)	(4,986.7)
INTERNAL	22,906.0	23,311.1	27,439.6	32,152.2	34,779.0	34,935.1	175,523.0
Total	21,201.2	21,974.3	26,564.6	31,731.0	34,587.4	34,477.8	170,536.3

[29] In the Day-Ahead Market, seven PJM interface pricing points (PJM/CPLEIMP, PJM/DUKIMP, PJM/NCMPAIMP, PJM/CPLEEXP, PJM/DUKEXP, PJM/NCMPAEXP and PJM/HUDS) had a net interchange of zero.

Table 8-12 Day-Ahead scheduled gross import volume by interface pricing point (GWh): January through June, 2013

	Jan	Feb	Mar	Apr	May	Jun	Total
HUDS					0.0	0.0	0.0
IMO	268.0	322.5	310.8	285.5	376.4	341.5	1,904.8
LINDENVFT	292.4	210.2	188.5	130.0	145.1	119.8	1,085.9
MISO	719.6	516.2	809.8	770.8	470.0	591.0	3,877.3
NEPTUNE	127.2	32.2	11.5	17.2	10.8	10.1	209.0
NIPSCO	35.0	17.1	15.0	65.2	180.8	135.0	448.3
NORTHWEST	287.9	214.8	229.9	818.0	1,184.5	728.3	3,463.3
NYIS	1,097.0	1,031.5	1,130.2	1,260.6	991.5	1,046.5	6,557.3
OVEC	2,096.0	1,643.5	2,137.2	1,858.8	2,029.3	1,879.4	11,644.3
SOUTHIMP	1,255.6	902.5	877.1	965.4	1,108.3	1,236.1	6,345.2
CPLEIMP	0.0	0.0	0.0	0.0	0.0	202.5	202.5
DUKIMP	22.5	22.0	9.0	7.0	17.5	46.8	124.8
NCMPAIMP	18.3	15.4	14.9	19.1	84.6	53.9	206.1
SOUTHEAST	488.4	326.9	366.3	268.4	188.8	182.9	1,821.8
SOUTHWEST	283.6	231.0	184.8	321.0	394.2	376.6	1,791.2
SOUTHIMP	442.8	307.4	302.0	349.9	423.2	373.5	2,198.8
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	6,178.8	4,890.5	5,710.0	6,171.5	6,496.8	6,087.8	35,535.3

Table 8-13 Up-to Congestion scheduled gross import volume by interface pricing point (GWh): January through June, 2013

	Jan	Feb	Mar	Apr	May	Jun	Total
HUDS					0.0	0.0	0.0
IMO	228.7	276.6	198.9	199.1	213.8	210.9	1,328.0
LINDENVFT	292.4	200.9	185.5	129.9	145.1	119.8	1,073.5
MISO	710.9	505.8	772.2	745.5	466.1	590.2	3,790.6
NEPTUNE	127.2	32.2	11.5	17.2	10.8	10.1	209.0
NIPSCO	35.0	17.1	15.0	65.2	180.8	135.0	448.3
NORTHWEST	287.9	214.8	229.9	818.0	1,184.5	728.3	3,463.3
NYIS	370.9	388.3	414.4	492.4	389.9	319.8	2,375.7
OVEC	1,534.5	1,151.2	1,730.2	1,534.2	1,506.5	1,234.6	8,691.4
SOUTHIMP	1,050.5	694.0	668.9	727.3	792.5	786.7	4,719.8
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	488.4	326.9	366.3	268.4	188.8	181.0	1,819.9
SOUTHWEST	283.6	231.0	184.8	321.0	394.2	376.6	1,791.2
SOUTHIMP	278.5	136.1	117.7	137.9	209.4	229.0	1,108.7
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	4,637.9	3,481.0	4,226.5	4,728.9	4,890.0	4,135.3	26,099.5

Table 8-14 Day-Ahead scheduled gross export volume by interface pricing point (GWh): January through June, 2013

	Jan	Feb	Mar	Apr	May	Jun	Total
HUDS					32.5	36.6	69.1
IMO	240.6	87.4	104.4	181.1	276.4	303.7	1,193.5
LINDENVFT	190.2	195.7	203.1	146.7	213.8	133.4	1,083.0
MISO	526.9	385.6	356.8	541.9	904.9	798.4	3,514.5
NEPTUNE	462.2	413.9	410.4	490.9	352.4	312.1	2,441.8
NIPSCO	962.3	774.6	758.5	657.2	302.4	405.0	3,859.9
NORTHWEST	1,032.4	1,025.5	876.4	618.5	663.8	600.0	4,816.5
NYIS	1,759.2	1,608.1	1,636.5	1,052.1	980.7	1,358.5	8,395.2
OVEC	1,841.4	1,433.0	1,698.8	1,589.5	1,936.8	1,737.2	10,236.6
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	1,766.4	1,094.4	1,527.3	1,809.8	1,518.9	1,370.0	9,086.8
CPLEEXP	32.4	27.8	40.7	29.6	22.8	29.5	182.7
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	1.0	0.8	0.5	0.9	1.3	1.1	5.6
SOUTHEAST	49.3	28.8	26.5	123.4	213.1	118.9	560.0
SOUTHWEST	912.1	535.5	800.2	1,017.5	653.5	638.6	4,557.3
SOUTHEXP	771.5	501.6	659.5	638.4	628.2	582.0	3,781.2
Total	8,781.6	7,018.2	7,572.2	7,087.7	7,182.4	7,054.9	44,697.0

Table 8-15 Up-to Congestion scheduled gross export volume by interface pricing point (GWh): January through June, 2013

	Jan	Feb	Mar	Apr	May	Jun	Total
HUDS					0.0	0.0	0.0
IMO	240.6	87.3	104.4	181.1	276.4	303.7	1,193.4
LINDENVFT	174.8	172.1	197.6	146.7	213.8	133.4	1,038.5
MISO	210.2	217.0	111.4	323.3	348.4	266.7	1,477.1
NEPTUNE	183.7	158.7	161.7	237.8	250.9	118.4	1,111.1
NIPSCO	962.3	774.6	758.5	657.2	302.4	405.0	3,859.9
NORTHWEST	549.4	589.8	398.7	195.5	179.8	137.1	2,050.3
NYIS	492.8	362.9	228.7	77.4	126.0	154.6	1,442.4
OVEC	1,841.4	1,433.0	1,698.8	1,589.5	1,936.8	1,737.2	10,236.6
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	1,687.4	1,022.2	1,441.8	1,741.8	1,447.2	1,336.7	8,677.1
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	49.3	28.8	26.5	123.4	213.1	118.9	560.0
SOUTHWEST	912.1	535.5	800.2	1,017.5	653.5	638.6	4,557.3
SOUTHEXP	725.9	457.9	615.1	600.9	580.6	579.2	3,559.8
Total	6,342.6	4,817.7	5,101.5	5,150.2	5,081.6	4,592.7	31,086.3

Table 8-16 Active interfaces: January through June, 2013[30,31,32]

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

Figure 8-3 PJM's footprint and its external interfaces

Table 8-17 Active pricing points: January through June, 2013[33]

	Jan	Feb	Mar	Apr	May	Jun
CPLEEXP	Active	Active	Active	Active	Active	Active
CPLEIMP	Active	Active	Active	Active	Active	Active
DUKEXP	Active	Active	Active	Active	Active	Active
DUKIMP	Active	Active	Active	Active	Active	Active
HUDSONTP						Active
LIND	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active
NCMPAEXP	Active	Active	Active	Active	Active	Active
NCMPAIMP	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active
Southeast	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active	Active
SOUTHIMP	Active	Active	Active	Active	Active	Active
Southwest	Active	Active	Active	Active	Active	Active

30 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of June 30, 2013, DUK, CPLE and CPLW have continued to operate as separate balancing authorities, and are still considered distinct interfaces within the PJM Energy Market.

31 On June 1, 2013, East Kentucky Power Cooperative (EKPC) integrated with PJM, resulting in the elimination of the EKPC Interface.

32 On June 3, 2013, the Hudson DC Line began commercial operation resulting in the addition of the HUDS Interface.

33 On June 3, 2013, the Hudson DC Line began commercial operation resulting in the addition of the HUDSONTP Interface Pricing Point.

Loop Flows

Actual energy flows are the real-time metered power flows at an interface for a defined period. The comparable scheduled flows are the real-time power 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 the difference between actual and scheduled power flows at specific interfaces. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface by the same amount. The result is loop flow, despite the fact that system actual and scheduled power flow net to a zero difference.[34]

For the first six months of 2013, net scheduled interchange was 2,989 GWh and net actual interchange was 3,058 GWh, a difference of 69 GWh. For the first six months of 2012, net scheduled interchange was 1,666 GWh and net actual interchange was 1,480 GWh, a difference of 185 GWh.[35] This difference is system inadvertent. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange.[36]

Table 8-18 Net scheduled and actual PJM flows by interface (GWh): January through June, 2013[37]

	Actual	Net Scheduled	Difference (GWh)
CPLE	3,718	(45)	3,763
CPLW	(703)	–	(703)
DUK	444	1,043	(599)
EKPC	957	(569)	1,526
LGEE	784	1,496	(713)
MEC	(922)	(2,424)	1,502
MISO	(6,152)	1,983	(8,134)
ALTE	(3,004)	(1,842)	(1,162)
ALTW	(1,097)	(86)	(1,011)
AMIL	5,640	849	4,791
CIN	(2,717)	1,537	(4,255)
CWLP	(99)	0	(99)
IPL	303	166	137
MECS	(5,657)	2,198	(7,855)
NIPS	(2,360)	(160)	(2,201)
WEC	2,840	(681)	3,521
NYISO	(4,349)	(4,421)	72
HUDS	(26)	(26)	0
LIND	(604)	(604)	0
NEPT	(1,273)	(1,273)	0
NYIS	(2,445)	(2,518)	72
OVEC	6,389	4,260	2,129
TVA	2,892	1,666	1,226
Total	3,058	2,989	69

Every external balancing authority is mapped to an import and export interface pricing point. The mapping is designed to reflect the physical flow of energy between PJM and each balancing authority. The net scheduled values for interface pricing points are defined as the flows that will receive the specific interface price.[38] 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.

The differences between the scheduled and actual power flows at the interface pricing points provide a better measure of loop flows than differences at the

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34 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.
35 The "Net Scheduled" values shown in Table 8-18 include dynamic schedules. Dynamic schedules are commonly used for scheduling generation from one another Balancing Authority Area to another. As defined by NERC, a dynamic schedule is a telemetered reading or value from such a generating unit that is updated in real time and used as a schedule in the AGC/ACE equation of the BA to which it is scheduled. The hourly integrated values of dynamic schedules are treated as a schedule for interchange accounting purposes. As a result, the net interchange in this table does not match the interchange values shown in Table 8-1 through Table 8-6.
36 See PJM. "M-12: Balancing Operations", Revision 23 (November 16, 2011).

37 There was a miscalculation in the values presented in the corresponding table of the *Q1 2013 State of the Market Report for PJM*.
38 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.)

interfaces. Scheduled transactions are assigned interface pricing points based on the generation balancing authority and load balancing authority. Scheduled power flows are assigned to interfaces based on the OASIS path that reflects the path of energy into or out of PJM to one neighboring balancing authority. Power flows at the interface pricing points provide a more accurate reflection of where scheduled power flows actually enter or leave the PJM footprint based on the complete transaction path.

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.

Because the SouthIMP and SouthEXP Interface Pricing Points are the same physical point, if there are net actual exports from the PJM footprint to the southern region, by definition, there cannot be net actual imports into the PJM footprint from the southern region and therefore there will not be actual flows at the SouthIMP Interface Pricing Point. Conversely, if there are net actual imports into the PJM footprint from the southern region, there cannot be net actual exports to the southern region and therefore there will not be actual flows on the SouthEXP interface pricing point. However, when analyzing the interface pricing points with the southern region, comparing the net scheduled and net actual flows as a sum of the pricing points, rather than the individual pricing points, provides some insight into how effective the interface pricing point mappings are. To accurately calculate the loop flows at the southern region, the net actual flows from the southern region (7,136 GWh of imports at the SouthIMP Interface Pricing Point) are compared with the net scheduled flows at the aggregate southern region (the sum of the net scheduled flows at the SouthIMP and SouthEXP Interface Pricing Points, or 5,561 GWh).

The IMO Interface Pricing Point with the IESO was created to reflect the fact that transactions that originate or sink in the IMO balancing authority create flows that are split between the MISO and NYISO Interface Pricing Points, so

a mapping to a single interface pricing point does not reflect the actual flows. PJM created the IMO Interface Pricing Point to reflect the actual power flows across both the MISO/PJM and NYISO/PJM Interfaces. The IMO does not have physical ties with PJM because it is not contiguous. Actual flows associated with the IMO Interface Pricing Point are shown as zero because there is no PJM/IMO interface. The actual flows between IMO and PJM are included in the actual flows at the MISO and NYISO interface pricing points.

Table 8-19 Net scheduled and actual PJM flows by interface pricing point (GWh): January through June, 2013[39]

	Actual	Net Scheduled	Difference (GWh)
HUDSONTP	(26)	(26)	0
IMO	0	3,344	(3,344)
LINDENVFT	(604)	(604)	0
MISO	(5,195)	(6,114)	919
NEPTUNE	(1,273)	(1,273)	0
NORTHWEST	(922)	(22)	(900)
NYIS	(2,445)	(2,137)	(309)
OVEC	6,389	4,260	2,129
SOUTHIMP	7,136	7,065	71
CPLEIMP	0	219	(219)
DUKIMP	0	583	(583)
NCMPAIMP	0	299	(299)
SOUTHWEST	0	0	0
SOUTHIMP	7,136	5,963	1,173
SOUTHEXP	0	(1,503)	1,503
CPLEEXP	0	(202)	202
DUKEXP	0	(148)	148
NCMPAEXP	0	(2)	2
SOUTHWEST	0	(33)	33
SOUTHEXP	0	(1,119)	1,119
Total	3,058	2,989	69

Table 8-20 shows the net scheduled and actual PJM flows by interface pricing point, with adjustments made to the MISO and NYISO scheduled interface pricing points based on the quantities of scheduled interchange where transactions from the Ontario Independent Electricity System Operator (IMO) entered the PJM Energy Market.

39 There was a miscalculation in the values presented in the corresponding table of the *Q1 2013 State of the Market Report for PJM*.

Table 8-20 Net scheduled and actual PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): January through June, 2013[40]

	Actual	Net Scheduled	Difference (GWh)
HUDSONTP	(26)	(26)	0
LINDENVFT	(604)	(604)	0
MISO	(5,195)	(2,759)	(2,436)
NEPTUNE	(1,273)	(1,273)	0
NORTHWEST	(922)	(22)	(900)
NYIS	(2,445)	(2,148)	(297)
OVEC	6,389	4,260	2,129
SOUTHIMP	7,136	7,065	71
CPLEIMP	0	219	(219)
DUKIMP	0	583	(583)
NCMPAIMP	0	299	(299)
SOUTHWEST	0	0	0
SOUTHIMP	7,136	5,963	1,173
SOUTHEXP	0	(1,503)	1,503
CPLEEXP	0	(202)	202
DUKEXP	0	(148)	148
NCMPAEXP	0	(2)	2
SOUTHWEST	0	(33)	33
SOUTHEXP	0	(1,119)	1,119
Total	3,058	2,989	69

PJM ensures that external energy transactions are priced appropriately through the assignment of interface prices based on the expected actual flow from the generation balancing authority (source) and load balancing authority (sink) as specified on the NERC eTag. Assigning prices in this manner is an adequate method for ensuring that transactions receive or pay the PJM market value of the transaction based on expected flows, but this methodology does not address loop flow issues.

The MMU recommends that PJM implement a validation method for submitted transactions that would require market participants to submit transactions on market paths that reflect the expected actual flow. This validation method would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, PJM should, recognizing that transactions sourcing in SPP and sinking in PJM will create flows across the southern border, require that market participants submit the transaction to enter the PJM footprint across

a neighboring balancing authority that is mapped to the SouthIMP Interface price. This validation method would provide PJM with a more accurate forecast of where actual energy flows are expected. This validation method would reduce the unscheduled power flows across neighboring balancing authorities that result in increased production costs caused by the increase of generation to control for the unscheduled loop flows without compensating transmission revenues associated with those flows. Requiring market paths to match as closely to the expected actual power flows as possible would result in a more economic dispatch of the entire Eastern Interconnection.

Table 8-21 shows the net scheduled and actual PJM flows by interface and interface pricing point. This table shows the Interface Pricing Points that were assigned to energy transactions that had market paths at each of PJM's interfaces. For example, Table 8-21 shows that for the first six months of 2013, the majority of imports to the PJM Energy Market for which a market participant specified Cinergy as the interface with PJM based on the scheduled transmission path, had a generation control area of the Ontario Independent Electricity System Operator (IMO), and thus actual flows were assigned the IMO Interface Pricing point (1,074 GWh). Conversely, the majority of exports from the PJM Energy Market for which a market participant specified Cinergy as the interface with PJM based on the scheduled transmission path had a load control area for which the actual flows would leave the PJM Energy Market at the MISO interface, and thus were assigned the MISO Interface Pricing point (817 GWh).

Table 8-22 shows the net scheduled and actual PJM flows by interface pricing point and interface. This table shows the interfaces where transactions were scheduled which received the individual interface pricing points. For example, Table 8-22 shows that for the first six months of 2013, the majority of imports to the PJM Energy Market for which a market participant specified a generation control area for which it was assigned the IMO Interface Pricing Point, had market paths that entered the PJM Energy Market at the MECS Interface (1,837 GWh). Conversely, the majority of exports from the PJM Energy Market for which a market participant specified a load control area for which it was assigned the IMO Interface Pricing Point, had market paths that exited the PJM Energy Market at the NYIS Interface (11 GWh).

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40 There was a miscalculation in the values presented in the corresponding table of the *Q1 2013 State of the Market Report for PJM.*

Table 8-21 Net scheduled and actual PJM flows by interface and interface pricing point (GWh): January through June, 2013[41]

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(3,004)	(1,842)	(1,162)	IPL		303	166	137
	MISO	(3,004)	(1,841)	(1,163)		IMO	0	445	(445)
	NORTHWEST	0	(1)	1		MISO	303	(445)	748
	SOUTHIMP	0	1	(1)		SOUTHIMP	0	167	(167)
ALTW		(1,097)	(86)	(1,011)	LGEE		784	1,496	(713)
	MISO	(1,097)	(85)	(1,012)		SOUTHEXP	0	(23)	23
AMIL		5,640	849	4,791		SOUTHIMP	784	1,520	(736)
	MISO	5,640	858	4,782	LIND		(604)	(604)	0
	NORTHWEST	0	(1)	1		LINDENVFT	(604)	(604)	0
	SOUTHIMP	0	25	(25)	MEC		(922)	(2,424)	1,502
	SOUTHWEST	0	(33)	33		MISO	0	(2,774)	2,774
CIN		(2,717)	1,537	(4,255)		NORTHWEST	(922)	4	(926)
	IMO	0	1,074	(1,074)		SOUTHIMP	0	346	(346)
	MISO	(2,717)	(817)	(1,900)	MECS		(5,657)	2,198	(7,855)
	NORTHWEST	0	(23)	23		IMO	0	1,837	(1,837)
	NYIS	0	370	(370)		MISO	(5,657)	(304)	(5,353)
	SOUTHIMP	0	934	(934)		SOUTHIMP	0	665	(665)
CPLE		3,718	(45)	3,763	NEPT		(1,273)	(1,273)	0
	CPLEEXP	0	(202)	202		NEPTUNE	(1,273)	(1,273)	0
	CPLEIMP	0	219	(219)	NIPS		(2,360)	(160)	(2,201)
	SOUTHEXP	0	(10)	10		MISO	(2,360)	(160)	(2,201)
	SOUTHIMP	3,718	(52)	3,771	NYIS		(2,445)	(2,518)	72
CPLW		(703)	0	(703)		IMO	0	(11)	11
	SOUTHIMP	(703)	0	(703)		NYIS	(2,445)	(2,506)	61
CWLP		(99)	0	(99)	OVEC		6,389	4,260	2,129
	MISO	(99)	0	(99)		OVEC	6,389	4,260	2,129
DUK		444	1,043	(599)	TVA		2,892	1,666	1,226
	DUKEXP	0	(148)	148		SOUTHEXP	0	(192)	192
	DUKIMP	0	583	(583)		SOUTHIMP	2,892	1,858	1,034
	NCMPAEXP	0	(2)	2	WEC		2,840	(681)	3,521
	NCMPAIMP	0	299	(299)		MISO	2,840	(681)	3,521
	SOUTHEXP	0	(103)	103	HUDS		(26)	(26)	0
	SOUTHIMP	444	414	30		HUDSONTP	(26)	(26)	0
EKPC		957	(569)	1,526	Total		3,058	2,989	69
	MISO	957	134	822					
	SOUTHEXP	0	(790)	790					
	SOUTHIMP	0	86	(86)					

41 There was a miscalculation in the values presented in the corresponding table of the *Q1 2013 State of the Market Report for PJM*.

Table 8-22 Net scheduled and actual PJM flows by interface pricing point and interface (GWh): January through June, 2013[42]

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
CPLEEXP		0	(202)	202	NORTHWEST		(922)	(22)	(900)
	CPLE	0	(202)	202		ALTE	0	(1)	1
CPLEIMP		0	219	(219)		ALTW	0	(0)	0
	CPLE	0	219	(219)		AMIL	0	(1)	1
DUKEXP		0	(148)	148		CIN	0	(23)	23
	DUK	0	(148)	148		MEC	(922)	4	(926)
DUKIMP		0	583	(583)		TVA	0	(0)	0
	DUK	0	583	(583)	NYIS		(2,445)	(2,137)	(309)
IMO		0	3,344	(3,344)		CIN	0	370	(370)
	ALTE	0	0	(0)		NYIS	(2,445)	(2,506)	61
	CIN	0	1,074	(1,074)	OVEC		6,389	4,260	2,129
	IPL	0	445	(445)		OVEC	6,389	4,260	2,129
	MECS	0	1,837	(1,837)	SOUTHEXP		0	(1,119)	1,119
	NIPS	0	0	(0)		CIN	0	(0)	0
	NYIS	0	(11)	11		CPLE	0	(10)	10
LINDENVFT		(604)	(604)	0		DUK	0	(103)	103
	LIND	(604)	(604)	0		EKPC	0	(790)	790
MISO		(5,195)	(6,114)	919		IPL	0	(0)	0
	ALTE	(3,004)	(1,841)	(1,163)		LGEE	0	(23)	23
	ALTW	(1,097)	(85)	(1,012)		TVA	0	(192)	192
	AMIL	5,640	858	4,782	SOUTHIMP		7,136	5,963	1,173
	CIN	(2,717)	(817)	(1,900)		ALTE	0	1	(1)
	CWLP	(99)	0	(99)		AMIL	0	25	(25)
	EKPC	957	134	822		CIN	0	934	(934)
	IPL	303	(445)	748		CPLE	3,718	(52)	3,771
	MEC	0	(2,774)	2,774		CPLW	(703)	0	(703)
	MECS	(5,657)	(304)	(5,353)		DUK	444	414	30
	NIPS	(2,360)	(160)	(2,201)		EKPC	0	86	(86)
	WEC	2,840	(681)	3,521		IPL	0	167	(167)
NCMPAEXP		0	(2)	2		LGEE	784	1,520	(736)
	DUK	0	(2)	2		MEC	0	346	(346)
NCMPAIMP		0	299	(299)		MECS	0	665	(665)
	DUK	0	299	(299)		TVA	2,892	1,858	1,034
NEPTUNE		(1,273)	(1,273)	0	SOUTHWEST		0	(33)	33
	NEPT	(1,273)	(1,273)	0		AMIL	0	(33)	33
					HUDSONTP		(26)	(26)	0
						HUDS	(26)	(26)	0
					Total		**3,058**	**2,989**	**69**

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42 There was a miscalculation in the values presented in the corresponding table of the *Q1 2013 State of the Market Report for PJM*.

PJM and MISO Interface Prices

If interface prices were defined in a comparable manner by PJM and MISO, and if time lags were not built into the rules governing interchange transactions then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that these conditions do not exist is important in explaining the observed relationship between interface prices and inter-RTO power flows, and those price differentials.

Both the PJM/MISO and MISO/PJM Interface pricing points represent the value of power at the relevant border, as determined in each market. In both cases, the interface price is the price at which transactions are settled. For example, a transaction into PJM from MISO would receive the PJM/MISO Interface price upon entering PJM, while a transaction into MISO from PJM would receive the MISO/PJM Interface price. PJM and MISO use network models to determine these prices and to attempt to ensure that the prices are consistent with the underlying electrical flows. PJM uses the LMP at nine buses[43] 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.[44]

Real-Time and Day-Ahead PJM/MISO Interface Prices

In the first six months of 2013, the direction of the average hourly flow was inconsistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. In the first six months of 2013, the PJM average hourly Locational Marginal Price (LMP) at the PJM/MISO border was $30.91 while the MISO LMP at the border was $30.22, a difference of $0.69. While the average hourly LMP difference at the PJM/MISO border was only $0.69, the average of the absolute values of the hourly differences was $8.75. The average hourly flow during the first six months of 2013 was -1,325 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 lower than the average PJM price.) The direction of flow was

consistent with price differentials in only 46.5 percent of hours in the first six months of 2013. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, the average difference was $11.23. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, the average difference was $6.97. In the first six months of 2013, when the MISO/PJM Interface price was greater than the PJM/MISO Interface price, and when the power flows were from PJM to MISO, the average price difference was $11.04. When the MISO/PJM Interface price was greater than the PJM/MISO Interface price, and when the power flows were from MISO to PJM, the average price difference was $13.27. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, and when power flows were from MISO to PJM, the average price difference was $12.09. When the PJM/MISO Interface price was greater than the MISO/PJM Interface price, and when power flows were from PJM to MISO, the average price difference was $6.15.

In the first six months of 2013, the day-ahead PJM average hourly LMP at the PJM/MISO border was $30.85 while the MISO LMP at the border was $31.34, a difference of $0.49.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 8-4). There are a number of relevant measures of variability, including the number of times the price differential fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Figure 8-6).

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43 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed July 17, 2013). PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.
44 Based on information obtained from MISO's Extranet <http://extranet.midwestiso.org> (January 15, 2010). (Accessed July 17, 2013)
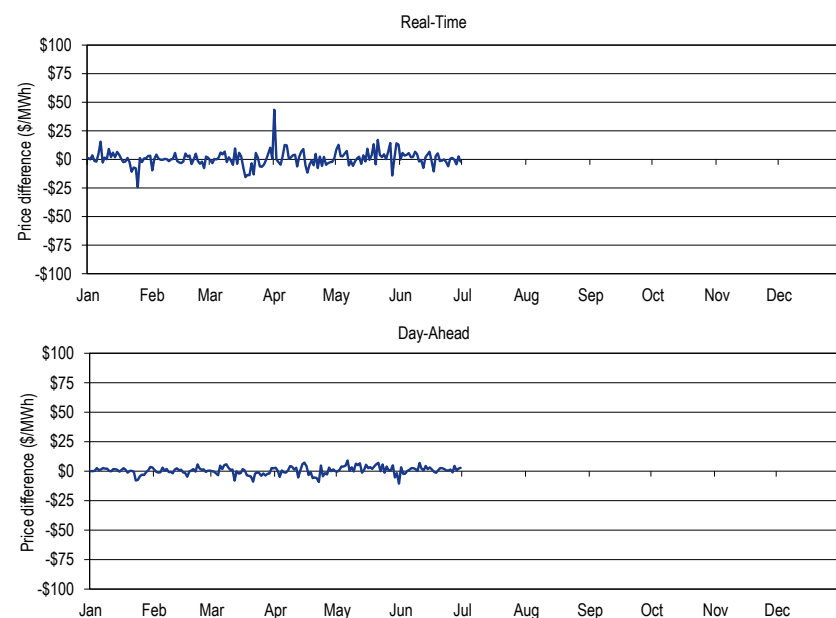
Distribution of Economic and Uneconomic Hourly Flows at the PJM/MISO Interface

During the first six months of 2013, the direction of hourly energy flows was consistent with PJM and MISO Interface Price differentials in 2,019 hours (46.5 percent of all hours), and was inconsistent with price differentials in 2,324 hours (53.5 percent of all hours). Table 8-23 shows the distribution of economic and uneconomic hours of energy flow between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices. Of the 2,324 hours where flows were uneconomic, 2,017 of those hours (86.8 percent) had a price difference greater than or equal to $1.00 and 859 of all uneconomic hours (37.0 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $272.26. Of the 2,019 hours where flows were economic, 1,760 of those hours (87.2

percent) had a price difference greater than or equal to $1.00 and 1,081 of all economic hours (53.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $887.50.

Table 8-23 Distribution of economic and uneconomic hourly flows between PJM and MISO: January through June, 2013

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	2,324	100.0%	2,019	100.0%
$1.00	2,017	86.8%	1,760	87.2%
$5.00	859	37.0%	1,081	53.5%
$10.00	365	15.7%	618	30.6%
$15.00	215	9.3%	415	20.6%
$20.00	129	5.6%	273	13.5%
$25.00	89	3.8%	192	9.5%
$50.00	21	0.9%	63	3.1%
$75.00	10	0.4%	30	1.5%
$100.00	6	0.3%	16	0.8%
$200.00	1	0.0%	2	0.1%
$300.00	0	0.0%	2	0.1%
$400.00	0	0.0%	1	0.0%
$500.00	0	0.0%	1	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.[45]

Real-Time and Day-Ahead PJM/NYISO Interface Prices

In the first six months of 2013, 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

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45 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.

differences in institutional and operating practices between PJM and the NYISO. In the first six months of 2013, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. In the first six months of 2013, the PJM average hourly LMP at the PJM/NYISO border was $42.70 while the NYISO LMP at the border was $42.04, a difference of $0.66. While the average hourly LMP difference at the PJM/NYISO border was only $0.66, the average of the absolute value of the hourly difference was $14.29. The average hourly flow during the first six months of 2013 was -527 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.) The direction of flow was consistent with price differentials in 55.9 percent of the hours in the first six months of 2013. In the first six months of 2013, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS Interface price, the average difference was $13.74. When the PJM/NYIS Interface price was greater than the NYIS/PJM proxy bus price, the average difference was $14.85. In the first six months of 2013, when the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, and when the power flows were from PJM to NYISO, the average price difference was $14.04. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, and when the power flows were from NYISO to PJM, the average price difference was $11.94. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, and when power flows were from NYISO to PJM, the average price difference was $13.03. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, and when power flows were from PJM to NYISO, the average price difference was $15.52.

In the first six months of 2013, the day-ahead PJM average hourly LMP at the PJM/NYIS border was $43.86 while the NYIS LMP at the border was $43.05, a difference of $0.81.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 8-5). There are a number of relevant measures of variability, including the number of times the price differential

fluctuates between positive and negative, the standard deviation of individual prices and of price differences and the absolute value of the price differences (Figure 8-6).

Figure 8–5 Real–time and day–ahead daily hourly average price difference (NY proxy – PJM/NYIS): January through June, 2013
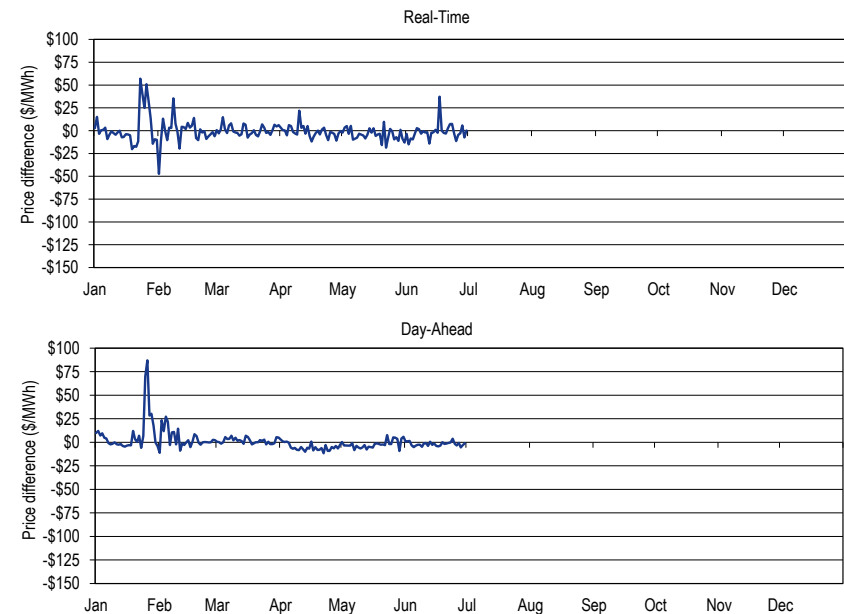
Distribution of Economic and Uneconomic Hourly Flows at the PJM/NYISO Interface

During the first six months of 2013, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 2,428 (55.9 percent of all hours), and was inconsistent with price differences in 1,915 hours (44.1 percent of all hours). Table 8-24 shows the distribution of economic and uneconomic hours of energy flow between PJM and NYISO based on the price differences between the PJM/NYISO and NYISO/PJM prices. Of the 1,915 hours where flows were uneconomic, 1,736 of those hours (90.7

percent) had a price difference greater than or equal to $1.00 and 1,122 of all uneconomic hours (58.6 percent) had a price difference greater than or equal to $5.00. The largest price difference with uneconomic flows was $231.63. Of the 2,428 hours where flows were economic, 2,242 of those hours (92.3 percent) had a price difference greater than or equal to $1.00 and 1,493 of all economic hours (61.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with economic flows was $812.91.

Table 8-24 Distribution of economic and uneconomic hourly flows between PJM and NYISO: January through June, 2013

Price Difference Range (Greater Than or Equal To)	Uneconomic Hours	Percent of Total Hours	Economic Hours	Percent of Total Hours
$0.00	1,915	100.0%	2,428	100.0%
$1.00	1,736	90.7%	2,242	92.3%
$5.00	1,122	58.6%	1,493	61.5%
$10.00	685	35.8%	829	34.1%
$15.00	487	25.4%	533	22.0%
$20.00	368	19.2%	377	15.5%
$25.00	290	15.1%	271	11.2%
$50.00	136	7.1%	115	4.7%
$75.00	72	3.8%	65	2.7%
$100.00	32	1.7%	49	2.0%
$200.00	3	0.2%	5	0.2%
$300.00	0	0.0%	3	0.1%
$400.00	0	0.0%	2	0.1%
$500.00	0	0.0%	2	0.1%

Summary of Interface Prices between PJM and Organized Markets

Some measures of the real-time and day-ahead PJM interface pricing with MISO and with the NYISO are summarized and compared in Figure 8-6, including average prices and measures of variability.

Figure 8-6 PJM, NYISO and MISO real-time and day-ahead border price averages: January through June, 2013
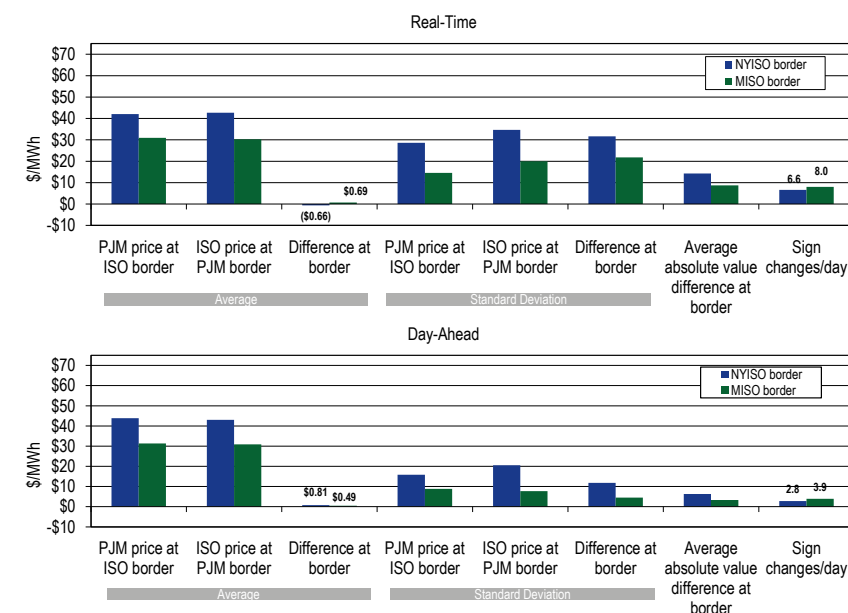
Neptune Underwater Transmission Line to Long Island, New York

The Neptune line is a 65 mile direct current (DC) merchant 230 kV transmission line, with a capacity of 660 MW, providing a direct connection between PJM (Sayreville, New Jersey), and NYISO (Nassau County on Long Island). Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. In the first six months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus. In the first six months of 2013, the PJM average hourly LMP at the Neptune Interface was $40.08 while the NYISO LMP at the Neptune Bus was

$75.31, a difference of $35.22.[46] While the average hourly LMP difference at the PJM/Neptune border was $35.22, the average of the absolute value of the hourly difference was $43.39. The average hourly flow during the first six months of 2013 was -293 MW.[47] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 78.3 percent of the hours in the first six months of 2013. When the NYISO/PJM Interface price was greater than the PJM/NYISO Interface price, the average hourly price difference was $46.09. When the PJM/NYISO Interface price was greater than the NYISO/PJM Interface price, the average price difference was $19.71.

Figure 8-7 Neptune hourly average flow: January through June, 2013

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 (Linden, New Jersey) and NYISO (Staten Island, New York). In the first six months of 2013, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO LMP Linden Bus. In the first six months of 2013, the PJM average hourly LMP at the Linden Interface was $41.42 while the NYISO LMP at the Linden Bus was $52.99, a difference of $11.56.[48] While the average hourly LMP difference at the PJM/Linden border was $11.56, the average of the absolute value of the hourly difference was $21.13. The average hourly flow during the first six months of 2013 was -139 MW.[49] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 70.6 percent of the hours in the first six months of 2013. When the NYISO/Linden Interface price was greater than the PJM/LIND Interface price, the average hourly price difference was $21.55. When the PJM/LIND Interface price was greater than the NYISO/Linden Interface price, the average price difference was $16.62.

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46 In the first six months of 2013, there were 833 hours where there was no flow on the Neptune DC Tie line. The PJM average hourly LMP at the Neptune Interface during non-zero flows was $40.03 while the NYISO LMP at the Neptune Bus during non-zero flows was $71.87, a difference of $31.84.

47 The average hourly flow during the first six months of 2013, ignoring hours with no flow, on the Neptune DC Tie line was -363 MW.

48 In the first six months of 2013, there were 841 hours where there was no flow on the Linden VFT line. The PJM average hourly LMP at the Linden Interface during non-zero flows was $41.32 while the NYISO LMP at the Neptune Bus during non-zero flows was $51.64, a difference of $10.32.

49 The average hourly flow during the first six months of 2013, ignoring hours with no flow, on the Linden VFT line was -173 MW.

Figure 8-8 Linden hourly average flow: January through June, 2013[50]
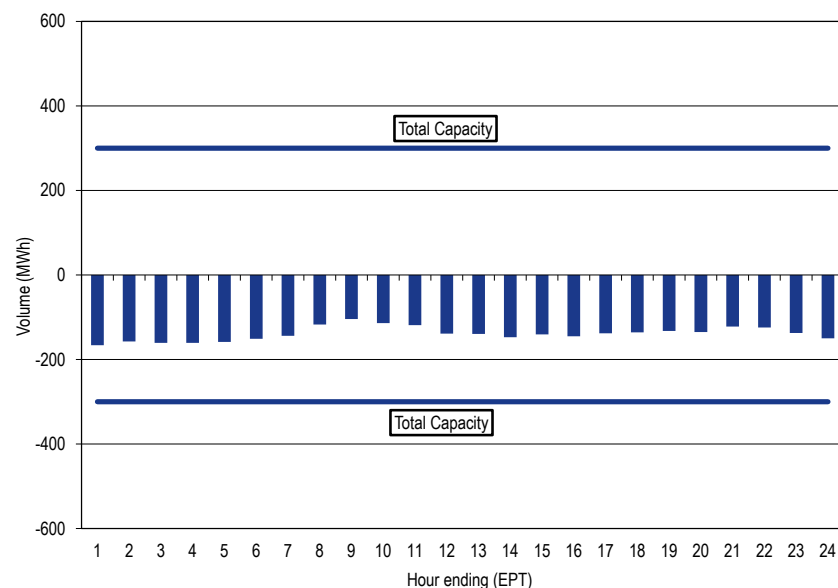
Hudson Direct Current (DC) Merchant Transmission Line

The Hudson direct current (DC) line began commercial operation on June 3, 2013. The Hudson direct current (DC) line is a bidirectional merchant 230 kV transmission line, with a capacity of 673 MW, providing a direct connection between PJM (Public Service Electric and Gas Company's (PSE&G) Bergen 230 kV Switching Station located in Ridgefield, New Jersey) and NYISO (Consolidated Edison's (ConEd) W. 49th Street 345 kV Substation in New York City). The connection is a submarine cable system. While the Hudson DC line is a bidirectional line, power flows are only from PJM to New York because the Hudson Transmission Partners, LLC have only requested withdrawal rights (320 MW of firm withdrawal rights, and 353 MW of non-firm withdrawal rights). In June, 2013, the first month of operations, the direction of the

average hourly flow was consistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO LMP Hudson Bus. The PJM average hourly LMP at the Hudson Interface was $39.54 while the NYISO LMP at the Hudson Bus was $42.46, a difference of $1.44.[51] While the average hourly LMP difference at the PJM/Hudson border was $1.44, the average of the absolute value of the hourly difference was $5.99. The average hourly flow during the first month of operations was -17 MW.[52] (The negative sign means that the flow was an export from PJM to NYISO.) The direction of flows was consistent with price differentials in 60.9 percent of the hours in the first six months of 2013. When the NYISO/Hudson Interface price was greater than the PJM/HUDS Interface price, the average hourly price difference was $9.14. When the PJM/HUDS Interface price was greater than the NYISO/Hudson Interface price, the average price difference was $8.89.

Figure 8-9 Hudson hourly average flow: June, 2013

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50 The Linden VFT line is a bidirectional facility. The "Total Capacity" lines represent the maximum amount of interchange possible in either direction. These lines were included to maintain a consistent scale, for comparison purposes, with the Neptune DC Tie line.
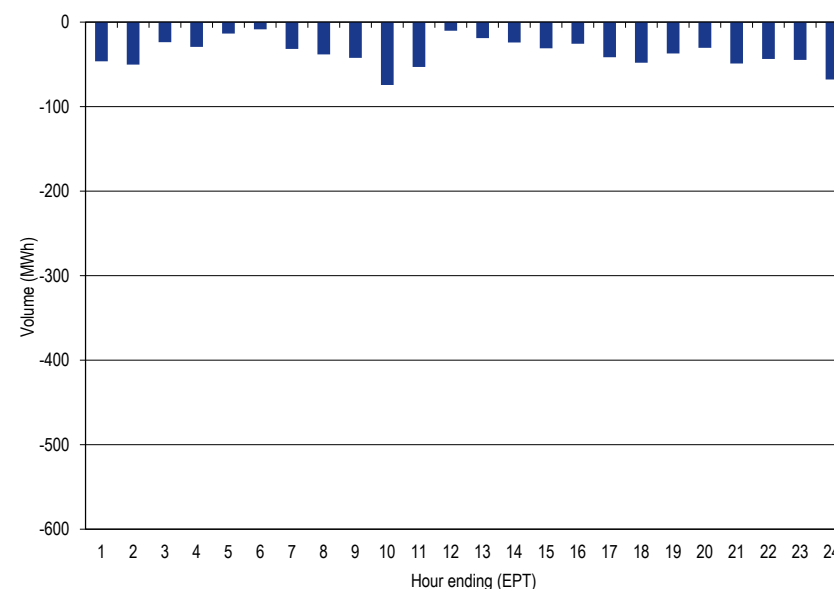
51 In the first month of operations, there were 550 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $37.17 while the NYISO LMP at the Hudson Bus during non-zero flows was $39.26, a difference of $2.09.

52 The average hourly flow during the first month of operations, ignoring hours with no flow, on the Hudson line was -147 MW.

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[53]

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 2012, MISO and PJM initiated a joint stakeholder process to address issues associated with the operation of the markets at the seam.[54]

Under the market to market rules, the organizations coordinate pricing at their borders. PJM and MISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses nine buses within MISO to calculate the PJM/MISO Interface pricing point LMP while MISO uses all of the PJM generator buses in its model of the PJM system in its computation of the MISO/PJM Interface pricing point.[55]

Coordinated Flowgates (CF) are flowgates that are monitored or controlled by either PJM or MISO, in which only one has a significant impact (defined as a greater than 5 percent impact based on transmission distribution factors and generation to load distribution factors). A Reciprocal Coordinated Flowgate (RCF) is a CF that is monitored and controlled by either PJM or MISO, on which both have significant impacts. Only RCFs are subject to the market to market congestion management process.

As of August 6, 2013, PJM had 166 flowgates and MISO had 269 flowgates eligible for M2M coordination. On May 10, 2013, PJM made an informational presentation to the PJM/MISO Joint and Common Market stakeholder meeting regarding the impacts of the market to market process on trends in PJM FTR revenue adequacy.[56] PJM requested input from stakeholders to determine if the issue should be considered as a future JCM initiative, as the difference in outage scheduling deadlines creates differences between the RTO's in their ability to add new M2M flowgates, which can contribute to underfunding due to the inability to account for the expected congestion in the FTR auction process. At the July 12, 2013, meeting of the PJM/MISO Joint and Common Market stakeholder meeting, PJM noted that further coordination of M2M flowgates was necessary to ensure the short-term FTR auctions included the new flowgates, which could minimize congestion on those facilities. PJM proposed that the RTOs agree on a list of flowgates prior to the yearly FTR allocation and auction process, and that the initiation of M2M redispatch caused by transmission outages or the initiation of new flowgates only occur if the non-monitoring RTO was notified of the outage or new flowgate within its internal outage scheduling deadline.[57]

During the first six months of 2013, 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 8-10 shows credits for coordinated congestion management between PJM and MISO.

53 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 July 17, 2013)
54 See www.pjm.com "2012 PJM/MISO Joint and Common Market Initiative," <http://www.pjm.com/committees-and-groups/stakeholder-meetings/stakeholder-groups/pjm-miso-joint-common.aspx>.
55 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.
56 See "*PJM FTR Revenue Adequacy Trends*," (May 10, 2013) <http://www.pjm.com/~/media/committees-groups/stakeholder-meetings/pjm-miso-joint-common/20130510/20130510-item-04-ftr-revenue-adequacy.ashx> (Accessed August 6, 2013)
57 See "*Outage Scheduling and Flowgate Additions*," (July 12, 2013) <http://www.pjm.com/~/media/committees-groups/stakeholder-meetings/pjm-miso-joint-common/20130712/20130712-item-02b-outages-and-new-flowgates-pjm.ashx> (Accessed August 6, 2013)

Figure 8-10 Credits for coordinated congestion management: January through June, 2013[58]
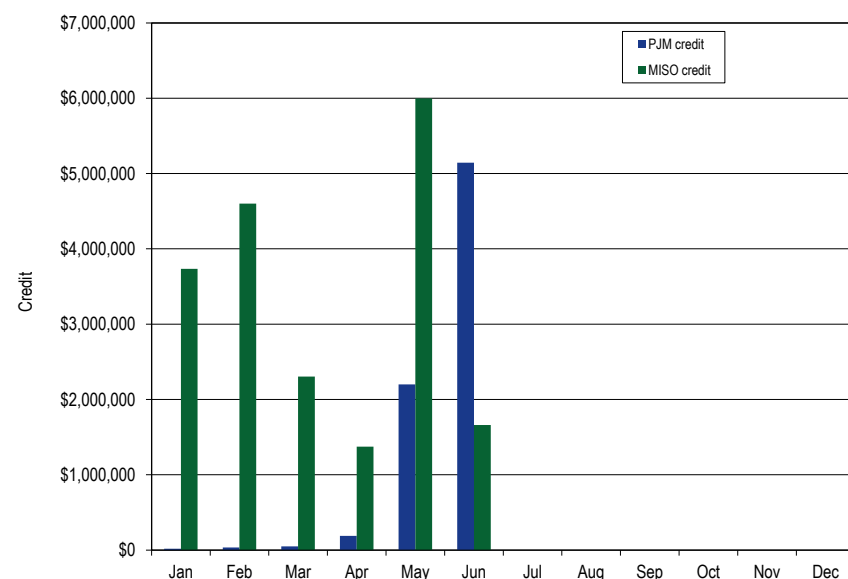
PJM and New York Independent System Operator Joint Operating Agreement (JOA)[59]

The Joint Operating Agreement between NYISO and PJM Interconnection, L.L.C. became effective on January 15, 2013. Under the market to market rules, the organizations coordinate pricing at their borders. PJM and NYISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses two buses within NYISO to calculate the PJM/MISO Interface pricing point LMP while The NYISO calculates the PJM interface price (represented by the Keystone proxy bus) using the assumption that 40 percent of the scheduled energy will flow across the PJM/NYISO border on the Branchburg to Ramapo PAR controlled tie, and the remaining 60 percent will enter the NYISO on their free flowing A/C tie lines.

Coordinated Flowgates (CF) are flowgates that are monitored or controlled by either PJM or NYISO, in which only one has a significant impact (defined as a greater than 5 percent impact based on transmission distribution factors and generation to load distribution factors). A Reciprocal Coordinated Flowgate (RCF) is a CF that is monitored and controlled by either PJM or MISO, on which both have significant impacts. Only RCF's are subject to the market to market congestion management process.

In the first six months of 2013, the market to market operations resulted in NYISO and PJM redispatching units to control congestion on flowgates located in the other's area and in the exchange of payments for this redispatch. The Firm Flow Entitlement (FFE) represents the amount of historic flow that each RTO had created on each RCF used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the non-monitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the non-monitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the non-monitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the non-monitoring RTO for congestion relief provided by the non-monitoring RTO based on the difference between the non-monitoring RTO's market flow and their FFE.

During the first six months of 2013, the market to market operations resulted in NYISO 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 8-11 shows credits for coordinated congestion management between PJM and NYISO.

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58 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

59 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (April 15, 2013) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx>. (Accessed July 17, 2013)

Figure 8-11 Credits for coordinated congestion management (flowgates): January through June, 2013[60]
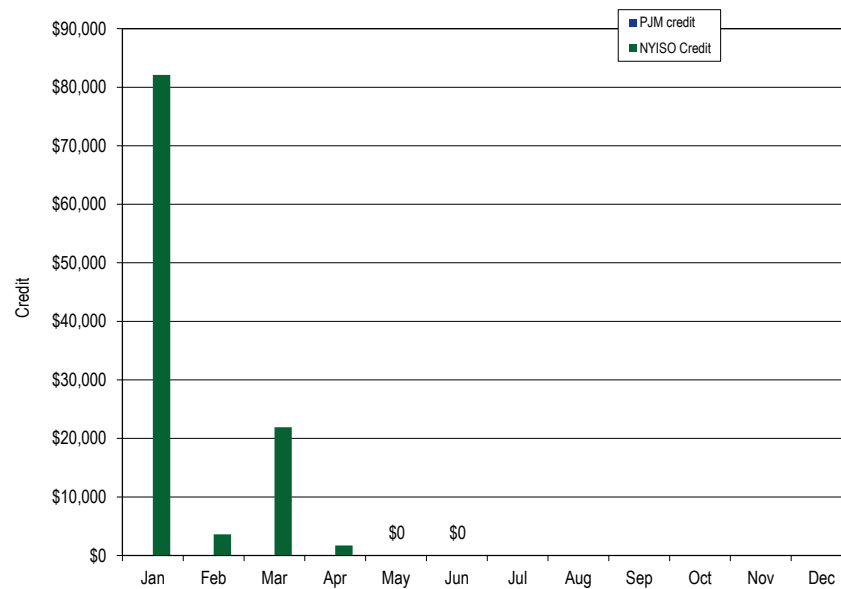
The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on the M2M Flowgates in a more cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the Ramapo PARs that are located at the NYISO – PJM interface. This real-time coordination results in a more efficient economic dispatch solution across both markets to manage the real-time transmission constraints that impact both markets, focusing on the actual flows in real-time to manage constraints.[61] For each M2M flowgate, a Ramapo PAR settlement will occur for each interval during coordinated operations. The Ramapo PAR settlements are determined based on whether the measured real-time flow on each of the Ramapo PARs is greater than or less than the calculated target value. If the actual flow is greater than the target flow, NYISO will make a payment to PJM. This

payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the actual and target PAR flow. If the actual flow is less than the target flow, PJM will make a payment to NYISO. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the target and actual PAR flow. In the first six months of 2013, PAR settlements resulted in monthly payments from PJM to NYISO. Figure 8-12 shows the Ramapo PAR credits for coordinated congestion management between PJM and NYISO.

Figure 8-12 Credits for coordinated congestion management (Ramapo PARs): January through June, 2013[62]
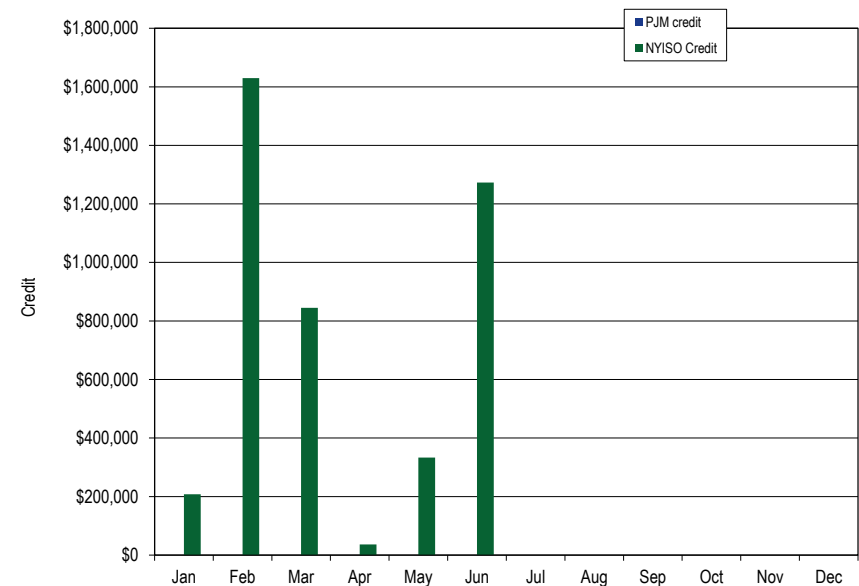
PJM, MISO and TVA Joint Reliability Coordination Agreement (JRCA)

The Joint Reliability Coordination Agreement (JRCA) executed on April 22, 2005, provides for comprehensive reliability management and congestion relief among the wholesale electricity markets of MISO and PJM and the service territory of TVA. Information-sharing among the parties enables each transmission provider to recognize and manage the effects of its operations on the adjoining systems. Additionally, the three organizations conduct joint planning sessions to ensure that improvements to their integrated systems are undertaken in a cost-effective manner and without adverse reliability impacts on any organization's customers. The parties meet on a yearly basis, and, in the first six months of 2013, there were no developments. The agreement continued to be in effect in the first six months of 2013.

PJM and Progress Energy Carolinas, Inc. Joint Operating Agreement

On September 9, 2005, the FERC approved a JOA between PJM and Progress Energy Carolinas, Inc. (PEC), with an effective date of July 30, 2005. As part of this agreement, both parties agreed to develop a formal Congestion Management Protocol (CMP). On February 2, 2010, PJM and PEC filed a revision to the JOA to include a CMP.[63] On January 20, 2011, the Commission conditionally accepted the compliance filing.

PJM and VACAR South Reliability Coordination Agreement

On May 23, 2007, PJM and VACAR South (comprised of Duke Energy Carolinas, LLC (DUK), PEC, South Carolina Public Service Authority (SCPSA), Southeast Power Administration (SEPA), South Carolina Energy and Gas Company (SCE&G) and Yadkin Inc. (a part of Alcoa)) entered into a reliability coordination agreement. This agreement was developed to augment and further support reliability. It provides for system and outage coordination, emergency procedures and the exchange of data. This arrangement permits each party to coordinate its plans and operations in the interest of reliability. Provisions are also made for making regional studies and recommendations to improve the reliability of the interconnected bulk power systems. The parties meet on a yearly basis, and, in the first six months of 2013, there were no developments. The agreement remained in effect in the first six months of 2013.

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.[64]

The PJM/PEC JOA allows for the PECIMP and PECEXP interface pricing points to be calculated using the "Marginal Cost Proxy Pricing" methodology.[65] The DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP interface pricing points are calculated based on the "high-low" pricing methodology as defined in the PJM Tariff.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies plan to operate separately for a period of time, they have a Joint Dispatch Agreement, and a Joint Open Access Transmission Tariff.[66] The MMU has confirmed that the rules governing the assignment of interface pricing under the PJM/PEC JOA related to simultaneous imports or exports have been maintained. However, the MMU recommends the termination of the existing PJM/PEC JOA, as some of the assumptions used in the development of the JOA were based on explicit assumptions about the Progress generation fleet and the dispatch of that generation.

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

64 PJM posted a copy of its notice, dated August 31, 2006, on its website at: <http://www.pjm.com/~/media/etools/oasis/pricing-information/interface-pricing-point-consolidation.ashx>. (Accessed July 17, 2013)

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

66 See Docket Nos. ER12-1338-000 and ER12-1343-000.

Table 8-25 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through June, 2013

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP – SOUTHIMP	Difference EXP LMP – SOUTHEXP
Duke	$34.05	$34.73	$33.92	$33.92	$0.13	$0.81
PEC	$34.96	$35.68	$33.92	$33.92	$1.04	$1.76
NCMPA	$34.40	$34.50	$33.92	$33.92	$0.48	$0.59

Table 8-26 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through June, 2013

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP – SOUTHIMP	Difference EXP LMP – SOUTHEXP
Duke	$35.13	$35.74	$34.40	$34.40	$0.73	$1.33
PEC	$35.87	$36.42	$34.40	$34.40	$1.46	$2.02
NCMPA	$35.41	$35.52	$34.40	$34.40	$1.01	$1.12

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 including lines controlled by PJM.[67] 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.[68]

PJM filed a settlement on February 23, 2009, on behalf of the parties to resolve remaining issues with these contracts.[69] By order issued September 16, 2010, the Commission approved this settlement, which extends Con Edison's special protocol indefinitely.[70] The settlement defined ConEd's cost responsibility

for upgrades included in the PJM Regional Transmission Expansion Plan. ConEd is responsible for required transmission enhancements, and must pay the associated charges during the term of its service, and any subsequent roll over of the service.[71] ConEd's rolled over service became effective on May 1, 2012. The additional transmission charges have been included in the wheeling agreement data as shown in Table 8-27 below reflecting those charges effective May 1, 2012.

Table 8-27 Con Edison and PSE&G wheeling agreement data: January through June, 2013

	Con Edison			PSE&G		
Billing Line Item	Day Ahead	Balancing	Total	Day Ahead	Balancing	Total
Congestion Charge	$4,517,940	$15,116	$4,533,057	$0	$0	$0
Congestion Credit			$2,025,540			$0
Adjustments and Transmission Charges			($17,964,856)			$2,030
Net Charge			$20,472,372			($2,030)

Interchange Transaction Issues

PJM Transmission Loading Relief Procedures (TLRs)

TLRs are called to control flows on electrical facilities when economic redispatch cannot solve overloads on those facilities. TLRs are called to control flows related to external balancing authorities, as redispatch within an LMP market can generally resolve overloads on internal transmission facilities.

PJM issued 23 TLRs of level 3a or high in the first six months of 2013, compared to eight TLRs issued in the first six months of 2012. The number of different flowgates for which PJM declared TLRs increased from four in the first six months of 2012 to 15 in the first six months of 2013. The total MWh of transaction curtailments increased by 385 percent, from 8,857 MWh in the first six months of 2012 to 34,061 MWh in the first six months of 2013.

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67 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.
68 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.
69 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.
70 132 FERC ¶ 61,221 (2010).

71 The terms of the settlement state that ConEd shall have no liability for transmission enhancement charges prior to the commencement of, or after the termination of, the term of the rolled over service.

Table 8-28 PJM MISO, and NYISO TLR procedures: January, 2010 through June, 2013[72]

Month	Number of TLRs Level 3 and Higher			Number of Unique Flowgates That Experienced TLRs			Curtailment Volume (MWh)		
	PJM	MISO	NYISO	PJM	MISO	NYISO	PJM	MISO	NYISO
Jan-10	6	23	20	3	5	4	18,393	13,387	60,427
Feb-10	1	9	19	1	7	3	1,249	13,095	69,569
Mar-10	6	18	21	3	10	6	2,376	27,412	78,366
Apr-10	15	40	14	7	11	2	26,992	29,832	59,041
May-10	11	20	7	4	12	4	22,193	54,702	10,463
Jun-10	19	19	13	6	8	6	64,479	183,228	23,969
Jul-10	15	25	4	8	8	3	44,210	169,667	2,262
Aug-10	12	22	0	9	7	0	32,604	189,756	0
Sep-10	11	15	1	7	7	1	82,066	32,782	232
Oct-10	4	26	1	3	12	1	2,305	29,574	0
Nov-10	1	25	0	1	10	0	59	66,113	0
Dec-10	9	7	4	6	5	1	18,509	5,972	4,224
Jan-11	7	8	29	5	5	4	75,057	14,071	156,508
Feb-11	6	7	10	5	4	2	6,428	23,796	27,649
Mar-11	0	14	28	0	5	3	0	10,133	57,472
Apr-11	3	23	12	3	9	3	8,129	44,855	15,761
May-11	9	15	15	4	7	4	18,377	36,777	24,857
Jun-11	15	14	24	7	6	9	17,865	19,437	31,868
Jul-11	7	8	17	4	7	7	18,467	3,697	20,645
Aug-11	4	6	4	4	4	2	3,624	11,323	12,579
Sep-11	7	17	7	6	7	3	6,462	25,914	11,445
Oct-11	4	16	5	2	6	1	16,812	27,392	3,665
Nov-11	0	10	2	0	5	2	0	22,672	484
Dec-11	0	5	8	0	3	2	0	8,659	26,523
Jan-12	1	9	5	1	6	2	4,920	6,274	8,058
Feb-12	4	6	16	2	6	2	0	5,177	35,451
Mar-12	1	11	10	1	6	2	398	31,891	26,761
Apr-12	0	14	11	0	7	1	0	8,408	29,911
May-12	2	17	12	1	10	5	3,539	30,759	21,445
Jun-12	0	24	0	0	7	0	0	31,502	0
Jul-12	11	19	1	5	4	1	34,197	46,512	292
Aug-12	8	13	0	1	6	0	61,151	13,403	0
Sep-12	2	5	0	1	4	0	21,134	12,494	0
Oct-12	3	9	0	2	6	0	0	12,317	0
Nov-12	4	10	5	2	6	2	444	24,351	6,250
Dec-12	1	22	0	1	12	0	0	17,761	0
Jan-13	4	42	2	3	17	1	13,453	103,463	1,045
Feb-13	4	26	0	3	10	0	14,609	66,086	0
Mar-13	0	39	0	0	13	0	0	53,122	0
Apr-13	1	45	0	1	20	0	84	64,938	0
May-13	10	29	0	7	14	0	879	20,778	0
Jun-13	4	25	1	1	11	1	5,036	76,240	4,102

72 The curtailment volume for PJM TLRs 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 TLRs was taken from the MISO monthly reports to their Reliability Subcommittee. These reports can be found at <https://www.midwestiso.org/STAKEHOLDERCENTER/COMMITTEESWORKGROUPSTASKFORCES/RSC/Pages/home.aspx>. (Accessed July 17, 2013)

MISO called more TLRs of level 3a or higher in the first six months of 2013 than in the first six months of 2012. MISO TLRs increased from 81 in the first six months of 2012 to 205 in the first six months of 2013.

NYISO called fewer TLRs of level 3a or higher in the first six months of 2013 than in the first six months of 2012. NYISO TLRs decreased from 54 in the first six months of 2012 to 3 in the first six months of 2013.

Table 8-29 Number of TLRs by TLR level by reliability coordinator: January through June, 2013

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2013	ICTE	0	0	0	0	0	0	0
	MISO	66	22	1	78	38	0	205
	NYIS	3	0	0	0	0	0	3
	ONT	6	0	0	0	0	0	6
	PJM	11	11	0	1	0	0	23
	SOCO	0	0	0	0	0	0	0
	SWPP	104	60	0	18	12	0	194
	TVA	17	17	0	3	3	0	40
	VACS	1	0	0	0	0	0	1
Total		208	110	1	100	53	0	472

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.[73]

Following elimination of the requirement to procure transmission for up-to congestion transactions, the volume of transactions increased significantly. The average number of up-to congestion bids submitted in the Day-Ahead Market increased to 107,215 bids per day, with an average cleared volume of 1,272,955 MWh per day, in the first six months of 2013, compared to an

73 See the *2012 State of the Market Report for PJM*, Volume II, "Interchange Transactions," for a more detailed discussion.

average of 54,180 bids per day, with an average cleared volume of 931,553 MWh per day, in the first six months of 2012 (See Figure 8-13).

The MMU is concerned about the impacts of the significant increase in up-to congestion transaction volume on the Day-Ahead Energy Market and on operating reserve charges. Up-to congestion transactions impact the day-ahead dispatch and unit commitment. Up-to congestion transactions do not pay operating reserves charges and there is a question as to whether current credit policies adequately address up to congestion transactions. Additionally, the MMU is concerned about the potential for market participants to utilize up-to congestion transactions to affect their other market positions, and the potential impacts that up-to congestion transactions may have on meeting FTR target allocations.

The MMU recommends that PJM perform a comprehensive evaluation of the up-to congestion product in coordination with the MMU and provide a joint report to PJM stakeholders to ensure that all market participants are aware of how these transactions impact the charges and credits to market participants in all other areas of the PJM Energy Market. The MMU recommends that during the period of study, up-to congestion transactions be required to pay a fee in lieu of operating reserve charges equal to $0.50 per MWh. This rate is intended to reflect the lowest operating reserve rates charged to other virtual transactions in 2012.

Figure 8-13 Monthly up-to congestion cleared bids in MWh: January, 2005 through June, 2013
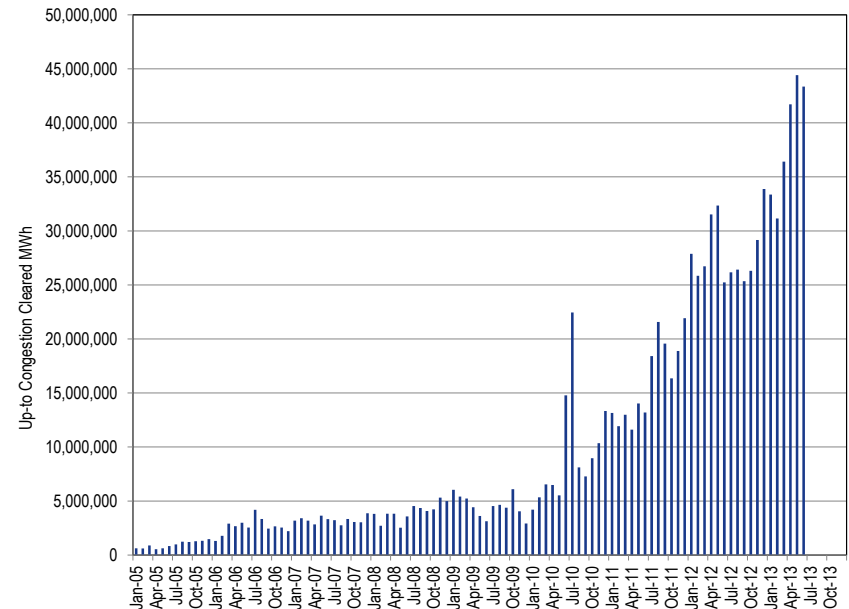
Table 8-30 Monthly volume of cleared and submitted up-to congestion bids: January, 2009 through June, 2013

	Bid MW					Bid Volume					Cleared MW					Cleared Volume				
Month	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total	Import	Export	Wheel	Internal	Total
Jan-09	4,218,910	5,787,961	319,122	–	10,325,993	90,277	74,826	6,042	–	171,145	2,591,211	3,242,491	202,854	–	6,036,556	56,132	45,303	4,210	–	105,645
Feb-09	3,580,115	4,904,467	318,440	–	8,803,022	64,338	70,874	6,347	–	141,559	2,374,734	2,836,344	203,907	–	5,414,985	42,101	44,423	4,402	–	90,926
Mar-09	3,649,978	5,164,186	258,701	–	9,072,865	64,714	72,495	5,531	–	142,740	2,285,412	2,762,459	178,507	–	5,226,378	42,408	42,007	4,299	–	88,714
Apr-09	2,607,303	5,085,912	73,931	–	7,767,146	47,970	67,417	2,146	–	117,533	1,797,302	2,582,294	48,478	–	4,428,074	32,088	35,987	1,581	–	69,656
May-09	2,196,341	4,063,887	106,860	–	6,367,088	40,217	54,745	1,304	–	96,266	1,496,396	2,040,737	77,553	–	3,614,686	26,274	29,720	952	–	56,946
Jun-09	2,598,234	3,132,478	164,903	–	5,895,615	47,625	44,755	2,873	–	95,253	1,540,169	1,500,560	88,723	–	3,129,452	28,565	23,307	1,522	–	53,394
Jul-09	3,984,680	3,776,957	296,910	–	8,058,547	67,039	56,770	5,183	–	128,992	2,465,891	1,902,807	163,129	–	4,531,826	41,924	31,176	2,846	–	75,946
Aug-09	3,551,396	4,388,435	260,184	–	8,200,015	64,652	64,052	3,496	–	132,200	2,278,431	2,172,133	194,415	–	4,644,978	41,774	34,576	2,421	–	78,771
Sep-09	2,948,353	4,179,427	156,270	–	7,284,050	51,006	64,103	2,405	–	117,514	1,774,589	2,479,898	128,344	–	4,382,831	31,962	40,698	1,944	–	74,604
Oct-09	3,172,034	6,371,230	154,825	–	9,698,089	46,989	100,350	2,217	–	149,556	2,060,371	3,931,346	110,646	–	6,102,363	31,634	70,964	1,672	–	104,270
Nov-09	3,447,356	3,851,334	103,325	–	7,402,015	53,067	61,906	1,236	–	116,209	2,065,813	1,932,595	51,929	–	4,050,337	33,769	32,916	653	–	67,338
Dec-09	2,323,383	2,502,529	66,497	–	4,892,409	47,099	47,223	1,430	–	95,752	1,532,579	1,359,936	34,419	–	2,926,933	31,673	28,478	793	–	60,944
Jan-10	3,794,946	3,097,524	212,010	–	7,104,480	81,604	55,921	3,371	–	140,896	2,250,689	1,789,018	161,977	–	4,201,684	49,064	33,640	2,318	–	85,022
Feb-10	3,841,573	3,937,880	316,150	–	8,095,603	80,876	80,685	2,269	–	163,830	2,627,101	2,435,650	287,162	–	5,349,913	50,958	48,008	1,812	–	100,778
Mar-10	4,877,732	4,454,865	277,180	–	9,609,777	97,149	74,568	2,239	–	173,956	3,209,064	3,071,712	263,516	–	6,544,292	60,277	48,596	2,064	–	110,937
Apr-10	3,877,306	5,558,718	210,545	–	9,646,569	67,632	85,358	1,573	–	154,563	2,622,113	3,690,889	170,020	–	6,483,022	42,635	54,510	1,154	–	98,299
May-10	3,800,870	5,062,272	149,589	–	9,012,731	74,996	78,426	1,620	–	155,042	2,366,149	3,049,405	112,700	–	5,528,253	47,505	48,996	1,112	–	97,613
Jun-10	9,126,963	9,568,549	1,159,407	–	19,854,919	95,155	89,222	6,960	–	191,337	6,863,803	6,850,098	1,072,759	–	14,786,660	59,733	55,574	5,831	–	121,138
Jul-10	12,818,141	11,526,089	5,420,410	–	29,764,640	124,929	106,145	18,948	–	250,022	8,971,914	8,237,557	5,241,264	–	22,450,734	73,232	60,822	16,526	–	150,580
Aug-10	8,231,393	6,767,617	888,591	–	15,887,601	115,043	87,876	10,664	–	213,583	4,430,832	2,894,314	785,726	–	8,110,871	62,526	40,485	8,884	–	111,895
Sep-10	7,768,878	7,561,624	349,147	–	15,679,649	184,697	161,929	4,653	–	351,279	3,915,814	3,110,580	256,039	–	7,282,433	63,405	45,264	3,393	–	112,062
Oct-10	8,732,546	9,795,666	476,665	–	19,004,877	189,748	154,741	7,384	–	351,873	4,150,104	4,564,039	246,594	–	8,960,736	76,042	65,223	3,670	–	144,935
Nov-10	11,636,949	9,272,885	537,369	–	21,447,203	253,594	170,470	9,366	–	433,430	5,765,905	4,312,645	275,111	–	10,353,661	112,250	71,378	4,045	–	187,673
Dec-10	17,769,014	12,863,875	923,160	–	31,556,049	307,716	215,897	15,074	–	538,687	7,851,235	5,150,286	337,157	–	13,338,678	136,582	93,299	7,380	–	237,261
Jan-11	20,275,932	11,807,379	921,120	–	33,004,431	351,193	210,703	17,632	–	579,528	7,917,986	4,925,310	315,936	–	13,159,232	151,753	91,557	8,417	–	251,727
Feb-11	18,418,511	13,071,483	800,630	–	32,290,624	345,227	226,292	17,634	–	589,153	6,806,039	4,879,207	248,573	–	11,933,818	151,003	99,302	8,851	–	259,156
Mar-11	17,330,353	12,919,960	749,276	–	30,999,589	408,628	274,709	15,714	–	699,051	7,104,642	5,603,583	275,682	–	12,983,906	178,620	124,990	7,760	–	311,370
Apr-11	17,215,352	9,321,117	954,283	–	27,490,752	513,881	265,334	17,459	–	796,674	7,452,366	3,797,819	351,984	–	11,602,168	229,707	113,610	8,118	–	351,435
May-11	21,058,071	11,204,038	2,937,898	–	35,200,007	562,819	304,589	24,834	–	892,242	8,294,422	4,701,077	1,031,519	–	14,027,018	261,355	143,956	11,116	–	416,427
Jun-11	20,455,508	12,125,806	395,833	–	32,977,147	524,072	285,031	12,273	–	821,376	7,632,235	5,361,825	198,482	–	13,192,543	226,747	132,744	6,363	–	365,854
Jul-11	24,273,892	16,837,875	409,863	–	41,521,630	603,519	338,810	13,781	–	956,110	9,585,027	8,617,284	205,599	–	18,407,910	283,287	186,866	7,008	–	477,161
Aug-11	23,790,091	21,014,941	229,895	–	45,034,927	591,170	403,269	8,278	–	1,002,717	10,594,771	10,875,384	103,141	–	21,573,297	274,398	208,593	3,648	–	486,639
Sep-11	21,740,208	18,135,378	232,626	–	40,108,212	526,945	377,158	7,886	–	911,989	10,219,806	9,270,121	82,200	–	19,572,127	270,088	185,585	3,444	–	459,117
Oct-11	20,240,161	19,476,556	333,077	–	40,049,794	540,877	451,507	8,609	–	1,000,993	8,376,208	7,853,947	126,718	–	16,356,873	255,206	198,778	4,236	–	458,220
Nov-11	27,007,141	28,994,789	507,788	–	56,509,718	594,397	603,029	13,379	–	1,210,805	9,064,570	9,692,312	131,670	–	18,888,552	254,851	256,270	5,686	–	516,807
Dec-11	34,990,790	34,648,433	531,616	–	70,170,839	697,524	655,222	14,187	–	1,366,933	11,738,910	10,049,685	137,689	–	21,926,284	281,304	248,008	6,309	–	535,621
Jan-12	38,906,228	36,928,145	620,448	–	76,454,821	745,424	689,174	16,053	–	1,450,651	13,610,725	14,120,791	145,773	–	27,877,288	289,524	304,072	5,078	–	598,674
Feb-12	37,231,115	36,736,507	323,958	–	74,291,580	739,200	724,477	8,572	–	1,472,249	12,883,355	12,905,553	54,724	–	25,843,632	299,055	276,563	2,175	–	577,793
Mar-12	38,824,528	39,163,001	297,895	–	78,285,424	802,983	842,857	8,971	–	1,654,811	13,328,968	13,306,689	89,262	–	26,724,918	320,210	320,252	3,031	–	643,493
Apr-12	42,085,326	44,565,341	436,632	–	87,087,299	884,004	917,430	12,354	–	1,813,788	15,050,798	16,297,303	171,252	–	31,519,354	369,273	355,669	4,655	–	729,597
May-12	44,436,245	43,888,405	489,938	–	88,814,588	994,735	885,319	10,294	–	1,890,348	17,416,386	14,733,838	189,667	–	32,339,891	434,919	343,872	4,114	–	782,905
Jun-12	38,962,548	32,828,393	975,776	–	72,766,718	872,764	684,382	21,781	–	1,578,927	12,675,852	12,311,609	250,024	–	25,237,485	355,731	295,911	6,891	–	658,533
Jul-12	45,565,682	41,589,191	855,676	–	88,010,549	1,077,721	911,300	27,173	–	2,016,194	13,001,225	12,823,361	348,946	–	26,173,532	399,135	321,062	9,958	–	730,155
Aug-12	44,972,648	45,204,886	931,161	–	91,108,675	1,054,472	987,293	31,580	–	2,073,345	12,768,023	13,354,850	300,038	–	26,422,911	377,146	343,717	12,738	–	733,601
Sep-12	40,796,522	39,411,713	957,800	–	81,166,035	1,037,179	949,941	29,246	–	2,016,366	12,089,136	12,961,955	292,095	–	25,343,186	341,925	329,217	9,620	–	680,762
Oct-12	35,567,607	42,489,970	1,415,992	–	79,473,570	908,200	1,048,029	46,802	–	2,003,031	11,969,576	13,949,871	392,286	–	26,311,733	345,788	376,513	14,089	–	736,390
Nov-12	24,795,325	25,498,103	1,258,755	52,022,007	103,574,190	542,992	614,349	43,829	1,631,255	2,832,425	6,517,798	7,872,496	286,535	14,482,701	29,159,529	186,492	245,943	15,042	509,436	956,913
Dec-12	22,957,985	22,560,837	1,727,510	84,548,868	131,435,199	489,208	515,873	55,376	2,767,292	3,827,749	5,116,607	6,350,080	454,289	21,958,089	33,879,065	180,592	224,830	24,459	820,991	1,250,872
Jan-13	16,718,393	21,312,321	2,010,317	76,937,535	116,978,566	422,501	527,037	63,227	2,115,649	3,128,414	4,115,418	5,820,177	522,459	22,906,008	33,364,063	149,282	199,123	23,926	657,602	1,029,933
Feb-13	12,567,004	15,509,978	1,477,275	67,258,116	96,812,373	352,963	400,563	43,133	1,798,434	2,595,093	3,019,380	4,356,113	461,615	23,311,066	31,148,173	110,397	158,085	15,892	669,364	953,738
Mar-13	14,510,721	17,019,755	1,601,487	88,109,152	121,241,114	372,402	402,711	48,112	1,959,294	2,782,519	3,868,303	4,743,283	358,180	27,439,606	36,409,373	131,506	166,295	17,884	774,020	1,089,705
Apr-13	14,538,907	17,419,505	1,337,680	105,927,107	139,223,200	358,245	364,008	47,048	2,275,846	3,045,147	4,413,047	4,834,302	315,867	32,152,243	41,715,459	145,860	157,031	16,315	892,562	1,211,768
May-13	16,565,868	17,640,682	1,640,097	115,572,648	151,419,296	431,892	389,254	54,873	2,660,793	3,536,812	4,556,277	4,747,887	333,677	34,778,962	44,416,803	144,444	144,482	16,317	944,116	1,249,359
Jun-13	16,698,203	18,904,971	1,337,373	128,595,957	165,536,504	452,145	433,010	48,007	3,384,811	4,317,973	3,823,166	4,280,538	312,158	34,935,141	43,351,002	143,223	151,603	17,518	1,116,318	1,428,662
TOTAL	947,691,236	910,905,826	41,899,867	718,971,390	2,619,468,319	21,157,414	18,823,414	912,428	18,593,374	59,486,630	354,298,642	343,298,040	19,180,966	211,963,816	928,741,463	8,817,334	7,829,849	386,142	6,384,409	23,417,734

In the first six months of 2013, the cleared MW volume of up-to congestion transactions was comprised of 10.3 percent imports, 12.5 percent exports, 1.0 percent wheeling transactions and 76.2 percent internal transactions. Only 0.1 percent of the up-to congestion transactions had matching Real-Time Energy Market transactions.

Sham Scheduling

Sham scheduling refers to a scheduling method under which a market participant breaks a single transaction, from generation balancing authority (source) to load balancing authority (sink), into multiple segments. Sham scheduling hides the actual source of generation from the load balancing authority. When unable to identify the source of the energy, the load balancing authority lacks a complete picture of how the power will flow to the load. This can create loop flows and inaccurate pricing for transactions.

For example, if the generation balancing authority (source) is NYISO, and the load balancing authority (sink) is PJM, the transaction would be priced, in the PJM Energy Market, at the PJM/NYIS Interface regardless of the submitted market path. However, if a market participant were to break the transaction into multiple segments, one on the NYIS-ONT market path, and a second segment on the ONT-MISO-PJM market path, the market participant would conceal the true source (NYISO) from PJM, and PJM would price the transaction as if its source is Ontario (the ONT Interface price).

The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU also recommends that PJM, NYISO, MISO and Ontario work together to create business rules that prevent sham scheduling among and between the RTO/ISO markets.

Elimination of Sources and Sinks

The MMU recommended that PJM eliminate the internal source and sink bus designations from external energy transaction scheduling in the PJM Day-Ahead and Real-Time Energy Markets. Designating a specific internal bus at which a market participant buys or sells energy creates a mismatch between the day-ahead and real-time energy flows, as it is impossible to control where the power will actually flow based on the physics of the system, and can affect the day-ahead clearing price, which can affect other participant positions. Market inefficiencies are created when the day-ahead dispatch does not match the real-time dispatch. On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the elimination of internal source and sink designations in both the Day-Ahead and Real-Time Energy Markets. On April 22, 2013, PJM implemented changes to its OASIS eliminating the internal source and sink designations on transmission reservations.

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 during the first six months of 2013 were -$2,860, compared to -$32 in the first six months of 2012 (Table 8-31). If a market participant is not willing to pay congestion, it is the responsibility of the PJM operators to curtail their transaction as soon as there is a difference in LMPs between the source and sink associated with their transaction. Uncollected congestion charges occur when PJM operators do not curtail a not willing to pay congestion transaction when there is congestion. 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 for the net uncollected congestion charges in the first six months of 2013. In other words, when market participants utilize the not willing to pay congestion product, it also means that they are not willing to receive congestion credits when the LMP at the source is greater than the LMP at

the sink. The fact that there was a total negative congestion collection in the first six months of 2013, for not willing to pay congestion transactions, means that market participants who utilized the not willing to pay congestion transmission option for their transactions had transactions that flowed in the direction opposite to congestion.

The MMU recommended that PJM modify the not willing to pay congestion product to further address the issues of uncollected congestion charges. The MMU recommended charging market participants for any congestion incurred while the transaction is loaded, regardless of their election of transmission service, and restricting the use of not willing to pay congestion transactions (as well as all other real-time external energy transactions) to transactions at interfaces. On April 12, 2011, the PJM Market Implementation Committee (MIC) endorsed the changes recommended by the MMU. The elimination of internal sources and sinks on transmission reservations mostly addresses these concerns, as there can no longer be uncollected congestion charges for imports to PJM or exports from PJM. There is still potential exposure to uncollected congestion charges in wheel through transactions, and the MMU will continue to evaluate if additional mitigation measures would be necessary in the future to address this exposure.

Table 8–31 Monthly uncollected congestion charges: January, 2010 through June, 2013

Month	2010	2011	2012	2013
Jan	$148,764	$3,102	$0	$5
Feb	$542,575	$1,567	($15)	$249
Mar	$287,417	$0	$0	$0
Apr	$31,255	$4,767	($68)	($3,114)
May	$41,025	$0	($27)	$0
Jun	$169,197	$1,354	$78	$0
Jul	$827,617	$1,115	$0	
Aug	$731,539	$37	$0	
Sep	$119,162	$0	$0	
Oct	$257,448	($31,443)	($6,870)	
Nov	$30,843	($795)	($4,678)	
Dec	$127,176	($659)	($209)	
Total	$3,314,018	($20,955)	($11,789)	($2,860)

Spot Imports

Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. Spot market imports, non-firm point-to-point and network services that are willing to pay congestion, collectively Willing to Pay Congestion (WPC), were part of the PJM LMP energy market design implemented on April 1, 1998. Under this approach, market participants could offer energy into or bid to buy from the PJM spot market at the border/interface as price takers without restrictions based on estimated available transmission capability (ATC). Price and PJM system conditions, rather than ATC, were the only limits on interchange. PJM interpreted its JOA with MISO to require restrictions on spot imports and exports although MISO has not implemented a corresponding restriction.[74] The result was that the availability of spot import service was limited by ATC and not all spot transactions were approved. Spot import service (a network service) is provided at no charge to the market participant offering into the PJM spot market.

Due to the timing requirements to submit transactions in the NYISO market, the limitation of ATC for spot market imports at the NYISO Interface experiences the most issues with potential hoarding. The MMU continues to recommend that PJM permit unlimited spot market imports (as well as all non-firm point-to-point willing to pay congestion imports and exports) at all PJM Interfaces.

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74 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>.

Figure 8-14 Spot import service utilization: January, 2009 through June, 2013
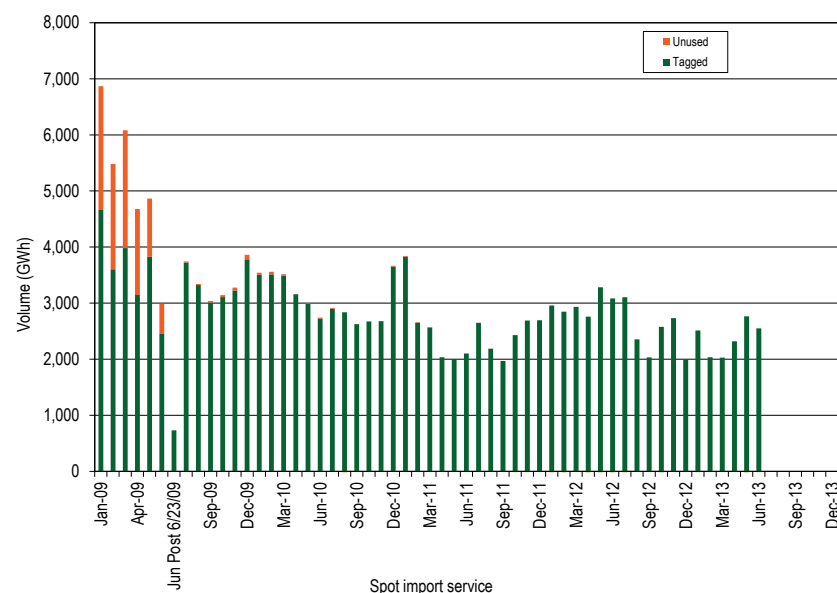
Dispatchable transactions now serve only as a potential mechanism for receiving operating reserve credits. Dispatchable transactions are made whole through the payment of balancing operating reserve credits when the hourly integrated LMP does not meet the specified minimum price offer in the hours when the transaction was active. There have been no balancing operating reserve credits paid to dispatchable transactions since July, 2011. The reasons for the reduction in these balancing operating reserve credits were active monitoring by the MMU and that no dispatchable schedules were submitted during the first six months of 2013.

Real-Time Dispatchable Transactions

Real-Time Dispatchable Transactions, also known as "real-time with price" transactions, allow market participants to specify a floor or ceiling price which PJM dispatch will evaluate on an hourly basis prior to implementing the transaction.

Dispatchable transactions were a valuable tool for market participants when implemented. The transparency of real-time LMPs and the reduction of the required notification period from 60 minutes to 20 minutes have eliminated the value that dispatchable transactions once provided market participants, but the risk to other market participants is substantial, as they are subject to paying the resultant operating reserve credits.

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.[2]

The Market Monitoring Unit (MMU) analyzed measures of market structure, conduct and performance for the PJM Regulation Market, the two regional Synchronized Reserve and Non-Synchronized Reserve Markets, and the PJM DASR Market for the first six months of 2013.

Table 9-1 The Regulation Market results were indeterminate for January through June, 2013

January through June 2013		
Market Element	Evaluation	Market Design
Market Structure	Not Competitive	
Participant Behavior	Competitive	
Market Performance	To Be Determined	To Be Determined

- The Regulation Market structure was evaluated as not competitive for January through June 2013 because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 90 percent of the hours in January through June, 2013.

- Participant behavior in the Regulation Market was evaluated as competitive for January through June, 2013 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 indeterminate, after the introduction of the new market design. It is too early to reach a definitive conclusion about performance under the new market design because important parts of the design is inefficient and because there is not yet enough information on performance.

- Market design was evaluated as indeterminate, after the introduction of the new market design. While the market design continues to include the incorrect definition of opportunity cost, overall the changes were positive. The market design also includes the incorrect definition of the marginal benefits factor for purposes of settlement. It is too early to reach a definitive conclusion about the new market design because there is not yet enough information about actual implementation of the design.

Table 9-2 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. The MMU estimates that the Synchronized Reserve Market would have had one or more pivotal suppliers which failed the three pivotal supplier test in 6.1 percent of the hours in January through June, 2013.

- 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 competitive prices.

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1   75 FERC ¶ 61,080 (1996).
2   For more details, see the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Service Markets."

- 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

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 market participants did not fail the three pivotal supplier test.
- Participant behavior was evaluated as mixed because while most offers appeared consistent with marginal costs (zero), 13 percent of offers reflected economic withholding.
- 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.

Overview
Regulation Market
The PJM Regulation Market continues to be operated as a single market.

Market Structure

- **Supply.** In January through June 2013, the supply of offered and eligible regulation in PJM was both stable and adequate. The ratio of offered and eligible regulation to regulation required averaged 3.99. This is a 22.4 percent increase over January through June 2012 when the ratio was 3.26.
- **Demand.** The on-peak regulation requirement is equal to 0.70 percent of the forecast peak load for the PJM RTO for the day and the off-peak requirement is equal to 0.70 percent of the forecast valley load for the PJM RTO for the day. The average hourly regulation demand in January through June, 2013, was 770 MW. This is a 173 MW decrease in the average hourly regulation demand of 943 MW in the same period of 2012.
- **Market Concentration.** In January through June 2013, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 2134 which is classified as highly concentrated.[3] In January through June 2013, 90 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test (53 percent of hours failed the three pivotal supplier test in January through June 2012).

Market Conduct

- **Offers.** Daily regulation offer prices are submitted for each unit by the unit owner. Owners are required to submit a cost offer along with cost parameters to verify the offer, and may optionally submit a price offer. Under the new market design, offers include both a capability offer and a performance offer. The performance offer is converted to $/MW by multiplying the MW offer by the ΔMW/MW value of the signal type of

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3 See the *2012 State of the Market Report for PJM*, Volume II, Section 2, "Energy Market," at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI). Consistent with common application, the market share and HHI calculations presented in the SOM are based on supply that is cleared in the market in every hour, not on measures of available capacity.

the unit. Owners must also specify which signal type the unit will be following, RegA or RegD.[4] As of June 30, 2013, there were 20 resources (eight generation and 12 demand response) offering performance regulation and following the RegD signal.

- **Price and Cost.** The weighted Regulation Market Clearing Price for the PJM Regulation Market for January through June 2013 was $31.80. This is an increase of $17.90, or 128.8 percent, from the weighted average price for regulation in January through June 2012. The cost of regulation from January through June 2013 was $36.47. This is an $18.12 (98.7 percent) increase from the same time period in 2012.

Synchronized Reserve Market

Although PJM has retained the two synchronized reserve markets it implemented on February 1, 2007, their definition has changed. The RFC Synchronized Reserve Zone has now merged with the former Southern Synchronized Reserve Zone into the RTO Reserve Zone. The former Mid-Atlantic Synchronized Reserve Zone has incorporated Dominion to become the Mid-Atlantic Dominion Reserve Zone. PJM further retains the right to define new zones or subzones "as needed for system reliability."[5]

Market Structure

- **Supply.** In January through June, 2013, the supply of offered and eligible synchronized reserve was both stable and adequate. The contribution of DSR to the Synchronized Reserve Market remains significant. Demand side resources are relatively low cost, and their participation in this market lowers overall Synchronized Reserve prices.
- **Demand.** PJM made a minor change to the default hourly required synchronized reserve requirements on October 1, 2012. When the RFC Zone became the RTO Zone on October 1, 2012, the synchronized reserve requirement increased from 1,350 MW to 1,375 MW. Although the Mid-Atlantic Subzone became the Mid-Atlantic Dominion Subzone on October 1, 2012, the requirement remained at 1,300 MW. The integration

of East Kentucky Power Cooperative (EKPC) into PJM on June 1, 2013 had no impact on the Synchronized Reserve Market requirement because the largest contingencies remain in the Mid-Atlantic Dominion Subzone. The EKPC integration did, however, increase the availability of both Tier 1 and Tier 2 MW available throughout the RTO.

In early June 2013, PJM implemented a modification to the way the transfer interface defines the Mid-Atlantic Dominion Subzone within the RTO Zone. The change makes calculations of the unit DFAX values across the interface consistent with the way these values are calculated in the energy market. Additionally PJM changed the reserve interface from Bedington – Black Oak to AP South. The net effect of these changes was to increase the amount of Tier 1 available in the RTO and decrease the amount of Tier 2 required in the Mid-Atlantic Dominion Subzone.

- **Market Concentration.** For January through June 2013, the average weighted HHI for cleared synchronized reserve in the Mid-Atlantic Dominion Subzone was 4002 which is classified as highly concentrated. The average weighted cleared Synchronized Reserve Market HHI for the Mid-Atlantic Subzone in January through June, 2012, was 3010, which is classified as "highly concentrated."[6] In January through June, 2013, 37 percent of hours had a maximum market share greater than 40 percent, compared to 56 percent of hours in January through June, 2012.

In the Mid-Atlantic Dominion Subzone, in January through June, 2013, the MMU estimates that 6.1 percent of hours that cleared a synchronized reserve market would have had three or fewer pivotal suppliers. In January through June, 2012, the MMU estimates that 40 percent of hours would have had three or fewer pivotal suppliers. The MMU concludes from these TPS results that the Mid-Atlantic Dominion Subzone Synchronized Reserve Market in January through June 2013 was characterized by structural market power.

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4   See the *2012 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."
5   See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 60 (June 1, 2013), p. 74.

6   See Section 2, "Energy Market" at "Market Concentration" for a more complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).

Market Conduct

- **Offers.** Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds opportunity cost calculated using the average of 5-minute LMPs, which together comprise the total offer for each unit to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost.

Market Performance

- **Price.** The weighted average price for Tier 2 synchronized reserve in the Mid-Atlantic Subzone was $6.38 per MW in January through June, 2013, an increase of $0.05 per MW over January through June, 2012. The total cost of synchronized reserves per MW in January through June 2013 was $12.89, a $4.73 increase from the $8.16 cost of synchronized reserve in January through June 2012. The market clearing price was 48 percent of the total synchronized reserve cost per MW in January through June, 2013, down from 77 percent in January through June, 2012.

- **Adequacy.** A synchronized reserve deficit occurs when the combination of Tier 1 and Tier 2 synchronized reserve is not adequate to meet the synchronized reserve requirement. Neither PJM Synchronized Reserve Market experienced a deficit in January through June period of 2013.

DASR

The purpose of the 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 a single market clearing price. The DASR 30-minute reserve requirements are determined for each reliability region.[7] If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

- **Concentration.** The MMU calculates that in January through June, 2013, zero hours in the DASR market would have failed the three pivotal supplier test. The current structure of PJM's DASR Market does not include the three pivotal supplier test. The MMU recommends that the three pivotal supplier test be incorporated in the DASR market.

- **Demand.** In 2013, the required DASR is 6.91 percent of peak load forecast, down from 7.03 percent in 2012.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero, but there is an opportunity cost associated with this direct marginal cost. As of June 30, 2013, thirteen percent of offers reflected economic withholding. PJM rules require all units with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[8] Units that do not offer have their offers set to zero.

- **DSR.** Demand side resources are eligible to participate in the DASR Market, but no demand resource cleared the DASR Market in January through June, 2013.

Market Performance

- **Price.** The weighted DASR market clearing price in January through June, 2013 was $0.06 per MW. In January through June, 2012, the weighted price of DASR was $0.41 per MW.

Black Start Service

Black start service is necessary to help ensure the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or is the demonstrated ability of

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7 See PJM. "Manual 13: Emergency Operations," Revision 53, (June 1, 2013); pp 11-12.

8 See PJM. "Manual 11, Energy and Ancillary Services Market Operations," Revision 60 (June 1, 2013), p. 144.

a generating unit to automatically remain operating at reduced levels when disconnected from the grid.[9]

In January through June 2013, black start credits were $58.5 million. Black start zonal credits in January through June 2013 ranged from $0.03 per MW in the ATSI zone (total credits: $70,284) to $11.42 per MW in the AEP zone (total credits: $48,178,521).

Ancillary services costs per MW of load: January through June 2002 – 2013

Table 9-4 shows PJM ancillary services costs for January through June, 2002, through 2013, 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[10]: January through June 2002 through 2013

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve	Total
2002	$0.37	$0.55	$0.23	$0.00	$0.59	$1.75
2003	$0.57	$0.61	$0.24	$0.14	$0.81	$2.37
2004	$0.53	$0.66	$0.26	$0.16	$0.93	$2.53
2005	$0.57	$0.51	$0.27	$0.11	$0.60	$2.05
2006	$0.48	$0.48	$0.29	$0.08	$0.32	$1.65
2007	$0.61	$0.46	$0.30	$0.09	$0.50	$1.95
2008	$0.73	$0.37	$0.30	$0.08	$0.66	$2.14
2009	$0.37	$0.43	$0.37	$0.04	$0.50	$1.71
2010	$0.37	$0.38	$0.36	$0.06	$0.75	$1.92
2011	$0.33	$0.38	$0.41	$0.11	$0.80	$2.03
2012	$0.20	$0.44	$0.47	$0.03	$0.65	$1.79
2013	$0.26	$0.41	$0.65	$0.03	$0.73	$2.09

9   OATT Schedule 1 § 1.3BB.
10 Results in this table differ slightly from the results reported previously because accounting load is used in the denominator in this table.

Conclusion

The design of the Regulation Market changed significantly effective October 1, 2012. While the market design continues to include the incorrect definition of opportunity cost, overall the changes were positive. It is too early to reach a definitive conclusion about performance under the new market design because there is not yet enough information on performance. It is essential that the Regulation Market incorporate the consistent implementation of the marginal benefit factor in optimization, pricing and settlement. But the experience of the last quarter of 2012 and the first two quarters of 2013 is cause for optimism with respect the performance of the Regulation Market under the new market design.

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. Compliance with calls to respond to actual spinning events has been an issue. Compliance with the synchronized reserve must-offer requirement has also been an issue.

The MMU concludes that the structure of the DASR Market was competitive in the first six months of 2013, although concerns remain about economic withholding and the absence of the three pivotal supplier test in this market.

The benefits of markets are realized under these approaches to ancillary service markets. Even in the presence of structurally noncompetitive markets, there can be transparent, market clearing prices based on competitive offers that account explicitly and accurately for opportunity cost. This is consistent with the market design goal of ensuring competitive outcomes that provide

appropriate incentives without reliance on the exercise of market power and with explicit mechanisms to prevent the exercise of market power.

Overall, the MMU concludes that it is not yet possible to reach a definitive conclusion about the new Regulation Market design, but there is reason for optimism. The MMU concludes that the Synchronized Reserve Market results were competitive in the first six months of 2013. The MMU concludes that the DASR Market results were competitive in the first six months of 2013.

Regulation Market

The PJM Regulation Market continues to be operated as a single market. Significant technical and structural changes were made to the Regulation Market in 2012. On May 7, 2012, PJM switched to an improved optimizer called the Ancillary Services Optimizer (ASO). On October 1, 2012, PJM made additional technical changes to the optimized solution and, to comply with FERC Order No. 755, implemented Performance Based Regulation.[11] On November 16, 2012, FERC modified the PJM market design that was introduced on October 1, 2012.[12]

Regulation Market Changes for Performance Based Regulation

Regulation is a key part of PJM's effort to minimize ACE so as to keep the reportable metrics CPS1 and BAAL within acceptable limits. On October 20, 2011, FERC issued Order No. 755 directing PJM and other RTOs/ISOs to modify their regulation market rules to make use of and properly compensate a mix of fast and traditional response regulation resources."[13] Order No. 755 also sought to correct "certain practices of some RTOs and ISOs result in economically inefficient economic dispatch of frequency regulation resources."[14]

A driver for the new market design was the assumption that new, fast response technologies could be used, in combination with traditional resources, to reduce the total amount of resources needed to meet regulation requirements and thereby reduce the cost of regulation. Order No. 755 required that the new and traditional resources be purchased in a single market, with compensation for both capacity (MW) and miles (total MW per minute measured in ΔMW/MW) provided.[15] Prior to October 1, 2012, regulation consisted of energy that could be added or removed within five minutes following a traditional (RegA) signal. On October 1, 2012, the PJM introduced a single market that included two distinct types of frequency response: RegA (traditional and slower oscillation signal) and RegD (faster oscillation signal). Within this new market design, resources can choose to follow RegA or RegD.

In a market defined in terms of units of RegA equivalent regulation service, the marginal benefits factor of all units following the RegA signal is one, while the marginal benefits factor of units following the RegD signal depends on how much RegD following resources are used. Under PJM's August 15, 2012, proposal, the benefits factor can be as high as 2.9 but never lower than zero. Effective regulation is a function of two components, the benefits factor, which itself is a function of the amount of RegD regulation already committed; and the historical performance of the unit as measured by the 100-hour average of performance scores. A unit's regulation capability MW multiplied by its benefits factor, and modified by its performance score, results in that unit's effective RegA signal following regulation MW.

FERC's November 16, 2012 order only partially accepted the market design in PJM's August 15, 2012, filing. FERC's November 16, 2012, order fixed the marginal benefits factor for RegD resources at a value of 1.0 for purposes of payment. This has created a dichotomy in the PJM regulation market between the marginal value of RegD resources in the dispatch, and the resulting market price and payments to resources in the settlement process in PJM's regulation market through the second quarter of 2013.

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11 For a description of the full history of the changes to the tariff provisions governing the Regulation Market, see the *2011 State of the Market Report for PJM,* Volume II, Section 9, "Ancillary Service Markets."

12 *PJM Interconnection, L.L.C.,* 139 FERC ¶ 61,130 (2012)

13 Order No. 755 at P 3. FERC ordered PJM "to compensate frequency regulation resources based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal."

14 *Id.* at P 2.

15 *Id.* at PP 99, 131 & 177

Performance tracking is an essential element of the performance based Regulation Market. Regulation performance scores (0.0 to 1.0) measure the response of a regulating unit to its chosen regulation signal (RegA or RegD) every ten seconds by measuring: delay – the time delay of the regulation response to a change in the regulation signal; correlation – the relationship between the regulating resource output and the regulation signal; and precision – the difference in energy provided from the difference in energy requested.[16] An hourly performance score is calculated and multiplied by the MW cleared when calculating payment. Additionally, hourly scores are stored and used as part of a 100 hour rolling average historical performance score to obtain an effective capability MW and performance MW used in clearing. Figure 9-1 shows the average performance score by unit type and signal followed.

Figure 9-1 Average performance score grouped by unit type and regulation signal type: January through June 2013
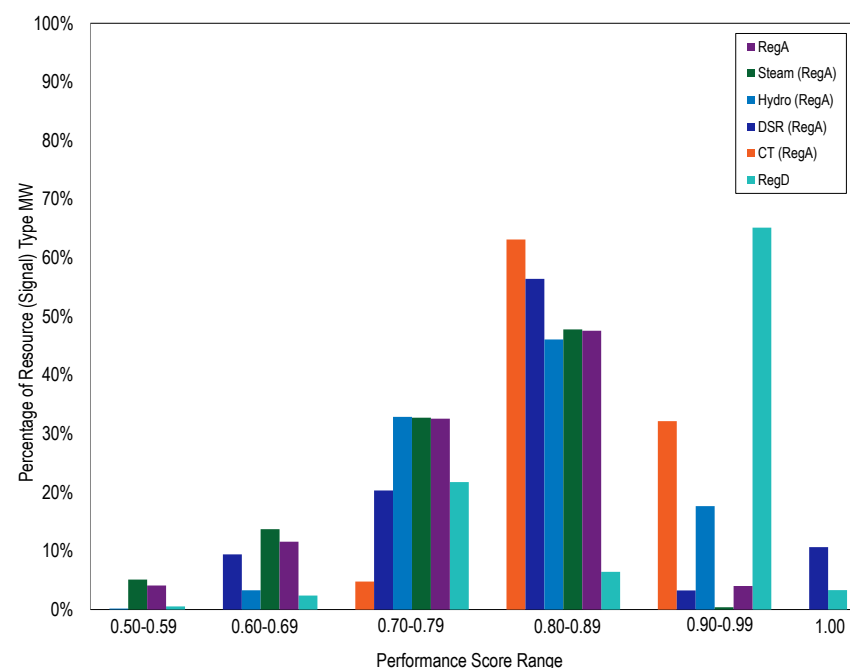
Using a performance score to measure the accuracy of a regulating resource, a mileage ratio to compare the effective MW of differing types of resources, and effective MW as a means of translating the value of actual MW for high performance units are the reasons that the required regulation has been lowered from 1.0 percent to 0.7 percent of forecast peak load.

The performance based Regulation Market requires that unit owners provide two-part offers for their regulation resources, an offer for regulation capability in terms of $/MW and a regulation performance offer in terms of $/ΔMW. In addition, unit owners must enter the regulation signal type the unit will follow, RegA or RegD. Owners may enter price based offers subject to a combined offer cap of $100/MW.

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16 A full specification of each of the three criteria used in the performance score is presented in PJM "Manual 12: Balancing Operations" Rev. 27 (December 20, 2012); 4.5.6, p 52.

Market Structure

Supply

Table 9-5 shows capability, average daily offer and average hourly eligible MW for all hours. The hourly regulation capability decreased in January through June 2013, to 8,262 MW from 9,298 MW during the same time period of 2012.

Table 9-5 PJM regulation capability, daily offer[17] and hourly eligible: January through June 2012 and 2013[18]

Period	Regulation Capability (MW)	Average Daily Offer (MW)	Percent of Capability Offered	Average Hourly Eligible (MW)	Percent of Capability Eligible
2013 (Jan–Jun)	8,262	4,327	52%	1,752	21%
2012 (Jan–Jun)	9,298	6,736	72%	3,009	32%

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

Table 9-6 Impact on PJM Regulation Market of currently regulating units scheduled to retire through 2015

Current Regulation Units, January through June 2013	Settled MW, January through June 2013	Units Scheduled To Retire Through 2015	Settled MW of Units Scheduled To Retire Through 2015	Percent Of Regulation MW To Retire Through 2015
281	3,326,236	32	33,926	1.02%

The cost of each unit is calculated in market clearing using its offer price, lost opportunity cost, capability MW, and the miles to MW ratio of the signal type they choose to follow, modified by resource benefit factor and historic performance score. As of October 1, 2012, a regulation resource's total offer is equal to the sum of its total capability ($/MW) and performance offer ($/MW). As of October 1, 2012, the within hour five minute clearing price for regulation is determined by the total offer, including the actual within hour lost opportunity cost, of the most expensive cleared regulation resource

17 Average Daily Offer MW excludes units that have offers but are unavailable for the day.
18 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.

in each interval. The total clearing price for the hour is the simple average of the twelve interval prices within the hour. The total clearing price of the hour (RMCP) is in two parts, the performance clearing price (RMPCP) and the capability clearing price (RMCCP). The performance clearing price ($/MW) is equal to the most expensive performance offer cleared for the hour. The capability clearing price ($/MW) is equal to the difference between the total clearing price for the hour and the performance clearing price for the hour.

Since the implementation of Regulation Performance on October 1, 2012, both regulation price and regulation cost per MW are higher than they were prior to October 1, 2012. Since the implementation of shortage pricing and changing the regulation requirement to 0.70 percent of peak load forecast (from one percent of peak load forecast prior to October 1) the price and cost of regulation have remained high. The weighted average regulation price for January through June, 2013 was $31.80. The regulation cost for January through June, 2013, was $36.47. The ratio of price to cost is significantly higher at 87 percent (compared with 76 percent in Q2 of 2012), meaning that more of the costs which used to come from LOC as a result of low load forecasts are now part of the price.

Starting October 1, a growing number of resources have followed the RegD signal. As of June 30, 2013, there were 20 resources (eight generation and 12 demand response) following the RegD signal, an increase of six resources (three generation and three demand response) from March 31, 2013. For January through June 2013, the weighted-average HHI of the set of RegD resources was 5864 (highly concentrated).

In the period from January 1, 2013 through June 30, 2013, the marginal benefits factor (contribution to ACE correction) for cleared RegD following resources has ranged from 1.743 to 2.899 with an average over all hours of 2.610.

Although the benefits factor for traditional (RegA following) resources is 1.0, the effective MW of RegA following resources is lower than the offered MW because the performance score is less than 1 (Figure 9-2). For January through June, 2013, the MW-weighted average RegA performance score was 0.79.

Figure 9-2 Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; all cleared regulation; January through June 2013
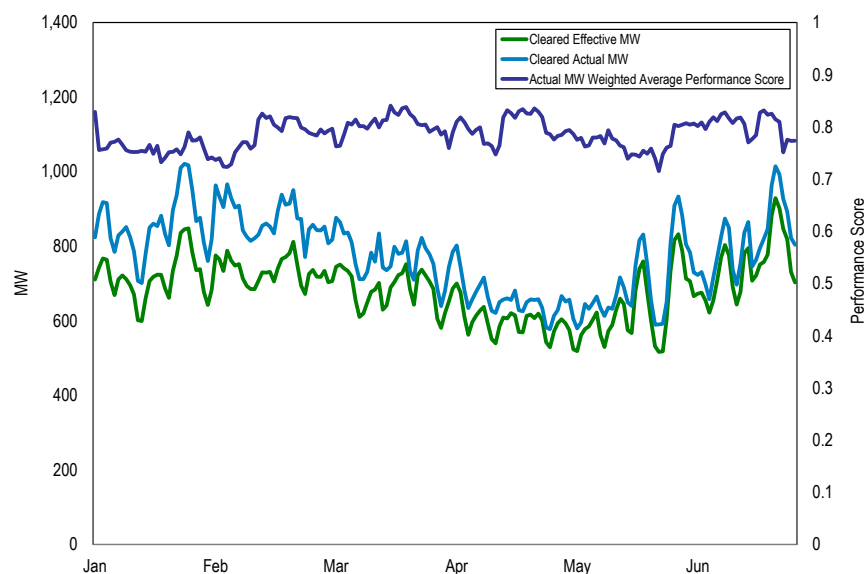
Figure 9-3 Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; RegD units only; January through June 2013
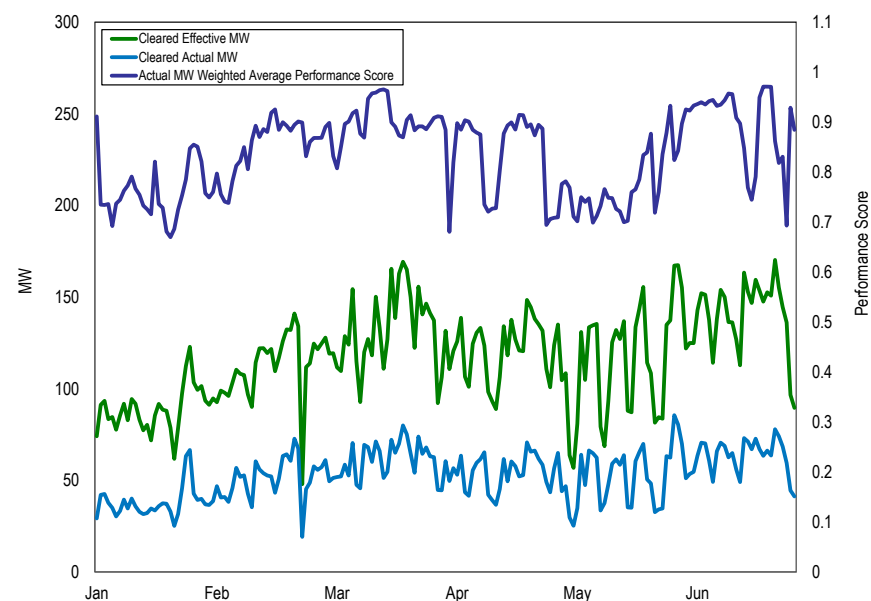
For RegD resources, the effective MW are higher than the actual MW because their benefits factor at current participant levels is significantly greater than 1.0 (Figure 9-3). For January through June, 2013, the MW-weighted average RegD resource performance score was 0.90.

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. Prior to October 1, 2012, the regulation requirement was 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. Between October 1, 2012, and December 31, 2012, PJM changed the regulation requirement

several times. It had been scheduled to be reduced from one percent of peak load forecast to 0.9 percent on October 1, 2012, but instead it was changed from 1 percent of peak load forecast to 0.78 percent of peak load forecast. It was further reduced to 0.74 percent of peak load forecast on November 22, 2012. Then it was reduced to its current value of 0.70 percent of peak load forecast on December 18, 2012.

Table 9-7 shows the average hourly required regulation by month 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 June 2012 and 2013

Month	Average Required Regulation (MW), 2012	Average Required Regulation (MW), 2013	Ratio of Supply to Requirement, 2012	Ratio of Supply to Requirement, 2013
Jan	1,005	851	3.29	3.66
Feb	979	870	3.45	4.65
Mar	876	766	3.14	4.86
Apr	826	656	3.19	2.55
May	918	678	3.26	3.91
Jun	1,055	801	3.21	4.34

PJM's performance as measured by CPS and BAAL standards has not declined as a result of the lower regulation requirement.[19]

Market Concentration

Table 9-8 shows Herfindahl-Hirschman Index (HHI) results for January through June of 2012 and 2013. The average HHI of 2134 is classified as highly concentrated and is higher than the HHI for the same period in 2012.

Table 9-8 PJM cleared regulation HHI: January through June 2012 and 2013

Period	Minimum HHI	Weighted Average HHI	Maximum HHI
2013 (Jan-Jun)	757	2134	5650
2012 (Jan-Jun)	813	1557	4962

Figure 9-4 compares the 2013 HHI distribution curves with distribution curves for the same periods of 2012 and 2011.

Figure 9-4 PJM Regulation Market HHI distribution: January through June 2011, 2012, and 2013

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19 See the *2012 State of the Market Report for PJM,* Appendix F: Ancillary Services.
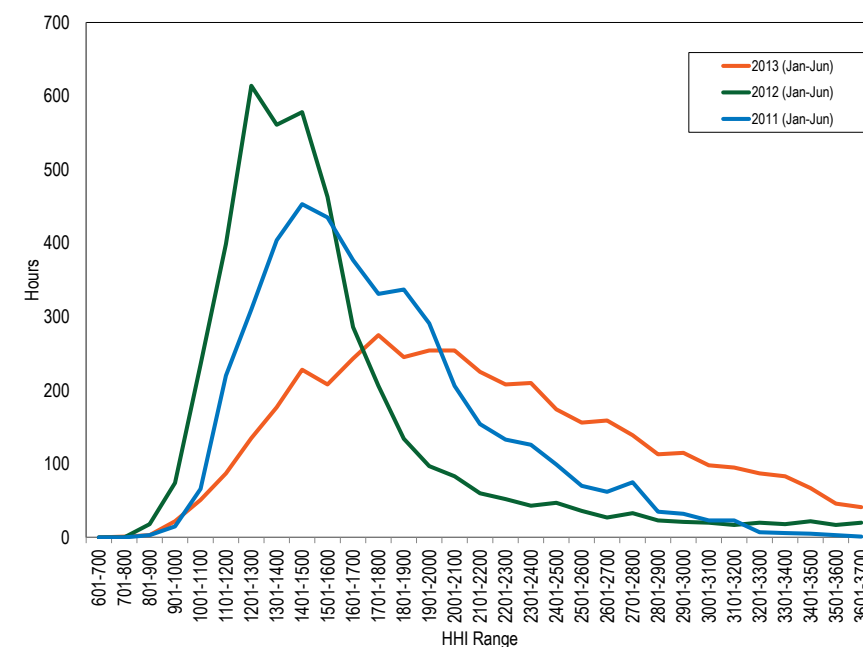
Table 9-9 includes a monthly summary of three pivotal supplier results. In January through June 2013, 90 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test.[20] Offer capping in the regulation market has little impact on prices because offers are a smaller component of price than is LOC (Figure 9-6).

The MMU concludes from these results that the PJM Regulation Market in January through June 2013 was characterized by structural market power in 90 percent of hours.

Table 9-9 Regulation market monthly three pivotal supplier results: January through June 2011, 2012 and 2013

Month	2013 Percent of Hours Pivotal	2012 Percent of Hours Pivotal	2011 Percent of Hours Pivotal
Jan	83%	71%	95%
Feb	82%	67%	93%
Mar	97%	64%	94%
Apr	88%	41%	97%
May	93%	37%	95%
Jun	95%	40%	89%

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 (Table 9-10).[21]

Figure 9-5 Off peak and on peak regulation levels: January through June 2013
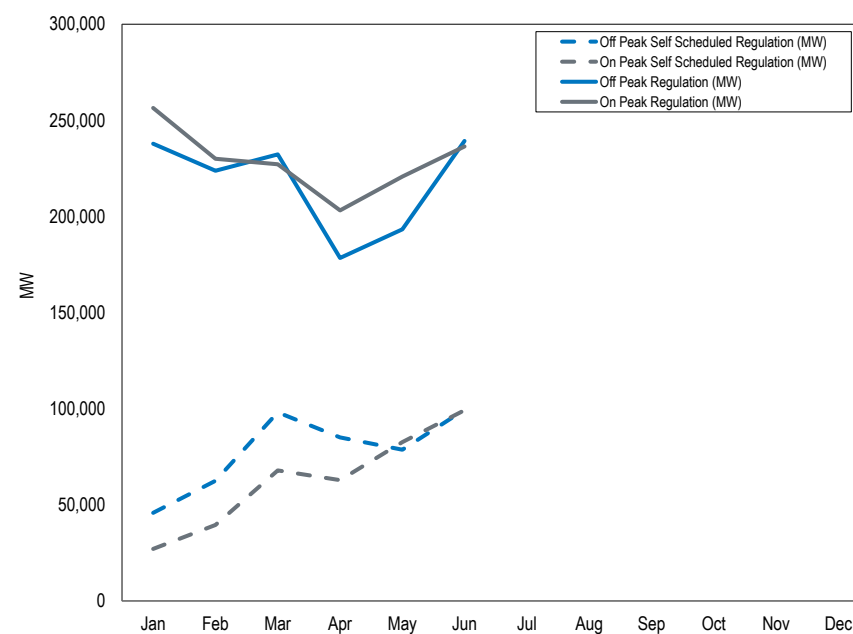
Increased self-scheduled regulation lowers the requirement for cleared regulation, resulting in fewer MW cleared in the market and lower clearing prices. Of the LSEs' obligation to provide regulation in January through June

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20 The MMU monitors the application of the TPS test by PJM and brings any issues to the attention of PJM.

21 See PJM. "Manual 28: Operating Agreement Accounting," Revision 60, (June 1, 2013); para 4.1, pp 15.

of 2013, 64.9 percent was purchased in the spot market, 31.7 percent was self-scheduled, and 3.4 percent was purchased bilaterally (Table 9-10).

Table 9-10 Regulation sources: spot market, self-scheduled, bilateral purchases: January through June 2012 and 2013

Year	Month	Spot Regulation (MW)	Self-Scheduled Regulation (MW)	Bilateral Regulation (MW)	Total Regulation (MW)
2013	Jan	413,304	72,880	8,070	494,253
2013	Feb	338,990	102,005	12,808	453,803
2013	Mar	275,880	165,987	17,554	459,421
2013	Apr	219,793	147,858	13,860	381,510
2013	May	235,849	161,270	16,934	414,053
2013	Jun	254,215	198,617	22,816	475,647
2012	Jan	553,686	164,806	21,261	739,753
2012	Feb	481,004	175,757	20,456	677,217
2012	Mar	477,564	144,408	19,683	641,655
2012	Apr	426,564	124,750	21,083	572,397
2012	May	542,585	97,574	17,849	658,008
2012	Jun	582,078	140,769	22,309	745,156

Demand resources offered and cleared regulation for the first time in November 2011. In April 2012, a tariff change allowing demand resources to offer 0.1 MW facilitated participation by demand resources. Although their impact remains small, the participation of demand resources in regulation is growing.

Market Performance

Price

The weighted average RMCP for January through June, 2013, was $31.80. This is a 128.8 percent increase from the January through June 2012 weighted average RMCP of $13.90. Figure 9-6 shows the daily average Regulation Market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market.

Figure 9-6 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): January through June 2013
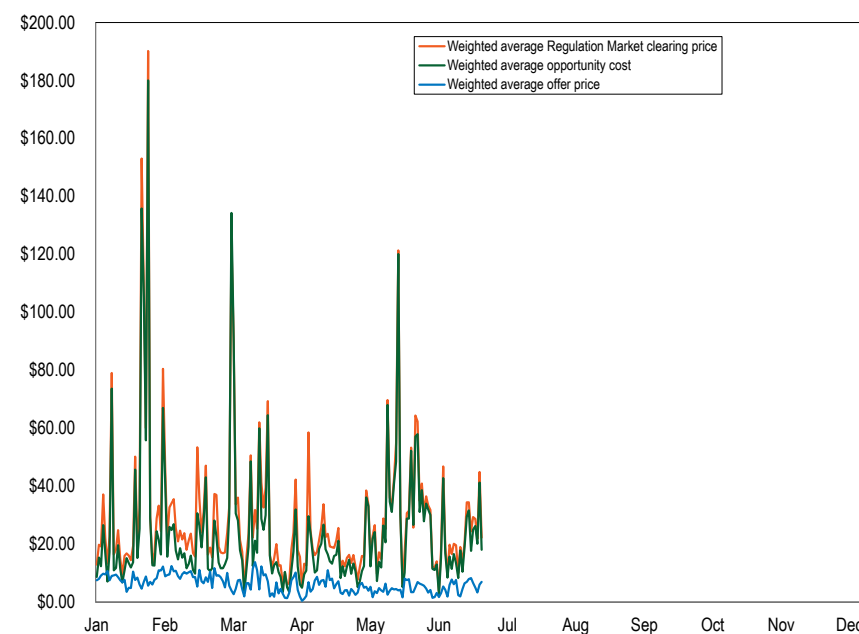
Table 9-11 shows monthly average regulation market clearing price, average marginal unit offer price, and average marginal unit LOC.

A breakdown of the cost of regulation into its capability, performance, and opportunity cost components is shown in Table 9-13.

Table 9-11 PJM Regulation Market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MWh): January through June 2013

Month	Weighted Average Regulation Market Clearing Price	Weighted Average Regulation Marginal Unit Offer	Weighted Average Regulation Marginal Unit LOC
Jan	$39.94	$7.72	$39.62
Feb	$29.51	$9.37	$23.01
Mar	$31.64	$5.02	$27.10
Apr	$26.49	$5.07	$14.48
May	$33.42	$4.32	$30.52
Jun	$29.81	$4.41	$20.18

Table 9-13 Components of regulation cost: January through June 2013

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	494,253	$33.74	$6.25	$6.28	$46.27
Feb	453,803	$25.50	$4.10	$4.06	$33.66
Mar	459,421	$28.31	$3.46	$4.53	$36.30
Apr	381,510	$23.21	$3.36	$4.69	$31.27
May	414,053	$30.44	$3.01	$4.22	$37.68
Jun	475,647	$26.80	$3.09	$3.74	$33.64

Total scheduled regulation MW, total regulation charges, regulation price and regulation cost are shown in Table 9-12.

Table 9-14 provides a comparison of the average price and cost for PJM Regulation. The difference between the Regulation Market price and the actual cost of regulation was less in January through June 2013 than it was in January through June 2012. This is an improvement which resulted from the use of pricing based on real-time LMP instead of forecast LMP as had been done prior to shortage pricing in October 1, 2012.

Table 9-12 Total regulation charges: January through June 2013 and 2012

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percentage of Cost
2013	Jan	494,253	$22,870,690	$39.94	$46.27	86%
2013	Feb	453,803	$15,273,604	$29.51	$33.66	88%
2013	Mar	459,421	$16,678,410	$31.64	$36.30	87%
2013	Apr	381,510	$11,930,098	$26.49	$31.27	85%
2013	May	414,053	$15,599,491	$33.42	$37.68	89%
2013	Jun	475,647	$15,999,677	$29.81	$33.64	89%
2012	Jan	739,753	$13,338,201	$13.41	$18.03	74%
2012	Feb	677,217	$10,108,296	$11.89	$14.93	80%
2012	Mar	641,655	$11,109,763	$12.61	$17.31	73%
2012	Apr	572,397	$9,038,430	$13.01	$15.79	82%
2012	May	658,008	$16,248,950	$17.44	$24.69	71%
2012	Jun	745,156	$14,181,461	$14.91	$19.03	78%

Table 9-14 Comparison of average price and cost for PJM Regulation, January through June 2007 through 2013

Period	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2007	$36.86	$52.91	70%
2008	$42.09	$64.43	65%
2009	$23.56	$29.87	79%
2010	$18.08	$32.07	56%
2011	$15.53	$30.89	50%
2012	$13.90	$18.35	76%
2013	$31.80	$36.47	87%

Primary Reserve

Reserves are provided by generating capability that is standing by ready for service if an unforeseen event causes a need for it. NERC defines reporting and response requirements for disturbance events in "NERC Performance Standard BAL-002-0, Disturbance Control Performance." and PJM defines its corresponding obligations in Manual 12.[22] NERC defines contingency reserves as energy available in 15 minutes. PJM calls this Primary Reserve and specifies it as energy available within 10 minutes. Units in a shutdown state may satisfy the primary reserve requirement if they can start within 10 minutes. PJM retains a separate synchronized reserve requirement.

Requirements

PJM must satisfy the contingency reserve requirements specifications of the Reliability*First* Corporation and VACAR. For the RTO reserve zone the primary reserve requirement is 150 percent of the largest contingency in the PJM footprint, currently 2,063 MW. Of that 2,063 MW, PJM requires that at least 1,375 MW be on line and synchronized to the grid (Figure 9-7).

Figure 9–7 PJM RTO geography and primary reserve requirement: January through June 2013
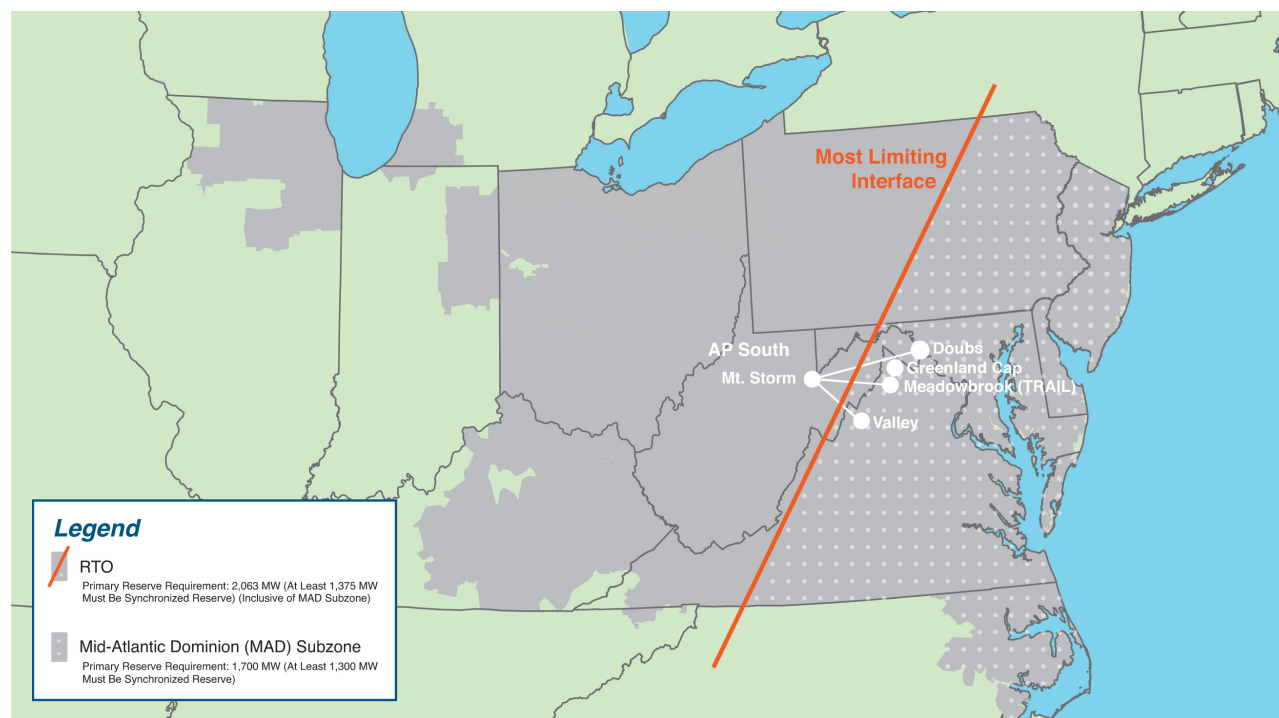
22 See PJM. "Manual 12: Balancing Operations" Revision 27, Attachment D, "Disturbance Control Performance/Standard" (December 20, 2012), p. 84.

Because of constrained deliverability within the RTO, PJM imposes a further restriction by creating a sub-zone within the RTO called the Mid-Atlantic Dominion Subzone. Of the 2,063 MW requirement for primary reserve in the RTO, 1,700 MW must be deliverable to the Mid-Atlantic Dominion Subzone. Of the 1,375 MW of synchronized reserve in the RTO, 1,300 MW must be deliverable to the Mid-Atlantic Dominion Subzone. The Mid-Atlantic Dominion Subzone is defined approximately by the geography in Figure 9-7. Between January 1, 2013 and May 31, 2013 the reserve interface had been defined by the set of all resources with a three percent or greater DFAX raise help on the constrained side of the Bedington - Black Oak constraint. From June 1, 2013 through June 30, 2013 PJM implemented several changes including changing the constraint interface from Bedington - Black Oak to AP South and calculating the impact of the constraint as the set of all resources with greater than zero percent DFAX raise help on the constrained side of the interface.[23] The effect of these changes to the reserve interface has been to significantly increase the supply of Tier 1 synchronized reserve in the Mid-Atlantic Dominion Subzone thereby decreasing the amount of Tier 2 synchronized reserve required to purchase (Figure 9-8). On June 1, 2013, PJM integrated the East Kentucky Power Cooperative transmission system. Since this is on the unconstrained side of the AP South constraint it had the effect of increasing the amount of Tier 1 MW available without increasing the reserve requirement.

The primary reserves requirement is not satisfied by a single market but by several products across the RTO Zone and Mid-Atlantic Dominion Subzone. The two requirements of the Mid-Atlantic Dominion Reserve Zone, primary reserve (1,700 MW) and synchronized reserve (1,300 MW) are satisfied by a set of energy products optimized to minimize total cost (Figure 9-8). The components of the Mid-Atlantic Dominion Primary Reserve Zone are Tier 1 synchronized reserve which is priced at $0 unless there is a shortage event or a spinning event, Tier 2 synchronized reserve which is satisfied by the Synchronized Reserve Market and priced economically, Demand Response (DR) which is priced at the Synchronized Reserve Market clearing price, non-

synchronized reserve (limited to no more than 50 percent of the primary reserve requirement) which is priced only when it must be dispatched at an optimized clearing price by the ASO, and synchronized reserve available in the Mid-Atlantic Dominion Reserve Zone from the RTO Reserve Zone across the most limiting constraint.

Figure 9-8 Components of Mid–Atlantic Dominion Subzone Primary Reserve (Daily Averages): January through June, 2013
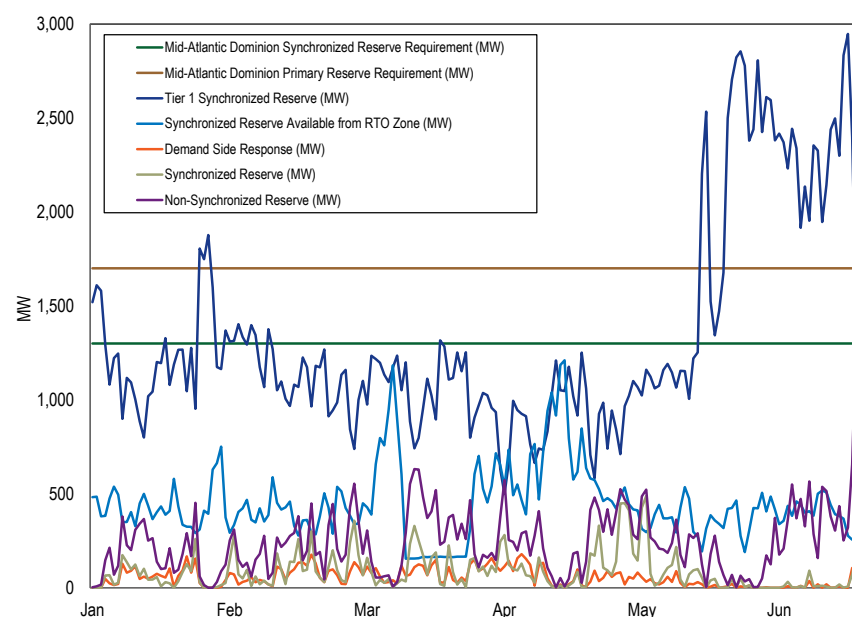
Figure 9-8 shows that Tier 1 Synchronized Reserve remains the major contributor to satisfying the reserve requirements. Synchronized reserve available inside the subzone from the RTO Zone is also a major contributor. Both of these components have a price of $0.00 unless a Tier 2 Synchronized Reserve or Non-Synchronized Reserve market is cleared in the RTO Zone. Non-synchronized reserve clears a separate market less frequently because (like DASR) it is available without redispatch from CTs and some hydro units. Tier 2 synchronized reserve is dispatched at a market clearing price.

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23 The specific constrained interface may be revised by PJM to meet system reliability needs. Additional subzones may be defined by PJM to meet system reliability needs. PJM will notify stakeholders in such an event. See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 60 (June 1, 2013), p. 78.

In 111 hours between January 1 and June 30, 2013 the Non-Synchronized Reserve Market for the Mid-Atlantic Dominion Subzone cleared at greater than $0.00 averaging $12.61. Non-synchronized reserve only clears when synchronized reserve also clears.

Shortage Pricing

On October 1, 2012 PJM introduced shortage pricing which made major changes to the structure and operation of the PJM reserve markets. PJM now has two markets to satisfy the primary reserve requirement; the Synchronized Reserve Market (Tier 2), and the new Non-Synchronized Reserve Market. The Synchronized Reserve Market dispatches Tier 2 synchronized reserve plus demand response to satisfy the synchronized reserve requirement minus the Tier 1 MW available. Both Tier 1 and Tier 2 consist of units on-line synchronized to the grid. Units offering synchronized reserve which clear the Synchronized Reserve Market are Tier 2 units. The primary reserve requirement is then satisfied by Tier 1 plus Tier 2 plus Non-Synchronized reserve.

If IT SCED and RT SCED forecast a primary reserve or synchronized reserve shortage, then PJM will implement shortage pricing through the inclusion of primary reserve or synchronized reserve penalty factors.[24]

With shortage pricing, PJM began specifying that all on-line, non-emergency, generation capacity resources must offer synchronized reserve in accordance with the resources' capability to provide these reserves. As of the end of June, 2013, a significant number of participants with generation resources have not complied with this requirement for a wide variety of reasons.

If PJM issues a Primary Reserve Warning, Voltage Reduction Warning, or Manual Load Dump Warning, all off line non-emergency generation capacity resources available to provide energy must submit an offer for Tier 2 synchronized reserve.[25] This rule ensures that IT-SCED and RT-SCED will be able to make accurate estimates of the amount of Primary Reserve available.

From January through June, 2013 no reserve zone or sub-zone experienced a reserve shortage.

Synchronized Reserve Market

Prior to October 1, 2012, PJM operated two synchronized reserve markets because of differing synchronized reserve requirements specified by two different reliability regional authorities, Reliability*First* Corporation and VACAR. Those two synchronized reserve zones (Southern and RFC) are now merged into one zone, the RTO Synchronized Reserve Zone, with its requirements structured to satisfy both regional specifications.[26]

Market Structure

Supply

For the first six months of 2013, the supply of offered and eligible synchronized reserve was stable and adequate in both the RTO Zone and the Mid-Atlantic Dominion Subzone. The contribution of demand resources to the Synchronized Reserve Market remains significant. Demand side resources (DR) are relatively low cost, and their participation lowers overall Synchronized Reserve prices. PJM has limited the amount of DR to 25 percent of the synchronized reserve requirement since it was introduced into the market in August 2006. On December 6, 2012, PJM increased this amount to 33 percent of the synchronized reserve requirement.

Total MW of cleared synchronized reserve increased in January through June of 2013 over 2012 (from 451,695 MW to 533,175 MW). The DSR share of the total Synchronized Reserve Market increased from 22 percent in January through June of 2012 to 43.6 percent in the same time period of 2013. Demand side resources satisfied 100 percent of the Tier 2 Synchronized Reserve market in 14 percent of cleared hours in January through June of 2013 compared to 8 percent of hours in during the same time period of 2012. The merging of the former Mid-Atlantic subzone with Dominion into the new Mid-Atlantic Dominion subzone, plus the changes made in June, 2013 has made more Tier

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24 See the *2012 State of the Market Report for PJM*, Volume II, "Ancillary Service Markets" for more details on the impact of shortage pricing on the Reserve Markets.
25 See PJM. "Manual 11: Energy and Ancillary Services Market Operations" Revision 60, (June 1, 2013), p. 72.

26 See the *2012 State of the Market Report for PJM*, Volume II, "Ancillary Service Markets" for more details on the impact of shortage pricing on the Synchronized Reserve Markets.

1 reserve available to the subzone (ref. Figure 9-8). The former Dominion Zone had an excess of Tier 1 lessening the number of hours when the subzone has to clear a Tier 2 market. The ratio of offered and eligible synchronized reserve MW to the synchronized reserve required (1,300 MW) was 1.47 for the Mid-Atlantic Dominion Subzone from January through June, 2013 a significant increase from the 1.18 ratio of offered and eligible reserve MW to required in January through June, 2012.[27] Most of the increase comes in May and June, 2013 because of the significant changes to the reserve zone interface. While the ratio was 1.32 from January through April, it was 1.46 in May and 2.11 in June. Much of the required synchronized reserve is supplied from on-line (Tier 1) synchronized reserve resources.

Demand

In late May and early June PJM made several changes, both geographic and procedural, to the Synchronized Reserve Market. The reserve interface (defined by the most limiting constraint) was changed from Bedington – Black Oak to AP South; calculating the effect of the interface was changed from all units with a three percent or greater raise help on the constrained side of the interface to all units; and the EKPC region was integrated into the RTO zone. These changes greatly increased the reserve available in the RTO Zone, the T1 available across the interface into the Mid-Atlantic Dominion Subzone (MAD), and the available T2 inside of MAD. The change of reserve interface from Bedington – Black Oak to AP South added 51 generation resources in the MAD sub-zone offering an average total of 2,090 MW of synchronized reserve to the sub-zone. These changes did not impact the largest contingency so the reserve requirement was unchanged.

Because there is a large amount of Tier 1 available in the non-Mid-Atlantic Dominion regions of the RTO, a Synchronized Reserve Market usually does not have to be cleared in the RTO Synchronized Reserve Zone. In January through June, 2013, in the RTO Synchronized Reserve Zone a Synchronized Reserve Market was cleared in less than one percent of hours (33 hours). From January through June 2013 in the Mid-Atlantic Dominion Subzone a

Tier 2 Synchronized Reserve Market was cleared in 31 percent of hours at an average of 167 MW. This is a sharp reduction from the average MW cleared both in January through June 2012 and also January through March, 2013. It is important to note that with shortage pricing a Synchronized Reserve Market can clear at $0. The MAD Synchronized Reserve Market cleared at $0 but assigned synchronized reserve in 11 percent of hours during January through June, 2013, clearing an average of 162 MW.

As of June 30, 2013, the synchronized reserve requirement for the RTO synchronized reserve zone is 1,375 MW. The Mid-Atlantic Dominion synchronized reserve zone requirement is 1,300 MW.

Table 9-15 Synchronized Reserve Market required MW, RTO Zone and Mid-Atlantic Dominion Subzone, December 2008 through June 2013

Mid-Atlantic Dominion Subzone			RTO Synchronized Reserve Zone		
From Date	To Date	Required MW	From Date	To Date	Required MW
May 10, 2008	May 8, 2010	1,150	May 10, 2008	Jan 1, 2009	1,305
May 8, 2010	Jul 13, 2010	1,200	Jan 1, 2009	Mar 15, 2010	1,320
July 13, 2010		1,300	Mar 15, 2010	Nov 12, 2012	1,350
			Nov 12, 2012		1,375

The market demand for Tier 2 synchronized reserve in the Mid-Atlantic Dominion sub-zone is determined by subtracting the amount of forecast Tier 1 synchronized reserve available plus the amount of Tier 1 available from the RTO Zone across the most limiting constraint (currently AP South) from the synchronized reserve zone's requirement each 5-minute period. Market demand is further reduced by subtracting the amount of self-scheduled Tier 2 resources.

Exceptions to this requirement can occur when grid maintenance or outages change the largest contingency. The requirement for both the RTO Zone and the Mid-Atlantic Dominion Subzone was raised to 1,780 MW for eight hours on February 2, 2013.

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27 The Synchronized Reserve Market in the Southern Region between January and September, 2012 cleared in so few hours that related data for that market are not meaningful.

Figure 9-9 shows the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled during January through June of 2013, for the Mid-Atlantic Dominion Synchronized Reserve Market.

Figure 9-9 Mid-Atlantic Dominion Synchronized Reserve Subzone monthly average synchronized reserve required vs. Tier 2 scheduled MW: January through June 2013
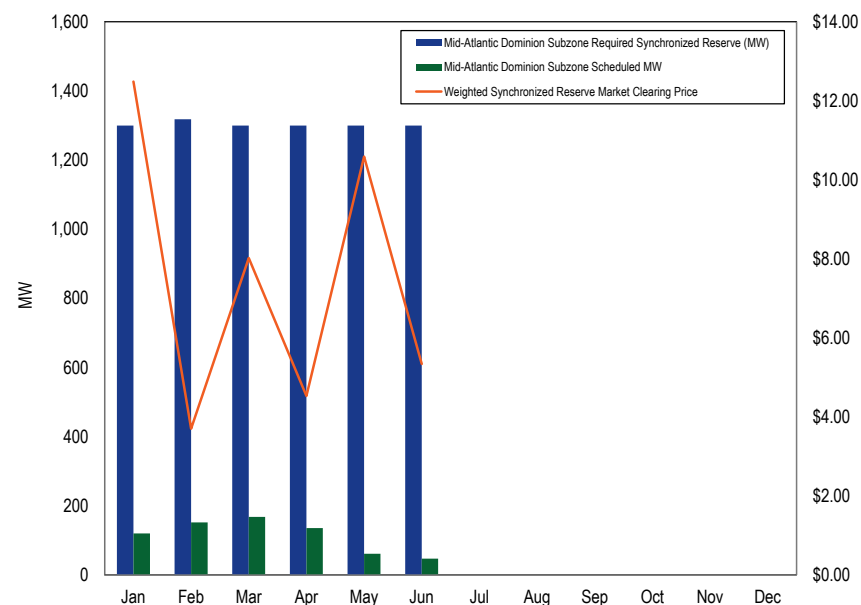
The RTO Synchronized Reserve Zone almost always has enough Tier 1 to cover its synchronized reserve requirement. Available Tier 1 in the western and southern part of the RTO Synchronized Reserve Zone generally exceeds the total synchronized reserve requirement. In January through June 2013, the RTO Synchronized Reserve Zone cleared a Tier 2 Synchronized Reserve Market in 33 hours with an average SRMCP of $1.52. The Mid-Atlantic Dominion Subzone cleared a separate Tier 2 market in 31 percent of all hours during January through June of 2013 at a weighted SRMCP of $6.38.

The former Southern Synchronized Reserve Zone (integrated into the Mid-Atlantic Dominion Synchronized Reserve Zone on October 1, 2012) 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 15 minute quick start reserve available in VACAR is sufficient to eliminate Tier 2 synchronized reserve demand for most hours. The VACAR requirement for the former Southern Synchronized Reserve Zone is now satisfied by the Synchronized Reserve requirement for the Mid-Atlantic Dominion Synchronized Reserve Subzone.

Market Concentration

The HHI from January through June 2012 for the Mid-Atlantic Subzone was 3010, which is defined as highly concentrated. The HHI for the Mid-Atlantic Dominion Subzone from January through June 2013 was 4002, which is defined as highly concentrated. Note that the HHI for 2013 includes both inflexible and flexible assigned MW. The largest hourly market share was 100 percent and 37 percent of all hours had a maximum market share greater than or equal to 40 percent (compared to 56 percent of all hours January through June 2012). Most synchronized reserve is provided by inflexible scheduled Tier 2 resources.[29] When there is not enough Tier 2 or when the IT SCED or RT SCED sees a need, flexible reserve units are assigned spinning. Flexible synchronized reserve is a much smaller market. Looking at the flexible unit sector of the synchronized reserve market from January through June, 2013, the hourly average HHI (all hours in which a market was cleared and flexible units were part of the market) was 8790.

The MMU estimates that in January through June, 2013, 6.1 percent of hours in the Mid-Atlantic Dominion Subzone would have failed a three pivotal supplier test (Table 9-12). This is significantly lower than the 40 percent that the MMU calculates would have failed the three pivotal supplier test

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28 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 60 (June 1, 2013), p. 73.
29 See the *2012 State of the Market Report for PJM*, Volume II, Appendix F, Ancillary Service Markets, Synchronized Reserve Market Clearing. With shortage pricing, PJM divided synchronized reserve into flexible and inflexible. A synchronized reserve resource can be either flexible or inflexible, but not both. Inflexible resources must be dispatched, which means incurring lost opportunity costs and/or startup and fuel costs associated with their synchronized reserve dispatch point. Flexible units can respond more quickly to a spinning event and need not be moved from their economic dispatch at the time the ASO or IT SCED runs.

in January through June, 2012. The reason for the decline is the increasing significance of demand response in the supply of synchronized reserve. Demand response MW were 43.6 percent of the settled synchronized reserve Tier 2 MW in January through June, 2013. These results indicate that the Mid-Atlantic Dominion Sub-zone, the only synchronized reserve market that clears on a regular basis, is not structurally competitive.

Table 9-16 Mid-Atlantic Dominion Subzone[30] Synchronized Reserve Market monthly three pivotal supplier results: 2010, 2011, 2012, and 2013

Month	2013 Percent of Hours Pivotal	2012 Percent of Hours Pivotal	2011 Percent of Hours Pivotal	2010 Percent of Hours Pivotal
Jan	1%	45%	92%	64%
Feb	11%	40%	99%	49%
Mar	7%	38%	74%	65%
Apr	8%	33%	83%	31%
May	10%	15%	46%	45%
Jun	0%	29%	14%	10%
Jul		10%	19%	23%
Aug		3%	25%	18%
Sep		4%	56%	17%
Oct		9%	73%	54%
Nov		17%	84%	83%
Dec		25%	88%	40%

Market Conduct

Offers

Daily cost based offer prices are submitted for each unit by the unit owner, and PJM adds opportunity cost calculated using the average of 5-minute LMPs, which together comprise the total offer for each unit to the Synchronized Reserve Market. The synchronized reserve offer made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW, plus lost opportunity cost. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost. Figure 9-10 shows the daily average of hourly offered Tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion

30 Note that the market expanded in October 2012 with the addition of Dominion.

Synchronized Reserve Sub-zone. Note that the geography of the RTO zone and the Mid-Atlantic subzone changed on October 1 with shortage pricing.

While offer volumes increased after October 1, 2012, because PJM adopted a new rule making synchronized reserve a must-offer for all generation that are on-line, non-emergency, and available for energy, compliance with this rule has been slow. The MMU along with PJM have begun efforts to clarify the must offer rules and to make participants aware of this requirement.

Figure 9-10 Tier 2 synchronized reserve average hourly offer volume (MW): January 2012 through June 2013

Synchronized reserve is offered by steam, CT, hydroelectric and DSR resources. Figure 9-11 shows average offer MW volume by market and unit type.

Figure 9-11 Average daily Tier 2 synchronized reserve offer by unit type (MW): January through June 2013

DSR
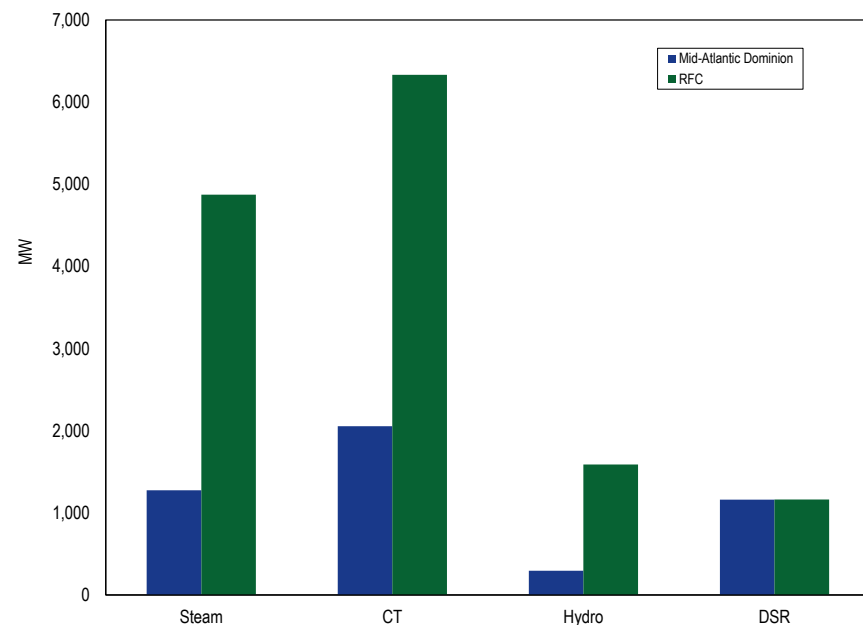
Demand-side resources were permitted to participate in the Synchronized Reserve Markets effective August, 2006. DSR has a significant impact on the Synchronized Reserve Market. As currently implemented in the Synchronized Reserve Market, DSR is always an inflexible resource. In January through June 2013, DSR was 43.6 percent of all cleared Tier 2 synchronized reserves, compared to 22 percent for the same period in 2012. In 14.3 percent of the hours in which synchronized reserve was cleared, all cleared MW were DSR

(Table 9-17). In the hours when all cleared MW were DSR, the simple average SRMCP was $0.08. The simple average SRMCP for all cleared hours was $6.38.

Table 9-17 Weighted average SRMCP, weighted average SRMCP when all cleared synchronized reserve is DSR, and percent of all cleared hours that all cleared synchronized reserve is DSR: January through June 2013 for Mid-Atlantic Dominion Sub-zone

Year	Month	Average SRMCP	Average SRMCP when all cleared synchronized reserve is DSR	Percent of cleared hours all synchronized reserve is DSR
2012	Oct	$16.15	$1.69	2%
2012	Nov	$11.44	$0.72	4%
2012	Dec	$5.06	$0.40	5%
2013	Jan	$9.96	$0.13	16%
2013	Feb	$3.42	$0.07	8%
2013	Mar	$7.27	$0.05	18%
2013	Apr	$3.66	$0.00	18%
2013	May	$8.57	$0.25	19%
2013	Jun	$5.37	$0.00	7%

Market Performance

Price

Figure 9-12 shows the weighted average Tier 2 price and the cost per MW associated with meeting synchronized reserve demand in the Mid-Atlantic Dominion Sub-zone. The price of Tier 2 synchronized reserve is the Synchronized Reserve Market Clearing Price (SRMCP).

Table 9-18 shows the monthly weighted average SRMCP, all credits including LOC credits, MW scheduled by PJM, and MW added by either the IT SCED or RT SCED for the Mid-Atlantic Dominion subzone. The weighted average price for synchronized reserve in the Mid-Atlantic Dominion Subzone in January through June 2013 was $7.45 while the corresponding cost of synchronized reserve was $12.77. The price for synchronized reserve in January through June 2012 was $6.32 while the cost was $8.16.

Table 9-18 Mid-Atlantic Dominion Sub-zone weighted synchronized reserve market clearing prices, credits, and MWs: January through June 2013

Year	Month	Weighted Synchronized Reserve Market Clearing Price	Synchronized Reserve Credits	PJM Tier 2 and DSR Scheduled Synchronized Reserve MW	Flexible Synchronized Reserve Added by SCED (MW)	Self Scheduled MW
2013	Jan	$9.96	$1,217,854	66,632	15,270	102
2013	Feb	$3.42	$1,203,289	86,561	41,251	598
2013	Mar	$7.27	$2,275,995	124,913	14,727	0
2013	Apr	$3.66	$938,914	103,892	3,362	165
2013	May	$8.57	$766,400	45,746	5,815	140
2013	Jun	$5.37	$331,984	22,018	2,988	0

The RTO Reserve Zone synchronized reserve requirement was satisfied by Tier 1 in all but 33 hours of January through June 2013. In the MAD sub-zone the Synchronized Reserve and Primary Reserve Requirements were satisfied by a combination of Tier 1 and non-synchronized reserve in 69 percent of hours from January through June 2013. In the 31 percent of hours when synchronized reserve was needed to fill the synchronized reserve and/or primary reserve requirement the maximum clearing price was $207.42 and the weighted average clearing price was $7.17.

Price and Cost

A price to cost ratio close to 1.0 is an indicator of an efficient market design. In the Mid-Atlantic Subzone of the RFC Synchronized Reserve Market for January through June 2013, the price of Tier 2 synchronized reserves was 56 percent of the cost. In January through June 2012, the price to cost ratio was 79 percent.

Figure 9-12 Comparison of Mid-Atlantic Dominion Subzone Tier 2 synchronized reserve weighted average price and cost (Dollars per MW): January through June 2013
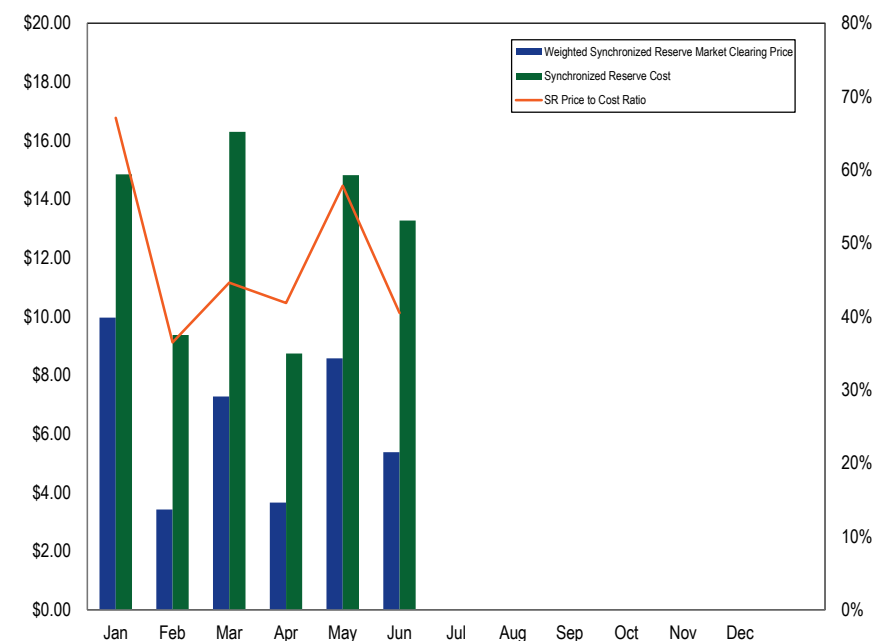
Table 9-19 shows the price and cost history of the Synchronized Reserve Market since 2005.

Year	Weighted Synchronized Reserve Market Price	Weighted Synchronized Reserve Cost	Synchronized Reserve Price as Percent of Cost
2005 (Jan–Jun)	$11.77	$15.52	76%
2006 (Jan–Jun)	$12.10	$18.25	66%
2007 (Jan–Jun)	$20.08	$22.89	88%
2008 (Jan–Jun)	$11.86	$17.46	68%
2009 (Jan–Jun)	$5.89	$10.15	58%
2010 (Jan–Jun)	$8.92	$12.13	74%
2011 (Jan–Jun)	$12.18	$15.72	77%
2012 (Jan–Jun)	$6.32	$8.16	77%
2013 (Jan–Jun)	$7.45	$12.77	58%

Before shortage pricing the reason for relatively low actual price to cost ratio was the difference in opportunity cost calculated using the forecast LMP and the actual LMP. In addition, the low price to cost ratio was in part a result of out of market purchases of Tier 2 synchronized reserve when PJM dispatchers needed the reserves for reliability reasons (Table 9-18). The problem of lower forecast LMPs than real-time LMPs was solved by the use of real-time pricing. But PJM Dispatch continues to add MW to the solved requirement.

Beginning with Shortage Pricing on October 1, 2012, PJM expanded its use of Tier 1 biasing (a technical term). Each market clearing engine (ASO, IT SCED, and RT SCED) can have its Tier 1 estimate manually biased. Negative Tier 1 biasing refers to the manual subtraction from the Tier 1 estimate that the market clearing engines uses to determine how much Tier 2 MW to schedule. A negative bias reduces the amount of Tier 1 estimated to be available and therefore increases the amount of inflexible Tier 2 which must be purchased. A negative bias means purchasing more inflexible Tier 2 MW than the market clearing software estimates it needs before the hour. The increased inflexible Tier 2 resources need to be compensated for their LOC and they must be paid even if they are not needed in real-time. This leads to Tier 2 synchronized reserves being assigned and paid when they are not needed or when the price

is zero. A price of $0 means that the Tier 2 synchronized reserve requirement was determined to be zero because there was enough Tier 1. From January through June, 2013, a total of 76,086 MW of Tier 2 synchronized reserve was purchased for hours when the price was later calculated to be $0. The charges (to compensate for lost opportunity costs) for this synchronized reserve were $407,193.

Between January and June, 2013 PJM has moderated its use of Tier 1 bias. Figure 9-14 shows by month the percentage of all hours ASO had its Tier 1 estimate biased. IT SCED biasing did not occur in Q2, 2013. RT SCED Tier 1 biasing occurred in April for a total of 47 hours, averaging 337 MW. In every hour which RT SCED Tier 1 biasing was used, it was used to add Tier 1 to the estimate, thereby lessening the need to schedule additional Tier 2 synchronized reserve.

Figure 9-13 Impact of flexible Tier 2 synchronized reserve added by IT SCED and RT SCED to the Mid-Atlantic Dominion Subzone: January through June 2013
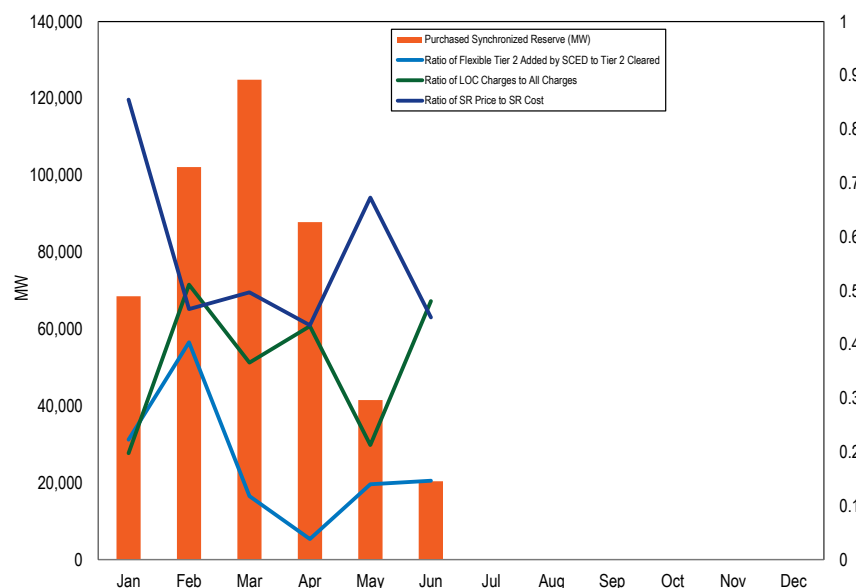
Figure 9-14 Use of ASO Tier 1 Estimate Biasing in the Middle Atlantic Dominion sub-zone: January through June 2013
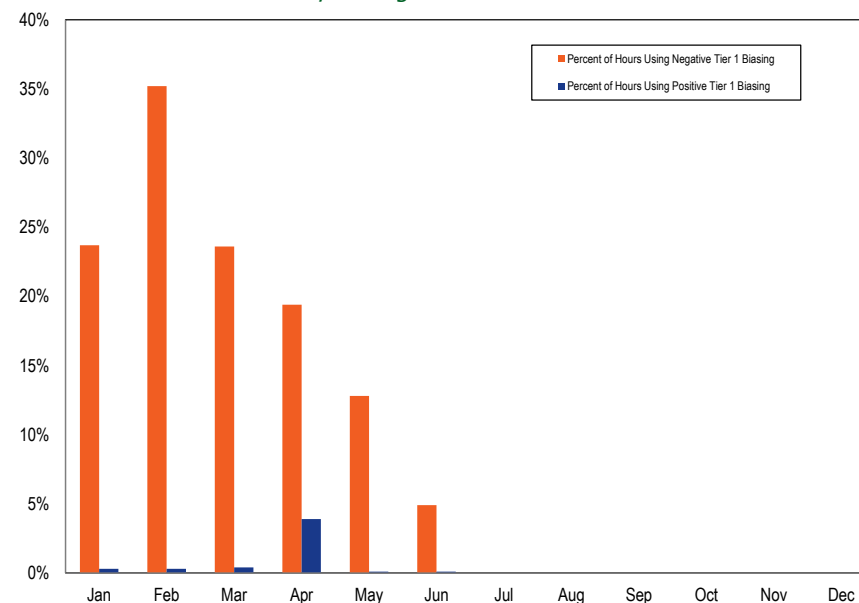
PJM gives several reasons for Tier 1 biasing: sometimes units do not achieve the ramp rate they have bid, sometimes units fail to follow PJM dispatch, and sometimes system conditions change rapidly during the hour between a market solution and the actual hour.

The MMU recommends that PJM be more explicit about why Tier 1 biasing is used. The MMU recommends that PJM define rules for calculating available Tier 1 MW and for the use of biasing during any phase of the market solution and then identify the relevant rule for each instance of biasing.

Compliance

Non-compliance in the Synchronized Reserve Market remains a problem. Non-compliance has two major components: failure to deliver cleared Tier 2 Synchronized Reserve MW during spinning events; and failure of non-emergency, generation resources capable of providing energy to provide a daily synchronized reserve offer.

The MMU has expressed increasing concern over noncompliance by Tier 2 synchronized reserve resources during spinning events since 2011.[31] When synchronized reserve resources clear the Synchronized Reserve Market they are obligated to provide their full cleared Tier 2 MW in a spinning event. The MMU has observed a wide range of spinning event response levels, presented its data to PJM and urged PJM to take action to increase compliance rates. For spinning events in January through June, 2013, longer than 10 minutes, approximately half of the generation providers offering more than half of the cleared synchronized reserve complied at a rate of less than 70 percent of their committed synchronized reserve MW. For demand response providers the compliance rate was worse with approximately half of the providers and 75 percent of the committed synchronized reserve MW complying at less than a 70 percent rate. In April, 2013, PJM through its Operating Committee began to address this problem. Several possible remedies are proposed and under consideration. The must-offer requirement for synchronized reserve changes the market, the nature of offers, and the penalty for non-compliance.

The Shortage Pricing changes introduced on October 1, 2012, included a must offer requirement for most generators under normal conditions, and an expanded set of generators under well-defined abnormal conditions related to peak load. For all hours, all on-line, non-emergency, generating resources that are providing energy and are capable of providing synchronized reserve are deemed available for Tier 1 and Tier 2 synchronized reserve and they must have an offer and be available for reserve. When PJM issues a Primary Reserve Warning, Voltage Reduction Warning, or Manual Load Dump Warning, all other non-emergency, generation capacity resources must have an offer and be available for reserve. PJM members were reminded of this rule change at

the June 5, 2013 Operating Committee meeting and PJM directed the MMU to enforce it. As of June 30, 2013, a significant number of generators are non-compliant.

FERC Order 719 imposes a synchronized reserve must-offer requirement. The MMU recommends that PJM remove the distinction between Tier 1 and Tier 2 synchronized reserve, remove the ability of participants to offer MW of synchronized reserve capability, remove the ability of participants to make reserve unavailable, and automatically dispatch primary reserve co-optimized with energy. In the interim, PJM should enforce a must-offer requirement for synchronized reserve based on physical capability (with physical capability the default offer) and increase penalties for non-compliance during spinning events.

History of Spinning Events

Spinning events (Table 9-20) are usually caused by a sudden generation outage or transmission disruption requiring PJM to load synchronized reserve.[32] The reserve remains loaded until system balance is recovered. From January 2010 through June 2013, PJM experienced 104 spinning events, or between two and three events per month. Spinning events had an average length of 12.7 minutes.

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31 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at pg. 250.

32 See PJM. "Manual 12, Balancing Operations," Revision 27 (December 20, 2012), pp. 36-37.

Table 9-20 Spinning Events, January 2010 through June 2013

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
FEB-18-2010 13:27	Mid-Atlantic	19	JAN-11-2011 15:10	Mid-Atlantic	6	JAN-03-2012 16:51	RFC	9	JAN-22-2013 08:34	RTO	8
MAR-18-2010 11:02	RFC	27	FEB-02-2011 01:21	RFC	5	JAN-06-2012 23:25	RFC	8	JAN-25-2013 15:01	RTO	19
MAR-23-2010 20:14	RFC	13	FEB-08-2011 22:41	Mid-Atlantic	11	JAN-23-2012 15:02	Mid-Atlantic	8	FEB-09-2013 22:55	RTO	10
APR-11-2010 13:12	RFC	9	FEB-09-2011 11:40	Mid-Atlantic	16	MAR-02-2012 19:54	RFC	9	FEB-17-2013 23:10	RTO	13
APR-28-2010 15:09	Mid-Atlantic	8	FEB-13-2011 15:35	Mid-Atlantic	14	MAR-08-2012 17:04	RFC	6	APR-17-2013 01:11	RTO	11
MAY-11-2010 19:57	Mid-Atlantic	9	FEB-24-2011 11:35	Mid-Atlantic	14	MAR-19-2012 10:14	RFC	10	APR-17-2013 20:01	RTO	9
MAY-15-2010 03:03	RFC	6	FEB-25-2011 14:12	RFC	10	APR-16-2012 00:20	Mid-Atlantic	9			
MAY-28-2010 04:06	Mid-Atlantic	5	MAR-30-2011 19:13	RFC	12	APR-16-2012 11:18	RFC	8			
JUN-15-2010 00:46	RFC	34	APR-02-2011 13:13	Mid-Atlantic	11	APR-19-2012 11:54	RFC	16			
JUN-19-2010 23:49	Mid-Atlantic	9	APR-11-2011 00:28	RFC	6	APR-20-2012 11:08	Mid-Atlantic	7			
JUN-24-2010 00:56	RFC	15	APR-16-2011 22:51	RFC	9	JUN-20-2012 13:35	RFC	7			
JUN-27-2010 19:33	Mid-Atlantic	15	APR-21-2011 20:02	Mid-Atlantic	6	JUN-26-2012 17:51	RFC	7			
JUL-07-2010 15:20	RFC	8	APR-27-2011 01:22	RFC	8	JUL-23-2012 21:45	RFC	18			
JUL-16-2010 20:45	Mid-Atlantic	19	MAY-02-2011 00:05	Mid-Atlantic	21	AUG-03-2012 12:44	RFC	10			
AUG-11-2010 19:09	RFC	17	MAY-12-2011 19:39	RFC	9	SEP-08-2012 04:34	RFC	12			
AUG-13-2010 23:19	RFC	6	MAY-26-2011 17:17	Mid-Atlantic	20	SEP-27-2012 17:19	Mid-Atlantic	7			
AUG-16-2010 07:08	RFC	17	MAY-27-2011 12:51	RFC	6	OCT-17-2012 10:48	RTO	10			
AUG-16-2010 19:39	Mid-Atlantic	11	MAY-29-2011 09:04	RFC	7	OCT-23-2012 22:29	RTO	19			
SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27	OCT-30-2012 05:12	RTO	14			
SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7	NOV-25-2012 16:32	RTO	12			
OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9	DEC-16-2012 07:01	RTO	9			
OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8	DEC-21-2012 05:51	RTO	7			
OCT-16-2010 03:25	RFCNonMA	7	JUN-26-2011 22:03	Mid-Atlantic	10	DEC-21-2012 10:29	RTO	5			
OCT-27-2010 10:35	RFC	7	JUL-10-2011 11:20	RFC	10						
OCT-27-2010 12:50	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12						
NOV-26-2010 14:24	RFC	13	AUG-02-2011 01:08	RFC	6						
NOV-27-2010 11:34	RFC	8	AUG-18-2011 06:45	Mid-Atlantic	6						
DEC-08-2010 01:19	RFC	11	AUG-19-2011 14:49	RFC	5						
DEC-09-2010 20:07	RFC	5	AUG-23-2011 17:52	RFC	7						
DEC-14-2010 12:02	Mid-Atlantic	24	SEP-24-2011 15:48	RFC	8						
DEC-16-2010 18:40	Mid-Atlantic	20	SEP-27-2011 14:20	RFC	7						
DEC-17-2010 22:09	Mid-Atlantic	6	SEP-27-2011 16:47	RFC	9						
DEC-29-2010 19:01	Mid-Atlantic	15	OCT-30-2011 22:39	Mid-Atlantic	10						
			DEC-15-2011 14:35	Mid-Atlantic	8						
			DEC-21-2011 14:26	RFC	18						

Figure 9-15 Spinning events duration distribution curve, January through June 2010 to 2013
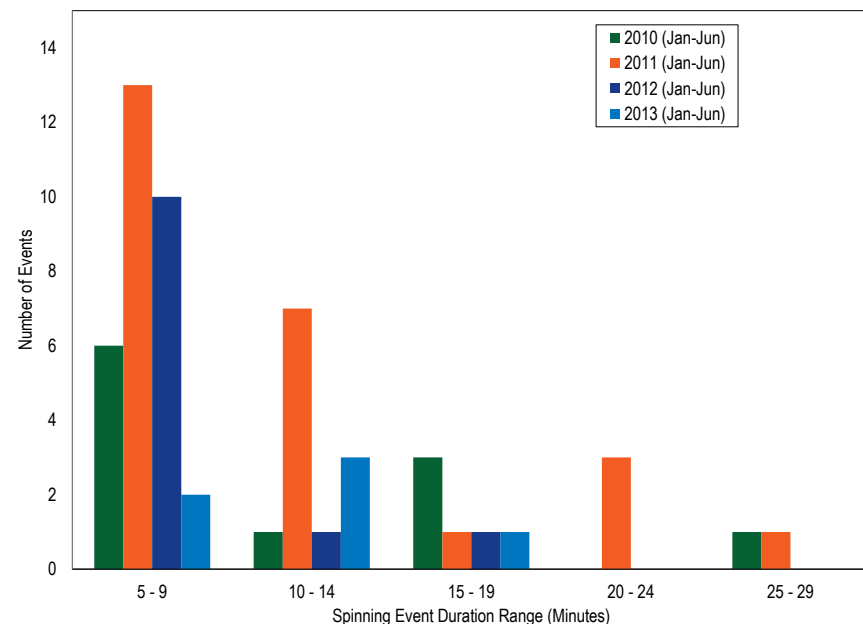
Adequacy

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. No primary reserve shortages occurred between January 1, 2013 and June 30, 2013.

Non-Synchronized Reserve Market

The primary reserve requirement is 150 percent of the largest contingency. For the RTO Reserve Zone this is 2,063 MW. For the Mid-Atlantic Dominion Reserve Zone this is 1,700 MW. The primary reserve requirement can be filled with Tier 1 synchronized reserve, Tier 2 synchronized reserve, or non-synchronized reserve subject to the requirement that there be 1,300 MW of synchronized

reserve in the Mid-Atlantic Dominion Reserve Zone. The Ancillary Services Optimizer determines the most economic combination of these products to fill the balance of the primary reserve requirement. As such there is no pre-defined hourly requirement for non-synchronized reserve.

Non-synchronized reserve is reserve MW available within ten minutes but not synchronized to the grid. PJM specifies that 1,300 MW of synchronized reserve must be available in the Mid-Atlantic Dominion Reserve Zone. The remainder can be made up of non-synchronized reserve. Examples of equipment that generally qualify in this category are shutdown run-of-river, pumped hydro, industrial combustion turbines, jet engine/expander turbines, combined cycle and diesels.[33]

As for Tier 1 synchronized reserve, PJM calculates the amount of non-synchronized reserve available each hour and every five minutes within the hour. The calculation is based upon a unit's startup and notification time, energy ramp rate, and economic minimum. There is no non-synchronized reserve offer price. Prices are determined by the lost opportunity cost created by any deviation from economic merit order required to maintain the non-synchronized reserve commitment. In most hours the non-synchronized reserve clearing price is zero.

Figure 9-16 shows the daily average non-synchronized reserve market clearing price and average scheduled MW. The Mid-Atlantic Dominion Reserve Zone non-synchronized reserve market cleared in 148 hours from January through June, 2013. The clearing price was greater than zero in 111 hours from January through June of 2013 with a maximum of $128.70 on January 22, 2013. The non-synchronized reserve market clearing price for the RTO Reserve Zone cleared in eight hours with a maximum clearing price of $6.50.

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33 See PJM. "Manual 11, Energy & Ancillary Services Market Operations" Revision 60 (June 1, 2013), p. 85.

Figure 9-16 Daily average Non-Synchronized Reserve Market clearing price and MW cleared: January through June 2013
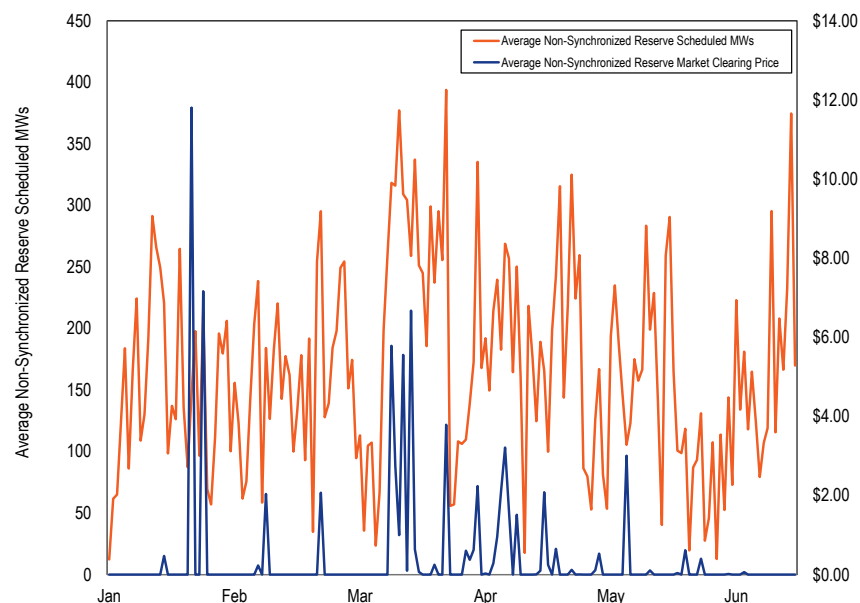
Day Ahead Scheduling Reserve (DASR)

The Day-Ahead Scheduling Reserve Market is a market based mechanism for the procurement of supplemental, 30-minute reserves on the PJM System.[34]

The DASR 30-minute reserve requirements are determined by the reliability region.[35] In the Reliability*First* (RFC) region, reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[36] The RFC and Dominion DASR requirements are added together to form a single RTO DASR requirement which is obtained via the DASR Market. The requirement is applicable for all hours of the operating day.

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34 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.
35 See PJM. "Manual 13, Emergency Requirements," Revision 53 (June 1, 2013), p. 11.
36 See PJM. "Manual 10, Pre-Scheduling Operations," Revision 27 (February 28, 2013), pp. 18-19.

If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.

Market Structure

In 2013, the required DASR is 6.91 percent of peak load forecast, down from 7.03 percent in 2012.[37] The DASR requirement is a sum of the load forecast error and the forced outage rate. From 2012 the load forecast error increased from 1.97 percent to 2.13 percent. The forced outage rate decreased from 4.93 percent to 4.66 percent. Added together, the 2013 DASR requirement is 6.91 percent. The DASR MW purchased averaged 6,614 MW per hour for January through June 2013, a slight decrease from 6,617 MW per hour in 2012.

In January through June, 2013, no hours failed the three pivotal supplier test in the DASR Market. No hours failed the three pivotal supplier test, calculated by the MMU, in January through June, 2012.

Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are also eligible to provide DASR. No demand side resources cleared the DASR market in January through June, 2013.

Market Conduct

PJM rules allow any unit with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[38] Units that do not offer have their offers set to $0.00 per MW.

Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. However, there is a positive opportunity cost in addition to this direct marginal cost, which is not part of the offer price but calculated by PJM. As of June 30, 2013, 13 percent of all units offered DASR at levels above $5 per MW. The impact on DASR prices of high offers was minor as a result of a favorable balance between supply and demand.

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37 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at Day Ahead Scheduling Reserve (DASR).
38 See PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 60 (June 1, 2013), p. 143.

Market Performance

For 90 percent of hours in January through June, 2013, DASR cleared at a price of $0.00 (Figure 9-17). For January through June 2013, the weighted DASR price was $0.06. The highest price was $23.37 on May 30, 2013. DASR prices are calculated as the sum of the offer price plus the opportunity cost. For most hours the price is comprised entirely of offer price. When the DASR clearing price is greater than $0, 91 percent of the time the price consists solely of the offer price. The breakdown of price into offer and LOC is in Figure 9-17.

Table 9-21 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: January through June 2012 and 2013

Year	Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Weighted Average Clearing Price	Total DASR MW Purchased	Total DASR Credits
2013	Jan	6,965	$0.00	$2.00	$0.01	5,182,020	$45,337
2013	Feb	6,955	$0.00	$0.75	$0.00	4,673,491	$20,062
2013	Mar	6,543	$0.00	$1.00	$0.02	4,861,811	$75,071
2013	Apr	5,859	$0.00	$0.05	$0.00	4,218,720	$8,863
2013	May	6,129	$0.00	$23.37	$0.20	4,560,238	$873,943
2013	Jun	7,262	$0.00	$15.88	$0.12	5,228,554	$615,557
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
2012	Apr	5,854	$0.00	$0.10	$0.00	4,214,993	$5,572
2012	May	6,491	$0.00	$5.00	$0.05	4,829,220	$226,881
2012	Jun	7,454	$0.00	$156.29	$2.39	5,366,935	$11,422,377

Figure 9-17 Hourly components of DASR clearing price: January through June 2013
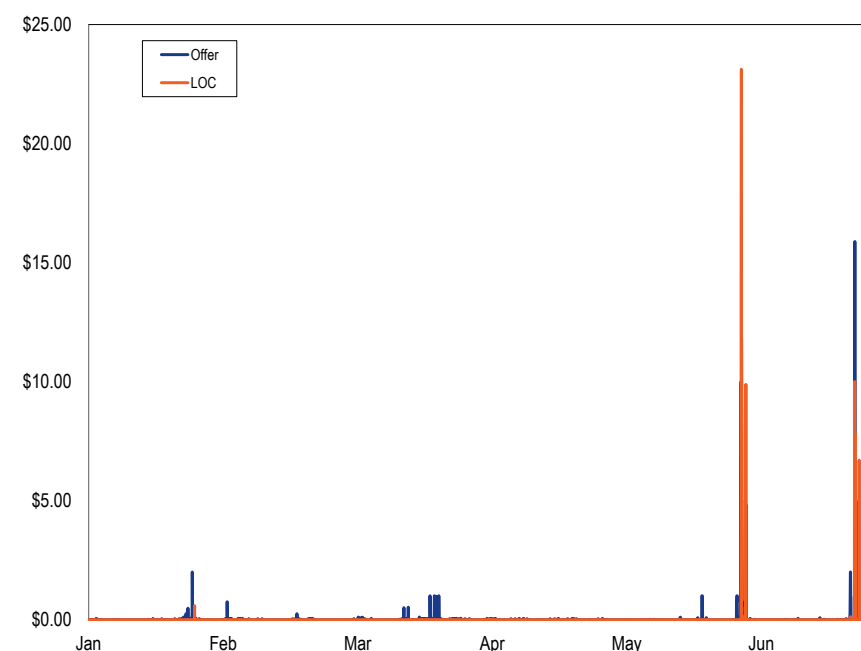
Black Start Service

Black start service is necessary to help ensure the reliable restoration of the grid following a blackout. Black start service is the ability of a generating unit to start without an outside electrical supply, or the demonstrated ability of a generating unit to automatically remain operating when disconnected from the grid.

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of an incentive rate or for the costs associated with providing this service.

Individual transmission owners, with PJM, identify the black start units included in each transmission owner's system restoration plan. PJM defines required black start capability zonally and ensures the availability of black start service by charging transmission customers according to their zonal load ratio share and compensating black start unit owners. (Table 9-22)

Following a stakeholder process in the System Restoration Strategy Task Force (SRSTF), substantial changes to the black start restoration and procurement strategy were introduced. The PJM and MMU proposal for system restoration was approved at the February 28, 2013, Markets and Reliability Committee (MRC).

The proposed changes include allowing PJM more flexibility in procuring black start resources by allowing cross zonal coordination between transmission zones, clarifying the responsibility for black start resources selection, revising the timing requirement for black start from 90 minutes to three hours, and implementing a process to revise black start plans on a five year basis in order to ensure system restoration needs are met. This proposal is a substantial improvement to current system restoration strategy, which does not give PJM adequate flexibility in procuring black start resources. This proposal also clarifies that PJM is the entity responsible for selecting the appropriate black start resources for each transmission zone based on system restoration requirements.

Black start payments are non-transparent payments made to units on the behalf of load to maintain adequate reliability to restart the system in case of a blackout. Current rules appear to prevent the publishing detailed data regarding these black start resources, hindering transparency and competitive replacement RFPs. The MMU recommends PJM revise the current confidentiality rules in order to specifically allow a more transparent disclosure of information regarding black start resources and their associated payments in PJM.

In January through June 2013, black start credits were $58.5 million. Black start zonal credits in January through June 2013 ranged from $0.03 per MW

in the ATSI zone (total credits: $70,284) to $11.42 per MW in the AEP zone (total credits: $48,178,521). For each zone, Table 9-22 shows black start revenue requirement credits, black start operating reserve credits, and black start rates (calculated as credits per MW).

Table 9-22 Black start zonal credits for network transmission use: January through June 2013

Zone	Revenue Requirement Credits	Operating Reserve Credits	Black Start Rate ($/MW)
AECO	$281,884	$10,562	$0.58
AEP	$326,715	$47,851,806	$11.42
AP	$115,656	$3,211	$0.08
ATSI	$70,284		$0.03
BGE	$3,856,607	$6,079	$3.05
ComEd	$2,113,689	$13,303	$0.50
DAY	$123,779	$5,530	$0.20
DEOK	$167,948	$2,604	$0.17
DLCO	$30,291		$0.05
DPL	$295,076	$2,978	$0.40
EKPC	$32,271		$0.45
JCPL	$294,472		$0.26
Met-Ed	$382,123	$7,084	$0.71
PECO	$703,854	$29,505	$0.47
PENELEC	$274,994		$0.52
Pepco	$142,327	$7,242	$0.12
PPL	$91,658		$0.07
PSEG	$1,269,863	$34,625	$0.69

Congestion and Marginal Losses

The Locational Marginal Price (LMP) is the incremental price of energy at a bus. The LMP at a bus is made up of three components: the system marginal price or energy component (SMP), the marginal loss component of LMP (MLMP), and the congestion component of LMP (CLMP).[1]

SMP, MLMP and CLMP are products 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. Total losses refer to the total system-wide transmission losses as a result of moving power from injections to withdrawals on the system. Total system-wide transmission losses for the first six months of 2013 were 8,622 GWh, a 6.5 percent increase compared to the first six months of 2012. Marginal losses are the incremental change in system losses caused by changes in load and generation. Congestion occurs when available, least-cost energy cannot be delivered to all load because transmission facilities are not adequate to deliver that energy and higher cost units in the constrained area must be dispatched to meet that load.[2] The result is that the price of energy in the constrained area is higher than in the unconstrained area.

Congestion is neither good nor bad but is a direct measure of the extent to which there are multiple marginal generating units dispatched to serve load as a result of transmission constraints.

The energy, marginal losses and congestion metrics must be interpreted carefully. The term total congestion refers to what is actually net congestion, which is calculated as net implicit congestion costs plus net explicit congestion costs plus net inadvertent congestion charges. The net implicit congestion

costs are the load congestion payments less generation congestion credits. This section refers to total energy costs and total marginal loss costs in the same way. As with congestion, total energy costs are more precisely termed net energy costs and total marginal loss costs are more precisely termed net marginal loss costs.

The components of LMP are the basis for calculating participant and location specific congestion and marginal losses.[3, 4]

Overview

Energy Cost

- **Total Energy Costs.** Total energy costs in the first six months of 2013 decreased by $70.6 million or 26.9 percent from the first six months of 2012, from -$262.0 million to -$332.6 million. Day-ahead net energy costs in the first six months of 2013 decreased by $110.4 million or 45.6 percent from the first six months of 2012, from -$241.9 million to -$352.2 million. Balancing net energy costs in the first six months of 2013 increased by $48.5 million or 177.2 percent from the first six months of 2012, from -$27.4 million to $21.1 million.

- **Monthly Total Energy Costs.** Significant monthly fluctuations in total energy costs were the result of load and energy import levels, and changes in dispatch of generation. Monthly total energy costs in the first six months of 2013 ranged from -$63.0 million in January to -$46.5 million in April.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs in the first six months of 2013 increased by $49.6 million or 11.2 percent from the first six months of 2012, from $444.9 million to $494.5 million. Day-ahead net marginal loss costs in the first six months of 2013 increased by $79.5 million or 17.1 percent from the first six months of 2012, from $466.5

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1 On January 1, 2012, PJM integrated the Duke Energy Ohio/Kentucky (DEOK) Control Zone. On June 1, 2013, PJM integrated the East Kentucky Power Cooperative (EKPC) Control Zone. The metrics reported in this section treat DEOK as part of MISO for the first hour of January 2012 and as part of PJM for the second hour of January through December 2012. The metrics reported in this section treat EKPC as part of MISO for the first hour of June 2013 and as part of PJM for the second hour of June through June 2013.

2 This is referred to as dispatching units out of economic merit order. Economic merit order is the order of all generator offers from lowest to highest cost. Congestion occurs when loadings on transmission facilities mean the next unit in merit order cannot be used and a higher cost unit must be used in its place. Dispatch within the constrained area follows merit order for the units available to relieve the constraint.

3 The total marginal loss and congestion results were calculated as of July 18, 2013, and are subject to change, based on continued PJM billing updates.

4 For more details on the concepts in this section, see the *2012 State of the Market Report for PJM, Volume II: Section 10,* "Congestion and Marginal Losses."

million to $546.0 million. Balancing net marginal loss costs decreased in the first six months of 2013 by $29.9 million or 138.5 percent from the first six months of 2012, from -$21.6 million to -$51.5 million.

- **Monthly Total Marginal Loss Costs.** Significant monthly fluctuations in total marginal loss costs were the result of changes in load and energy import levels, and changes in the dispatch of generation. Monthly total marginal loss costs in the first six months of 2013 ranged from $66.2 million in April to $101.1 million in January.

- **Marginal Loss Credits.** Marginal Loss Credits are calculated as total energy costs (net energy costs minus net energy credits plus net inadvertent energy charges) plus total marginal loss costs (net marginal loss costs minus net marginal loss credits plus net explicit loss costs plus net inadvertent loss charges) plus net residual market adjustments. Marginal loss credit or loss surplus is the remaining loss amount from overcollection of marginal losses, after accounting for total net energy costs and net residual market adjustments, which is paid back in full to load and exports on a load ratio basis.[5] The marginal loss credits decreased in the first six months of 2013 by $20.8 million or 11.4 percent from the first six months of 2012, from $182.1 million to $161.3 million.

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $42.8 million or 16.3 percent, from $263.3 million in the first six months of 2012 to $306.1 million in the first six months of 2013.[6]

- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $137.5 million or 35.3 percent, from $389.6 million in the first six months of 2012 to $527.1 million in the first six months of 2013.

- **Balancing Congestion.** Balancing congestion costs decreased by $94.7 million or 74.9 percent from -$126.4 million in the first six months of 2012 to -$221.1 million in the first six months of 2013.

- **Monthly Congestion.** Monthly congestion costs in the first six months of 2013 ranged from $27.8 million in April to $77.4 million in February.

- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM was primarily a result of congestion on the AP South interface, the Readington - Roseland and Laporte – Michigan line, the Cloverdale transformers, and the West Interface. (Table 10-27)

- **Congested Facilities.** Congestion frequency continued to be significantly higher in the Day-Ahead Market than in the Real-Time Market in the first six months of 2013. Day-ahead congestion frequency increased by 62.8 percent from 106,904 congestion event hours in the first six months of 2012 to 174,063 congestion event hours in the first six months of 2013. Day-ahead, congestion-event hours decreased on the flowgates while congestion frequency on internal PJM interfaces, transmission lines and transformers increased.

Real-time congestion frequency increased by 7.8 percent from 9,260 congestion event hours in the first six months of 2012 to 9,984 congestion event hours in the first six months of 2013. Real-time, congestion-event hours increased on the flowgates, the interfaces, and the transformers, and the transmission lines.

Facilities were constrained in the Day-Ahead Market more frequently than in the Real-Time Market. In the first six months of 2013, for only 2.1 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. In the first six months of 2013, for 38.0 percent of Real-Time Market facility constrained hours, the same facilities were also constrained in the Day-Ahead Market.

The AP South Interface was the largest contributor to congestion costs in the first six months of 2013. With $104.3 million in total congestion costs, it accounted for 34.1 percent of the total PJM congestion costs in the first six months of 2013. The top five constraints in terms of congestion costs together contributed $132.2 million, or 43.2 percent, of the total PJM congestion costs in the first six months of 2013. The top five constraints

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5 See PJM. "Manual 28: Operating Agreement Accounting," Revision 60 (June 1, 2013). Note that the over collection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.
6 The total zonal congestion numbers were calculated as of July 18, 2013, and are based on continued PJM billing updates, subject to change.

were the AP South and West interfaces, the Readington – Roseland and the Laporte – Michigan transmission lines, and the Cloverdale transformer.

- **Zonal Congestion.** ComEd was the most congested zone in the first six months of 2013. ComEd had -$201.9 million in total load costs, -$277.4 million in total generation credits and -$8.6 million in explicit congestion, resulting in $66.9 million in net congestion costs, reflecting significant local congestion between local generation and load, despite being on the upstream side of system wide congestion patterns. The AP South interface, the Braidwood transformer, the Crete - St Johns Tap and Prairie State - W Mt. Vernon flowgates and the Braidwood - East Frankfort line contributed $25.6 million, or 38.3 percent of the total ComEd Control Zone congestion costs.

  The AP Control Zone was the second most congested zone in PJM in the first six months of 2013, with $50.2 million. The AP South interface contributed $33.4 million or 66.5 percent of the total AP Control Zone congestion cost in first six months of 2013. The Dominion Control Zone was the third most congested zone in PJM in the first six months of 2013, with a cost of $39.7 million.

- **Ownership.** In the first six months of 2013, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. In the first six months of 2013, financial companies received $54.3 million in net congestion credits, an increase of $11.5 million or 26.6 percent compared to the first six months of 2012. In the first six months of 2013, physical companies paid $360.7 million in net congestion charges, an increase of $54.3 million or 17.7 percent compared to the first six months of 2012.

Conclusion

Energy costs are the incremental costs to the system, which are the same at every bus for each hour, without taking losses and congestion into account.

Marginal losses are the costs of incremental power losses which result from the geographic distribution of generation and load and the physical characteristics of the transmission system interconnecting generation and load. When calculating marginal losses, load is charged and generation is credited for the power losses to the system. Marginal loss costs had been decreasing since 2010, due to decreases in LMP and fuel costs. However, increases in the LMP and fuel costs have led to higher marginal loss costs in the first six months of 2013 compared to the first six months of 2012. Total marginal loss costs increased in the first six months of 2013 by $49.6 million or 11.2 percent from the first six months of 2012, from $444.9 million to $494.5 million.

Congestion reflects the underlying characteristics of the power system, including the nature and capability of transmission facilities, the offers and geographic distribution of generation facilities and the geographic distribution of load.

ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 88.8 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2011 to 2012 planning period. In the 2012 to 2013 planning period, total ARR and FTR revenues offset 92.6 percent of the congestion costs. FTRs were paid at 80.6 percent of the target allocation level for the 2011 to 2012 planning period, and at 67.8 percent of the target allocation level for the 2012 to 2013 planning period.[7] Revenue adequacy, measured relative to target allocations for a planning period is not final until the end of the period.

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7   See the *2012 State of the Market Report for PJM, Volume II: Section 12*, "Financial Transmission and Auction Revenue Rights," at Table 12-23, "Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2011 to 2012 and 2012 to 2013."

Locational Marginal Price (LMP)
Components

Table 10-1 shows the PJM real-time, load-weighted average LMP components for the first six months of 2009 to 2013. The load-weighted average real-time LMP increased $6.75 or 21.9 percent from $31.21 in the first six months of 2012 to $37.96 in the first six months of 2013. The load-weighted average congestion component decreased $0.01 or 35.9 percent from $0.04 in the first six months of 2012 to $0.02 in the first six months of 2013. The load-weighted average loss component increased $0.01 or 145.8 percent from $0.01 in the first six months of 2012 to $0.02 in the first six months of 2013. The load-weighted average energy component increased $6.75 or 21.7 percent from $31.17 in the first six months of 2012 to $37.92 in the first six months of 2013.

Table 10-1 PJM real–time, load–weighted average LMP components (Dollars per MWh): January through June of 2009 through 2013

(Jan–Jun)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	$42.48	$42.40	$0.05	$0.03
2010	$45.75	$45.65	$0.06	$0.04
2011	$48.47	$48.40	$0.05	$0.03
2012	$31.21	$31.17	$0.04	$0.01
2013	$37.96	$37.92	$0.02	$0.02

Table 10-2 shows the PJM day-ahead, load-weighted average LMP components for the first six months of 2009 through 2013. The load-weighted average day-ahead LMP increased $6.40 or 20.1 percent from $31.83 in the first six months of 2012 to $38.23 in the first six months of 2013. The load-weighted average congestion component decreased $0.01 or 13.0 percent from $0.10 in the first six months of 2012 to $0.09 in the first six months of 2013. The load-weighted average loss component increased $0.03 or 113.0 percent from -$0.02 in the first six months of 2012 to $0.00 in the first six months of 2013. The load-weighted average energy component increased $6.39 or 20.1 percent from $31.76 in the first six months of 2012 to $38.14 in the first six months of 2013.

Table 10-2 PJM day-ahead, load–weighted average LMP components (Dollars per MWh): January through June of 2009 through 2013

(Jan–Jun)	Day–Ahead LMP	Energy Component	Congestion Component	Loss Component
2009	$42.21	$42.47	($0.14)	($0.12)
2010	$46.12	$46.04	$0.08	$0.00
2011	$47.12	$47.32	($0.10)	($0.11)
2012	$31.83	$31.76	$0.10	($0.02)
2013	$38.23	$38.14	$0.09	$0.00

Zonal Components

The real-time components of LMP for each PJM control zone are presented in Table 10-3 for the first six months of 2012 and 2013. The day-ahead components of LMP for each control zone are presented in Table 10-4 for the first six months of 2012 and 2013.

Table 10-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): January through June of 2012 and 2013

	2012 (Jan–Jun)				2013 (Jan–Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$31.72	$31.37	($0.59)	$0.94	$39.42	$37.91	$0.04	$1.48
AEP	$29.98	$30.95	($0.33)	($0.64)	$35.98	$37.77	($0.96)	($0.84)
AP	$31.50	$31.10	$0.35	$0.05	$37.49	$37.87	($0.25)	($0.12)
ATSI	$30.32	$31.02	($0.79)	$0.09	$37.08	$37.78	($1.02)	$0.32
BGE	$36.38	$31.39	$3.48	$1.51	$43.07	$38.15	$3.14	$1.78
ComEd	$28.09	$31.05	($1.49)	($1.47)	$32.58	$37.72	($3.21)	($1.94)
DAY	$30.81	$31.12	($0.51)	$0.20	$36.33	$37.94	($1.62)	$0.00
DEOK	$29.41	$31.13	($0.43)	($1.29)	$34.56	$37.92	($1.60)	($1.75)
DLCO	$30.31	$31.02	$0.11	($0.83)	$34.89	$37.83	($1.62)	($1.32)
Dominion	$33.09	$31.42	$1.25	$0.42	$40.58	$38.20	$1.94	$0.44
DPL	$33.74	$31.35	$1.10	$1.28	$40.43	$38.10	$0.46	$1.87
EKPC	NA	NA	NA	NA	$34.68	$37.71	($1.12)	($1.91)
JCPL	$32.41	$31.63	($0.21)	$0.99	$40.84	$38.24	$0.98	$1.62
Met-Ed	$31.62	$31.20	$0.03	$0.39	$38.87	$37.96	$0.19	$0.72
PECO	$31.33	$31.26	($0.55)	$0.62	$38.42	$37.94	($0.45)	$0.93
PENELEC	$31.17	$30.89	($0.19)	$0.47	$38.30	$37.69	$0.10	$0.50
Pepco	$35.43	$31.42	$3.03	$0.97	$42.42	$38.21	$2.94	$1.27
PPL	$31.09	$31.14	($0.45)	$0.40	$38.50	$37.89	($0.04)	$0.65
PSEG	$32.14	$31.30	($0.24)	$1.08	$44.76	$37.93	$5.41	$1.42
RECO	$31.86	$31.79	($0.90)	$0.97	$47.44	$38.34	$7.79	$1.32
PJM	$31.21	$31.17	$0.04	$0.01	$37.96	$37.92	$0.02	$0.02

Table 10-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through June of 2012 and 2013

	2012 (Jan–Jun)				2013 (Jan–Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$33.09	$32.13	($0.04)	$1.01	$39.70	$38.26	($0.08)	$1.53
AEP	$30.56	$31.57	($0.28)	($0.74)	$36.19	$38.02	($1.00)	($0.84)
AP	$32.01	$31.68	$0.26	$0.08	$37.52	$38.09	($0.44)	($0.13)
ATSI	$30.75	$31.60	($0.75)	($0.09)	$37.05	$38.11	($1.18)	$0.13
BGE	$37.29	$32.07	$3.46	$1.76	$43.19	$38.34	$3.12	$1.72
ComEd	$28.11	$31.72	($1.74)	($1.87)	$33.25	$38.04	($2.83)	($1.96)
DAY	$31.43	$31.84	($0.46)	$0.05	$36.75	$38.22	($1.37)	($0.10)
DEOK	$29.90	$31.69	($0.26)	($1.53)	$35.11	$38.08	($1.38)	($1.59)
DLCO	$31.20	$31.71	$0.34	($0.85)	$35.24	$38.12	($1.55)	($1.33)
Dominion	$33.91	$32.06	$1.29	$0.56	$40.78	$38.50	$1.92	$0.35
DPL	$34.55	$32.07	$0.86	$1.62	$40.73	$38.24	$0.58	$1.92
EKPC	NA	NA	NA	NA	$35.28	$38.38	($1.16)	($1.93)
JCPL	$33.38	$32.22	$0.07	$1.09	$41.07	$38.42	$0.93	$1.71
Met-Ed	$32.25	$31.62	$0.20	$0.43	$38.94	$37.99	$0.29	$0.67
PECO	$32.34	$31.89	($0.25)	$0.70	$38.82	$38.11	($0.24)	$0.95
PENELEC	$31.97	$31.45	($0.09)	$0.61	$38.92	$37.95	$0.24	$0.73
Pepco	$36.10	$31.93	$2.85	$1.32	$42.49	$38.21	$3.04	$1.24
PPL	$31.65	$31.63	($0.30)	$0.32	$38.73	$38.01	$0.13	$0.58
PSEG	$33.46	$32.04	$0.12	$1.29	$44.93	$38.32	$4.98	$1.62
RECO	$32.87	$32.23	($0.42)	$1.06	$46.74	$38.39	$6.90	$1.44
PJM	$31.83	$31.76	$0.10	($0.02)	$38.23	$38.14	$0.09	$0.00

Component Costs

Table 10-5 shows the total energy, loss and congestion component costs and the total PJM billing for the first six months of 2009 through 2013. These totals are actually net energy, loss and congestion costs.

Table 10-5 Total PJM costs by component (Dollars (Millions)): January through June of 2009 through 2013[8, 9]

	Component Costs (Millions)					
(Jan–Jun)	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2009	($344)	$705	$408	$769	$13,457	5.7%
2010	($373)	$751	$644	$1,022	$16,314	6.3%
2011	($394)	$701	$570	$878	$18,685	4.7%
2012	($262)	$445	$263	$446	$13,991	3.2%
2013	($333)	$495	$306	$468	$15,571	3.0%

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8 The Energy Costs, Loss Costs and Congestion Costs include net inadvertent charges.
9 Total PJM Billing is provided by PJM, and the MMU is not able to reproduce and verify the calculation.

Energy Costs

Energy Accounting

The energy component of LMP is the system reference bus LMP, also called the system marginal price (SMP). The energy cost is based on the day-ahead and real-time energy components of LMP. Total energy costs, analogous to total congestion costs, are equal to the load energy payments minus generation energy credits, plus explicit energy costs, incurred in both the Day-Ahead Energy Market and the balancing energy market, plus net inadvertent energy charges. Total energy costs can by more accurately thought of as net energy costs.

Ignoring interchange, total generation MWh must be greater than total load MWh in every hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus in every hour, the net energy costs are negative (ignoring net interchange), with generation credits greater than load payments in every hour. These net energy costs plus net marginal loss costs plus net residual market adjustments, equal the marginal loss surplus which is distributed to load and exports.[10]

The total energy cost for the first six months of 2013 was -$332.6 million, which was comprised of load energy payments of $20,488.2 million, generation energy credits of $20,819.3 million, explicit energy costs of $0.0 million and inadvertent energy charges of -$1.5 million. The monthly energy costs for the first six months of 2013 ranged from -$63.0 million in January to -$46.5 million in April.

Total Energy Costs

Table 10-6 shows total energy component costs and total PJM billing, for the first six months of 2009 through 2013. The total energy component costs appear low compared to total PJM billing because these totals are actually net energy costs.

Table 10-6 Total PJM costs by energy component (Dollars (Millions)): January through June of 2009 through 2013[11]

| (Jan–Jun) | Component Costs (Millions) | | | | | |
	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2009	($344)	$705	$408	$769	$13,457	5.7%
2010	($373)	$751	$644	$1,022	$16,314	6.3%
2011	($394)	$701	$570	$878	$18,685	4.7%
2012	($262)	$445	$263	$446	$13,991	3.2%
2013	($333)	$495	$306	$468	$15,571	3.0%

Energy costs for the first six months of 2009 through 2013 are shown in Table 10-7 and Table 10-8. Table 10-7 shows PJM energy costs by category for the first six months of 2009 through 2013 and Table 10-8 shows PJM energy costs by market category for the first six months of 2009 through 2013. These energy costs are the actual total energy costs rather than the net energy costs in Table 10-6.

Table 10-7 Total PJM energy costs by category (Dollars (Millions)): January through June of 2009 through 2013

| (Jan–Jun) | Energy Costs (Millions) | | | | |
	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2009	$22,815.7	$23,162.1	$0.0	$2.9	($343.6)
2010	$25,040.9	$25,406.7	$0.0	($7.1)	($372.8)
2011	$23,524.8	$23,932.1	$0.0	$13.3	($393.9)
2012	$16,823.4	$17,092.7	$0.0	$7.2	($262.0)
2013	$20,488.2	$20,819.3	$0.0	($1.5)	($332.6)

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10 Net residual adjustments are comprised of the known day-ahead error value minus the sum of the day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data.

11 The Energy Costs include net inadvertent charges.

Table 10-8 Total PJM energy costs by market category (Dollars (Millions)): January through June of 2009 through 2013

	Energy Costs (Millions)									
	Day Ahead				Balancing					
(Jan–Jun)	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2009	$22,893.0	$23,278.1	$0.0	($385.1)	($77.3)	($116.0)	$0.0	$38.7	$2.9	($343.6)
2010	$25,072.6	$25,450.1	$0.0	($377.5)	($31.6)	($43.4)	$0.0	$11.8	($7.1)	($372.8)
2011	$23,685.6	$24,076.3	$0.0	($390.6)	($160.8)	($144.1)	$0.0	($16.7)	$13.3	($393.9)
2012	$16,907.0	$17,148.9	$0.0	($241.9)	($83.6)	($56.2)	$0.0	($27.4)	$7.2	($262.0)
2013	$20,543.4	$20,895.6	$0.0	($352.2)	($55.1)	($76.3)	$0.0	$21.1	($1.5)	($332.6)

Monthly Energy Costs

Table 10-9 shows a monthly summary of energy costs by type for the first six months of 2012 and 2013.

Table 10-9 Monthly energy costs by type (Dollars (Millions)): January through June of 2012 and 2013

	Energy Costs (Millions)							
	2012				2013			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($48.5)	($10.1)	$2.5	($56.1)	($69.2)	$5.8	$0.5	($63.0)
Feb	($36.0)	($9.9)	$2.4	($43.5)	($60.6)	$5.9	($0.1)	($54.8)
Mar	($30.1)	($8.6)	$1.9	($36.8)	($63.9)	$4.2	($0.3)	($60.0)
Apr	($30.7)	($2.8)	$0.7	($32.8)	($46.8)	$0.9	($0.6)	($46.5)
May	($39.4)	$0.0	($0.3)	($39.7)	($48.3)	($3.4)	($0.3)	($52.0)
Jun	($57.1)	$4.0	$0.0	($53.1)	($63.4)	$7.8	($0.6)	($56.2)
Total	($241.9)	($27.4)	$7.2	($262.0)	($352.2)	$21.1	($1.5)	($332.6)

Figure 10-1 shows PJM monthly energy costs of January 2009 through June 2013.

Figure 10-1 PJM monthly energy costs (Dollars (Millions)): January 2009 through June 2013
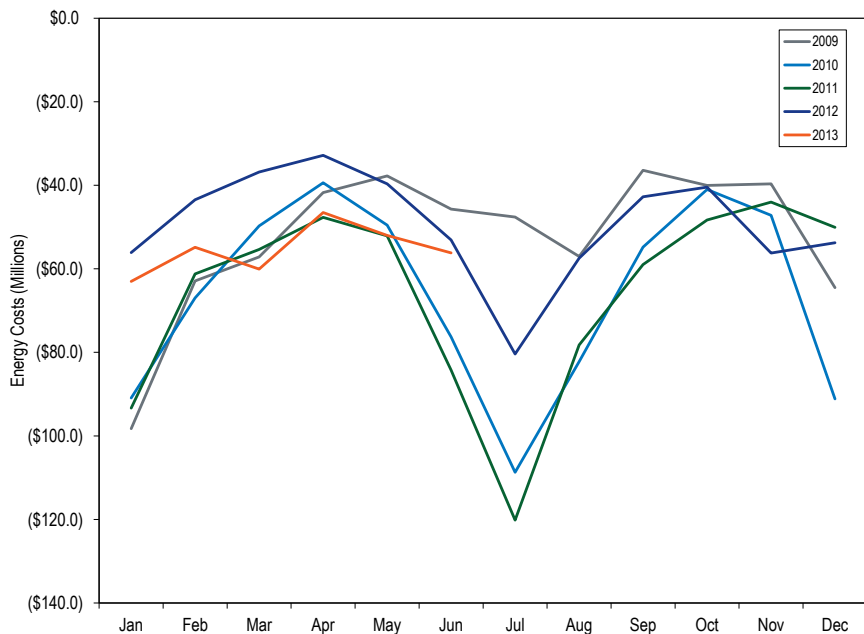
Marginal Losses
Marginal Loss Accounting

PJM calculates marginal loss costs for each PJM member. The loss cost is based on the applicable day-ahead and real-time loss component of LMP (MLMP). Each PJM member is charged for the cost of losses on the transmission system.

Total marginal loss costs, analogous to total congestion costs, are equal to the net of the load loss payments minus generation loss credits, plus explicit loss costs, incurred in both the Day-Ahead Energy Market and the balancing energy market. Total marginal loss costs can by more accurately thought of as net marginal loss costs.

Marginal loss costs can be both positive and negative and consequently load payments and generation credits can also be both positive and negative. The loss component of LMP is calculated with respect to the system marginal price (SMP). An increase in generation at a bus that results in an increase in losses will cause the marginal loss component of that bus to be negative. If the increase in generation at the bus results in a decrease of system losses, then the marginal loss component is positive.

The total marginal loss cost in PJM for the first six months of 2013 was $494.5 million, which was comprised of load loss payments of $8.6 million, generation loss credits of -$512.4 million, explicit loss costs of -$26.5 million and inadvertent loss charges of -$0.0 million. Monthly marginal loss costs in the first six months of 2013 ranged from $66.2 million in April to $101.1 million in January. Marginal loss credits decreased in the first six months of 2013 by $20.8 million or 11.4 percent from the first six months of 2012, from $182.1 million to $161.3 million.

Total Marginal Loss Costs

Table 10-10 shows the total marginal loss component costs for the first six months of 2009 through 2013. The yearly total loss component costs appear low compared to total PJM billing because these totals are actually net loss costs.

Table 10-10 Total PJM costs by loss component (Dollars (Millions)): January through June of 2009 through 2013[12, 13]

(Jan–Jun)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	$705	NA	$13,457	5.2%
2010	$751	6.5%	$16,314	4.6%
2011	$701	(6.6%)	$18,685	3.8%
2012	$445	(36.6%)	$13,991	3.2%
2013	$495	11.2%	$15,571	3.2%

[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] The Loss Costs include net inadvertent charges.

Total marginal loss costs for the first six months of 2009 through 2013 are shown in Table 10-11 and Table 10-12. Table 10-11 shows PJM total marginal loss costs by category for the first six months of 2009 through 2013. Table 10-12 shows PJM total marginal loss costs by market category for the first six months of 2009 through 2013.

Table 10-11 Total PJM marginal loss costs by category (Dollars (Millions)): January through June of 2009 through 2013

(Jan–Jun)	Marginal Loss Costs (Millions)				
	Load Payments	Generation Credits	Explicit	Inadvertent Charges	Total
2009	($42.2)	($726.4)	$20.7	$0.0	$704.8
2010	($15.7)	($750.5)	$16.2	($0.0)	$750.9
2011	($70.6)	($755.3)	$16.8	$0.0	$701.5
2012	($17.9)	($473.4)	($10.6)	$0.0	$444.9
2013	$8.6	($512.4)	($26.6)	($0.0)	$494.5

Table 10-12 Total PJM marginal loss costs by market category (Dollars (Millions)): January through June of 2009 through 2013

(Jan–Jun)	Marginal Loss Costs (Millions)									
	Day Ahead				Balancing					
	Load Payments	Generation Credits	Explicit	Total	Load Payments	Generation Credits	Explicit	Total	Inadvertent Charges	Grand Total
2009	($43.8)	($723.3)	$44.6	$724.1	$1.5	($3.1)	($23.9)	($19.3)	$0.0	$704.8
2010	($27.2)	($751.6)	$33.5	$757.9	$11.4	$1.2	($17.3)	($7.0)	($0.0)	$750.9
2011	($90.4)	($774.1)	$44.3	$728.1	$19.8	$18.8	($27.5)	($26.6)	$0.0	$701.5
2012	($30.4)	($481.4)	$15.5	$466.5	$12.5	$8.0	($26.1)	($21.6)	$0.0	$444.9
2013	($7.2)	($528.2)	$25.0	$546.0	$15.9	$15.8	($51.6)	($51.5)	($0.0)	$494.5

Monthly Marginal Loss Costs

Table 10-13 shows a monthly summary of marginal loss costs by type for the first six months of 2012 and 2013.

Table 10-13 Monthly marginal loss costs by type (Dollars (Millions)): January through June of 2012 and 2013

	Marginal Loss Costs (Millions)							
	2012				2013			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$100.6	($5.4)	$0.0	$95.2	$105.8	($4.7)	$0.0	$101.1
Feb	$80.4	($3.1)	$0.0	$77.2	$93.2	($6.5)	($0.0)	$86.7
Mar	$67.1	($5.2)	$0.0	$61.9	$97.2	($7.4)	($0.0)	$89.8
Apr	$55.4	($4.4)	$0.0	$51.0	$77.7	($11.5)	($0.0)	$66.2
May	$69.6	($2.5)	($0.0)	$67.1	$80.5	($12.4)	($0.0)	$68.1
Jun	$93.3	($0.8)	$0.0	$92.5	$91.7	($9.0)	($0.0)	$82.7
Total	$466.5	($21.6)	$0.0	$444.9	$546.0	($51.5)	($0.0)	$494.5

Figure 10-2 shows PJM monthly marginal loss costs of January 2009 through June 2013.

Figure 10-2 PJM monthly marginal loss costs (Dollars (Millions)): January 2009 through June of 2013

Ignoring interchange, total generation MWh must be greater than total load MWh in any hour in order to provide for losses. Since the hourly integrated energy component of LMP is the same for every bus within every hour, the net energy bill is negative (ignoring net interchange), with more generation credits than load payments in every hour. Total energy costs plus total marginal loss costs plus net residual market adjustments equal marginal loss credits which are distributed to load and exports as marginal loss credits.

Table 10-14 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss credits redistributed for the first six months of 2009 through 2013. The total marginal loss credits decreased $20.8 million in the first six months of 2013 from the first six months of 2012.

Table 10-14 Marginal loss credits (Dollars (Millions)): January through June, 2009 through 2013[14]

| (Jan–Jun) | Loss Credit Accounting (Millions) | | | |
	Total Energy Charges	Total Marginal Loss Charges	Adjustments	Loss Credits
2009	($343.6)	$704.8	$1.3	$362.5
2010	($372.8)	$750.9	($0.6)	$377.5
2011	($393.9)	$701.5	$0.8	$308.4
2012	($262.0)	$444.9	($0.8)	$182.1
2013	($332.6)	$494.5	($0.7)	$161.3

Marginal Loss Costs and Loss Credits

Marginal loss credits (loss surplus) are calculated by adding the total energy costs, the total marginal loss costs and net residual market adjustments. The total energy costs are equal to the net implicit energy costs (generation energy credits less load energy payments) plus net explicit energy costs plus net inadvertent energy charges. Total marginal loss costs are equal to the net implicit marginal loss costs (generation loss credits less load loss payments) plus net explicit loss costs plus net inadvertent loss charges.

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14 The net residual market adjustments included in the table are comprised of the known day-ahead error value minus the sum of the day-ahead loss MW congestion value, balancing loss MW congestion value and measurement error caused by missing data.

Congestion

Congestion Accounting

Total congestion costs in PJM in the first six months of 2013 were $306.1 million, which was comprised of load congestion payments of $124.8 million, generation credits of -$215.7 million and explicit congestion of -$34.5 million (Table 10-16).

Total Congestion

Table 10-15 shows total congestion from January through June by year from 2008 through 2013.[15]

Table 10-15 Total PJM congestion (Dollars (Millions)): January through June, 2008 to 2013

	Congestion Costs (Millions)			
(Jan – Jun)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,166.1	NA	$16,549	7.0%
2009	$408.2	(65.0%)	$13,457	3.0%
2010	$644.0	57.8%	$16,314	3.9%
2011	$570.0	(11.5%)	$18,685	3.1%
2012	$263.3	(53.8%)	$13,991	1.9%
2013	$306.1	16.3%	$15,571	2.0%

Total congestion costs in Table 10-16 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO and in the NYISO.[16, 17]

Table 10-16 shows the congestion costs by category for the first six months of 2013. The January through June 2013 PJM total congestion costs were comprised of $124.8 million in load congestion payments, -$215.7 million in generation congestion credits, and -$34.5 million in explicit congestion costs.

Table 10-16 Total PJM congestion costs by category (Dollars (Millions)): January through June, 2008 to 2013

	Congestion Costs (Millions)				
(Jan – Jun)	Load Payments	GenerationCredits	Explicit Costs	Inadvertent Charges	Total
2008	$625.2	($521.3)	$19.6	$0.0	$1,166.1
2009	$142.3	($301.8)	($35.9)	$0.0	$408.2
2010	$144.2	($525.5)	($25.8)	($0.0)	$644.0
2011	$287.1	($364.3)	($81.4)	$0.0	$570.0
2012	$51.8	($247.9)	($36.4)	$0.0	$263.3
2013	$124.8	($215.7)	($34.5)	($0.0)	$306.1

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15 Congestion charges for 2010 reflect an updated calculation compared to the results in the *2010 State of the Market Report for PJM*.

16 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 April 17, 2013).

17 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc and PJM Interconnection, L.L.C." (January 17, 2013) Section 35.2.1 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).

Table 10-17 Total PJM congestion costs by market category (Dollars (Millions)): January through June, 2008 to 2013

| | Congestion Costs (Millions) | | | | | | | | | |
| | Day Ahead | | | | Balancing | | | | | |
(Jan – Jun)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$727.6	($589.4)	$86.7	$1,403.8	($102.4)	$68.2	($67.1)	($237.7)	$0.0	$1,166.1
2009	$159.3	($299.4)	$63.1	$521.7	($17.0)	($2.4)	($99.0)	($113.6)	$0.0	$408.2
2010	$151.5	($544.1)	$38.1	$733.8	($7.3)	$18.6	($63.9)	($89.8)	($0.0)	$644.0
2011	$256.0	($420.3)	$25.6	$701.9	$31.1	$56.0	($107.0)	($131.9)	$0.0	$570.0
2012	$56.8	($267.4)	$65.4	$389.6	($5.0)	$19.5	($101.8)	($126.4)	$0.0	$263.3
2013	$133.2	($306.1)	$87.8	$527.1	($8.4)	$90.4	($122.3)	($221.1)	($0.0)	$306.1

Monthly Congestion

Table 10-18 shows that during the first six months of 2012 and 2013, monthly congestion costs ranged from $27.8 million to $77.4 million in 2013. Table 10-18 shows the monthly congestion costs in the first six months of 2013 were higher than in the first six months of 2012.

Table 10-18 Monthly PJM congestion costs by market type (Dollars (Millions)): January through June, 2012 to 2013

| | Congestion Costs (Millions) | | | | | | | |
| | 2012 | | | | 2013 | | | |
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$66.3	($20.0)	$0.0	$46.3	$136.8	($76.8)	$0.0	$60.0
Feb	$54.8	($19.2)	$0.0	$35.5	$125.1	($47.7)	$0.0	$77.4
Mar	$59.8	($19.1)	$0.0	$40.7	$69.9	($21.4)	($0.0)	$48.5
Apr	$72.0	($37.1)	$0.0	$34.9	$37.7	($9.9)	$0.0	$27.8
May	$67.2	($18.2)	($0.0)	$49.1	$75.3	($35.8)	($0.0)	$39.5
Jun	$69.6	($12.7)	($0.0)	$56.8	$82.2	($29.4)	($0.0)	$52.8
Total	$389.6	($126.4)	$0.0	$263.3	$527.1	($221.1)	($0.0)	$306.1

Figure 10-3 shows PJM monthly congestion for January 2009 through June 2013.

Figure 10-3 PJM monthly congestion (Dollars (Millions)): January 2009 to June 2013
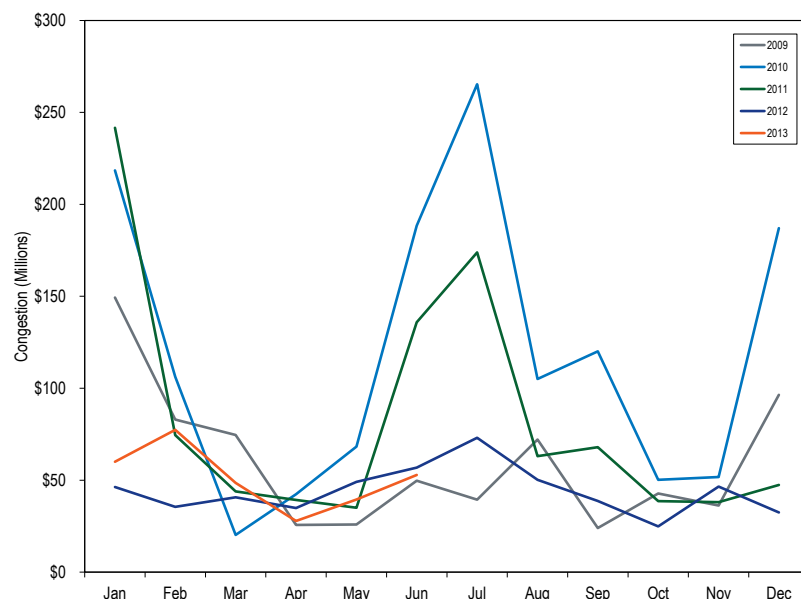
Congested Facilities

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 six months of 2013, there were 174,063 day-ahead, congestion-event hours compared to 106,904 day-ahead, congestion-event hours in the first six months of 2012. In the first six months of 2013, there were 9,984 real-time, congestion-event hours compared to 9,260 real-time, congestion-event hours in the first six months of 2012.

During the first six months of 2013, for only 2.1 percent of Day-Ahead Market facility constrained hours were the same facilities also constrained in the Real-Time Market. During the first six months of 2013, for 38.0 percent of Real-Time Market facility constrained hours, the same facilities were also constrained in the Day-Ahead Market.

The AP South interface was the largest contributor to congestion costs in the first six months of 2013. With $104.3 million in total congestion costs, it accounted for 34.1 percent of the total PJM congestion costs in the first six months of 2013. The top five constraints contributed $132.2 million, or 43.2 percent, of the total PJM congestion costs in the first six months of 2013. The top five constraints were the AP South and West interfaces, the Readington – Roseland and the Laporte – Michigan transmission line, and the Cloverdale transformer.

Congestion by Facility Type and Voltage

In the first six months of 2013, compared to the first six months of 2012, day-ahead, congestion-event hours decreased on the flowgates, while congestion frequency on internal PJM interfaces, transmission lines and transformers increased. Real-time, congestion-event hours increased on all types of facilities.

Day-ahead congestion costs decreased on the flowgates in the first six months of 2013 compared to the first six months of 2012 and increased on PJM interfaces, transmission lines and transformers in the first six months of 2013 compared to the first six months of 2012. Balancing congestion costs increased on flowgates and decreased on transmission lines, interfaces and transformers in the first six months of 2013 compared to the first six months of 2012.

Table 10-19 provides congestion-event hour subtotals and congestion cost subtotals comparing the first six months of 2013 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[18, 19] For comparison, this information is presented in Table 10-20 for the first six months of 2012.[20]

Table 10-19 Congestion summary (By facility type): January through June 2013

| | Congestion Costs (Millions) | | | | | | | | | Event Hours | |
| | Day Ahead | | | | Balancing | | | | | | |
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
Flowgate	($17.7)	($72.3)	$13.1	$67.7	$0.6	$10.4	($32.0)	($41.8)	$25.9	11,963	3,553
Interface	$95.5	($56.8)	$6.5	$158.8	$8.8	$18.0	($2.9)	($12.1)	$146.7	6,744	830
Line	$32.2	($143.3)	$41.3	$216.8	($17.1)	$52.9	($72.6)	($142.7)	$74.2	99,748	4,715
Other	$3.8	($1.7)	$5.5	$11.0	($0.0)	$0.0	$0.0	($0.0)	$11.0	6,884	5
Transformer	$15.7	($28.6)	$14.5	$58.7	($0.7)	$7.9	($17.2)	($25.8)	$33.0	48,724	881
Unclassified	$3.7	($3.4)	$7.0	$14.1	($0.1)	$1.0	$2.4	$1.3	$15.3	NA	NA
Total	$133.2	($306.1)	$87.8	$527.1	($8.4)	$90.4	($122.3)	($221.1)	$306.1	174,063	9,984

Table 10-20 Congestion summary (By facility type): January through June 2012

| | Congestion Costs (Millions) | | | | | | | | | Event Hours | |
| | Day Ahead | | | | Balancing | | | | | | |
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
Flowgate	($28.2)	($99.0)	$29.6	$100.4	($0.5)	$6.7	($56.9)	($64.1)	$36.4	13,771	3,242
Interface	$20.5	($40.6)	($2.3)	$58.8	$6.5	$8.2	($1.7)	($3.4)	$55.5	2,740	254
Line	$45.1	($86.3)	$29.7	$161.0	($9.0)	$6.4	($39.0)	($54.5)	$106.6	63,777	4,598
Other	$8.0	($3.7)	$0.8	$12.5	($0.7)	($0.1)	($0.8)	($1.5)	$11.0	2,105	411
Transformer	$16.6	($30.8)	$6.1	$53.5	$2.0	$1.6	($3.2)	($2.8)	$50.7	24,511	755
Unclassified	$0.5	($1.4)	$1.4	$3.4	$0.1	$0.1	($0.2)	($0.2)	$3.1	NA	NA
Total	$62.5	($261.7)	$65.4	$389.6	($1.6)	$23.0	($101.8)	($126.4)	$263.3	106,904	9,260

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18 Unclassified are congestion costs related to non-transmission facility constraints in the Day-Ahead Market and any unaccounted for difference between PJM billed congestion charges and calculated congestion costs including rounding errors. Non-transmission facility constraints include Day-Ahead Market only constraints such as constraints on virtual transactions and constraints associated with phase-angle regulators.

19 The term flowgate refers to MISO flowgates and NYISO flowgates in this section.

20 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 10-21 and Table 10-22 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the Day-Ahead Market, the number of hours during which the facility is also constrained in the Real-Time Market are presented in Table 10-21. In the first six months of 2013, there were 174,063 congestion event hours in the Day-Ahead Market. Among those, only 3,621 (2.1 percent) were also constrained in the Real-Time Market. In the first six months of 2012, among the 106,904 day-ahead congestion event hours, only 3,932 (3.7 percent) were binding in the Real-Time Market.[21]

Among the hours for which a facility is constrained in the Real-Time Market, the number of hours during which the facility is also constrained in the Day-Ahead Market are presented in Table 10-22. In the first six months of 2013, there were 9,984 congestion event hours in the Real-Time Market. Among these, 3,798 (38.0 percent) were also constrained in the Day-Ahead Market. In the first six months of 2012, among the 9,260 real-time congestion event hours, only 3,873 (41.8 percent) were binding in the day-ahead.

Table 10–21 Congestion Event Hours (Day Ahead against Real Time): January through June 2012 to 2013

| | Congestion Event Hours | | | | | |
| | 2012 (Jan – Jun) | | | 2013 (Jan – Jun) | | |
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	13,771	1,464	10.6%	11,963	1,246	10.4%
Interface	2,740	105	3.8%	6,744	647	9.6%
Line	63,777	1,836	2.9%	99,748	1,452	1.5%
Other	2,105	258	12.3%	6,884	5	0.1%
Transformer	24,511	269	1.1%	48,724	271	0.6%
Total	106,904	3,932	3.7%	174,063	3,621	2.1%

Table 10–22 Congestion Event Hours (Real Time against Day Ahead): January through June 2012 to 2013

| | Congestion Event Hours | | | | | |
| | 2012 (Jan – Jun) | | | 2013 (Jan – Jun) | | |
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	3,242	1,518	46.8%	3,553	1,380	38.8%
Interface	254	103	40.6%	830	690	83.1%
Line	4,598	1,769	38.5%	4,715	1,455	30.9%
Other	411	222	54.0%	5	5	100.0%
Transformer	755	261	34.6%	881	268	30.4%
Total	9,260	3,873	41.8%	9,984	3,798	38.0%

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21 Constraints are mapped to transmission facilities. In the Day-Ahead Market, within a given hour, a single facility may be associated with multiple constraints. In such situations, the same facility accounts for more than one constraint-hour for a given hour in the Day-Ahead Market. Similarly in the Real-Time Market a facility may account for more than one constraint-hour within a given hour.

Table 10-23 shows congestion costs by facility voltage class for the first six months of 2013. In comparison to the first six months of 2012 (shown in Table 10-24), congestion costs decreased for facilities rated at 345 kV, 230 kV, 161 kV, 138 kV and 115kV in the first six months of 2013.

Table 10-23 Congestion summary (By facility voltage): January through June 2013

| | Congestion Costs (Millions) | | | | | | | | | Event Hours | |
| | Day Ahead | | | | Balancing | | | | | | |
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	$7.2	($4.4)	$5.9	$17.5	$0.0	$0.0	$0.0	$0.0	$17.5	5,426	0
500	$96.9	($66.5)	$7.4	$170.8	$12.3	$20.4	($12.2)	($20.3)	$150.5	9,088	1,063
345	($13.3)	($63.2)	$12.5	$62.3	($1.5)	$10.6	($34.3)	($46.4)	$16.0	29,296	2,205
230	$33.7	($91.2)	$29.6	$154.6	($8.7)	$45.0	($38.9)	($92.6)	$62.0	29,109	1,971
161	($2.1)	($4.0)	($0.4)	$1.5	($0.9)	$0.3	($2.9)	($4.1)	($2.6)	801	589
138	($3.5)	($71.0)	$24.8	$92.3	($5.9)	$10.0	($36.6)	($52.5)	$39.8	78,550	3,640
115	$2.0	($2.5)	$1.4	$5.9	($0.0)	$0.7	($0.7)	($1.5)	$4.4	7,864	296
69	$8.6	$0.2	($0.3)	$8.1	($3.7)	$2.2	$0.8	($5.0)	$3.0	9,537	220
34	($0.0)	($0.0)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	4,372	0
12	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	20	0
Unclassified	$3.7	($3.4)	$7.0	$14.1	($0.1)	$1.0	$2.4	$1.3	$15.3	NA	NA
Total	$133.2	($306.1)	$87.8	$527.1	($8.4)	$90.4	($122.3)	($221.1)	$306.1	174,063	9,984

Table 10-24 Congestion summary (By facility voltage): January through June 2012

| | Congestion Costs (Millions) | | | | | | | | | Event Hours | |
| | Day Ahead | | | | Balancing | | | | | | |
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	($0.2)	($2.4)	$2.2	$4.4	$0.1	($0.0)	($0.1)	($0.0)	$4.4	1,648	78
500	$24.0	($49.4)	($0.5)	$72.8	$6.9	$8.2	($3.5)	($4.8)	$68.0	5,463	434
345	($15.1)	($53.7)	$8.2	$46.9	$0.8	$2.9	($20.9)	($23.0)	$23.8	14,640	1,226
230	$45.3	($27.8)	$5.0	$78.1	$1.7	$2.9	($8.1)	($9.3)	$68.8	18,563	2,128
161	($6.0)	($9.7)	$5.6	$9.3	($0.6)	$0.9	($9.5)	($11.0)	($1.7)	1,948	720
138	($8.9)	($117.1)	$40.4	$148.6	($5.3)	$6.6	($57.7)	($69.5)	$79.1	52,116	3,932
115	$15.7	($0.5)	$2.1	$18.3	($0.4)	$0.7	($0.6)	($1.7)	$16.7	8,874	490
69	$7.2	$0.3	$1.0	$7.9	($4.9)	$0.8	($1.2)	($6.9)	$1.0	3,643	252
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	$0.5	($1.4)	$1.4	$3.4	$0.1	$0.1	($0.2)	($0.2)	$3.1	NA	NA
Total	$62.5	($261.7)	$65.4	$389.6	($1.6)	$23.0	($101.8)	($126.4)	$263.3	106,904	9,260

Constraint Duration

Table 10-25 lists constraints in the first six months of 2012 and 2013 that were most frequently in effect and Table 10-26 shows the constraints which experienced the largest change in congestion-event hours from the first six month of 2012 to the first six months of 2013.

Table 10-25 Top 25 constraints with frequent occurrence: January through June 2012 and 2013

| | | | Event Hours | | | | | | Percent of Annual Hours | | | | | |
| | | | Day Ahead | | | Real Time | | | Day Ahead | | | Real Time | | |
No.	Constraint	Type	2012	2013	Change	2012	2013	Change	2012	2013	Change	2012	2013	Change
1	Sporn	Transformer	5,062	6,015	953	0	0	0	58%	68%	11%	0%	0%	0%
2	Gould Street - Westport	Line	0	4,372	4,372	0	0	0	0%	50%	50%	0%	0%	0%
3	AP South	Interface	1,211	3,275	2,064	82	646	564	14%	37%	23%	1%	7%	6%
4	Braidwood	Transformer	0	3,914	3,914	0	0	0	0%	45%	45%	0%	0%	0%
5	Readington - Roseland	Line	340	3,128	2,788	0	713	713	4%	36%	32%	0%	8%	8%
6	Howard - Shelby	Line	1,450	3,248	1,798	0	0	0	17%	37%	20%	0%	0%	0%
7	Tanners Creek	Transformer	178	2,993	2,815	0	0	0	2%	34%	32%	0%	0%	0%
8	Sunbury	Transformer	0	2,865	2,865	0	0	0	0%	33%	33%	0%	0%	0%
9	Haurd - Steward	Line	794	2,669	1,875	1	0	(1)	9%	30%	21%	0%	0%	(0%)
10	West Moulton-City Of St. Marys	Line	0	2,406	2,406	0	0	0	0%	27%	27%	0%	0%	0%
11	Zion	Line	165	2,220	2,055	0	0	0	2%	25%	23%	0%	0%	0%
12	Monticello - East Winamac	Flowgate	1,683	1,598	(85)	541	449	(92)	19%	18%	(1%)	6%	5%	(1%)
13	Cloverdale	Transformer	3	1,979	1,976	9	0	(9)	0%	23%	22%	0%	0%	(0%)
14	Nelson - Cordova	Line	390	1,852	1,462	16	101	85	4%	21%	17%	0%	1%	1%
15	Rockport Works	Transformer	0	1,891	1,891	0	0	0	0%	22%	22%	0%	0%	0%
16	Prairie State - W Mt. Vernon	Flowgate	422	1,021	599	156	836	680	5%	12%	7%	2%	10%	8%
17	Bridgewater - Middlesex	Line	237	1,663	1,426	1	157	156	3%	19%	16%	0%	2%	2%
18	Danville - East Danville	Line	1,369	1,763	394	0	0	0	16%	20%	4%	0%	0%	0%
19	Hunlock Creek - A.G.A. Gas	Line	4	1,754	1,750	0	0	0	0%	20%	20%	0%	0%	0%
20	Devon - Skokie	Line	19	1,729	1,710	0	0	0	0%	20%	19%	0%	0%	0%
21	South Cadiz	Transformer	513	1,596	1,083	0	0	0	6%	18%	12%	0%	0%	0%
22	Loretto	Transformer	166	1,587	1,421	0	0	0	2%	18%	16%	0%	0%	0%
23	Miami Fort	Transformer	504	1,560	1,056	25	25	0	6%	18%	12%	0%	0%	(0%)
24	Huntingdon - Huntingdon1	Line	1,941	1,515	(426)	0	0	0	22%	17%	(5%)	0%	0%	0%
25	Electric Junction - Frontenac	Line	0	1,499	1,499	0	0	0	0%	17%	17%	0%	0%	0%

Table 10–26 Top 25 constraints with largest year–to–year change in occurrence: January through June 2012 and 2013

| | | | Event Hours | | | | | | Percent of Annual Hours | | | | | |
| | | | Day Ahead | | | Real Time | | | Day Ahead | | | Real Time | | |
No.	Constraint	Type	2012	2013	Change	2012	2013	Change	2012	2013	Change	2012	2013	Change
1	Gould Street - Westport	Line	0	4,372	4,372	0	0	0	0%	50%	50%	0%	0%	0%
2	Braidwood	Transformer	0	3,914	3,914	0	0	0	0%	45%	45%	0%	0%	0%
3	Readington - Roseland	Line	340	3,128	2,788	0	713	713	4%	36%	32%	0%	8%	8%
4	Graceton - Raphael Road	Line	2,331	0	(2,331)	616	0	(616)	27%	0%	(27%)	7%	0%	(7%)
5	Sunbury	Transformer	0	2,865	2,865	0	0	0	0%	33%	33%	0%	0%	0%
6	Tanners Creek	Transformer	178	2,993	2,815	0	0	0	2%	34%	32%	0%	0%	0%
7	AP South	Interface	1,211	3,275	2,064	82	646	564	14%	37%	23%	1%	7%	6%
8	West Moulton-City Of St. Marys	Line	0	2,406	2,406	0	0	0	0%	27%	27%	0%	0%	0%
9	Zion	Line	165	2,220	2,055	0	0	0	2%	25%	23%	0%	0%	0%
10	Cloverdale	Transformer	3	1,979	1,976	9	0	(9)	0%	23%	22%	0%	0%	(0%)
11	Rockport Works	Transformer	0	1,891	1,891	0	0	0	0%	22%	22%	0%	0%	0%
12	Haurd - Steward	Line	794	2,669	1,875	1	0	(1)	9%	30%	21%	0%	0%	(0%)
13	Howard - Shelby	Line	1,450	3,248	1,798	0	0	0	17%	37%	20%	0%	0%	0%
14	Belmont	Transformer	1,723	0	(1,723)	60	0	(60)	20%	0%	(20%)	1%	0%	(1%)
15	Hunlock Creek - A.G.A. Gas	Line	4	1,754	1,750	0	0	0	0%	20%	20%	0%	0%	0%
16	Rockwell - Crosby	Line	2,050	329	(1,721)	0	0	0	23%	4%	(20%)	0%	0%	0%
17	Devon - Skokie	Line	19	1,729	1,710	0	0	0	0%	20%	19%	0%	0%	0%
18	Bridgewater - Middlesex	Line	237	1,663	1,426	1	157	156	3%	19%	16%	0%	2%	2%
19	Nelson - Cordova	Line	390	1,852	1,462	16	101	85	4%	21%	17%	0%	1%	1%
20	Electric Junction - Frontenac	Line	0	1,499	1,499	0	0	0	0%	17%	17%	0%	0%	0%
21	Wolf creek	Transformer	1,480	0	(1,480)	9	0	(9)	17%	0%	(17%)	0%	0%	(0%)
22	Conesville	Transformer	1,445	0	(1,445)	0	0	0	16%	0%	(16%)	0%	0%	0%
23	Marlowe	Transformer	0	1,427	1,427	0	0	0	0%	16%	16%	0%	0%	0%
24	Loretto	Transformer	166	1,587	1,421	0	0	0	2%	18%	16%	0%	0%	0%
25	Cumberland - Bush	Flowgate	1,667	402	(1,265)	283	152	(131)	19%	5%	(14%)	3%	2%	(2%)

Constraint Costs

Table 10-27 and Table 10-28 present the top constraints affecting congestion costs by facility for the periods January through June 2013 and 2012.

Table 10-27 Top 25 constraints affecting PJM congestion costs (By facility): January through June 2013

| | | | | Congestion Costs (Millions) | | | | | | | | | Percent of Total PJM Congestion Costs |
| | | | | Day Ahead | | | | Balancing | | | | | |
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2013 (Jan – Jun)
1	AP South	Interface	500	$81.4	($26.2)	$5.8	$113.3	$5.7	$12.3	($2.3)	($9.0)	$104.3	34.1%
2	Readington – Roseland	Line	PSEG	($1.7)	($49.4)	$5.2	$52.8	($10.5)	$38.1	($20.7)	($69.3)	($16.4)	(5.4%)
3	Unclassified	Unclassified	Unclassified	$3.7	($3.4)	$7.0	$14.1	($0.1)	$1.0	$2.4	$1.3	$15.3	5.0%
4	Cloverdale	Transformer	AEP	$7.4	($3.2)	$4.4	$15.1	$0.0	$0.0	$0.0	$0.0	$15.1	4.9%
5	West	Interface	500	$2.6	($13.0)	($0.4)	$15.2	$1.8	$2.4	($0.7)	($1.3)	$13.9	4.5%
6	Laporte – Michigan	Line	AEP	$0.0	$0.0	$0.0	$0.0	($6.5)	$1.3	($4.7)	($12.5)	($12.5)	(4.1%)
7	Bagley – Graceton	Line	BGE	$10.2	($0.5)	$1.8	$12.5	$0.1	($1.2)	($1.6)	($0.4)	$12.1	4.0%
8	Clover	Transformer	Dominion	$0.0	$0.0	$0.0	$0.0	($0.2)	$5.1	($6.8)	($12.1)	($12.1)	(4.0%)
9	Bridgewater – Middlesex	Line	PSEG	($0.2)	($14.9)	$1.3	$16.0	($0.0)	$3.5	($1.1)	($4.7)	$11.3	3.7%
10	Crete – St Johns Tap	Flowgate	MISO	($0.4)	($6.8)	$2.6	$9.0	$0.0	$0.0	$0.0	$0.0	$9.0	2.9%
11	5004/5005 Interface	Interface	500	$0.9	($10.5)	($0.3)	$11.1	$1.2	$3.9	$0.5	($2.2)	$8.9	2.9%
12	Bedington	Transformer	AP	$3.5	($5.1)	($0.0)	$8.6	$0.0	$0.4	$0.3	($0.1)	$8.5	2.8%
13	Bcpep	Interface	Pepco	$6.0	($0.2)	$1.6	$7.9	$0.0	$0.0	$0.0	$0.0	$7.9	2.6%
14	Monticello – East Winamac	Flowgate	MISO	($1.3)	($19.2)	$4.1	$22.0	$0.2	$4.6	($10.5)	($14.9)	$7.2	2.3%
15	New Dover – Westfield	Line	PSEG	$0.5	($5.7)	$0.9	$7.1	$0.0	$0.0	$0.0	$0.0	$7.1	2.3%
16	Braidwood	Transformer	ComEd	($0.1)	($6.2)	$0.9	$7.0	$0.0	$0.0	$0.0	$0.0	$7.0	2.3%
17	Conastone – Graceton	Line	BGE	$3.8	($0.9)	$1.4	$6.1	$0.1	($0.2)	($0.3)	($0.0)	$6.1	2.0%
18	Bristers – Ox	Line	Dominion	$2.5	($2.6)	$0.5	$5.5	$0.8	$0.3	($0.3)	$0.1	$5.5	1.8%
19	AEP – DOM	Interface	500	$3.3	($2.2)	($0.0)	$5.5	($0.1)	$0.1	($0.0)	($0.2)	$5.3	1.7%
20	Breed – Wheatland	Flowgate	MISO	($0.6)	($5.6)	$1.4	$6.4	$0.0	($0.0)	($1.1)	($1.0)	$5.3	1.7%
21	Michigan City – Laporte	Flowgate	MISO	($3.2)	($6.4)	$1.8	$5.0	$0.0	$0.0	$0.0	$0.0	$5.0	1.6%
22	Crete – St Johns	Line	ComEd	$0.0	$0.0	$0.0	$0.0	$0.2	$0.7	($3.7)	($4.3)	($4.3)	(1.4%)
23	Prairie State – W Mt. Vernon	Flowgate	MISO	($2.0)	($5.2)	($0.4)	$2.8	($0.0)	($0.1)	$0.7	$0.8	$3.6	1.2%
24	Dickerson – Pleasant View	Line	Pepco	$0.7	($3.2)	$1.2	$5.1	$0.4	$1.0	($1.2)	($1.8)	$3.3	1.1%
25	Lakeview – Greenfoe	Line	ATSI	($1.0)	($3.9)	$0.8	$3.7	$0.1	$0.2	($0.3)	($0.4)	$3.3	1.1%

Table 10-28 Top 25 constraints affecting PJM congestion costs (By facility): January through June 2012

| | | | | Congestion Costs (Millions) | | | | | | | | | Percent of Total PJM Congestion Costs |
| | | | | Day Ahead | | | | Balancing | | | | | |
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2012 (Jan – Jun)
1	Graceton – Raphael Road	Line	BGE	$23.6	($7.8)	($1.8)	$29.5	($0.1)	($0.6)	$0.9	$1.3	$30.8	11.7%
2	Woodstock	Flowgate	MISO	($7.0)	($30.2)	$6.8	$30.0	$0.0	$0.0	$0.0	$0.0	$30.0	11.4%
3	AP South	Interface	500	$18.8	($8.3)	$0.1	$27.2	$3.3	$2.6	($2.6)	($1.9)	$25.4	9.6%
4	Belvidere – Woodstock	Line	ComEd	($0.2)	($4.6)	$1.0	$5.3	($2.4)	$3.2	($16.9)	($22.5)	($17.2)	(6.5%)
5	West	Interface	500	($0.6)	($16.6)	($2.3)	$13.7	$1.0	$1.1	$0.3	$0.1	$13.8	5.2%
6	Northwest	Other	BGE	$7.8	($2.4)	$0.4	$10.6	($0.7)	($0.1)	($0.8)	($1.5)	$9.1	3.5%
7	Pleasant Valley – Belvidere	Line	ComEd	($2.1)	($7.9)	$1.8	$7.5	$0.1	$0.1	($0.8)	($0.7)	$6.8	2.6%
8	Monticello – East Winamac	Flowgate	MISO	($0.1)	($13.7)	$9.3	$22.9	$0.4	$1.9	($15.1)	($16.6)	$6.3	2.4%
9	Kammer	Transformer	AEP	($2.3)	($8.5)	($1.0)	$5.2	($0.2)	$0.1	$0.2	($0.0)	$5.1	2.0%
10	Crescent	Transformer	DLCO	$0.9	($4.3)	($0.2)	$5.1	$0.2	$0.1	($0.1)	$0.0	$5.1	1.9%
11	Hunterstown	Transformer	Met-Ed	$1.4	($3.4)	$0.2	$5.0	$0.1	$0.0	($0.0)	$0.0	$5.0	1.9%
12	Belmont	Transformer	AP	$0.6	($5.4)	$0.5	$6.6	($0.4)	$0.8	($0.4)	($1.5)	$5.0	1.9%
13	Breed – Wheatland	Flowgate	MISO	($0.9)	($5.4)	$0.0	$4.5	$0.3	$0.3	($9.3)	($9.3)	($4.8)	(1.8%)
14	Electric Junction – Nelson	Line	ComEd	($1.3)	($4.2)	$1.7	$4.6	$0.0	$0.0	$0.0	$0.0	$4.6	1.8%
15	Silver Lake – Pleasant Valley	Line	ComEd	($2.8)	($6.0)	$1.3	$4.5	$0.0	$0.0	$0.0	$0.0	$4.5	1.7%
16	5004/5005 Interface	Interface	500	$0.1	($3.9)	$0.4	$4.5	$1.8	$2.3	$0.5	($0.0)	$4.5	1.7%
17	Loudoun – Gainsville	Line	Dominion	$0.0	($4.9)	($0.5)	$4.4	$0.4	$0.6	$0.2	($0.0)	$4.4	1.7%
18	East	Interface	500	($2.5)	($7.6)	($0.6)	$4.5	$0.1	$0.5	($0.1)	($0.5)	$4.0	1.5%
19	Bedington – Black Oak	Interface	500	$2.9	($1.4)	($0.2)	$4.0	$0.0	$0.0	($0.0)	($0.0)	$4.0	1.5%
20	Lancaster – Maryland	Line	ComEd	$0.2	($0.2)	$0.2	$0.6	($0.3)	$0.6	($3.5)	($4.4)	($3.8)	(1.4%)
21	Unclassified	Unclassified	Unclassified	$0.5	($1.4)	$1.4	$3.4	$0.1	$0.1	($0.2)	($0.2)	$3.1	1.2%
22	AEP – DOM	Interface	500	$2.6	($1.3)	$0.1	$4.1	$0.3	$1.6	$0.2	($1.0)	$3.1	1.2%
23	Hillsdale – New Milford	Line	PSEG	$0.2	($0.6)	$4.3	$5.1	$0.1	$1.1	($7.2)	($8.1)	($3.0)	(1.1%)
24	Three Mile Island	Transformer	Met-Ed	$1.3	($1.0)	$0.7	$2.9	$0.3	($1.0)	($1.3)	$0.1	$3.0	1.1%
25	Brues – West Bellaire	Line	AEP	$2.0	($1.4)	($0.5)	$2.9	($0.0)	$0.1	$0.1	($0.0)	$2.9	1.1%

Figure 10-4 shows the locations of the top 10 constraints affecting PJM congestion costs in the first six months of 2013.

Figure 10-4 Location of the top 10 constraints affecting PJM congestion costs: January through June 2013[22]
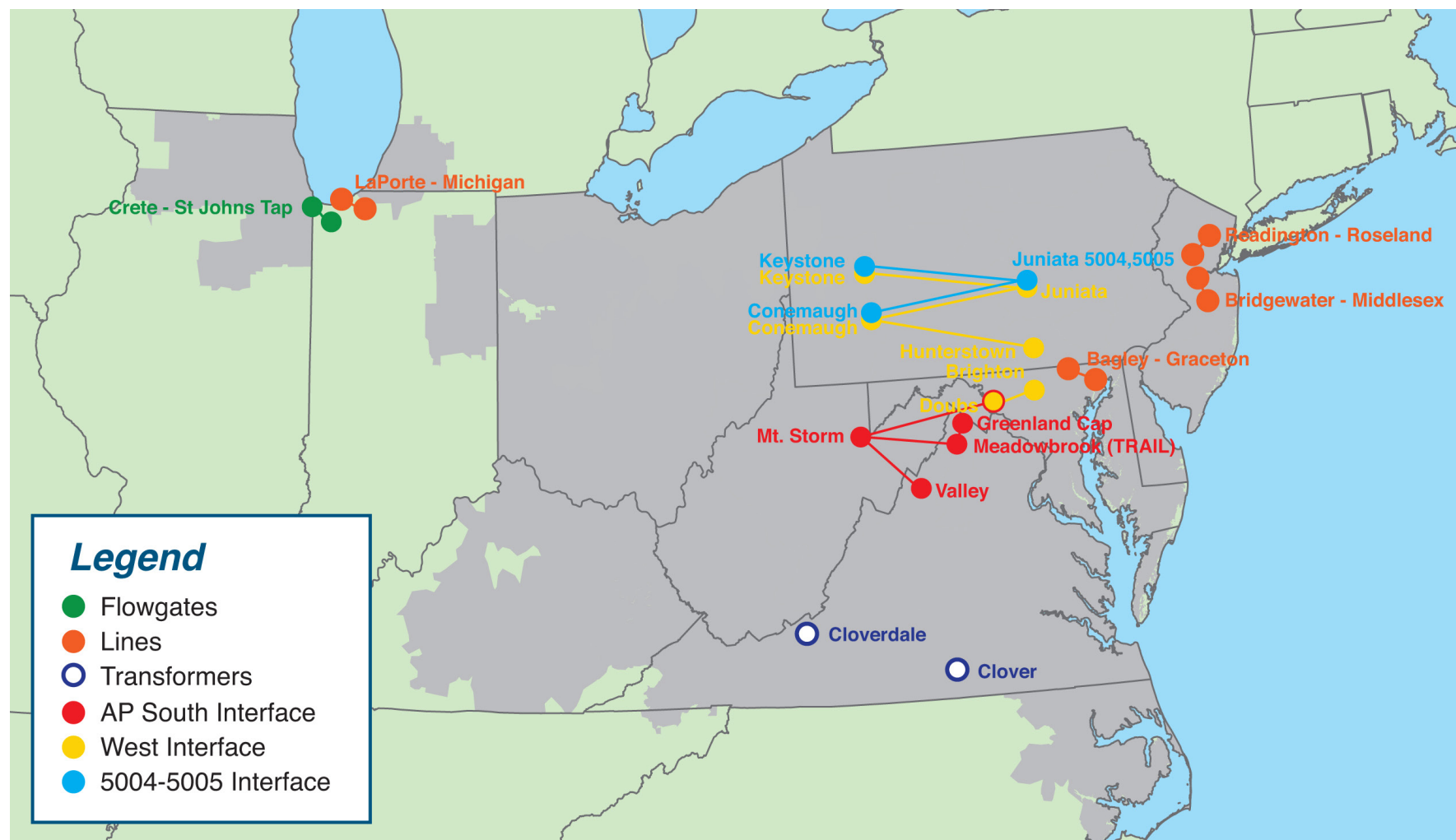
Congestion-Event Summary for MISO Flowgates

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.[23] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[24] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch. Table 10-29 and Table 10-30 show the MISO flowgates which PJM and/or MISO took dispatch action

to control during the first six months of 2013 and 2012, 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 six months of 2013, the Crete - St Johns Tap flowgate made the most significant contribution to positive congestion while the Beaver Channel - Albany flowgate made the most significant contribution to negative congestion.

Table 10-29 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through June 2013

| | | Congestion Costs (Millions) | | | | | | | | | Event Hours | |
| | | Day Ahead | | | | Balancing | | | | | | |
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Crete - St Johns Tap	($0.4)	($6.8)	$2.6	$9.0	$0.0	$0.0	$0.0	$0.0	$9.0	1,056	0
2	Monticello - East Winamac	($1.3)	($19.2)	$4.1	$22.0	$0.2	$4.6	($10.5)	($14.9)	$7.2	1,598	449
3	Breed - Wheatland	($0.6)	($5.6)	$1.4	$6.4	$0.0	($0.0)	($1.1)	($1.0)	$5.3	724	152
4	Michigan City - Laporte	($3.2)	($6.4)	$1.8	$5.0	$0.0	$0.0	$0.0	$0.0	$5.0	964	0
5	Prairie State - W Mt. Vernon	($2.0)	($5.2)	($0.4)	$2.8	($0.0)	($0.1)	$0.7	$0.8	$3.6	1,021	836
6	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($0.6)	$0.1	($2.5)	($3.2)	($3.2)	0	80
7	Edwards - Kewanee	($2.0)	($3.5)	$1.6	$3.0	$0.0	$0.0	$0.0	$0.0	$3.0	1,201	12
8	Benton Harbor - Palisades	($0.7)	($4.3)	$1.5	$5.1	($0.0)	$0.7	($1.8)	($2.6)	$2.5	752	100
9	Volunteer - Phiipps Bend	$0.0	$0.0	$0.0	$0.0	$0.8	$0.0	($2.9)	($2.1)	($2.1)	0	63
10	Stillwell	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.4	($1.4)	($1.9)	($1.9)	0	64
11	Cumberland - Bush	($0.1)	($2.0)	$0.6	$2.5	$0.4	$1.2	($3.5)	($4.3)	($1.8)	402	152
12	Miami Fort	($0.4)	($2.0)	$0.1	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	621	0
13	Hennepin	($0.2)	($0.5)	($0.1)	$0.1	($0.2)	$0.0	($1.4)	($1.6)	($1.5)	0	160
14	Rantoul Jct - Sidney	$0.0	$0.0	$0.0	$0.0	($0.3)	$0.5	($0.4)	($1.2)	($1.2)	0	116
15	Rantoul - Rantoul Jct	($0.9)	($1.3)	$0.5	$0.9	$0.0	$0.0	$0.0	$0.0	$0.9	340	0
16	Oak Grove - Galesburg	($2.1)	($4.0)	($0.4)	$1.5	($0.2)	$0.2	($0.4)	($0.8)	$0.6	801	504
17	Lanesville	($0.1)	($0.5)	$0.2	$0.6	$0.0	($0.0)	($0.0)	$0.0	$0.6	290	14
18	Beaver Channel - Albany	($0.6)	($1.2)	($0.0)	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	85	0
19	Pana North	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.5)	($0.6)	($0.6)	0	7
20	Rising	($0.4)	($1.5)	$0.6	$1.7	($0.1)	$0.1	($1.0)	($1.2)	$0.5	534	138

23 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>.
24 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>.

Table 10–30 Top congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through June 2012

		Congestion Costs (Millions)									Event Hours	
		Day Ahead				Balancing						
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Woodstock	($7.0)	($30.2)	$6.8	$30.0	$0.0	$0.0	$0.0	$0.0	$30.0	1,073	0
2	Monticello – East Winamac	($0.1)	($13.7)	$9.3	$22.9	$0.4	$1.9	($15.1)	($16.6)	$6.3	1,683	541
3	Breed – Wheatland	($0.9)	($5.4)	$0.0	$4.5	$0.3	$0.3	($9.3)	($9.3)	($4.8)	693	224
4	Crete – St Johns Tap	($4.6)	($14.7)	($1.2)	$8.8	$0.3	$1.0	($5.4)	($6.1)	$2.7	1,766	268
5	Oak Grove – Galesburg	($6.0)	($9.7)	$5.6	$9.3	($0.6)	$0.9	($9.5)	($11.0)	($1.7)	1,948	720
6	Cumberland – Bush	($1.0)	($5.0)	$5.6	$9.5	$0.4	$1.2	($10.3)	($11.1)	($1.6)	1,667	283
7	Miami Fort – Hebron	($0.6)	($1.9)	$0.1	$1.4	($0.1)	($0.0)	$0.1	$0.0	$1.4	455	58
8	Prairie State – W Mt. Vernon	($1.6)	($2.6)	$0.5	$1.5	($0.0)	($0.0)	($0.2)	($0.2)	$1.3	422	156
9	Bunsonville – Eugene	($0.7)	($1.1)	$0.2	$0.7	$0.0	($0.1)	($0.1)	($0.0)	$0.7	236	37
10	Pana North	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.7)	($0.7)	($0.7)	0	11
11	Brokaw – Gibson	($0.5)	($0.9)	$0.2	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	160	4
12	Sheffield – Marktown	($1.1)	($2.1)	$0.2	$1.2	$0.2	$0.5	($0.3)	($0.7)	$0.5	1,055	66
13	Lanesville	$0.1	($0.0)	$0.6	$0.7	($0.0)	$0.0	($0.2)	($0.3)	$0.5	319	21
14	Edwards – Kewanee	($0.3)	($0.5)	$0.4	$0.7	$0.0	($0.0)	($0.2)	($0.2)	$0.5	127	36
15	Palisades – Roosevelt	($0.2)	($1.0)	($0.2)	$0.6	$0.0	($0.0)	($0.2)	($0.1)	$0.5	160	42
16	Beaver Channel – Albany	($1.6)	($5.1)	$0.8	$4.2	($1.3)	$0.6	($2.7)	($4.7)	($0.5)	360	111
17	Burnham – Munster	($0.3)	($0.6)	$0.1	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	226	0
18	Roxana – Praxair	($0.0)	($0.5)	($0.1)	$0.4	$0.0	$0.0	$0.0	$0.0	$0.4	135	0
19	Bush – Lafayette	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.1	($0.3)	($0.4)	($0.4)	0	0
20	Kenosha – Lakeview	($0.0)	($0.3)	$0.1	$0.4	($0.1)	$0.1	($0.6)	($0.7)	($0.3)	102	37

Congestion-Event Summary for NYISO Flowgates

PJM and NYISO have a joint operating agreement (JOA) which defines a coordinated methodology for congestion management. This agreement establishes a structure and framework for the reliable operation of the interconnected PJM and NYISO transmission systems and efficient market operation through M2M coordination.[25] Only a subset of all transmission constraints that exist in either market are eligible for coordinated congestion management. This subset of transmission constraints is identified as M2M Flowgates. Flowgates eligible for the M2M coordination process are called M2M Flowgates.[26]

Table 10-31 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during the first six months of 2013, and which had the greatest congestion cost impact on PJM.

Table 10-31 Top congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): January through June 2013

| | | | | Congestion Costs (Millions) | | | | | | | | | Event Hours | |
| | | | | Day Ahead | | | | Balancing | | | | | | |
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Central east	Flowgate	NYISO	$0.3	($1.2)	($0.2)	$1.3	$0.6	$2.1	($1.4)	($2.9)	($1.6)	48	167
2	Dysinger East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.2	$0.0	($0.2)	($0.2)	0	9

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25 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc and PJM Interconnection, L.L.C." (January 17, 2013) Section 35.3.1 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).

26 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc and PJM Interconnection, L.L.C." (January 17, 2013) Section 35.23 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed April 17, 2013).

Congestion–Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 10-32 and Table 10-33 show the 500 kV constraints impacting congestion costs in PJM for the first six months of 2013 and 2012. 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 10-32 Regional constraints summary (By facility): January through June 2013

| | | | | Congestion Costs (Millions) | | | | | | | | | | | |
| | | | | Day Ahead | | | | Balancing | | | | | Event Hours | | |
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$81.4	($26.2)	$5.8	$113.3	$5.7	$12.3	($2.3)	($9.0)	$104.3	3,275	646
2	West	Interface	500	$2.6	($13.0)	($0.4)	$15.2	$1.8	$2.4	($0.7)	($1.3)	$13.9	760	41
3	5004/5005 Interface	Interface	500	$0.9	($10.5)	($0.3)	$11.1	$1.2	$3.9	$0.5	($2.2)	$8.9	422	107
4	AEP – DOM	Interface	500	$3.3	($2.2)	($0.0)	$5.5	($0.1)	$0.1	($0.0)	($0.2)	$5.3	1,005	9
5	Bedington – Black Oak	Interface	500	$2.1	($1.2)	$0.2	$3.5	$0.1	($0.0)	($0.3)	($0.2)	$3.3	502	10
6	Central	Interface	500	($0.6)	($2.7)	($0.4)	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	128	0
7	Conemaugh – Hunterstown	Line	500	$0.1	($1.6)	$0.3	$2.0	$0.5	$0.7	($0.7)	($0.9)	$1.1	67	68
8	Cleveland	Interface	500	$0.0	$0.0	$0.0	$0.0	$0.1	($0.7)	$0.0	$0.8	$0.8	0	13
9	East	Interface	500	($0.2)	($0.8)	$0.0	$0.6	$0.0	$0.0	$0.0	$0.0	$0.6	151	0
10	Nagel – Phipps Bend	Line	500	$0.0	($0.0)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	22	0
11	Cloverdale – Lexington	Line	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	($0.1)	$0.0	$0.0	0	0
12	EAST	Interface	500	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	($0.0)	($0.0)	($0.0)	0	4

Table 10-33 Regional constraints summary (By facility): January through June 2012

| | | | | Congestion Costs (Millions) | | | | | | | | | | | |
| | | | | Day Ahead | | | | Balancing | | | | | Event Hours | | |
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	AP South	Interface	500	$18.8	($8.3)	$0.1	$27.2	$3.3	$2.6	($2.6)	($1.9)	$25.4	1,211	82
2	West	Interface	500	($0.6)	($16.6)	($2.3)	$13.7	$1.0	$1.1	$0.3	$0.1	$13.8	318	14
3	5004/5005 Interface	Interface	500	$0.1	($3.9)	$0.4	$4.5	$1.8	$2.3	$0.5	($0.0)	$4.5	152	83
4	East	Interface	500	($2.5)	($7.6)	($0.6)	$4.5	$0.1	$0.5	($0.1)	($0.5)	$4.0	177	5
5	Bedington – Black Oak	Interface	500	$2.9	($1.4)	($0.2)	$4.0	$0.0	$0.0	($0.0)	($0.0)	$4.0	136	16
6	AEP – DOM	Interface	500	$2.6	($1.3)	$0.1	$4.1	$0.3	$1.6	$0.2	($1.0)	$3.1	564	52
7	Central	Interface	500	($0.7)	($1.4)	$0.1	$0.8	$0.0	$0.0	($0.0)	($0.0)	$0.8	182	2
8	Kammer	Transformer	500	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	19
9	Burches Hill – Chalk Point	Line	500	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	2	0

Congestion Costs by Physical and Financial Participants

In order to evaluate the recipients and payers of congestion, the MMU categorized all participants 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.

In the first six months of 2013, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges.[27] In the first six months of 2013, financial companies received $54.7 million, an increase of $11.5 million or 26.6 percent compared to the first six months of 2012. In the first six months of 2013, physical companies paid $360.7 million in congestion charges, an increase of $54.3 million or 17.7 percent compared to the first six months of 2012.

Table 10–34 Congestion cost by the type of the participant: January through June 2013

| | Congestion Costs (Millions) | | | | | | | | | |
| | Day Ahead | | | | Balancing | | | | | |
Participant Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	$35.9	$30.5	$55.2	$60.7	($21.6)	$2.8	($91.0)	($115.3)	$0.0	($54.7)
Physical	$97.3	($336.6)	$32.6	$466.5	$13.1	$87.6	($31.3)	($105.7)	$0.0	$360.7
Total	$133.2	($306.1)	$87.8	$527.1	($8.4)	$90.4	($122.3)	($221.1)	$0.0	$306.1

Table 10–35 Congestion cost by the type of the participant: January through June 2012

| | Congestion Costs (Millions) | | | | | | | | | |
| | Day Ahead | | | | Balancing | | | | | |
Participant Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
Financial	($3.1)	($1.9)	$45.4	$44.1	($11.2)	($3.3)	($79.5)	($87.3)	$0.0	($43.2)
Physical	$65.6	($259.8)	$20.0	$345.5	$9.6	$26.3	($22.3)	($39.1)	$0.0	$306.4
Total	$62.5	($261.7)	$65.4	$389.6	($1.6)	$23.0	($101.8)	($126.4)	$0.0	$263.3

27 The total zonal congestion numbers were calculated as of April 15, 2013 and are, based on continued PJM billing updates, subject to change.

Generation and Transmission Planning

Overview

Planned Generation and Retirements

- **Planned Generation.** At June 30, 2013, 72,537 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 195,000 MW in the first six months of 2013. Wind projects account for 18,612 MW of nameplate capacity or 25.7 percent of the capacity in the queues and combined-cycle projects account for 42,925 MW of capacity or 59.2 percent of the capacity in the queues.

- **Generation Retirements.** As shown in Table 11-12, 768.2 MW are planning to deactivate by the end of calendar year 2019. A total of 7,195.7 MW of generation capacity retired from January 1, 2012 through June 30, 2013, and it is expected that a total of 22,160.4 MW will have retired from 2011 through 2019, with most of this capacity retiring by the end of 2015. Retirements from January 1, 2011 through June 30, 2013, account for 8,392.2 MW, or 37.9 percent of retirements during this period. Units planning to retire in 2013 account for 2,402.6 MW, or 10.8 percent of retirements during this period. Overall, 3,508.1 MW, or 28.7 percent of all MW planned for deactivation from 2013 through 2019, are expected in the AEP zone.

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

Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a generating facility, including increases to the capacity of an existing generating unit, or that requests interconnection of a merchant transmission facility, must follow the process defined in the PJM tariff to obtain interconnection service.[1] The process is complex and time consuming as a result of the nature of the required analyses. The cost, time and uncertainty associated with interconnecting to the grid may create barriers to entry for potential entrants.

- The queue contains a substantial number of projects that are not likely to be built, including 19,043.7 MW that should already be in service based on the original queue date, but that is not yet even under construction. These projects may also create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.

Key Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects. The backbone projects are intended to resolve a wide range of reliability criteria violations and congestion issues and have substantial impacts on energy and capacity markets. The current backbone projects are: Mount Storm – Doubs; Jacks Mountain; and Susquehanna – Roseland.

Economic Planning Process

- **Transmission and Markets.** As a general matter, transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities can have significant impacts on energy and capacity markets, but there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in an area. PJM has taken a first step towards

1 OATT Parts IV & VI.

integrating transmission investments into the market through the use of economic evaluation metrics.[2] The goal of transmission planning should be the incorporation of transmission investment decisions into market driven processes as much as possible.

Conclusion

The goal of PJM market design should be to enhance competition and to ensure that competition is the driver for all the key elements of PJM markets. But transmission investments have not been fully incorporated into competitive markets. The construction of new transmission facilities has significant impacts on energy and capacity markets. But when generating units retire, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in that area. In addition, despite Order No. 1000, there is not yet a robust mechanism to permit competition between transmission developers to build transmission projects.[3] The addition of a planned transmission project changes the parameters of the capacity auction for the area, changes the amount of capacity needed in the area, changes the capacity market supply and demand fundamentals in the area and effectively forestalls the ability of generation to compete. There is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no evaluation of whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. Creating such a mechanism should be a goal of PJM market design.

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 June 30, 2013, 72,537 MW of capacity were in generation request queues for construction through 2020, compared to an average installed capacity of 195,000 MW in 2013. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000 (Table 11-1).[4] Overall, 535 MW of nameplate capacity were added in PJM in the first six months of 2013.

Table 11-1 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through the first six months of 2013[5]

	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
2012	2,669
2013	535

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 Z was active through June 30, 2013.

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2 *See* 126 FERC ¶ 61,152 (2009) (final approval for an approach with predefined formulas for determining whether a transmission investment passes the cost-benefit test including explicit accounting for changes in production costs, the costs of complying with environmental regulations, generation availability trends and demand-response trends), *order on reh'g*, 123 FERC ¶ 61,051 (2008).
3 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012).

4 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.
5 The capacity described in this table refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Capacity in generation request queues for the twelve year period beginning in 2013 and ending in 2024 decreased by 3,850 MW from 76,387 MW in 2012 to 72,537 MW on June 30, 2013, or 5.0 percent (Table 11-2).[6] Queued capacity scheduled for service in 2013 decreased from 22,120 MW to 16,359 MW, or 26.0 percent. Queued capacity scheduled for service in 2014 decreased from 8,086 MW to 7,386 MW, or 8.7 percent. The 72,537 MW include generation with scheduled in-service dates in 2013 and units still active in the queue with in-service dates scheduled before 2013, listed at nameplate capacity, although these units are not yet in service.

Table 11-2 Queue comparison (MW): June 30, 2013 vs. December 31, 2012

	MW in the Queue 2012	MW in the Queue 2013	Year-to-Year Change (MW)	Year-to-Year Change
2013	22,120	16,359	(5,762)	(26.0%)
2014	8,086	7,386	(701)	(8.7%)
2015	22,295	17,769	(4,526)	(20.3%)
2016	11,788	13,470	1,681	14.3%
2017	8,932	12,662	3,730	41.8%
2018	3,165	2,952	(213)	(6.7%)
2019	0	0	0	NA
2020	0	346	346	NA
2024	0	1,594	1,594	NA
Total	76,387	72,537	(3,850)	(5.0%)

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.[7]

Table 11-3 Capacity in PJM queues (MW): At June 30, 2013[8,9]

Queue	Active	In-Service	Under Construction	Withdrawn	Total
A Expired 31-Jan-98	0	8,103	0	17,347	25,450
B Expired 31-Jan-99	0	4,646	0	14,957	19,602
C Expired 31-Jul-99	0	531	0	3,471	4,002
D Expired 31-Jan-00	0	851	0	7,182	8,033
E Expired 31-Jul-00	0	795	0	8,022	8,817
F Expired 31-Jan-01	0	52	0	3,093	3,145
G Expired 31-Jul-01	0	1,116	0	17,934	19,050
H Expired 31-Jan-02	0	703	0	8,422	9,124
I Expired 31-Jul-02	0	103	0	3,728	3,831
J Expired 31-Jan-03	0	40	0	846	886
K Expired 31-Jul-03	0	218	80	2,345	2,643
L Expired 31-Jan-04	0	257	0	4,034	4,290
M Expired 31-Jul-04	0	505	300	3,556	4,360
N Expired 31-Jan-05	0	2,399	38	8,090	10,527
O Expired 31-Jul-05	10	1,688	825	5,069	7,592
P Expired 31-Jan-06	183	3,065	463	4,928	8,638
Q Expired 31-Jul-06	120	2,248	2,694	9,472	14,534
R Expired 31-Jan-07	1,296	1,216	728	19,514	22,755
S Expired 31-Jul-07	1,640	3,281	452	11,769	17,142
T Expired 31-Jan-08	3,704	1,275	631	21,936	27,545
U Expired 31-Jan-09	2,514	776	789	29,278	33,357
V Expired 31-Jan-10	4,850	264	1,617	10,275	17,005
W Expired 31-Jan-11	7,464	352	1,701	14,714	24,232
X Expired 31-Jan-12	14,184	216	3,638	12,335	30,373
Y Expired 30-Apr-13	21,740	28	191	4,364	26,324
Z through 30-Jun-13	687	0	0	0	687
Total	58,391	34,727	14,147	246,680	353,944

Data presented in Table 11-4 show that through the first six months of 2013, 36.7 percent of total in-service capacity from all the queues was from Queues A and B and an additional 6.3 percent was from Queues C, D and E.[10] As of June 30, 2013, 9.8 percent of all queued capacity has been placed in service, and 13.8 percent of all queued capacity is either complete or under construction.

The data presented in Table 11-4 show that for successful projects there is an average time of 835 days between entering a queue and the in-service date,

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6 See the *2012 State of the Market Report for PJM*: Volume II, Section 11, pp. 318-323, for the queues in 2012.
7 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.

8 The *2013 Quarterly State of the Market Report for PJM: January through June* contains all projects in the queue including reratings of existing generating units and energy only resources.
9 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.
10 The data for Queue Z include projects through June 30, 2013.

an increase of 4 days over the 2012 average. The data also show that for withdrawn projects, there is an average time of 569 days between entering a queue and exiting. For each status, there is substantial variability around the average results.

Table 11-4 Average project queue times (days): At June, 2013

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	915	688	0	4,636
In-Service	835	717	0	3,964
Suspended	2,006	906	704	3,849
Under Construction	1,486	828	0	6,380
Withdrawn	569	581	0	4,249

Table 11-5 shows queued capacity with an "active" status that is planned to be in service by January 1, 2015. This indicates there is a substantial amount of queued capacity, 19,043.7 MW, that should already be in service or under construction based on the original queue date, but has not progressed far enough in the development process to begin construction. The MMU recommends that a review process be created to ensure that projects are removed from the queue, if they are no longer viable or no longer planning to complete the project.

Table 11-5 Active capacity queued to be in service prior to January 1, 2015

	MW
2007	27.0
2008	190.0
2009	285.0
2010	1,199.8
2011	2,449.4
2012	2,907.0
2013	7,467.6
2014	4,518.0
Total	19,043.7

Table 11-6 shows queued capacity with an "active" status that is planned to be in service by January 1, 2015, by zone. Projects that have yet to start construction by July 1, 2013, yet are expected to be complete by January 1, 2015, are defined as non-viable. Currently, 63.2 percent of all generation that

appears to be non-viable is located in the AEP and ComEd control zones. Further, certain owners appear to have significant MW positions in generation queues that appear non-viable. There are six owners with more than 500 MW of non-viable queue positions. Additionally, a significant number of queue positions are lacking an identifiable interconnection customer.

Table 11-6 Active capacity queued to be in service prior to January 1, 2015, by zone

	2007	2008	2009	2010	2011	2012	2013	2014	Total
AECO	0	0	4	103	332	67	8	350	864
AEP	0	0	0	750	1,047	426	4,938	1,391	8,552
AP	0	0	70	0	32	209	91	1,021	1,422
ATSI	0	0	0	0	175	200	536	212	1,123
BGE	0	0	0	0	0	0	4	0	4
ComEd	27	166	141	220	616	1,394	881	40	3,486
DAY	0	0	0	0	0	200	412	0	612
DEOK	0	0	0	0	0	0	50	4	54
DLCO	0	0	0	0	0	0	0	0	0
Dominion	0	0	0	5	20	20	41	0	86
DPL	0	0	0	20	112	40	35	150	357
EKPC	0	0	0	0	0	0	0	0	0
JCPL	0	0	0	0	0	4	7	6	16
Met-Ed	0	24	0	0	0	3	17	150	194
PECO	0	0	0	2	2	73	5	0	82
PENELEC	0	0	70	0	14	84	144	167	479
Pepco	0	0	0	0	0	0	0	36	36
PPL	0	0	0	100	100	0	0	235	435
PSEG	0	0	0	0	0	188	300	756	1,244
Total	27	190	285	1,200	2,449	2,907	7,468	4,518	19,044

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 June 30, 2013, 72,537 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 195,000 MW in 2013. Wind projects account for 18,612 MW of nameplate capacity or 25.7 percent of the capacity in the queues and combined-cycle projects account for 42,925 MW

of capacity or 59.2 percent of the capacity in the queues.[11] On June 30, 2013, there were 42,925 MW of capacity from combined cycle units in the queue, compared to 42,724 MW in 2012, an increase of 0.5 percent. At June 30, 2013, there was queued combined cycle capacity in nearly every zone in PJM, and after accounting for the derating of wind and solar resources, combined cycle capacity comprises 78.0 percent of the MW in the queue able to offer into RPM auctions.

Table 11-7 shows the projects under construction or active as of June 30, 2013, by unit type and control zone. Most of the steam projects (99.3 percent of the MW) and most of the wind projects (92.5 percent of the MW) are outside the Eastern MAAC (EMAAC)12 and Southwestern MAAC (SWMAAC)13 locational deliverability areas (LDAs).14 Of the total capacity additions, only 14,605 MW, or 20.1 percent, are projected to be in EMAAC, while 4,240 MW or 5.8 percent are projected to be constructed in SWMAAC. Of total capacity additions, 27,720 MW, or 38.2 percent of capacity, is being added inside MAAC zones.

Overall, 74.0 percent of capacity is being added outside EMAAC and SWMAAC, and 61.7 percent of capacity is being added outside MAAC zones. Wind projects account for 2,565 MW of capacity in MAAC LDAs, or 9.3 percent. While there are no wind projects in the SWMAAC LDA, in the EMAAC LDA wind projects account for 1,387 MW of capacity, or 9.5 percent. Of non-steam, non-wind projects, 65.6 percent of capacity is being added outside EMAAC and SWMAAC zones.

Table 11-7 Capacity additions in active or under-construction queues by control zone (MW): At June 30, 2013

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	2,849	71	9	0	0	493	0	0	1,069	4,491
AEP	5,682	40	20	70	0	44	2,124	98	8,510	16,588
AP	1,999	48	50	75	0	142	199	0	497	3,012
ATSI	3,475	1,020	6	7	0	15	135	0	849	5,507
BGE	678	256	4	0	0	22	0	0	0	960
ComEd	2,691	441	46	23	473	64	0	42	4,837	8,616
DAY	0	0	2	112	0	23	12	12	600	761
DEOK	20	0	0	0	0	0	50	4	0	74
DLCO	285	0	0	0	48	0	460	0	0	793
Dominion	6,593	60	11	0	1,594	65	219	0	505	9,046
DPL	1,223	2	16	0	0	238	22	8	318	1,826
EKPC	170	0	0	0	0	0	0	0	250	420
JCPL	1,755	0	30	0	0	800	0	20	0	2,605
Met-Ed	1,818	0	2	0	39	3	0	0	0	1,862
PECO	1,609	7	4	45	330	0	0	4	0	1,998
PENELEC	879	43	28	0	0	32	3	0	675	1,661
Pepco	3,245	0	20	0	0	15	0	0	0	3,280
PPL	4,671	0	7	3	100	29	0	40	503	5,352
PSEG	3,284	172	9	0	50	170	0	0	0	3,685
Total	42,925	2,160	264	335	2,634	2,156	3,224	228	18,612	72,537

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 11-8)

Table 11-8 Capacity additions in active or under-construction queues by LDA (MW): At June 30, 2013[15]

	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total
EMAAC	10,719	251	67	45	380	1,702	22	32	1,387	14,605
SWMAAC	3,923	256	24	0	0	37	0	0	0	4,240
WMAAC	7,368	43	36	3	139	64	3	40	1,178	8,874
Non-MAAC	20,915	1,609	136	287	2,115	353	3,199	156	16,047	44,817
Total	42,925	2,160	264	335	2,634	2,156	3,224	228	18,612	72,537

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 18,612 MW of wind resources and 2,156 MW of solar resources, the 72,537 MW currently active in the queue would be reduced to 55,008 MW.

12 EMAAC consists of the AECO, DPL, JCPL, PECO and PSEG Control Zones.

13 SWMAAC consists of the BGE and Pepco Control Zones.

14 See the *2012 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for a map of PJM LDAs.

15 WMAAC consists of the Met-Ed, PENELEC, and PPL Control Zones.

Table 11-9 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 11-7) 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 11-9 Existing PJM capacity: At June 30, 2013[16] (By zone and unit type (MW))

	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	164	706	21	0	0	0	40	1,087	0	8	2,025
AEP	4,900	3,682	63	0	1,072	2,071	0	21,145	0	1,753	34,686
AP	1,129	1,215	48	0	80	0	36	7,358	27	999	10,892
ATSI	685	1,661	74	0	0	2,134	0	6,540	0	0	11,094
BGE	0	835	22	0	0	1,716	0	2,996	0	0	5,569
ComEd	1,770	7,244	100	0	0	10,438	0	5,417	5	2,454	27,428
DAY	0	1,369	48	0	0	0	1	3,180	0	0	4,597
DEOK	0	842	0	0	0	0	0	4,154	0	0	4,996
DLCO	244	15	0	0	6	1,777	0	784	0	0	2,826
Dominion	4,030	3,762	171	0	3,589	3,581	3	8,419	0	0	23,554
DPL	1,125	1,820	96	30	0	0	4	1,800	0	0	4,876
EKPC	0	774	0	0	70	0	0	1,882	0	0	2,726
External	0	111	0	0	0	13	0	3,819	0	0	3,942
JCPL	1,693	1,233	27	0	400	615	42	15	0	0	4,024
Met-Ed	2,051	408	41	0	20	805	0	844	0	0	4,168
PECO	3,209	836	3	0	1,642	4,547	3	979	1	0	11,220
PENELEC	0	344	46	0	513	0	0	6,831	0	931	8,663
Pepco	230	1,092	12	0	0	0	0	3,649	0	0	4,983
PPL	1,808	617	49	0	582	2,520	15	5,537	0	220	11,346
PSEG	3,091	2,838	12	0	5	3,493	105	2,050	2	0	11,597
Total	26,128	31,402	832	30	7,978	33,709	249	88,484	35	6,364	195,211

16 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Table 11-10 shows the age of PJM generators by unit type.

Table 11-10 PJM capacity (MW) by age: at June 30, 2013

Age (years)	Combined Cycle	Combustion Turbine	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 11	13,883	4,452	456	30	8	0	249	3,385	6,264	35	28,761
11 to 20	9,287	16,969	131	0	51	0	0	2,738	100	0	29,276
21 to 30	2,517	2,753	56	0	3,316	12,605	0	7,708	0	0	28,955
31 to 40	244	1,415	24	0	241	16,075	0	25,201	0	0	43,199
41 to 50	198	5,813	151	0	2,915	5,029	0	31,721	0	0	45,827
51 to 60	0	0	15	0	112	0	0	14,609	0	0	14,736
61 to 70	0	0	0	0	267	0	0	2,973	0	0	3,240
71 to 80	0	0	0	0	215	0	0	95	0	0	310
81 to 90	0	0	0	0	614	0	0	54	0	0	668
91 to 100	0	0	0	0	108	0	0	.	0	0	108
101 and over	0	0	0	0	131	0	0	0	0	0	131
Total	26,128	31,402	832	30	7,978	33,709	249	88,484	6,364	35	195,211

Table 11-11 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 2024. The expected role of gas-fired generation depends largely on projects in the queues and continued retirement of coal-fired generation. New gas-fired capability would represent 89.0 percent of all new capacity in EMAAC when the derating of wind and solar capacity is reflected.

In 2012, a planned addition of 1,640 MW of nuclear capacity to Calvert Cliffs in SWMAAC was withdrawn from the queue. Without the planned nuclear capability in SWMAAC, new gas-fired capability represents 98.6 percent of all new capability in the SWMAAC. In 2020, this would mean that CC and CT generators would comprise 54.9 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.[17] In these zones, 88.2 percent of all generation 40 years or older is steam (primarily coal). With the retirement of these units in 2020, wind farms would comprise 15.4 percent of total MW ICAP in Non-MAAC zones, if all queued MW are built.

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17 Non-MAAC zones consist of the AEP, AP, ATSI, ComEd, DAY, DEOK, DLCO, and Dominion Control Zones.

Table 11-11 Comparison of generators 40 years and older with slated capacity additions (MW): Through 2024[18]

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 2024	Estimated Capacity 2024	Percent of Area Total
EMAAC	Combined Cycle	198	2.4%	9,282	27.5%	10,719	19,803	48.5%
	Combustion Turbine	2,229	27.5%	7,433	22.0%	251	5,456	13.4%
	Diesel	48	0.6%	159	0.5%	67	178	0.4%
	Fuel Cell	0	0.0%	30	1.6%	0	30	1.8%
	Hydroelectric	2,042	25.2%	2,047	6.1%	45	665	1.6%
	Nuclear	615	7.6%	8,654	25.6%	380	8,420	20.6%
	Solar	0	0.0%	194	0.6%	1,702	1,896	4.6%
	Steam	2,981	36.7%	5,931	17.6%	22	2,972	7.3%
	Storage	0	0.0%	3	0.0%	32	35	0.1%
	Wind	0	0.0%	8	0.0%	1,387	1,395	3.4%
	EMAAC Total	8,112	100.0%	33,741	100.0%	14,605	40,848	100.0%
SWMAAC	Combined Cycle	0	0.0%	230	2.2%	3,923	4,153	39.4%
	Combustion Turbine	542	12.8%	1,927	18.3%	256	1,640	15.6%
	Diesel	0	0.0%	34	0.3%	24	58	0.6%
	Hydroelectric	0	0.0%	0	0.0%	0	0	0.0%
	Nuclear	0	0.0%	1,716	16.3%	0	1,716	16.3%
	Solar	0	0.0%	0	0.0%	37	37	0.4%
	Steam	3,702	87.2%	6,645	63.0%	0	2,943	27.9%
	SWMAAC Total	4,244	100.0%	10,552	100.0%	4,240	10,548	100.0%
WMAAC	Combined Cycle	0	0.0%	3,859	16.0%	7,368	11,227	45.4%
	Combustion Turbine	558	6.1%	1,368	5.7%	43	854	3.4%
	Diesel	46	0.5%	136	0.6%	36	126	0.5%
	Hydroelectric	887	9.7%	1,114	4.6%	3	1,117	4.5%
	Nuclear	0	0.0%	3,325	13.8%	139	3,464	14.0%
	Solar	0	0.0%	15	0.1%	64	79	0.3%
	Steam	7,702	83.8%	13,211	54.6%	3	5,513	22.3%
	Storage	0	0.0%	0	0.0%	40	40	0.2%
	Wind	0	0.0%	1,151	4.8%	1,178	2,328	9.4%
	WMAAC Total	9,193	100.0%	24,178	100.0%	8,874	24,747	100.0%
Non-MAAC	Combined Cycle	0	0.0%	12,758	10.1%	20,915	33,673	24.5%
	Combustion Turbine	942	2.7%	20,674	16.3%	1,609	21,342	15.5%
	Diesel	53	0.1%	503	0.4%	136	587	0.4%
	Hydroelectric	1,433	4.1%	4,818	3.8%	287	5,104	3.7%
	Nuclear	1,751	5.0%	20,013	15.8%	2,115	20,378	14.8%
	Solar	0	0.0%	40	0.0%	353	393	0.3%
	Steam	31,118	88.2%	62,697	49.5%	3,199	34,778	25.3%
	Storage	0	0.0%	32	0.0%	156	188	0.1%
	Wind	0	0.0%	5,206	4.1%	16,047	21,253	15.4%
	Non-MAAC Total	35,295	100.0%	126,741	100.0%	44,817	137,696	100.0%
All Areas	Total	56,844		195,211		72,537	213,839	

18 Percentages shown in Table 11-11 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 11-12, 13,768.2 MW are planning to deactivate by the end of calendar year 2019. A total of 7,195.7 MW of generation capacity retired from January 1, 2012, through June 30, 2013, and it is expected that a total of 22,160.4 MW will have retired from 2011 through 2019, with most of this capacity retiring by June, 2015. Retirements from January 1, 2011, through June 30, 2013, account for 8,392.2 MW, or 37.9 percent of retirements during this period. Units planning to retire in 2013 account for 2,402.6 MW, or 10.8 percent of retirements during this period. Overall, 3,508.1 MW, or 28.7 percent of all MW planned for deactivation from 2013 through 2019, are expected in the AEP zone. Since January 1, 2013, 1,340.5 MW that were scheduled to be deactivated have withdrawn their deactivation notices, and are planning to continue operating, including the Avon Lake and New Castle generating units in the ATSI zone.

Table 11-12 Summary of PJM unit retirements (MW): 2011 through 2019

	MW
Retirements 2011	1,196.5
Retirements 2012	6,961.9
Retirements 2013	233.8
Planned Retirements 2013	2,402.6
Planned Retirements 2014	1,712.0
Planned Retirements 2015	9,039.1
Planned Retirements Post-2015	614.5
Total	22,160.4

Figure 11-1 Map of unit retirements in PJM: 2012 through 2019
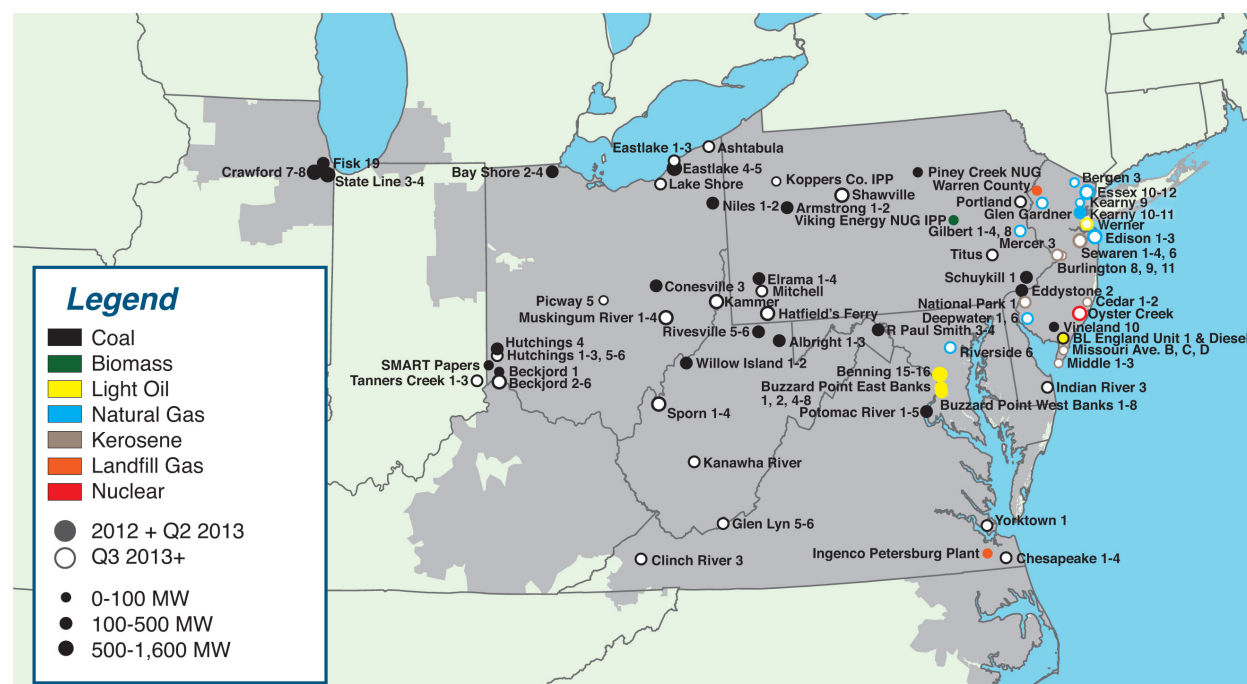
Table 11-13 Planned deactivations of PJM units, as of July 15, 2013

Unit	Zone	MW	Fuel	Unit Type	Projected Deactivation Date
Warren County Landfill	JCPL	1.9	Landfill Gas	Reciprocating engine	09-Jan-13
Piney Creek NUG	PENELEC	31.0	Waste Coal	Steam	12-Apr-13
Titus	Met-Ed	243.0	Coal	Steam	01-Sep-13
Koppers Co. IPP	PPL	8.0	Wood waste	Steam	30-Sep-13
Hatfield's Ferry	AP	1,590.0	Coal	Steam	09-Oct-13
Mitchell	AP	359.0	Coal	Steam	09-Oct-13
Indian River 3	DPL	169.7	Coal	Steam	31-Dec-13
BL England 1	AECO	113.0	Coal	Steam	01-May-14
Riverside 6	BGE	115.0	Natural gas	Combustion Turbine	01-Jun-14
Portland	Met-Ed	401.0	Coal	Steam	01-Jun-14
Burlington 9	PSEG	184.0	Kerosene	Combustion Turbine	01-Jun-14
Chesapeake 1-4	Dominion	576.0	Coal	Steam	31-Dec-14
Yorktown 1-2	Dominion	323.0	Coal	Steam	31-Dec-14
Beckjord 2-6	DEOK	1,024.0	Coal	Steam	01-Apr-15
Shawville	PENELEC	603.0	Coal	Steam	16-Apr-15
Gilbert 1-4, 8	JCPL	188.0	Natural gas	Combustion Turbine	01-May-15
Glen Gardner	JCPL	160.0	Natural gas	Combustion Turbine	01-May-15
Werner 1-4	JCPL	212.0	Light oil	Combustion Turbine	01-May-15
Kearny 9	PSEG	21.0	Natural gas	Combustion Turbine	01-May-15
Cedar 1-2	AECO	65.6	Kerosene	Combustion Turbine	31-May-15
Deepwater 1, 6	AECO	158.0	Natural gas	Steam	31-May-15
Middle 1-3	AECO	74.7	Kerosene	Combustion Turbine	31-May-15
Missouri Ave B, C, D	AECO	57.9	Kerosene	Combustion Turbine	31-May-15
Essex 12	PSEG	184.0	Natural gas	Combustion Turbine	31-May-15
Clinch River 3	AEP	230.0	Coal	Steam	01-Jun-15
Glen Lyn 5-6	AEP	325.0	Coal	Steam	01-Jun-15
Kammer	AEP	600.0	Coal	Steam	01-Jun-15
Kanawha River	AEP	400.0	Coal	Steam	01-Jun-15
Muskingum River 1-4	AEP	790.0	Coal	Steam	01-Jun-15
Picway 5	AEP	95.0	Coal	Steam	01-Jun-15
Sporn	AEP	580.0	Coal	Steam	01-Jun-15
Tanners Creek 1-3	AEP	488.1	Coal	Steam	01-Jun-15
Ashtabula	ATSI	210.0	Coal	Steam	01-Jun-15
Eastlake 1-3	ATSI	327.0	Coal	Steam	01-Jun-15
Lake Shore	ATSI	190.0	Coal	Steam	01-Jun-15
Hutchings 1-3, 5-6	DAY	271.8	Coal	Steam	01-Jun-15
Bergen 3	PSEG	21.0	Natural gas	Combustion Turbine	01-Jun-15
Burlington 8, 11	PSEG	205.0	Kerosene	Combustion Turbine	01-Jun-15
Edison 1-3	PSEG	504.0	Natural gas	Combustion Turbine	01-Jun-15
Essex 10-11	PSEG	352.0	Natural gas	Combustion Turbine	01-Jun-15
Mercer 3	PSEG	115.0	Kerosene	Combustion Turbine	01-Jun-15
National Park 1	PSEG	21.0	Kerosene	Combustion Turbine	01-Jun-15
Sewaren 1-4	PSEG	453.0	Natural gas	Steam	01-Jun-15
Sewaren 6	PSEG	105.0	Kerosene	Combustion Turbine	01-Jun-15
BL England Diesels	AECO	8.0	Diesel	Diesel	01-Oct-15
Oyster Creek	JCPL	614.5	Nuclear	Steam	31-Dec-19
Total		13,768.2			

Table 11-14 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2019. The majority, 73.8 percent, of all MW retiring during this period are coal steam units. These units have an average age of 57 years, and an average size of 165 MW. This indicates that, on average, retirements have consisted of smaller sub-critical coal steam units, and those without adequate environmental controls to remain viable beyond 2015.

Table 11-14 Deactivations of PJM units, 2011 through 2019

	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW
Coal	99	165.0	57.2	16,333.4
Diesel	3	5.6	43.3	16.9
Heavy Oil	1	166.0	55.0	166.0
Kerosene	20	41.4	45.5	828.2
LFG	1	1.9	7.0	1.9
Light Oil	19	64.0	43.8	1,216.0
Natural Gas	50	58.6	46.3	2,928.5
Nuclear	1	614.5	50.0	614.5
Waste Coal	1	31.0	20.0	31.0
Wood Waste	2	12.0	23.5	24.0

Table 11-15 HEDD Units in PJM as of June 30, 2013[19]

Unit	Zone	MW	Deactivation Date
Carlls Corner 1-2	AECO	72.6	NA
Cedar Station 1-3	AECO	66.0	31-May-15
Cumberland 1	AECO	92.0	NA
Mickleton 1	AECO	72.0	NA
Middle Street 1-3	AECO	75.3	31-May-15
Missouri Ave. B,C,D	AECO	60.0	31-May-15
Sherman Ave.	AECO	92.0	NA
Vineland West CT	AECO	26.0	01-Sep-12
Forked River 1-2	JCPL	65.0	NA
Gilbert 4-7, 9, C1-C4	JCPL	446.0	01-May-15
Glen Gardner A1-A4, B1-B4	JCPL	160.0	01-May-15
Lakewood 1-2	JCPL	316.1	NA
Parlin NUG	JCPL	114.0	NA
Sayreville C1-C4	JCPL	224.0	NA
South River NUG	JCPL	299.0	NA
Werner C1-C4	JCPL	212.0	01-May-15
Bayonne	PSEG	118.5	NA
Bergen 3	PSEG	21.0	01-Jun-15
Burlington 111-114, 121-124, 91-94, 8	PSEG	557.0	01-Jun-15
Camden	PSEG	145.0	NA
Eagle Point 1-2	PSEG	127.1	NA
Edison 11-14, 21-24, 31-34	PSEG	504.0	01-Jun-15
Elmwood	PSEG	67.0	NA
Essex 101-104, 111-114, 121,124	PSEG	536.0	01-Jun-15
Kearny 9-11, 121-124	PSEG	446.0	01-May-15
Linden 1-2	PSEG	1,230.0	NA
Mercer 3	PSEG	115.0	01-Jun-15
National Park	PSEG	21.0	01-Jun-15
Newark Bay	PSEG	120.2	NA
Pedricktown	PSEG	120.3	NA
Salem 3	PSEG	38.4	NA
Sewaren 6	PSEG	105.0	01-Jun-15
Total		6,663.5	

Actual Generation Deactivations in 2013

Table 11-16 shows unit deactivations for 2013 through June 30, 2013.[20] A total of 233.8 MW retired from January 1, 2013, through June 30, 2013.

Table 11-16 Unit deactivations: January 2013 through June 30, 2013

Company	Unit Name	ICAP	Primary Fuel	Zone Name	Age (Years)	Retirement Date
Exelon Corporation	Schuylkill 1	166.0	Heavy Oil	PECO	54	01-Jan-13
Exelon Corporation	Schuylkill Diesel	3.0	Diesel	PECO	45	01-Jan-13
Ingenco Wholesale Power, LLC	Ingenco Petersburg	2.9	Diesel	Dominion	22	31-May-13
The AES Corporation	Hutchings 4	61.9	Coal	DAY	62	01-Jun-13

Updates on Key Backbone Facilities

PJM baseline upgrade projects are implemented to resolve reliability criteria violations. PJM backbone projects are a subset of baseline upgrade projects that have been given the informal designation of backbone due to their relative significance. Backbone upgrades are on the EHV (Extra High Voltage) system and resolve a wide range of reliability criteria violations and market congestion issues. The current backbone projects are: Mount Storm – Doubs; Jacks Mountain; and Susquehanna – Roseland.

The Mount Storm – Doubs transmission line, that serves West Virginia, Virginia and Maryland, was originally built in 1966. The structures and equipment are approaching the end of their expected service life, and require replacement to ensure reliability in its service areas. "As of June, 2013, construction is proceeding ahead of schedule. All structure foundations are complete, approximately 70 percent of the structures have been erected, and more than 70 percent of the line is complete."[21]

The Jacks Mountain project is required to resolve voltage problems for load deliverability starting June 1, 2017. Jacks Mountain will be a new 500kV substation connected to the existing Conemaugh – Juniata and Keystone –

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19 See "Current New Jersey Turbines that are HEDD Units," <http://www.state.nj.us/dep/workgroups/docs/apcrule_20110909turbinelist.pdf> (Accessed July 1, 2013).

20 See "PJM Generator Deactivations," PJM.com <http://pjm.com/planning/generation-retirements/gr-summaries.aspx> (January 24, 2013).
21 See *Mt. Storm – Doubs 500kV Rebuild Project*," Dom.com <https://www.dom.com/about/electric-transmission/mtstorm/index.jsp> (July 30, 2013).

Juniata 500kV circuits. The plans are for construction of the foundation in late 2013, construction in 2014 and completion in early 2015.

The Susquehanna – Roseland project is required to resolve reliability criteria violations starting June 1, 2012. Susquehanna – Roseland will be a new 500 kV transmission line connecting the Susquehanna – Lackawanna – Hopatcong – Roseland buses. On October 1, 2012, the Susquehanna – Roseland project received final approval from the National Park Service (NPS) for the project to be constructed on the route selected by PSEG and PPL.[22] The Susquehanna – Hopatcong portion of the project is currently expected to be in-service by June, 2014, with the remainder of the project to be completed by June, 2015.

Regional Transmission Expansion Plan (RTEP) Proposal Windows

On July 22, 2013, PJM made a second filing in compliance with Order No. 1000 and in compliance with the order on its first compliance filing issued March 22, 2013.[23] PJM's Order No. 1000 compliance filing addressed a number of procedural issues identified by the Commission in the March 22nd order. In the initial filing PJM proposed to expand the regional planning process to provide greater opportunity for non-incumbent transmission developers to submit solution proposals.[24] PJM's filing established proposal windows for competitive solicitations but limited the ability of competitors to make proposals within a defined time window.[25]

A test of whether PJM's new process can operate transparently and offer a meaningful opportunity for non-incumbents to compete involves Artificial Island, which includes the Salem and Hope Creek nuclear plants. On April 29, 2013, PJM submitted a request for proposal (RFP), seeking technical solutions to improve stability issues, operational performance under a range of anticipated system conditions, and to eliminate potential planning criteria violations in

the Artificial Island Area. The RFP window closed on June 28, 2013. PJM received 26 individual proposals from 7 entities, including proposals from the incumbent transmission owner, PSEG, and a range of proposals from other non-incumbents. The costs of solutions proposed ranged from approximately $54 million to $1.4 billion.[26] These proposals are currently being evaluated by PJM.

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22 See PSEG.com. "Susquehanna-Roseland line receives final federal approval," <http://www.pseg.com/info/media/newsreleases/2012/2012-10-02.jsp> (Accessed July 30, 2013).

23 PJM filing, Docket No. ER13-198-002 (July 22nd PJM Filing"); 142 FERC ¶ 61,214. PJM Transmission Owners made a separate filing addressing cost allocation issues, also on March 22, 2013.

24 PJM compliance filing, Docket No. ER13-198-001 (October 25, 2012).

25 Id.; see also "*RTEP Proposal Windows*," PJM.com <http://www.pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000/rtep-proposal-windows.aspx> (Accessed July 30, 2013).

26 See "*PJM 2013 RTEP Proposal Window Tracking*," PJM.com <http://www.pjm.com/~/media/committees-groups/committees/teac/20130710/20130710-pjm-2013-rtep-proposal-window-tracking.ashx> (Accessed July 30, 2013).

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 (FTRs) 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.[2,3]

The *2013 Quarterly State of the Market Report for PJM: January through June*, focuses on the Annual and Monthly Balance of Planning Period FTR Auctions during the 2012 to 2013 and 2013 to 2014 planning periods, covering June 1, 2012 through June 30, 2013.

Table 12-1 The FTR Auction Markets results were competitive

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

- 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.

- Market 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 mixed because while there are many positive features of the FTR design including a wide range of options for market participants to acquire FTRs and a competitive auction mechanism, there are several features of the FTR design which result in underfunding and features of the FTR design which incorporate subsidies which also contribute to underfunding. The market design incorporates widespread cross subsidies which are not consistent with an efficient market design.

Overview

Financial Transmission Rights

Market Structure

- **Supply.** Market participants can also sell FTRs. In the 2013 to 2014 Annual FTR Auction, total participant FTR sell offers were 417,118 MW, up from 356,299 MW in the 2012 to 2013 planning period. In the Monthly Balance of Planning Period FTR Auctions for the 2012 to 2013 planning period, total participant FTR sell offers were 5,010,437 MW, down from 5,852,635 MW for the same period during the 2011 to 2012 planning period.

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1 *See* 81 FERC ¶ 61,257, at 62,241 (1997).
2 *See Id.* at 62, 259–62,260 & n. 123.
3 For a more complete explanation, see the *2012 State of the Market Report for PJM*, Volume II, Section 12, "FTRs."

- **Demand.** There were 3,274,373 MW of buy and self-scheduled bids in the 2013 to 2014 Annual FTR Auction, up from 2,561,835 MW in the previous planning period. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the 2012 to 2013 planning period increased 11.6 percent from 17,634,256 MW for the same time period of the prior planning period, to 19,685,688 MW.

- **Patterns of Ownership.** For the 2013 to 2014 Annual FTR Auction, financial entities purchased 54.7 percent of prevailing flow FTRs and 82.2 percent of counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 73.4 percent of prevailing flow and 83.1 percent of counter flow FTRs for January through June of 2013. Financial entities owned 59.0 percent of all prevailing and counter flow FTRs, including 50.6 percent of all prevailing flow FTRs and 75.3 percent of all counter flow FTRs during January through June 2013.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the 2012 to 2013 planning period were $523,227 for Increment Offers and Decrement Bids.

- **Credit Issues.** Six participants defaulted during 2013 from ten default events. The average of these defaults was $55,939 with seven based on inadequate collateral and three based on nonpayment. The average collateral default was $16,587 and the average nonpayment default was $147,761. The majority of these defaults were promptly cured, with one partial cure. These defaults were not necessarily related to FTR positions.

Market Performance

- **Volume.** In the Annual FTR Auction for the 2013 to 2014 planning period 420,489 MW (12.8 percent) of buy and self-schedule bids cleared. For the 2012 to 2013 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 2,246,640 MW (11.4 percent) of FTR buy bids and 737,111 MW (14.7 percent) of FTR sell offers.

- **Price.** The weighted-average buy-bid FTR price for the 2013 to 2014 Annual FTR Auction was $0.13 per MW, down from $0.23 per MW in the

2012 to 2013 planning period. The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the 2012 to 2013 planning period was $0.09, down from $0.14 per MW in the 2011 to 2012 planning period.

- **Revenue.** The 2013 to 2014 Annual FTR Auction generated $558.4 million in net revenue, down $44.5 million in the 2012 to 2013 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $23.9 million in net revenue for all FTRs for the 2012 to 2013 planning period, down from $26.3 million for the same time period in the 2011 to 2012 planning period.

- **Revenue Adequacy.** FTRs were paid at 80.6 percent of the target allocation for the entire 2011 to 2012 planning period. FTRs were paid at 67.8 percent of the target allocation level for the entire 2012 to 2013 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $614.0 million of FTR revenues during the 2012 to 2013 planning period and $799.1 million during the 2011 to 2012 planning period. For the 2013 to 2014 planning period, the top sink and top source with the highest positive FTR target allocations were Dominion Zone and Mt. Storm. Similarly, the top sink and top source with the largest negative FTR target allocations were Quad Cities and Buchanan.

- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. The cost of self-scheduled FTRs is zero in the FTR profitability calculation. FTRs were profitable overall, with $83.7 million in profits for physical entities, of which $90.3 million was from self-scheduled FTRs, and $61.2 million for financial entities. As shown in Table 12-13, not every FTR was profitable. For example, prevailing flow FTRs purchased by physical entities, but not self-scheduled, were not profitable in March 2013.

Auction Revenue Rights

Market Structure

- **Residual ARRs.** Effective August 1, 2012, PJM is required to offer ARRs to eligible participants when a transmission outage was modeled in the

Annual ARR Allocation, but the facility becomes available during the relevant planning year. These ARRs are automatically assigned the month before the effective date and only available on paths prorated in Stage 1 of the Annual ARR Allocation. Residual ARRs are only effective for single, whole months, cannot be self scheduled and their clearing prices are based on monthly FTR auction clearing prices. In the 2012 to 2013 planning period PJM allocated a total of 17,467.5 MW of residual ARRs with a total target allocation of $5,083,608.

- **ARR Reassignment for Retail Load Switching.** There were 52,825 MW of ARRs associated with approximately $498,800 of revenue that were reassigned in the 2012 to 2013 planning period. There were 41,770 MW of ARRs associated with approximately $758.900 of revenue that were reassigned for the full twelve months of the 2011 to 2012 planning period.

Market Performance

- **Revenue Adequacy.** For the 2012 to 2013 planning period, the ARR target allocations were $570.5 million while PJM collected $626.7 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2011 to 2012 planning period, the ARR target allocations were $982.9 million while PJM collected $1,091.8 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

- **ARRs and FTRs as an Offset to Congestion.** The effectiveness of ARRs as an offset to congestion can be measured by comparing the revenue received by ARR holders to the congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market. For the 2012 to 2013 planning period, the total revenues received by ARR holders, including self-scheduled FTRs, offset 92.6 percent of the congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market. For the 2011 to 2012 planning period, the total revenues received by the holders of all ARRs

and FTRs offset more than 88.8 percent of the total congestion costs within PJM and for the 2010 to 2011 planning period 97.3 percent.

Recommendations

- Report correct monthly payout ratios to reduce overstatement of underfunding problem on a monthly basis.
- Eliminate portfolio netting to eliminate cross subsidies across FTR marketplace participants.
- Eliminate subsidies to counter flow FTR holders by treating them comparably to prevailing flow FTR holders when the payout ratio is applied.
- Eliminate cross geographic subsidies.
- Improve transmission outage modeling in the FTR auction models.
- Reduce FTR sales on paths with persistent underfunding including clear rules for what defines persistent underfunding and how the reduction will be applied.
- Implement a seasonal ARR and FTR allocation system to better represent outages.
- Eliminate over allocation requirement of ARRs in the Annual ARR Allocation process.

Conclusion

The annual ARR allocation provides firm transmission service customers with the financial equivalent of physically firm transmission service, without requiring physical transmission rights that are difficult to define and enforce. The fixed charges paid for firm transmission services result in the transmission system which provides physically firm transmission service. With the creation of ARRs, FTRs no longer serve their original function of providing firm transmission customers with the financial equivalent of physically firm transmission service. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy.

Revenue adequacy has received a lot of attention in the PJM FTR market. There are several factors that can affect the reported, distribution of and quantity of funding in the FTR market. Revenue adequacy is misunderstood. FTR holders, with the creation of ARRs, do not have the right to financially firm transmission service and FTR holders do not have the right to revenue adequacy. ARR holders do have those rights based on their payment for the transmission system. FTR holders appropriately receive revenues based on actual congestion in both day-ahead and real-time markets. When day-ahead congestion differs significantly from real-time congestion, as has occurred only recently, this is evidence that there are reporting issues, cross subsidization issues, issues with the level of FTRs sold, and issues with modeling differences between the day-ahead and real time. Such differences are not an indication that FTR holders are being underallocated total congestion dollars.

The market response to the revenue adequacy issue has been to reduce bid prices and to increase bid volumes and offer volumes. Clearing prices have fallen and cleared quantities have increased.

In the 2010 to 2011 planning period the clearing price for an FTR obligation was $0.71 per MW, and in the 2013 to 2014 planning period the clearing price was $0.30 per MW, a 57.7 percent decrease. In the 2010 to 2011 planning period, the clearing price for FTR Obligation sell offers was $0.22 per MW, and in the 2013 to 2014 planning period was $0.05 per MW for, a 340 percent decrease.

The volume of cleared buy bids and self-scheduled bids in the Annual FTR Auctions increased from 287,294 MW in the 2010 to 2011 planning period to 420,489 MW in the 2013 to 2014 planning period, an increase of 133,095 MW or 115.9 percent. The volume of cleared sell offers increased from 10,315 MW in the 2010 to 2011 planning period to 37,821 MW in the 2013 to 2014 planning period, an increase of 266.7 percent.

In June 2010, which includes the Annual, Long Term and monthly auctions, the bid volume was 3,894,566 MW, with a net bid volume of 3,177,131 MW. The net bid volume is the buy bid volume minus the sell bid volume. In June 2013 the bid volume was 7,909,805 MW (a 103.1 percent increase) and the net bid volume was 6,607,570 MW (a 108.0 percent increase). The net bid volume to bid volume ratio in June 2010 was 0.82, while the ratio was 0.84 in June 2013, indicating a slight increase in the ratio of sell offers to buy bids.

The payout ratio reported by PJM monthly is understated. The PJM reported monthly payout ratio does not appropriately consider negative target allocations as a source of revenue to fund FTRs on a monthly basis. The MMU recommends that the calculation of the monthly FTR payout ratio appropriately include negative target allocations as a source of revenue, consistent with actual settlement payout.

FTR target allocations are currently netted within each organization in each hour. This means that within an hour, positive and negative target allocations within an organization's portfolio are offset prior to the application of the payout ratio to the positive target allocation FTRs. The payout ratios are also calculated based on these net FTR positions. The current method requires those participants with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs. The current method treats a positive target allocation FTR differently depending on the portfolio of which it is a part. The correct method would treat all FTRs with positive target allocations exactly the same, which would eliminate this form of cross subsidy. This should also be extended to include the end of planning period FTR uplift calculation. The net of a participant's portfolio should not determine their FTR uplift liability, rather their portion of total positive target allocations should be used to determine a participant's uplift charge.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in the 2012 to 2013 planning period would have been 84.6 percent instead of the reported 67.8 percent. The MMU recommends that netting of positive and negative target allocations within portfolios be eliminated.

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. Counter flow FTR holders make payments over the

planning period, in the form of negative target allocations. These negative target allocations are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the burden of underfunding among counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would increase the calculated payout ratio in the 2012 to 2013 planning period from the reported 67.8 percent to 88.6 percent. The MMU recommends that counter flow and prevailing flow FTRs should be treated symmetrically with respect to the application of a payout ratio.

In addition to addressing these issues, the approach to the question of FTR funding should also look at the fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion. These reasons include the inadequate transmission outage modeling which ignores all but long term outages known in advance; the different approach to transmission line ratings in the day-ahead and real time markets, including reactive interfaces; differences in day-ahead and real time modeling including the treatment of loop flows, the treatment of outages, the modeling of PARs and the nodal location of load; the overallocation of ARRs; the appropriateness of seasonal ARR allocations; and the role of up-to congestion transactions; reduced FTR capability on persistently underfunded pathways. The MMU recommends that these issues be reviewed and modifications implemented where possible. Funding issues that persist as a result of modeling differences should be borne by FTR holders operating in the voluntary FTR market.

Financial Transmission Rights

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the Day-Ahead Energy Market across specific FTR transmission paths, subject to revenue availability. Effective June 1, 2007, PJM added marginal losses as a component in the calculation of LMP.[4] 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 on individual FTR paths are used to fund FTRs on paths which received less than their target allocations. Available revenue to pay FTR holders is based on the amount of Day-Ahead and Balancing congestion collected, along with Market to Market payments, excess ARR revenues available at the end of a month and any charges made to Day-Ahead Operating Reserves.

FTR funding is not on a path specific basis or on a time specific basis. There are widespread cross subsidies paid to equalize payments across paths and across time periods within a planning period. All paths receive the same proportional level of target revenue at the end of the planning period. FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs for the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning year.

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4 For additional information on marginal losses, see the *2012 State of the Market Report for PJM*, Volume II, Section 10, "Congestion and Marginal Losses," at "Marginal Losses."

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.

There are two types of FTR products: obligations and options. An obligation provides a credit, positive or negative, equal to the product of the FTR MW and the congestion price difference between FTR sink (destination) and source (origin) that occurs in the Day-Ahead Energy Market. An option provides only positive credits and options are available for only a subset of the possible FTR transmission paths.

There are three classes of FTR 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 following three consecutive planning years. 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 classes. FTR self-scheduled bids are available only as obligations and 24-hour class, consistent with the associated ARRs, and only in the Annual FTR Auction.

As one of the measures to address FTR funding, effective August 5, 2011, PJM does not allow FTR buy bids to clear with a price of zero unless there is at least one constraint in the auction which affects the FTR path.

Market Structure

Any PJM member can participate in the Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions.

Supply and Demand

PJM oversees the process of selling and buying FTRs through FTR Auctions. Market participants purchase FTRs by participating in Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.[5] FTRs can also be traded between market participants through bilateral transactions. ARRs may be self scheduled as FTRs for participation only in the Annual FTR Auction.

Total FTR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested FTRs and the numerous combinations of FTRs that are feasible. For the Annual FTR Auction, known transmission outages that are expected to last for two months or more are included in the model, while known outages of five days or more are included in the model for the Monthly Balance of Planning Period FTR Auctions as well as any outages of a shorter duration that PJM determines would cause FTR revenue inadequacy if not modeled.[6] But the auction process does not

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5 See PJM. "Manual 6: Financial Transmission Rights," Revision 13 (June 28, 2012), p. 38.
6 See PJM. "Manual 6: Financial Transmission Rights," Revision 13 (June 28, 2012), p. 54.

account for the fact that significant transmission outages, which have not been provided to PJM by transmission owners prior to the auction date, will occur during the periods covered by the auctions. Such transmission outages may or may not be planned in advance or may be emergency outages. In addition, it is difficult to model in an annual auction two outages of similar significance and similar duration in different areas which do not overlap in time. The choice of which to model may have significant distributional consequences.

Annual FTR Auctions

Figure 12-1 shows the geographic location of the top ten binding constraints from the 2013 to 2014 Annual FTR Auction and the 2013 to 2014 Annual ARR allocation. Many of the top binding constraints are flowgates and the binding constraints are primarily concentrated near the PJM-MISO border.

Figure 12-1 Geographic location of top five binding constraints for the Annual FTR Auction and Annual ARR Allocation: Planning period 2013 to 2014
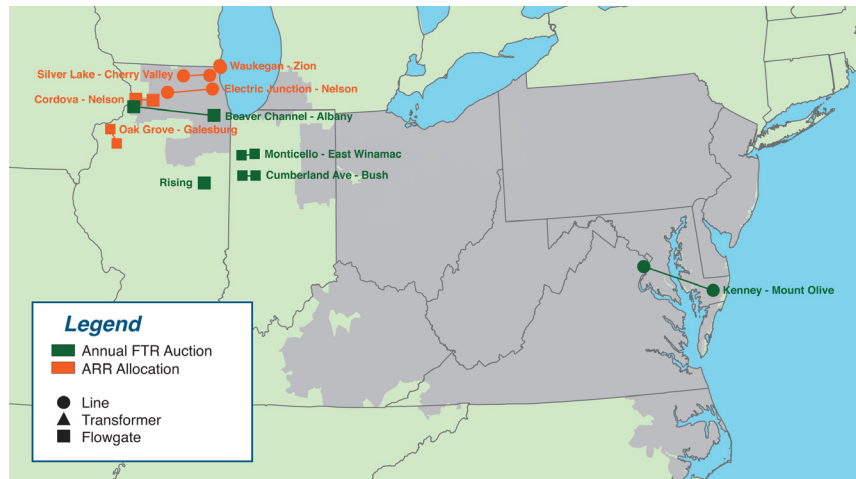
Table 12-2 shows the top 10 binding constraints for the 2013 to 2014 Annual FTR Auction based on the marginal value of on peak hours. The severity

ranking is based on the marginal value of the constraint in the simultaneous feasibility test.

Table 12-2 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2013 to 2014

Constraint	Type	Control Zone	Severity Ranking by Auction Round			
			1	2	3	4
Cumberland Ave – Bush	Flowgate	MISO	1	1	1	1
Beaver Channel – Albany	Flowgate	MISO	2	3	2	3
Monticello – East Winamac	Flowgate	MISO	3	2	3	2
Rising	Flowgate	MISO	NA	NA	NA	4
Kenney – Mount Olive	Line	DPL	7	NA	4	5
Roxbury – Shade Gap	Line	PENELEC	4	8	8	10
Prairie State – W. Mt. Vernon	Flowgate	MISO	5	5	10	NA
Glenarm – Windy Edge	Line	BGE	6	7	5	6
Kenney – Stockton	Line	DPL	NA	4	NA	NA
Pana North	Flowgate	MISO	8	6	6	NA

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. Existing FTRs are modeled as fixed injections and withdrawals. Outages expected to last five or more days are included in the determination of the simultaneous feasibility test for the Monthly Balance of Planning Period FTR Auction. These are single-round monthly auctions that allow any transmission service customer or PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. Market participants can bid for or offer monthly FTRs for any of the next three months remaining in the planning period, or quarterly FTRs for any of the quarters remaining in the planning period. FTRs in the auctions include obligations and options and 24-hour, on peak and 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

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7   See PJM. "Manual 6: Financial Transmission Rights," Revision 13 (June 28, 2012), p. 39.

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.

Buy Bids

The total FTR buy bids in the 2013 to 2014 Annual FTR Auction were 3,274,373 MW. The total FTR buy bids in the Monthly Balance of Planning Period FTR Auctions for the 2012 to 2013 planning period were 19,685,688 MW.

Patterns of Ownership

The overall ownership structure of FTRs and the ownership of prevailing flow and counter flow FTRs is descriptive and is not necessarily a measure of actual or potential FTR market structure issues, as the ownership positions result from competitive auctions. The percentage of FTR ownership shares may change when FTR owners buy or sell FTRs in the Monthly Balance of Planning Period FTR Auctions or the 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.

Table 12-3 presents the Annual FTR Auction cleared FTRs for the 2013 to 2014 planning period by trade type, organization type and FTR direction. In the Annual FTR Auction for the 2013 to 2014 planning period, financial entities purchased 54.7 percent of prevailing flow FTRs and 82.2 percent of counter flow FTRs, with the result that financial entities purchased 61.5 percent of all Annual FTR Auction cleared buy bids for the 2013 to 2014 planning period.

Table 12-3 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2013 to 2014

| Trade Type | Organization Type | Self-Scheduled FTRs | FTR Direction | | |
			Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	9.2%	0.2%	7.0%
		No	36.1%	17.5%	31.5%
		Total	45.3%	17.8%	38.5%
	Financial	No	54.7%	82.2%	61.5%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		20.7%	19.0%	20.2%
	Financial		79.3%	81.0%	79.8%
	Total		100.0%	100.0%	100.0%

Table 12-4 presents the Monthly Balance of Planning Period FTR Auction cleared FTRs for January through June 2013 by trade type, organization type and FTR direction. Financial entities purchased 73.4 percent of prevailing flow and 83.1 percent of counter flow FTRs for the first six months of the year, with the result that financial entities purchased 77.1 percent of all prevailing and counter flow FTR buy bids in the Monthly Balance of Planning Period FTR Auction cleared FTRs for January through June 2013.

Table 12–4 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through June 2013

Trade Type	Organization Type	FTR Direction		
		Prevailing Flow	Counter Flow	All
Buy Bids	Physical	26.6%	16.9%	22.9%
	Financial	73.4%	83.1%	77.1%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	32.7%	32.9%	32.7%
	Financial	67.3%	67.1%	67.3%
	Total	100.0%	100.0%	100.0%

Table 12-5 presents the daily net position ownership for all FTRs for January through June 2013, by FTR direction.

Table 12–5 Daily FTR net position ownership by FTR direction: January through June 2013

Organization Type	FTR Direction		
	Prevailing Flow	Counter Flow	All
Physical	49.4%	24.7%	41.0%
Financial	50.6%	75.3%	59.0%
Total	100.0%	100.0%	100.0%

Market Behavior

FTR Forfeitures

An FTR holder may be subject to forfeiture of any profits from an FTR if it meets the criteria defined in Section 5.2.1 (b) of Schedule 1 of the PJM Operating Agreement. If a participant has a cleared increment offer or decrement bid for an applicable hour at or near the source or sink of any FTR they own and the day-ahead congestion LMP difference is greater than the real time congestion LMP difference the profits from that FTR may be subject to forfeiture for that hour. An increment offer or decrement bid is considered near the source or sink point if 75 percent or more of the energy injected or withdrawn, and which is withdrawn or injected at any other bus, is reflected on the constrained path between the FTR source or sink. This rule only applies to increment offers and decrement bids that would increase the price separation between the FTR source and sink points.

Figure 12-2 shows the FTR forfeitures values for both counter flow and prevailing flow FTRs for each month of June 2010 through June 2013 by company type. Total forfeitures for the 2012 to 2013 planning period were $519,317 (0.06 percent of total FTR target allocations).

Figure 12-2 Monthly FTR Forfeitures for physical and financial participants: June 2010 through June 2013
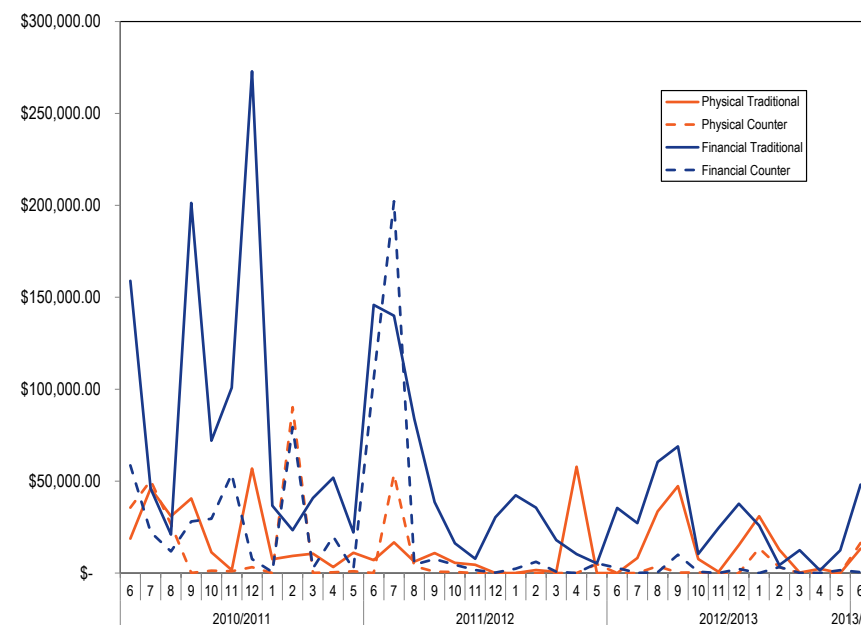
Credit Issues

The credit issues reported here were not necessarily related to FTR positions.

Six participants defaulted during 2013 from ten default events. The average of these defaults was $55,939 with seven based on inadequate collateral and three based on nonpayment. The average collateral default was $16,587 and the average nonpayment default was $147,761. The majority of these defaults were promptly cured, with one partial cure.

Market Performance

Volume

Table 12-6 provides the Annual FTR Auction market volume for the 2013 to 2014 planning period. Total FTR buy bids were 3,274,373 MW, up 27.8 percent from 2,561,835 MW for the previous planning period. For the 2013 to 2014 planning period 391,148 MW (12.1 percent) of buy bids cleared, up 5.3 percent from 371,295 MW for the last planning period. There were 417,118 MW of sell offers with 37,821 MW (9.1 percent) clearing for the 2013 to 2014 planning period.

Table 12-7 provides the Monthly Balance of Planning Period FTR Auction market volume for the entire 2012 to 2013 planning period and the first month of the 2013 to 2014 planning period. There were 12,956,832 MW of FTR buy bid obligations and 3,922,225 MW of FTR sell offer obligations for all bidding periods in the 2012 to 2013 planning period. The monthly balance of planning period auctions cleared 2,171,751 MW (16.8 percent) of FTR buy bid obligations and 468,426 MW (11.9 percent) of FTR sell off obligations.

There were 6,728,856 MW of FTR buy bid options and 1,088,212 MW of FTR sell offer options for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2012 to 2013 planning period. The monthly auctions cleared 74,889 MW (1.1 percent) of FTR buy bid options, and 268,684 MW (24.7 percent) of FTR sell offers.

Table 12-6 Annual FTR Auction market volume: Planning period 2013 to 2014

Trade Type	Hedge Type	FTR Direction	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Obligations	Counter Flow	76,647	365,441	103,814	28.4%	261,627	71.6%
		Prevailing Flow	234,724	1,650,737	225,006	13.6%	1,425,731	86.4%
		Total	311,371	2,016,178	328,820	16.3%	1,687,358	83.7%
	Options	Counter Flow	172	8,829	0	0.0%	8,829	100.0%
		Prevailing Flow	42,659	1,220,026	62,328	5.1%	1,157,698	94.9%
		Total	42,831	1,228,855	62,328	5.1%	1,166,527	94.9%
	Total	Counter Flow	76,819	374,269	103,814	27.7%	270,455	72.3%
		Prevailing Flow	277,383	2,870,763	287,334	10.0%	2,583,430	90.0%
		Total	354,202	3,245,033	391,148	12.1%	2,853,885	87.9%
Self-scheduled bids	Obligations	Counter Flow	129	231	231	100.0%	0	0.0%
		Prevailing Flow	2,847	29,110	29,110	100.0%	0	0.0%
		Total	2,976	29,341	29,341	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	76,776	365,672	104,045	28.5%	261,627	71.5%
		Prevailing Flow	237,571	1,679,847	254,116	15.1%	1,425,731	84.9%
		Total	314,347	2,045,518	358,161	17.5%	1,687,358	82.5%
	Options	Counter Flow	172	8,829	0	0.0%	8,829	100.0%
		Prevailing Flow	42,659	1,220,026	62,328	5.1%	1,157,698	94.9%
		Total	42,831	1,228,855	62,328	5.1%	1,166,527	94.9%
	Total	Counter Flow	76,948	374,500	104,045	27.8%	270,455	72.2%
		Prevailing Flow	280,230	2,899,873	316,444	10.9%	2,583,430	89.1%
		Total	357,178	3,274,373	420,489	12.8%	2,853,885	87.2%
Sell offers	Obligations	Counter Flow	36,423	144,023	11,356	7.9%	132,667	92.1%
		Prevailing Flow	54,723	262,545	25,761	9.8%	236,784	90.2%
		Total	91,146	406,568	37,117	9.1%	369,451	90.9%
	Options	Counter Flow	1	1	0	0.0%	1	100.0%
		Prevailing Flow	406	10,549	704	6.7%	9,845	93.3%
		Total	407	10,550	704	6.7%	9,846	93.3%
	Total	Counter Flow	36,424	144,024	11,356	7.9%	132,668	92.1%
		Prevailing Flow	55,129	273,095	26,465	9.7%	246,630	90.3%
		Total	91,553	417,118	37,821	9.1%	379,297	90.9%

Table 12-7 Monthly Balance of Planning Period FTR Auction market volume: January through June 2013

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-13	Obligations	Buy bids	150,397	963,036	166,622	17.3%	796,414	82.7%
		Sell offers	84,563	297,609	34,710	11.7%	262,899	88.3%
	Options	Buy bids	2,830	104,318	6,767	6.5%	97,551	93.5%
		Sell offers	10,204	73,624	17,322	23.5%	56,302	76.5%
Feb-13	Obligations	Buy bids	164,620	1,035,756	166,386	16.1%	869,369	83.9%
		Sell offers	76,210	261,631	36,402	13.9%	225,229	86.1%
	Options	Buy bids	2,518	94,039	4,749	5.0%	89,290	95.0%
		Sell offers	9,053	62,833	16,434	26.2%	46,399	73.8%
Mar-13	Obligations	Buy bids	168,718	1,092,986	188,849	17.3%	904,138	82.7%
		Sell offers	77,248	256,820	40,079	15.6%	216,741	84.4%
	Options	Buy bids	2,674	103,046	5,591	5.4%	97,455	94.6%
		Sell offers	10,054	84,993	21,581	25.4%	63,411	74.6%
Apr-13	Obligations	Buy bids	130,671	742,450	143,747	19.4%	598,703	80.6%
		Sell offers	55,739	206,725	33,203	16.1%	173,522	83.9%
	Options	Buy bids	1,852	47,911	4,069	8.5%	43,842	91.5%
		Sell offers	6,017	58,130	17,259	29.7%	40,870	70.3%
May-13	Obligations	Buy bids	99,964	562,240	119,522	21.3%	442,718	78.7%
		Sell offers	25,028	93,603	19,917	21.3%	73,686	78.7%
	Options	Buy bids	792	33,223	2,901	8.7%	30,322	91.3%
		Sell offers	2,634	24,643	15,506	62.9%	9,137	37.1%
Jun-13	Obligations	Buy bids	268,004	1,548,839	275,485	17.8%	1,273,354	82.2%
		Sell offers	150,754	474,950	59,536	12.5%	415,415	87.5%
	Options	Buy bids	4,155	313,972	14,825	4.7%	299,147	95.3%
		Sell offers	23,090	198,850	55,455	27.9%	143,395	72.1%
2012/2013*	Obligations	Buy bids	2,255,105	12,956,832	2,171,751	16.8%	10,785,081	83.2%
		Sell offers	1,080,775	3,922,225	468,426	11.9%	3,453,798	88.1%
	Options	Buy bids	103,926	6,728,856	74,889	1.1%	6,653,967	98.9%
		Sell offers	149,274	1,088,211	268,684	24.7%	819,527	75.3%
2013/2014**	Obligations	Buy bids	268,004	1,548,839	275,485	17.8%	1,273,354	82.2%
		Sell offers	150,754	474,950	59,536	12.5%	415,415	87.5%
	Options	Buy bids	4,155	313,972	14,825	4.7%	299,147	95.3%
		Sell offers	23,090	198,850	55,455	27.9%	143,395	72.1%

* Shows Twelve Months for 2012/2013; ** Shows one month ended 30-Jun-13 for 2013/2014

Table 12-8 presents the buy-bid, bid and cleared volume of the Monthly Balance of Planning Period FTR Auction, and the effective periods for the volume. The average monthly cleared volume for January through June 2013 is 183,252.2 MW. The average monthly cleared volume for January through June 2012 was 149,141.2 MW.

Table 12-8 Monthly Balance of Planning Period FTR Auction buy–bid, bid and cleared volume (MW per period): January through June 2013

Monthly Auction	MW Type	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-13	Bid	595,260	191,417	115,207				165,471	1,067,354
	Cleared	125,075	24,018	8,251				16,045	173,389
Feb-13	Bid	654,446	174,360	177,548				123,440	1,129,794
	Cleared	131,562	15,659	13,975				9,939	171,135
Mar-13	Bid	645,247	232,876	224,105				93,804	1,196,032
	Cleared	136,007	27,219	24,669				6,544	194,440
Apr-13	Bid	610,571	179,789						790,360
	Cleared	127,896	19,920						147,816
May-13	Bid	595,463							595,463
	Cleared	122,423							122,423
Jun-13	Bid	766,947	218,427	205,723	112,180	195,196	193,766	170,571	1,862,810
	Cleared	141,332	31,035	25,346	14,149	27,397	25,560	25,491	290,310

Figure 12-3 shows cleared auction volumes as a percent of the total FTR cleared volume by calendar months for June 2004 through June 2013, by type of auction. FTR volumes are included in the calendar month they are effective, with Long Term and Annual FTR auction volume spread equally to each month in the relevant planning period. This figure shows the share of FTRs purchased in each auction type by month. Over the course of the planning period an increasing number of Monthly Balance of Planning Period FTRs are purchased, making them a greater portion of active FTRs. When the Annual FTR Auction occurs, FTRs purchased in any previous Monthly Balance of Planning Period Auction, other than the current June auction, are no longer in effect, so there is a reduction in their share of total FTRs with an accompanying rise in the share of Annual FTRs.

Figure 12-3 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through June 2013
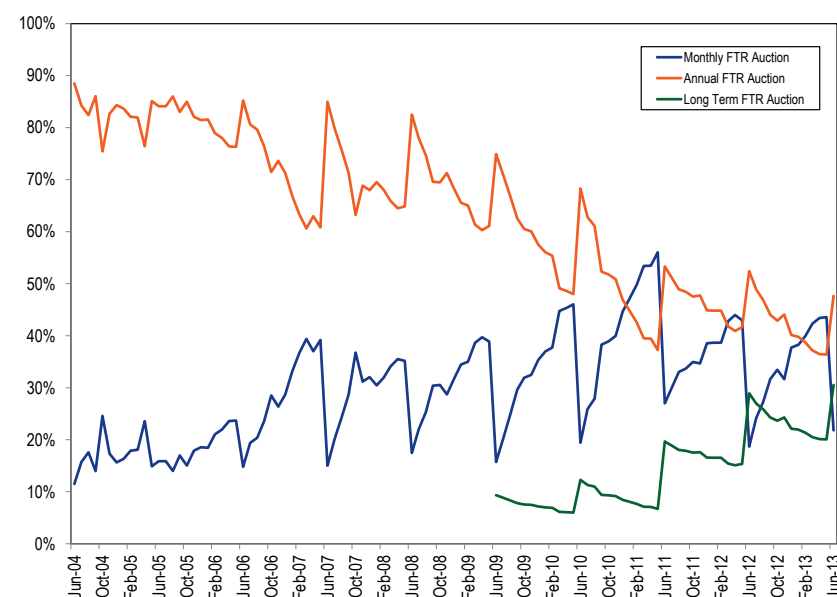
Table 12-9 provides the secondary bilateral FTR market volume for the entire 2011 to 2012 and 2012 to 2013 planning periods.

Table 12-9 Secondary bilateral FTR market volume: Planning periods 2011 to 2012 and 2012 to 2013[8]

Planning Period	Hedge Type	Class Type	Volume (MW)
2011/2012	Obligation	24-Hour	239
		On Peak	11,925
		Off Peak	4,268
		Total	16,431
	Option	24-Hour	0
		On Peak	8,965
		Off Peak	6,330
		Total	15,296
2012/2013	Obligation	24-Hour	95
		On Peak	137
		Off Peak	60
		Total	292
	Option	24-Hour	0
		On Peak	0
		Off Peak	0
		Total	0

Figure 12-4 shows the FTR bid, cleared and net bid volume from June 2003 through June 2013 for Long Term, Annual and Monthly Balance of Planning Period Auctions. Cleared volume is the volume of FTR buy and sell offers that were accepted. The net bid volume includes the total buy, sell and self-scheduled offers, counting sell offers as a negative volume. The bid volume is the total of all bid and self-scheduled offers, excluding sell offers. Bid volumes and net bid volumes have increased since 2003. Cleared volume was relatively steady until 2010, with an increase in 2011 followed by a slight decrease in 2012. The demand for FTRs has increased while availability of FTRs generally did not increase until 2011.

Figure 12-4 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through June 2013
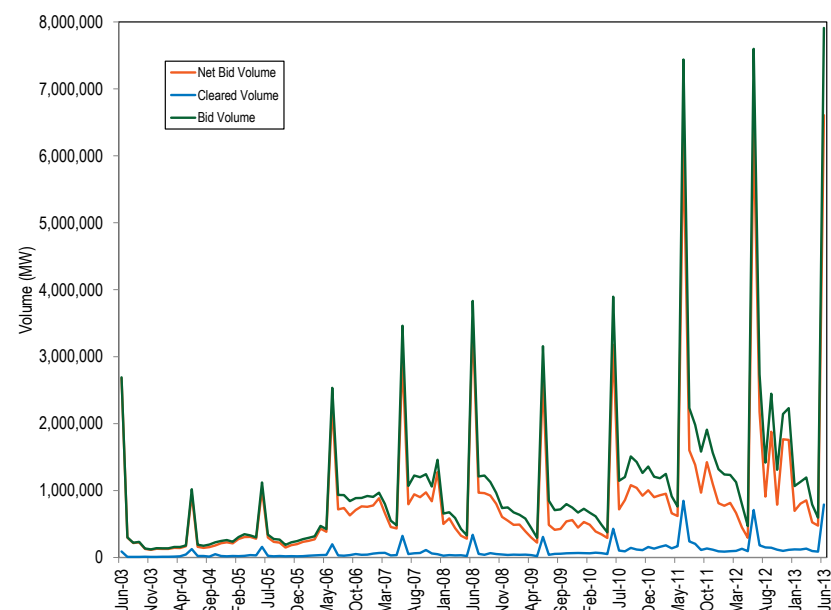
Price

Table 12-10 shows the weighted-average cleared buy-bid prices by trade type, hedge type, FTR direction and class type for the Annual FTR Auction for the 2013 to 2014 planning period. The weighted-average buy-bid FTR price in the 2013 to 2014 Annual FTR Auction was $0.13 per MW, down from $0.23 per MW in the 2012 to 2013 planning period.

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8 The 2012 to 2013 planning period covers bilateral FTRs that are effective for any time between June 1, 2012 through March 31, 2013, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

Table 12–10 Annual FTR Auction weighted-average cleared prices (Dollars per MW): Planning period 2013 to 2014

Trade Type	Hedge Type	FTR Direction	Class Type			
			24–Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.17)	($0.30)	($0.15)	($0.22)
		Prevailing Flow	$0.59	$0.51	$0.32	$0.43
		Total	$0.45	$0.27	$0.16	$0.23
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$1.19	$0.17	$0.10	$0.13
		Total	$1.19	$0.17	$0.10	$0.13
Self-scheduled bids	Obligations	Counter Flow	($0.24)	NA	NA	($0.24)
		Prevailing Flow	$0.73	NA	NA	$0.73
		Total	$0.72	NA	NA	$0.72
Buy and self-scheduled bids	Obligations	Counter Flow	($0.18)	($0.30)	($0.15)	($0.22)
		Prevailing Flow	$0.69	$0.51	$0.32	$0.49
		Total	$0.64	$0.27	$0.16	$0.30
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$1.19	$0.17	$0.10	$0.13
		Total	$1.19	$0.17	$0.10	$0.13
Sell offers	Obligations	Counter Flow	($1.95)	($0.57)	($0.35)	($0.54)
		Prevailing Flow	$0.35	$0.38	$0.21	$0.30
		Total	($0.18)	$0.14	$0.02	$0.05
	Options	Counter Flow	NA	NA	NA	NA
		Prevailing Flow	$0.00	$0.07	$0.07	$0.07
		Total	$0.00	$0.07	$0.07	$0.07

Figure 12–5 Annual FTR Auction clearing price per MW: Planning period 2013 to 2014

Figure 12-5 shows the weighted-average cleared buy-bid price frequency for the 2013 to 2014 Annual FTR Auction. 92.9 percent of Annual FTRs were purchased for less than $1 per MW.
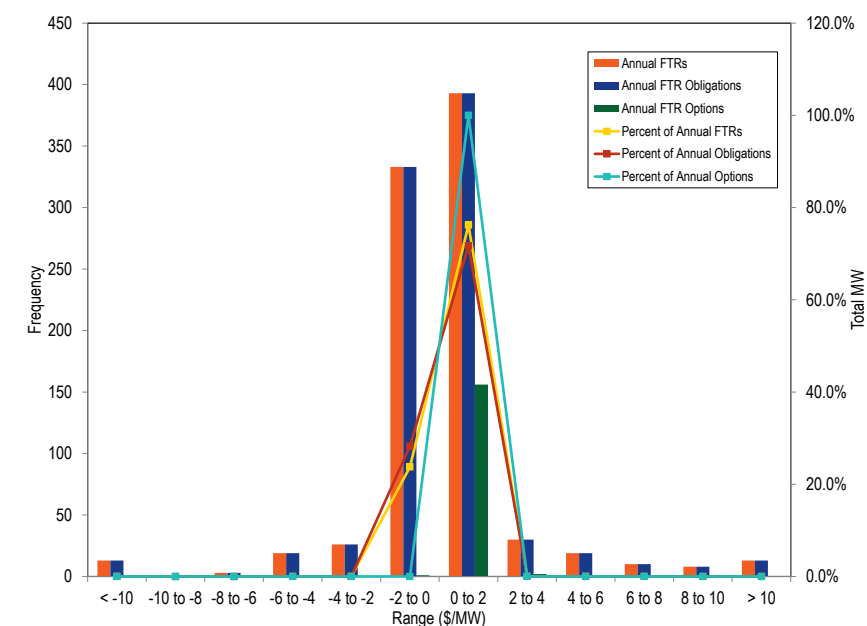
Table 12-11 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2013 through June 2013. For example, for the January 2013 Monthly Balance of Planning Period FTR Auction, the current month column is January, the second month column is February and the third month column is March. Quarters 1 through 4 are represented in the Q1, Q2, Q3 and Q4 columns. The total column represents all of the activity within the January 2013 Monthly Balance of Planning Period FTR Auction.

The cleared weighted-average price paid in the Monthly Balance of Planning Period FTR Auctions for January through June 2013 was $0.09 per MW, down from $0.14 per MW in the same time last year.

Table 12-11 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MW): January through June 2013

Monthly Auction	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-13	$0.11	$0.20	$0.05				$0.09	$0.11
Feb-13	$0.09	$0.12	$0.10				$0.13	$0.10
Mar-13	$0.10	$0.12	$0.10				$0.05	$0.10
Apr-13	$0.10	$0.16						$0.11
May-13	$0.09	$0.00						$0.09
Jun-13	$0.08	$0.21	$0.19	$0.15	$0.16	$0.14	$0.10	$0.06

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 actual revenue that an FTR holder receives and the auction price is the cost. For a counter flow FTR, the auction price is the revenue that an FTR holder is paid and the FTR credits are the cost to the FTR holder, which the FTR holder must pay. The cost of self-scheduled FTRs is zero. ARR holders that self schedule FTRs purchase the FTRs in the Annual FTR Auction, but the ARR holders receive offsetting ARR credits that equal the purchase price of the FTRs. Table 12-12 lists FTR profits by organization type and FTR direction for the period from January through June, 2013. FTR profits are the sum of the daily FTR credits, including for 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 profitable overall, with $83.7 million in profits for physical entities, of which $90.3 million was from self-scheduled FTRs, and $61.2 million for financial entities.

Table 12-12 FTR profits by organization type and FTR direction: January through June 2013

		FTR Direction			
Organization Type	Prevailing Flow	Self Scheduled Prevailing Flow	Counter Flow	Self Scheduled Counter Flow	All
Physical	($33,880,475)	$90,346,068	$25,201,278	$2,030,678	$83,697,550
Financial	$2,865,974	NA	$58,329,046	NA	$61,195,020
Total	($31,014,501)	$90,346,068	$83,530,324	$2,030,678	$144,892,570

Table 12-13 lists the monthly FTR profits in 2013 by organization type.

Table 12-13 Monthly FTR profits by organization type: January through June 2013

	Organization Type			
Month	Physical	Self Scheduled Physical FTRs	Financial	Total
Jan	$4,433,798.26	$24,630,018.53	$13,640,158.47	$42,703,975.26
Feb	$14,090,796.32	$20,676,306.40	$16,980,941.03	$51,748,043.75
Mar	$(9,498,907.60)	$15,149,289.30	$4,849,731.20	$10,500,112.90
Apr	$(12,666,550.49)	$6,571,358.42	$2,187,795.84	$(3,907,396.23)
May	$(3,242,261.28)	$14,590,963.47	$12,513,107.45	$23,861,809.65
Jun	$(1,796,071.62)	$10,758,810.69	$11,023,285.97	$19,986,025.04
Total	$(8,679,196.40)	$92,376,746.83	$61,195,019.96	$144,892,570.38

Revenue

Annual FTR Auction Revenue

Table 12-14 shows the Annual FTR Auction revenue by trade type, hedge type, FTR direction and class type. The Annual FTR Auction for the 2013 to 2014 planning period generated $558.4 million, down 7.4 percent from $602.9 million in the 2012 to 2013 planning period, and down 45.8 percent from the 2011 to 2012 planning period. Counter flow FTR holders received $73.5 million from the auction and prevailing flow FTR holders paid $631.9 million.

Table 12–14 Annual FTR Auction revenue: Planning period 2013 to 2014

Trade Type	Type	FTR Direction	24–Hour	On Peak	Off Peak	All
				Class Type		
Buy bids	Obligations	Counter Flow	($3,584,655)	($61,297,999)	($34,970,300)	($99,852,954)
		Prevailing Flow	$57,603,843	$244,753,274	$143,657,697	$446,014,815
		Total	$54,019,189	$183,455,275	$108,687,397	$346,161,861
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$773,687	$20,414,078	$15,109,880	$36,297,645
		Total	$773,687	$20,414,078	$15,109,880	$36,297,645
	Total	Counter Flow	($3,584,655)	($61,297,999)	($34,970,300)	($99,852,954)
		Prevailing Flow	$58,377,530	$265,167,352	$158,767,577	$482,312,460
		Total	$54,792,875	$203,869,353	$123,797,277	$382,459,506
Self-scheduled bids	Obligations	Counter Flow	($484,421)	NA	NA	($484,421)
		Prevailing Flow	$185,666,567	NA	NA	$185,666,567
		Total	$185,182,146	NA	NA	$185,182,146
Buy and self-scheduled bids	Obligations	Counter Flow	($4,069,076)	($61,297,999)	($34,970,300)	($100,337,375)
		Prevailing Flow	$243,270,411	$244,753,274	$143,657,697	$631,681,382
		Total	$239,201,335	$183,455,275	$108,687,397	$531,344,007
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$773,687	$20,414,078	$15,109,880	$36,297,645
		Total	$773,687	$20,414,078	$15,109,880	$36,297,645
	Total	Counter Flow	($4,069,076)	($61,297,999)	($34,970,300)	($100,337,375)
		Prevailing Flow	$244,044,097	$265,167,352	$158,767,577	$667,979,027
		Total	$239,975,022	$203,869,353	$123,797,277	$567,641,652
Sell offers	Obligations	Counter Flow	($6,178,881)	($10,761,004)	($9,879,378)	($26,819,263)
		Prevailing Flow	$3,672,742	$21,045,102	$11,155,364	$35,873,207
		Total	($2,506,139)	$10,284,097	$1,275,986	$9,053,944
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$0	$87,616	$133,050	$220,666
		Total	$0	$87,616	$133,050	$220,666
	Total	Counter Flow	($6,178,881)	($10,761,004)	($9,879,378)	($26,819,263)
		Prevailing Flow	$3,672,742	$21,132,718	$11,288,414	$36,093,874
		Total	($2,506,139)	$10,371,714	$1,409,036	$9,274,610
Total			$242,481,161	$193,497,639	$122,388,241	$558,367,042

Figure 12-6 summarizes the total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue in the Annual FTR Auction for the 2013 to 2014 planning period. The top ten positive revenue sinks accounted for 65.0 percent of total revenue. The top ten negative revenue sinks accounted for 3.9 percent of total revenue.

Figure 12-6 Ten largest positive and negative revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2013 to 2014

Figure 12-7 Ten largest positive and negative revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2013 to 2014
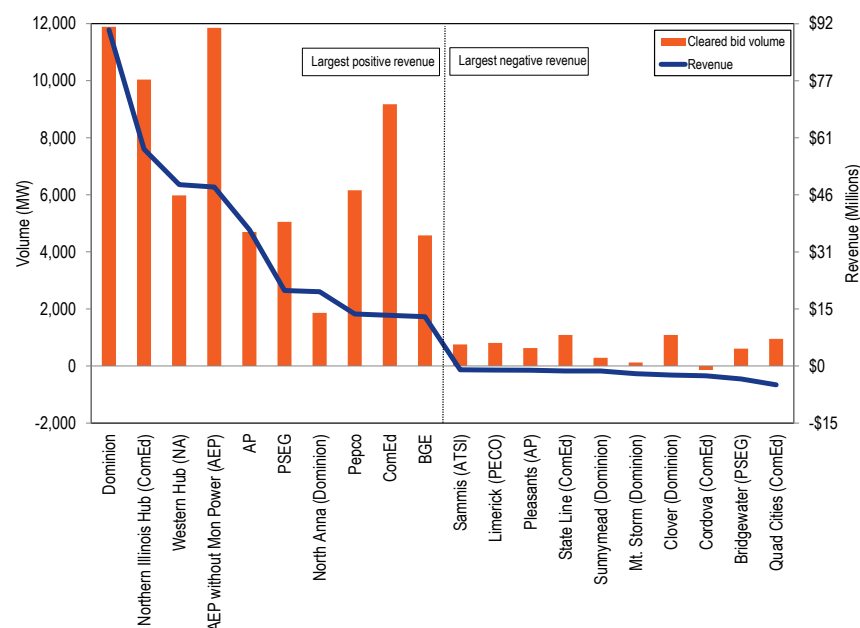
Figure 12-7 summarizes the total revenue associated with all FTRs, regardless of sink, to the FTR sinks that produced the largest positive and negative revenue in the Annual FTR Auction for the 2013 to 2014 planning period. The top ten positive revenue sinks accounted for 45.2 percent of total revenue. The top ten negative revenue sinks accounted for 2.6 percent of total revenue.
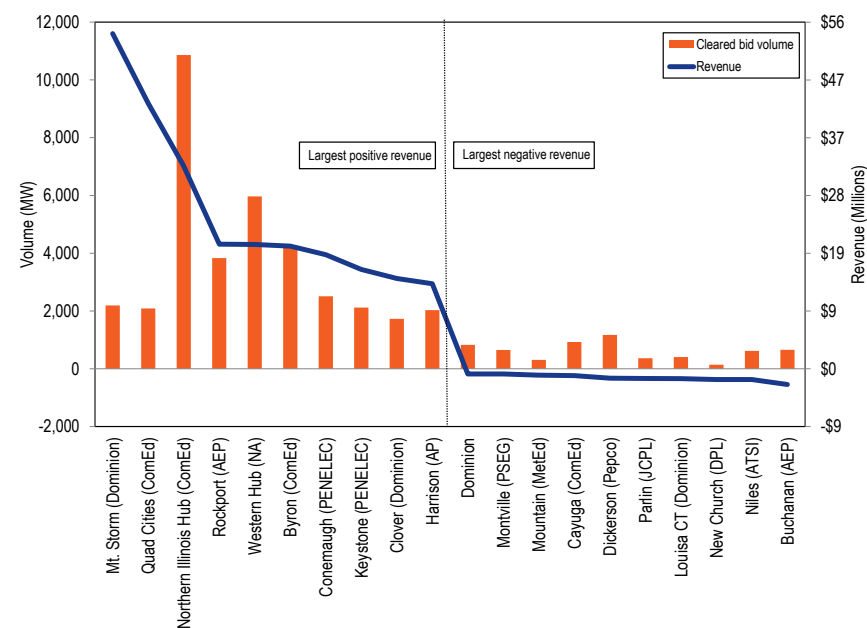
Monthly Balance of Planning Period FTR Auction Revenue

Table 12-15 shows Monthly Balance of Planning Period FTR Auction revenue data by trade type, type and class type for January through June 2013. The Monthly Balance of Planning Period FTR Auction netted $23.9 million in revenue, with buyers paying $149.8 million and sellers receiving $124.8 million. For the entire 2012 to 2013 planning period, the Monthly Balance of Planning Period FTR Auctions netted $23.8 million in revenue with buyers paying $127.7 million and sellers receiving $22.1 million. For the entire 2011 to 2012 planning period, the Monthly Balance of Planning Period FTR Auctions netted $26.3 million in revenue with buyers paying $132.6 million and sellers receiving $106.4 million.

Table 12-15 Monthly Balance of Planning Period FTR Auction revenue: January through June 2013

Monthly Auction	Type	Trade Type	Class Type			
			24-Hour	On Peak	Off Peak	All
Jan-13	Obligations	Buy bids	$42,552	$4,558,023	$3,371,362	$7,971,937
		Sell offers	$106,975	$2,609,123	$1,599,772	$4,315,870
	Options	Buy bids	$0	$237,321	$153,334	$390,655
		Sell offers	$0	$1,133,641	$1,206,317	$2,339,958
Feb-13	Obligations	Buy bids	$176,565	$3,587,647	$2,468,155	$6,232,366
		Sell offers	$401,600	$1,782,016	$1,097,066	$3,280,682
	Options	Buy bids	$5,100	$99,651	$128,731	$233,482
		Sell offers	$0	$861,109	$904,603	$1,765,712
Mar-13	Obligations	Buy bids	$189,939	$4,040,854	$3,035,268	$7,266,060
		Sell offers	$61,862	$2,221,264	$1,434,875	$3,718,001
	Options	Buy bids	$16,526	$229,272	$95,137	$340,935
		Sell offers	$0	$1,242,062	$1,381,010	$2,623,072
Apr-13	Obligations	Buy bids	($27,848)	$3,384,641	$2,231,023	$5,587,816
		Sell offers	$414,627	$1,703,707	$1,085,350	$3,203,684
	Options	Buy bids	$46,767	$236,939	$92,241	$375,947
		Sell offers	$0	$816,642	$702,628	$1,519,270
May-13	Obligations	Buy bids	$22,637	$2,501,391	$1,418,753	$3,942,781
		Sell offers	$210,649	$1,133,878	$524,793	$1,869,320
	Options	Buy bids	$0	$146,702	$55,903	$202,605
		Sell offers	$441	$739,219	$602,794	$1,342,454
Jun-13	Obligations	Buy bids	$258,896	$12,840,102	$8,210,854	$21,309,852
		Sell offers	$6,203,476	$4,763,316	$2,821,569	$13,788,360
	Options	Buy bids	$1,937	$527,792	$270,176	$799,905
		Sell offers	$0	$4,338,954	$2,862,300	$7,201,254
2012/2013*	Obligations	Buy bids	$67,116	$76,349,386	$43,832,157	$120,248,659
		Sell offers	$4,731,328	$40,127,400	$18,982,130	$63,840,858
	Options	Buy bids	$152,160	$4,512,768	$2,793,076	$7,458,004
		Sell offers	$313,760	$22,240,204	$17,444,010	$39,997,974
	Total		($4,825,812)	$18,494,550	$10,199,092	$23,867,830
2013/2014**	Obligations	Buy bids	$258,896	$12,840,102	$8,210,854	$21,309,852
		Sell offers	$6,203,476	$4,763,316	$2,821,569	$13,788,360
	Options	Buy bids	$1,937	$527,792	$270,176	$799,905
		Sell offers	$0	$4,338,954	$2,862,300	$7,201,254
	Total		($5,942,643)	$4,265,624	$2,797,162	$1,120,143

* Shows Twelve Months; ** Shows one month ended 30-Jun-2013 for 2013/2014

Figure 12-8 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 2012 to 2013 planning period. The top 10 positive revenue producing FTR sources accounted for $46.9 million of the total revenue of $23.9 million paid in the auction, they also comprised 5.7 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sinks accounted for -$16.3 million of revenue and constituted 0.2 percent of all FTRs bought in the auction.

Figure 12-8 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: planning period 2012 to 2013

Figure 12-9 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 2012 to 2013 planning period. The top 10 positive revenue producing FTR sources accounted for $45.4 million of the total revenue of $23.9 million paid in the auction, they also comprised 7.0 percent of all FTRs bought in

the auction. The top 10 negative revenue producing FTR sinks accounted for -$13.3 million of revenue and constituted 1.1 percent of all FTRs bought in the auction.
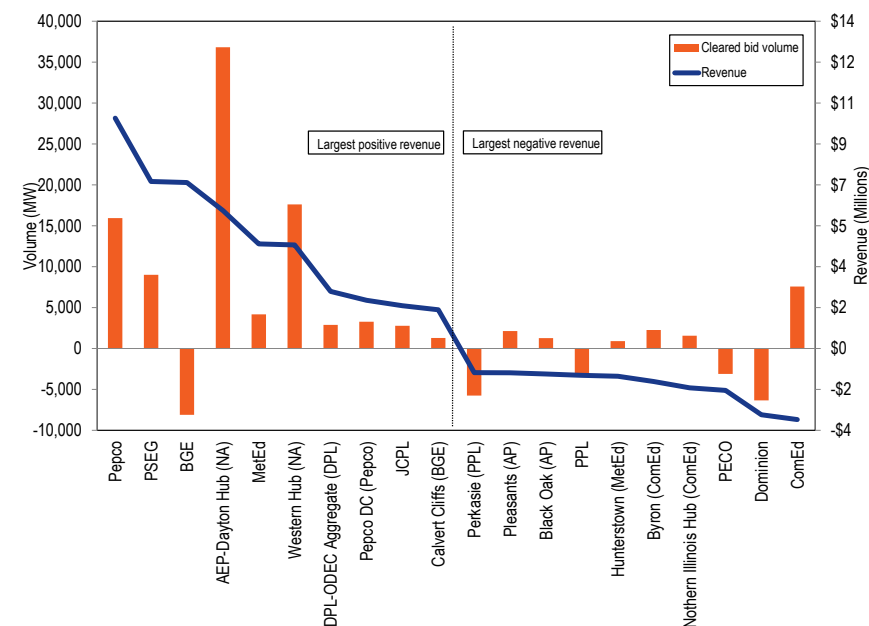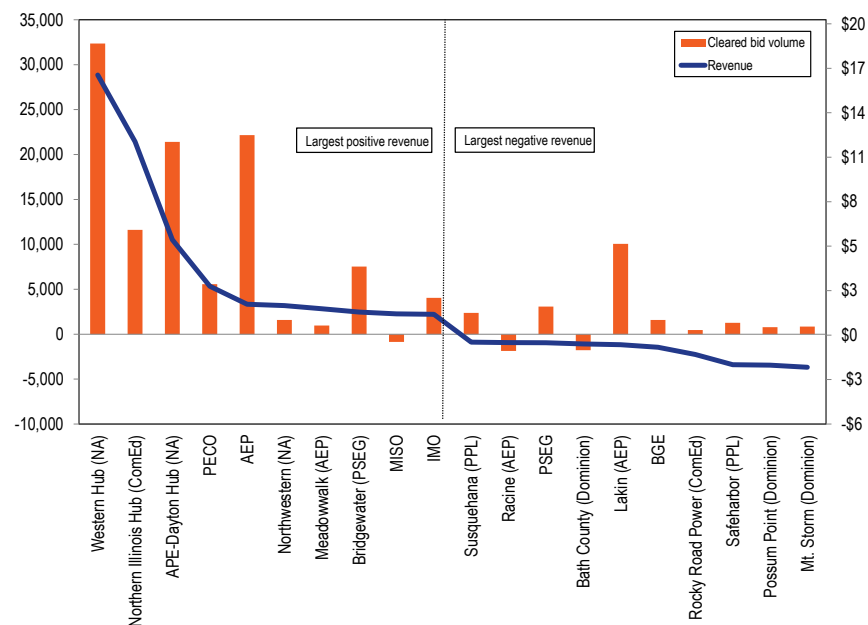
Figure 12-9 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: planning period 2013 to 2014

FTR Target Allocations

FTR target allocations were examined separately by source and sink contribution. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source for the 2012 to 2013 planning. Figure 12-10 shows the ten largest positive and negative FTR target allocations, summed by sink, for the 2012 to 2013 planning period. The top 10 sinks that produced financial benefit accounted for 23.6 percent of total positive target allocations during the 2012 to 2013 planning period with the

PSEG zone accounting for 4.4 percent of all positive target allocations. The top 10 sinks that created liability accounted for 8.7 percent of total negative target allocations with the Western Hub accounting for 1.9 percent of all negative target allocations.

Figure 12-10 Ten largest positive and negative FTR target allocations summed by sink: 2012 to 2013 planning period

Figure 12-11 shows the ten largest positive and negative FTR target allocations, summed by source, for the 2012 to 2013 planning period. The top 10 sources with a positive target allocation accounted for 12.9 percent of total positive target allocations with the Western Hub accounting for 2.6 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 10.7 percent of all negative target allocations, with the Western Hub accounting for 2.3 percent.

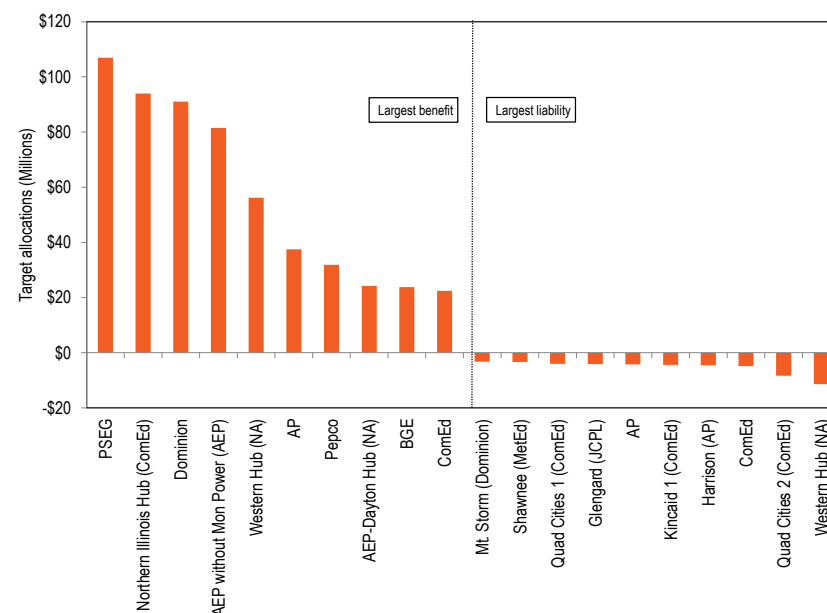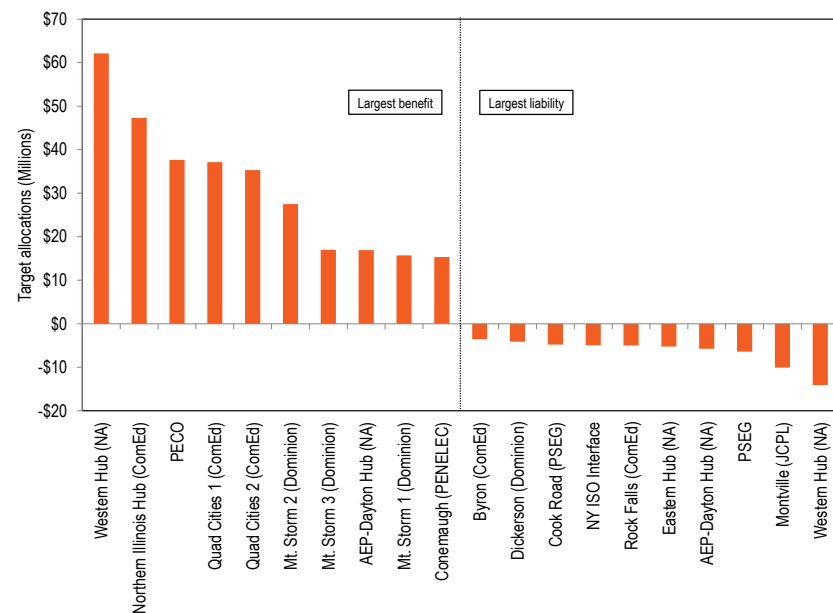**Figure 12-11 Ten largest positive and negative FTR target allocations summed by source: 2012 to 2013 planning period**

Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay and all generators receive their respective LMPs. When load in a constrained area 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.[9] That is the source of the congestion revenue to pay holders of ARRs and FTRs. In general, FTR revenue adequacy exists when the sum of congestion credits is equal to or greater than the sum of congestion across the positively valued FTRs. If PJM allocated FTRs equal to the transmission capability into constrained areas, FTR payouts would equal the sum of congestion.

Revenue adequacy must be distinguished from the adequacy of FTRs as an offset against total congestion. Revenue adequacy is a narrower concept that compares total congestion revenues to the total target allocations across the specific paths for which FTRs were available and purchased. A path specific target allocation is not a guarantee of payment. 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 are carried forward from prior months and distributed back from later months. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs during the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning year. For the 2011 to 2012 planning period, FTRs were not fully funded and thus an uplift charge was collected.

FTR revenues are primarily comprised of hourly congestion revenue, from the day ahead and balancing markets, and net negative congestion.[10] 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

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9 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."

10 Hourly congestion revenues may be negative.

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 12-16 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.[11] 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 payment of $0.2 million in congestion charges to Con Edison in the 2011 to 2012 planning period.[12,13]

FTRs were paid at 67.8 percent of the target allocation level for the 2012 to 2013 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $614.0 million of FTR revenues during the 2012 to 2013 planning period, and $799.6 million during the 2011 to 2012 planning period, a 23.2 percent decrease. For the 2012 to 2013 planning period, the top sink and top source with the highest positive FTR target allocations were PSEG and the Western Hub. Similarly, the top sink and top source with the largest negative FTR target allocations were both the Western Hub.

Table 12-16 presents the PJM FTR revenue detail for the 2011 to 2012 and 2012 to 2013 planning period.

Table 12-16 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2011 to 2012 and 2012 to 2013

Accounting Element	2011/2012	2012/2013
ARR information		
ARR target allocations	$982.9	$587.0
FTR auction revenue	$1,091.8	$653.6
ARR excess	$108.9	$66.7
FTR targets		
FTR target allocations	$992.8	$906.8
Adjustments:		
Adjustments to FTR target allocations	($1.1)	($1.0)
Total FTR targets	$991.7	$905.8
FTR revenues		
ARR excess	$108.9	$66.7
Competing uses	$0.1	$0.1
Congestion		
Net Negative Congestion (enter as negative)	($64.5)	($90.6)
Hourly congestion revenue	$835.5	$668.4
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($79.6)	$41.1
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	(0.2)	$0.0
Adjustments:		
Excess revenues carried forward into future months	$0.0	$0.0
Excess revenues distributed back to previous months	$0.0	$0.0
Other adjustments to FTR revenues	($0.8)	($0.0)
Total FTR revenues	$799.4	$603.4
Excess revenues distributed to other months	$0.0	$0.0
Net Negative Congestion charged to DA Operating Reserves	$0.0	$11.1
Excess revenues distributed to CEPSW for end-of-year distribution	$0.0	$0.0
Excess revenues distributed to FTR holders	$0.0	$0.0
Total FTR congestion credits	$799.4	$614.0
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$799.6	$614.0
Remaining deficiency	$192.3	$291.8

Unallocated Congestion Charges

When congestion revenue at the end of an hour is negative, target allocations in that hour are set to zero, and there is a congestion liability for that hour. At the end of the month, if excess ARR revenue and excess congestion from other hours and months are not adequate to offset the sum of these hourly differences, Day-Ahead Operating Reserves are charged the unallocated congestion charges so that the total congestion for the month is not less than

11 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)
12 111 FERC ¶ 61,228 (2005).
13 See the *2012 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 E-2, "Con Edison and PSE&G wheel settlements data: 2012."

zero. This charge is applied retroactively at the end of the month as additional Day-Ahead Operating Reserves charges and is never credited back to Day-Ahead Operating Reserves in the case of excess congestion. This means that within an hour, the congestion dollars collected from load were less than the congestion dollars paid to generation and there was not enough excess during the month to pay the difference. From 2010 through May 31, 2012, these charges were only made three times, for a total of $7.3 million. However, in the 2012 to 2013 planning period these charges were made in five months for a total of $12.1 million in just one planning period.

Table 12-17 shows the monthly unallocated congestion charges made to Day-Ahead Operating Reserves for the 2012 to 2013 planning period. Months with no unallocated congestion are excluded from the table.[14]

Table 12-17 Unallocated congestion charges: Planning period 2012 to 2013 and 2013 to 2014

Period	Charge
Oct-12	$794,752
Dec-12	$193,429
Jan-13	$5,233,445
Mar-13	$701,303
May-13	$5,210,739
Jun-13	$2,828,660
2012/2013	$12,133,668
2013/2014	$2,828,660

FTR target allocations are based on hourly prices in the Day-Ahead Energy Market for the respective FTR paths and are defined to be the revenue required to compensate FTR holders 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 12-18 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 12-18 is not the 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 12-18 Monthly FTR accounting summary (Dollars (Millions)): Planning period 2012 to 2013 and 2013 to 2014

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-12	$58.5	$62.9	92.9%	$58.5	93.0%	($4.4)
Jul-12	$71.3	$80.0	88.9%	$71.3	88.9%	($8.8)
Aug-12	$54.1	$55.4	97.1%	$54.1	97.3%	($1.3)
Sep-12	$38.7	$82.5	46.7%	$38.7	46.8%	($43.8)
Oct-12	$24.3	$58.2	41.8%	$25.1	42.7%	($33.1)
Nov-12	$52.0	$59.6	87.2%	$52.0	87.3%	($7.5)
Dec-12	$36.3	$50.1	72.2%	$36.5	72.5%	($13.6)
Jan-13	$63.4	$120.3	53.4%	$68.6	56.5%	($51.7)
Feb-13	$77.2	$128.1	60.5%	$77.2	60.2%	($50.9)
Mar-13	$51.7	$70.7	73.2%	$52.4	74.2%	($18.2)
Apr-13	$32.7	$47.4	69.4%	$32.7	69.0%	($14.7)
May-13	$41.8	$90.7	46.1%	$47.0	51.9%	($43.7)
	Summary for Planning Period 2012 to 2013					
Total	$601.9	$905.8		$614.0	67.8%	($291.8)
Jun-13	$61.3	$82.0	74.7%	$64.1	78.2%	($17.9)
	Summary for Planning Period 2013 to 2014					
Total	$61.3	$82.0	74.7%	$64.1	78.2%	($17.9)

Figure 12-12 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through June 2013. The months with payout ratios above 100 percent are overfunded and the months with payout ratios under 100 percent are underfunded. Figure 12-12 also shows the payout ratio after distributing excess revenue across months within the planning period. If there are excess revenues in a given month, the excess is distributed to other months within the planning period that were revenue deficient. The payout ratios for months in the 2012 to 2013 planning

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14 See Section 3, "Operating Reserves" at "Operating Reserve Charges" for the impact of Unallocated Congestion Charges on Operating Reserve rates.

period may change if excess revenue is collected in the remainder of the planning period.

Figure 12-12 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through June 2013
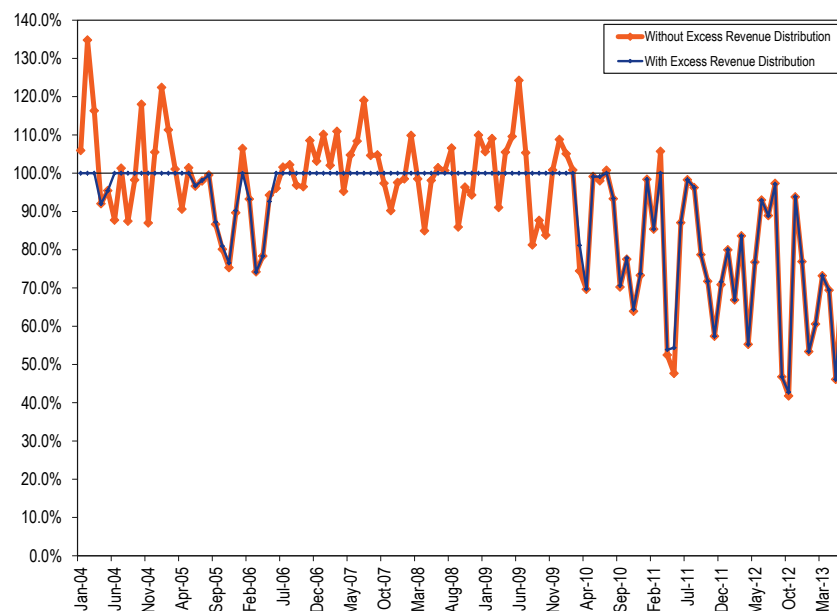

Table 12-19 shows the FTR payout ratio by planning period from the 2003 to 2004 planning period forward. Planning period 2013 to 2014 includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves.

Table 12-19 PJM Reported FTR payout ratio by planning period

Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011	85.0%
2011/2012	80.6%
2012/2013	67.8%
2013/2014	78.2%

*2013/2014 Through 30-Jun-13

FTR Uplift Charge

At the end of the planning period, an uplift charge is applied to FTR holders. This charge is to cover the net of the monthly deficiencies in the target allocations calculated for individual participants. An individual participant's uplift charge is a pro-rata charge, to cover this deficiency, based on their net target allocation with respect to the total net target allocation of all participants with net positive target allocations for the planning period. Participants pay an uplift charge that is a ratio of their share of net positive target allocations to the total net positive target allocations.

The uplift charge is only applied to, and calculated from, members with a net positive target allocation at the end of the planning period. Members with a net negative target allocation have their year-end target allocation set to zero for all uplift calculations. Since participants in the FTR market with net positive target allocations are paying the uplift charge to fully fund FTRs, their payout ratio cannot be 100 percent. The end of planning period payout ratio is calculated as the participant's target allocations minus the uplift charge applied to them divided by their target allocations. The calculations of uplift are structured so that, at the end of the planning period, every participant in the FTR market with a positive net target allocation receives payments based on the same payout ratio. At the end of the planning period and the end of a given month no payout ratio is actually applied to a participant's

target allocations. The payout ratio is simply used as a reporting mechanism to demonstrate the amount of revenue available to pay target allocations and represent the percentage of target allocations a participant with a net positive portfolio has been paid for the planning period. However, this same calculation is not accurate when calculating a single month's payout ratio as currently reported, where the calculation of available revenue is not the same.

The total planning period target allocation deficiency is the sum of the monthly deficiencies throughout the planning period. The monthly deficiency is the difference in the net target allocation of all participants and the total revenue collected for that month. The total revenue paid to FTR holders is based on the hourly congestion revenue collected, which includes hourly M2M, wheel payments and unallocated congestion credits.

Table 12-20 provides a demonstration of how the FTR uplift charge is calculated. In this example it is important to note that the sum of the net positive target allocations is $32 and the total monthly deficiency is $10. The uplift charge is structured so that those with higher target allocations pay more of the deficit, which ultimately impacts their net payout. Also, in this example, and in the PJM settlement process, the monthly payout ratio varies for all participants, but the uplift charge is structured so that once the uplift charge is applied the end of planning period payout ratio is the same for all participants.

For the 2012 to 2013 planning period, the total deficiency was $291.8 million. The top ten participants with the highest target allocations paid 53.6 percent of the total deficiency for the planning period. All of the uplift money is collected from individual participants, and distributed so that every participant experiences the same payout ratio. This means that some participants subsidize others and receive less payout from their FTRs after the uplift is applied, while others receive a subsidy and get a higher payout after the uplift is applied. In this example participants 1 and 5 are paid less after the uplift charge is applied, while participants 3 and 4 are paid more.

Table 12-20 End of planning period FTR uplift charge example

Participant	Net Target Allocation	Total Monthly Payment	Monthly Deficiency	Uplift Charge	Net Payout	Monthly Payout Ratio	EOPP Payout Ratio
1	$10.00	$8.00	$2.00	$3.13	$6.88	80.0%	68.8%
2	-$4.00	$0.00	$0.00	$0.00	-$4.00	100.0%	100.0%
3	$15.00	$10.00	$5.00	$4.69	$10.31	66.7%	68.8%
4	$3.00	$1.00	$2.00	$0.94	$2.06	33.3%	68.8%
5	$4.00	$3.00	$1.00	$1.25	$2.75	75.0%	68.8%
Total	$28.00	$22.00	$10.00	$10.00	$18.00		

Revenue Adequacy Issues and Solutions

PJM Reported Payout Ratio

The payout ratios shown above in Table 12-19 reflect the PJM reported payout ratios for each month of the planning period. These reported payout ratios equal congestion revenue divided by the sum of the net positive and net negative target allocations for each hour of the month. This does not correctly measure the payout ratio actually received by positive target allocation FTR holders in the month, but provides an estimate of the ratio based on the approach to end of planning period calculations, including cross subsidies.

The payout ratio is intended to measure the proportion of the target allocation received by the holders of FTRs with positive target allocations in a month. In fact, the actual monthly payout ratio includes the net negative target allocations as a source of funding for FTRs with net positive target allocations in an hour. Revenue from FTRs with net negative target allocations in an hour are included with congestion revenue when funding FTRs with net positive target allocations.[15] Also included in this revenue is any M2M charge or credit for the month and any excess ARR revenues for the month. The revenue and net target allocations are then summed over the month to calculate the monthly payout ratio. There is no payout ratio applied on a monthly basis, each participant receives a different share of the available revenue based on availability, it is simply used as a reporting mechanism. At the end of a given month, a participant's FTR payments are a proportion of the congestion credits collected, based on the participant's share of the total monthly target

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15 See PJM. "Manual 28: Operating Agreement Accounting," Revision 56 (October 1, 2012), p. 50

allocation. The payout ratio is only used and calculated at the end of the planning period after uplift is applied to each participant. The actual monthly payout ratio received by FTR holders equals congestion revenue plus the net negative target allocations divided by the net positive target allocations for each hour. The actual payout ratio received by the holders of positive target allocation FTRs, reported on a monthly basis, is greater than reported by PJM.

Table 12-21 shows the PJM reported and actual monthly payout ratio for the 2012 to 2013 planning period. In September the PJM reported payout ratio is 8.8 percentage points below the actual payout ratio. On a month to month basis, the payout ratio currently reported by PJM does not take into account all sources of revenue available to pay FTR holders. This provides a slightly overstated level of underfunding on a monthly basis.

Table 12-21 PJM Reported and Actual Monthly Payout Ratios: Planning period 2012 to 2013

	Reported Monthly Payout Ratio	Actual Monthly Payout Ratio
Jun-12	93.0%	93.6%
Jul-12	89.0%	90.1%
Aug-12	97.5%	97.7%
Sep-12	47.0%	55.8%
Oct-12	42.7%	50.9%
Nov-12	87.3%	88.5%
Dec-12	72.3%	74.6%
Jan-13	56.8%	59.7%
Feb-13	60.2%	62.5%
Mar-13	74.2%	75.5%
Apr-13	69.0%	70.8%
May-13	51.9%	54.2%
Jun-13	78.2%	79.4%

Netting Target Allocations within Portfolios

Currently FTR target allocations are netted within each organization in each hour. This means that within an hour, positive and negative target allocations within an organization's portfolio are offset prior to the application of the payout ratio to the positive target allocation FTRs. The payout ratios are also calculated based on these net FTR positions.

The current method requires those with fewer negative target allocation FTRs to subsidize those with more negative target allocation FTRs. The current method treats a positive target allocation FTR differently depending on the portfolio of which it is a part. The correct method would treat all FTRs with positive target allocations exactly the same, which would eliminate this form of cross subsidy.

For example, a participant has $200 of positive target allocation FTRs and $100 of negative target allocation FTRs and the payout ratio is 80 percent. Under the current method, the positive and negative positions are first netted to $100 and then the payout ratio is applied. In this example, the holder of the portfolio would receive 80 percent of $100, or $80.

The correct method would first apply the payout ratio to FTRs with positive target allocations and then net FTRs with negative target allocations. In the example, the 80 percent payout ratio would first be applied to the positive target allocation FTRs, 80 percent of $200 is $160. Then the negative target allocation FTRs would be netted against the positive target allocation FTRs, $160 minus $100, so that the holder of the portfolio would receive $60.

In fact, if done correctly, the payout ratio would also change, although the total net payments made to or from participants would not change. The sum of all positive and negative target allocations is the same in both methods. The net result of this change would be that holders of portfolios with smaller shares of negative target allocation FTRs would no longer subsidize holders of portfolios with larger shares of negative target allocation FTRs.

Under the current system all participants with a net positive target allocation in a month are paid a payout ratio based on each participant's net portfolio position. The correct approach would calculate payouts to FTRs with positive target allocations, without netting in an hour. This would treat all FTRs the same, regardless of a participant's portfolio. This approach would also eliminate the requirement that participants with larger shares of positive target allocation FTRs subsidize participants with larger shares of negative target allocation FTRs.

Elimination of portfolio netting should also be applied to the end of planning period FTR uplift calculation. With this approach, negative target allocations would not offset positive target allocations at the end of the planning period when allocating uplift. The FTR uplift charge would be based on participants' share of the total positive target allocations paid for the planning period.

Table 12-22 shows an example of the effects of calculating FTR payouts on a per FTR basis rather than the current method of portfolio netting for four hypothetical organizations for an example hour. The positive and negative TA columns show the total positive and negative target allocations, calculated separately, for each organization. The percent negative target allocations is the share of the portfolio which is negative target allocation FTRs. The net TA is the net of the positive and negative target allocations for the given hour. The FTR netting payout column shows what a participant would see on their bill, including payout ratio adjustments, under the current method. The per FTR payout column shows what a participant would see on their bill, including payout ratio adjustments, if FTR target allocations were done correctly.

This table shows the effects of a per FTR target allocation calculation on individual participants. The total payout does not change, but the allocation across individual participants does.

The largest change in payout is for participants 1 and 2. Participant 1, who has a large proportion of FTRs with negative target allocations, receives less payment. Participant 2, who has no negative target allocations, receives more payment.

Table 12-22 Example of FTR payouts from portfolio netting and without portfolio netting

Participant	Positive TA	Negative TA	Percent Negative TA	Net TA	FTR Netting Payout (Current)	No Netting Payout (Proposed)	Percent Change
1	$60.00	($40.00)	66.7%	$20.00	$8.33	($3.33)	(140.0%)
2	$30.00	$0.00	0.0%	$30.00	$12.50	$18.33	46.7%
3	$90.00	($20.00)	22.2%	$70.00	$29.17	$35.00	20.0%
4	$0.00	($5.00)	100.0%	($5.00)	($5.00)	($5.00)	0.0%
Total	$180.00	($65.00)	–	$115.00	$45.00	$45.00	–

Table 12-23 shows the total value for the 2012 to 2013 and first month of the 2013 to 2014 planning periods of FTRs with positive and negative target allocations. The Net Positive Target Allocation column shows the value of all portfolios with an hourly net positive value after negative target allocation FTRs are netted against positive target allocation FTRs. The Net Negative Target Allocation column shows the value of all portfolios with an hourly net negative value after negative target allocation FTRs are netted against positive target allocation FTRs. The Per FTR Positive Allocation column shows the total value of the hourly positive target allocation FTRs without netting. The Per Negative Allocation column shows the total value of the hourly negative target allocation FTRs without netting.

The Reported Payout Ratio column is the monthly payout ratio as currently reported by PJM, calculated as total revenue divided by the sum of the net positive and net negative target allocations. The No Netting FTR Payout Ratio column is the payout ratio that participants with positive target allocations would receive if FTR payouts were calculated without portfolio netting, calculated by dividing the total revenue minus the per FTR negative target allocation by the per FTR positive target allocations. The total revenue available to fund the holders of positive target allocation FTRs is calculated by adding any negative target allocations to the congestion credits for that month.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio for the 2012 to 2013 planning period would have been 84.6 percent instead of the reported 67.8 percent.

Table 12-23 Monthly positive and negative target allocations and payout ratios with and without hourly netting: Planning period 2012 to 2013 and 2013 to 2014

	Net Positive Target Allocations	Net Negative Target Allocations	Per FTR Positive Target Allocations	Per FTR Negative Target Allocations	Total Congestion Revenue	Reported Payout Ratio (Current)	No Netting Payout Ratio (Proposed)
Jun-12	$69,557,299	($6,623,560)	$121,217,938	($58,280,956)	$58,501,718	93.0%	96.3%
Jul-12	$89,179,225	($9,034,200)	$173,602,611	($93,421,963)	$71,290,265	89.0%	94.9%
Aug-12	$60,694,118	($5,115,960)	$111,642,193	($55,976,928)	$54,162,229	97.5%	98.7%
Sep-12	$99,154,010	($16,477,176)	$179,647,915	($96,844,326)	$38,826,756	47.0%	75.5%
Oct-12	$68,051,707	($9,827,426)	$137,698,279	($79,454,756)	$25,103,801	43.1%	75.9%
Nov-12	$66,233,739	($6,557,217)	$124,142,020	($64,424,379)	$52,074,746	87.3%	93.8%
Dec-12	$54,866,078	($4,610,245)	$110,328,974	($59,848,711)	$36,538,590	72.7%	87.4%
Jan-13	$129,107,968	($8,672,497)	$233,783,161	($113,347,680)	$68,687,855	57.0%	77.9%
Feb-13	$135,713,011	($7,613,077)	$259,657,461	($131,557,526)	$77,178,125	60.2%	80.4%
Mar-13	$74,434,140	($3,760,700)	$146,552,085	($75,878,638)	$52,441,084	74.2%	87.6%
Apr-13	$50,520,958	($3,090,289)	$108,760,047	($61,325,460)	$32,702,818	68.9%	86.5%
May-13	$95,366,498	($4,678,790)	$190,798,195	($100,110,478)	$47,029,109	51.9%	77.1%
Jun-13	$86,787,810	($4,822,658)	$164,066,220	($82,101,063)	$64,080,191	78.2%	89.1%
2012/2013 Total	$992,878,752	($86,061,137)	$1,897,830,880	($990,471,801)	$614,537,096	67.8%	84.6%
2013/2014 Total	$86,787,810	($4,822,658)	$164,066,220	($82,101,063)	$64,080,191	78.2%	89.1%

Counter Flow FTRs and Revenues

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. Counter flow FTR holders make payments over the planning period, in the form of negative target allocations. These negative target allocation FTRs are paid at 100 percent regardless of whether positive target allocation FTRs are paid at less than 100 percent.

A counter flow FTR is profitable if the hourly negative target allocation is smaller than the hourly auction payment they received. A prevailing flow FTR is profitable if the hourly positive target allocation is larger than the auction payment they made.

For a prevailing flow FTR, the target allocation would be subject to a reduced payout ratio, while a counter flow FTR holder would not be subject to the reduced payout ratio. The profitability of the prevailing flow FTRs is affected by the payout ratio while the profitability of the counter flow FTRs is not affected by the payout ratio.

There is no reason to treat counter flow FTRs more favorably than prevailing flow FTRs. Counter flow FTRs should also be affected when the payout ratio is less than 100 percent. This would mean that counter flow FTRs would pay back an increased amount that mirrors the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide the burden of underfunding among counter flow FTR holders and prevailing flow FTR holders by increasing negative counter flow target allocations by the same amount it decreases positive target allocations. This increased payout ratio would apply only to negative target allocations associated with counter flow FTRs.

Table 12-24 provides an example of how the counter flow adjustment method would impact a two FTR system. In this example there is $15 of total congestion revenue available, corresponding to a reported payout ratio of 75 percent and a monthly actual payout ratio of 87.5 percent. In the example, the profit before and after underfunding can be seen in addition to the profit after underfunding with the counter flow adjustment made. As illustrated, a counter flow FTR's profit does not change when underfunding is applied, whereas a prevailing flow FTR's profit decreases. Applying the counter flow adjustment distributes the underfunding penalty evenly to both prevailing and counter flow FTR holders.

Table 12-24 Example implementation of counter flow adjustment method

	Prevailing A-B 10MW	Counter C-D 10MW
Auction Cost	$50.00	($30.00)
Target Allocation	$40.00	($20.00)
Payout	$30.00	($20.00)
Profit without underfunding	($10.00)	$10.00
Profit after underfunding	($20.00)	$10.00
Payout for Positive TA	$35.00	($20.00)
Profit for Positive TA	($15.00)	$10.00
Payout after CF Adjustment	$36.67	($21.67)
Profit after CF Adjustment	($13.33)	$8.33
Profit Difference	$1.67	($1.67)

in revenue available to fund positive target allocations for the 2012 to 2013 planning period.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would increase the calculated payout ratio for the 2012 to 2013 planning period from the reported 67.8 percent to 88.6 percent.

Figure 12-13 shows the FTR surplus, collected day-ahead, balancing and total congestion payments from January 2005 through June 2013.

### Table 12-25 Counter flow FTR payout ratio adjustment impacts

	Positive Target Allocations	Negative Target Allocations	Total Target Allocations	Total Congestion Revenue	Reported Payout Ratio*	Total Revenue Available	Adjusted Counterflow Payout Ratio	Adjusted Counter Flow Revenue Available
Jun-12	$121,217,938	($58,280,956)	$62,936,981	$58,501,718	93.0%	$116,782,674	97.1%	$117,691,035
Jul-12	$173,602,611	($93,421,963)	$80,180,649	$71,290,265	88.9%	$164,712,228	96.1%	$166,783,011
Aug-12	$111,642,193	($55,976,928)	$55,665,265	$54,162,229	97.3%	$110,139,157	99.0%	$110,479,244
Sep-12	$179,647,915	($96,844,326)	$82,803,589	$38,826,756	46.9%	$135,671,082	82.3%	$147,867,390
Oct-12	$137,698,279	($79,454,756)	$58,243,523	$25,103,801	43.1%	$104,558,557	82.9%	$114,167,539
Nov-12	$124,142,020	($64,424,379)	$59,717,640	$52,074,746	87.2%	$116,499,125	95.3%	$118,360,564
Dec-12	$110,328,974	($59,848,711)	$50,480,263	$36,538,590	72.4%	$96,387,301	90.7%	$100,020,037
Jan-13	$233,783,161	($113,347,680)	$120,435,482	$68,687,855	57.0%	$182,035,534	83.4%	$194,918,106
Feb-13	$259,657,461	($131,557,526)	$128,099,935	$77,178,125	60.2%	$208,735,651	85.4%	$221,802,099
Mar-13	$146,552,085	($75,878,638)	$70,673,447	$52,441,084	74.2%	$128,319,722	90.8%	$133,050,166
Apr-13	$108,760,047	($61,325,460)	$47,434,587	$32,702,818	68.9%	$94,028,278	90.2%	$98,080,581
May-13	$190,798,195	($100,110,478)	$90,687,717	$47,029,109	51.9%	$147,139,587	82.9%	$158,223,288
Jun-13	$164,066,220	($82,101,063)	$81,965,157	$64,080,191	78.2%	$146,181,254	91.9%	$150,785,406
Total 2012/2013	$1,897,830,880	($990,471,801)	$907,359,079	$614,537,096	67.7%	$1,605,008,896	88.6%	$1,681,443,058
Total 2013/2014	$164,066,220	($82,101,063)	$81,965,157	$64,080,191	78.2%	$146,181,254	91.9%	$150,785,406

* Reported payout ratios may vary due to rounding differences when netting

Table 12-25 shows the monthly positive, negative and total target allocations.[16] Table 12-25 also shows the total congestion revenue available to fund FTRs, as well as the total revenue available to fund positive target allocation FTR holders on a per FTR basis and on a per FTR basis with counter flow payout adjustments. Implementing this change to the payout ratio for counter flow FTRs would result in an additional $76.4 million (26.1 percent of underfunding)

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16 Reported payout ratio may differ between Table 12-23 and Table 12-25 due to rounding differences when netting target allocations and considering each FTR individually.

Figure 12-13 FTR Surplus and the collected Day-Ahead, Balancing and Total congestion: January 2005 through June 2013
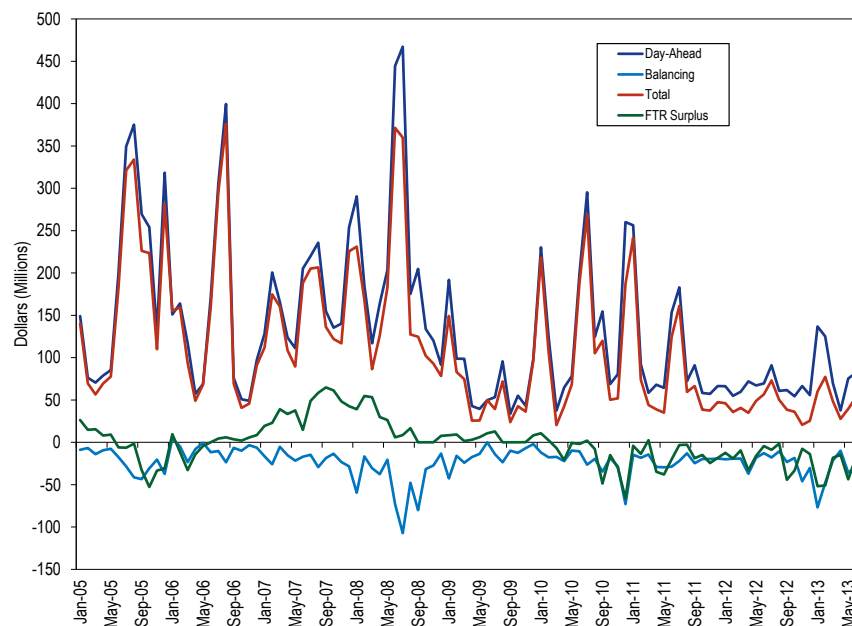
Up-to-Congestion Transaction FTR Forfeitures

Currently there is no FTR forfeiture rule implemented for Up-to-Congestion Transactions (UTCs). A rule that would apply the FTR forfeiture rule to UTCs is pending at the Commission.[17] The intent of an FTR forfeiture rule applied to UTCs should be the same as with INCs and DECs, to prevent the use of virtual bids to increase Day-Ahead congestion on an FTR path. The proposed penalty should be the same as it is for the INC and DEC rule, namely the forfeiture of any profits due to an FTR found to be influenced by a UTC.

The rule submitted by PJM and scheduled for implementation will not appropriately address the impact of UTCs on FTRs and will not be consistent with the application of the current forfeiture rule.

The appropriate and consistent method for determining whether a UTC is eligible for forteiture would also take the net of the UTC into consideration. However, in the case of a UTC that does not span a constraint, the net of the UTC would be used to determine if the UTC was a net injection (INC) or withdrawal (DEC) on the system. If a UTC does span a constraint the net of the UTC is calculated and it is treated as both an injection and a withdrawal. After the net effect of the UTC is calculated the net injection or withdrawal of the UTC is treated the same way an INC or DEC is treated in the current implementation of the FTR forfeiture rule.

Table 12-25 shows the amount of FTR profit that would have been forfeited in the first six months of 2013 under the PJM method and the appropriate method.

Table 12-26 Up-to-Congestion Transaction FTR forfeiture totals for the two proposed methods

Month	IMM	PJM
Jan-13	$198,025	$24,070
Feb-13	$527,000	$59,241
Mar-13	$285,527	$9,000
Apr-13	$34,598	$359
May-13	$609,518	$21,845
Jun-13	$267,079	$7,011
Total	$1,921,747	$121,525

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.[18] These price differences are based on the bid prices of participants in the Annual FTR Auction. The auction clears the set of feasible FTR bids which produce the highest net revenue. ARR revenues are a function of FTR auction participants' expectations of locational congestion price differences and the associated level of revenue sufficiency.[19]

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17 *See* FERC Docket No. ER13-1654.

18 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.

19 For a more complete explanation, see the *2012 State of the Market Report for PJM*, Volume II, Section 12, "FTRs."

Market Structure

ARRs have been available to network service and firm, point-to-point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003 to 2004 planning period. The initial allocation covered the Mid-Atlantic Region and the AP Control Zone. For the 2006 to 2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the AEP, DAY, DLCO and Dominion control zones. For the 2007 to 2008 and subsequent planning periods through the 2013 to 2014 planning period, all eligible market participants were allocated ARRs.

Table 12-27 shows the top 10 principal binding transmission constraints that limited the 2013 to 2014 Annual ARR Allocation. For the 2013 to 2014 ARR Stage 1A allocation, PJM was required to increase capability limits for several facilities in order to make the ARR allocation feasible.[20]

Table 12-27 Top 10 principal binding transmission constraints limiting the Annual ARR Allocation: Planning period 2013 to 2014

Constraint	Type	Control Zone
Cordova – Nelson	Flowgate	MISO
Silver Lake – Cherry Valley	Line	COMED
Electric Junction – Nelson	Line	COMED
Oak Grove – Galesburg	Flowgate	MISO
Waukegan–Zion	Line	COMED
Zion – Lakeview	Line	COMED
Lakeview	Transformer	MISO
Zion	Transformer	COMED
Braidwood – East Frankfort	Line	COMED
Greystone – West Wharton	Line	JCPL

ARR Reassignment for Retail Load Switching

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.[21]

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 ARRs for the receiving LSE compared to the total value held by the original ARR holder.

There were 52,825 MW of ARRs associated with approximately $498,800 of revenue that were reassigned in the 2012 to 2013 planning period. There were 41,770 MW of ARRs associated with approximately $758,000 of revenue that were reassigned for the full twelve months of the 2011 to 2012 planning period.

Table 12-28 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2011 and June 2013.

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20 It is a requirement of Section 7.4.2 (i) in the OATT that any ARR request made in Stage 1A must be feasible and transmission capability must be raised if an ARR request is found to be infeasible.

21 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 28.

Table 12-28 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2011, through June 30, 2013

Control Zone	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
	2012/2013 (12 months)	2013/2014 (1 month)*	2012/2013 (12 months)	2013/2014 (1 month)*
AECO	581	219	$3.0	$0.7
AEP	4,656	893	$58.9	$4.9
AP	3,518	543	$84.1	$11.9
ATSI	5,314	1,355	$8.3	$1.1
BGE	3,203	758	$37.3	$7.8
ComEd	11,824	919	$170.7	$7.8
DAY	589	74	$0.9	$0.1
DEOK	2,979	801	$1.6	$0.7
DLCO	2,708	2,619	$19.1	$6.0
DPL	1,989	469	$11.5	$3.7
Dominion	0	5	$0.0	$0.1
EKPC	NA	0	NA	$0.0
JCPL	1,373	414	$5.6	$1.2
Met-Ed	1,107	220	$8.6	$1.7
PECO	3,416	281	$22.7	$2.0
PENELEC	920	208	$8.3	$2.3
PPL	3,198	799	$20.5	$2.8
PSEG	2,312	613	$16.5	$5.0
Pepco	3,073	660	$21.4	$2.4
RECO	67	23	$0.0	$0.0
Total	52,825	11,871	$498.8	$62.2

* Through 30-Jun-2013

Incremental ARRs (IARRs) for RTEP Upgrades

Table 12-29 lists the incremental ARR allocation volume for the current and previous planning periods from the 2008 to 2009 planning period through the 2013 to 2014 planning period.

Table 12-29 Incremental ARR allocation volume: Planning periods 2008 to 2009 through 2013 to 2014

Planning Period	Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2008/2009	15	891	891	100%	0	0%
2009/2010	14	531	531	100%	0	0%
2010/2011	14	531	531	100%	0	0%
2011/2012	15	595	595	100%	0	0%
2012/2013	15	687	687	100%	0	0%
2013/2014	17	1087	1087	100%	0	0%

Table 12-30 lists the three RTEP upgrade projects that were allocated a total of 678.2 MW of IARRs.

Table 12-30 IARRs allocated for 2013 to 2014 Annual ARR Allocation for RTEP upgrades[22]

Project #	Project Description	IARR Parameters		
		Source	Sink	Total MW
B0287	Install 600 MVAR Dynamic Reactive Device at Elroy 500kV	RTEP B0287 Source	DPL	190.6
B0328	TrAIL Project: 502 JCT - Loudoun 500kV	RTEP B0328 Source	Pepco	391.2
B0329	Cason-Suffolk 500 kV	RTEP B0329 Source	Dominion	96.4

Residual ARRs

Only ARR holders that had their Stage 1A or Stage 1B ARRs prorated are eligible to receive residual ARRs. Residual ARRs are available if additional transmission system capability is added during the planning period after the annual ARR allocation. This additional transmission system capability would not have been accounted for in the initial annual ARR allocation, but it enables the creation of residual ARRs. Residual ARRs are effective on the first day of the month in which the additional transmission system capability is included in FTR auctions and exist until the end of the planning period. For the following planning period, any residual ARRs are available as ARRs in the annual ARR allocation. Stage 1 ARR holders have a priority right to ARRs. Residual ARRs are a separate product from incremental ARRs.

22 RTEP B0287 Source is a new aggregate comprised of an equal ten percent weighting of the following ten pnodes: MUDDYRN 13 KV Unit1, MUDDYRN 13 KV Unit2, MUDDYRN 13 KV Unit3, MUDDYRN 13 KV Unit4, MUDDYRN 13 KV Unit5, MUDDYRN 13 KV Unit6, MUDDYRN 13 KV Unit7, MUDDYRN 13 KV Unit8, PEACHBOT 22 KV UNIT02 and PEACHBOT 22 KV UNIT03.

Effective August 1, 2012, as ordered by FERC in Docket No. EL12-50-000, in addition to new transmission, residual ARRs are now available for eligible participants when a transmission outage was modeled in the Annual ARR Allocation, but the transmission facility becomes available during the modeled year. These residual ARRs are determined the month before the effective date, are only available on paths prorated in Stage 1 of the Annual ARR Allocation and are allocated automatically to participants. Residual ARRs are effective for single, whole months and cannot be self scheduled. ARR target allocations are based on the clearing prices from FTR obligations in the effective monthly auction, may not exceed zonal Network Services Peak Load or Firm Transmission Reservation Levels and are only available up to the prorated ARR MW capacity as allocated in the Annual ARR Allocation.

Table 12-31 shows the Residual ARRs automatically allocated to eligible participants, along with the target allocations from the effective month.

Table 12-31 Residual ARR allocation volume and target allocation

Month	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
Aug-12	4,508.2	2,460.5	54.6%	$1,026,836
Sep-12	4,696.3	2,343.1	49.9%	$1,003,031
Oct-12	6,502.2	1,698.9	26.1%	$584,810
Nov-12	3,677.8	1,530.6	41.6%	$393,221
Dec-12	7,006.6	1,614.5	23.0%	$463,325
Jan-13	6,773.0	1,547.2	22.8%	$488,251
Feb-13	1,567.4	1,493.7	95.3%	$229,856
Mar-13	5,351.2	1,522.7	28.5%	$286,193
Apr-13	5,452.1	1,608.9	29.5%	$325,662
May-13	6,054.7	1,647.4	27.2%	$282,425
Jun-13	10,864.1	1,272.7	11.7%	$667,291

Market Performance

Volume

Table 12-32 shows the volume of ARR allocations for each round of the 2012 to 2013 and 2013 to 2014 planning periods.

Table 12-32 Annual ARR Allocation volume: planning periods 2012 to 2013 and 2013 to 2014

Planning Period	Stage	Round	Requested Count	Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2012/2013	1A	0	16,069	67,302	67,300	100.0%	2	0.0%
	1B	1	11,487	30,013	18,432	61.4%	11,581	38.6%
	2	2	4,887	22,597	2,701	12.0%	19,896	88.0%
		3	3,682	22,496	3,334	14.8%	19,162	85.2%
		4	3,023	22,362	6,219	27.8%	16,143	72.2%
		Total	11,592	67,455	12,254	18.2%	55,201	81.8%
	Total		39,148	164,770	97,986	59.5%	66,784	40.5%
2013/2014	1A	0	18,022	67,861	67,861	100.0%	0	0.0%
	1B	1	14,227	32,679	15,782	48.3%	16,897	51.7%
	2	2	5,476	22,096	3,519	15.9%	18,577	84.1%
		3	4,128	22,480	3,200	14.2%	19,280	85.8%
		4	3,335	22,348	2,612	11.7%	19,736	88.3%
		Total	12,939	66,924	9,331	13.9%	57,593	86.1%
	Total		45,188	167,464	92,974	55.5%	74,490	44.5%

Stage 1A Infeasibility

Stage 1A ARRs are allocated for a 10 year period, with the ability for a participant to opt out of any planning period. PJM conducts a simultaneous feasibility analysis to determine transmission upgrades so that the long term ARRs can remain feasible. If a simultaneous feasibility test violation occurs in any year of this test PJM will identify or accelerate any transmission upgrades to resolve the violation and these upgrades will be included in the PJM RTEP process.

For the 2012 to 2013 planning period, Stage 1A of the Annual ARR Allocation was infeasible. According to Section 7.4.2 (i) of the PJM OATT the capability limits of the binding constraints rendering these ARRs infeasible must be increased in the model and that these increased limits must then be used in subsequent ARR and FTR allocations and auctions for the entire planning period, except in the case of extraordinary circumstances. These infeasibilities are due to newly monitored facilities where upgrades could not be planned in advance, facilities not owned by PJM and an overall reduced system capability.

The consequence of this increased capability in the models which does not reflect actual capability is an over allocation of both ARRs and FTRs for the entire planning period. In the case of ARRs this over allocation will lower the ARR funding level by selling more capability on the same transmission network. In the case of FTRs the over allocation will exacerbate the underfunding problem by selling more FTRs than are physically feasible with no increase in congestion collected.

Table 12-33 lists the constraints for which ARR requests were found to be infeasible for the 2012 to 2013 ARR Stage 1A Allocation and the MW increase in modeled facility ratings required to make them feasible. In addition, the reason for infeasibility is provided, whether it is an increase in network load, or due to transmission outages in the simultaneous feasibility test.

Table 12–33 Constraints with capacity increases due to Stage 1A infeasibility for the 2013 to 2014 ARR Allocation

Constraint	Contingency	Type	Zone	MW Increase	Reason
Silver Lake – Cherry Valley	Nelson – Electric Junction	Line	COMED	251	Load
Cordova – Nelson	Nelson	Flowgate	MISO	215	Load
Electric Junction – Nelson	Nelson – Electric Junction	Line	COMED	202	Load
Oak Grove – Galesburg	Nelson – Electric Junction	Flowgate	MISO	151	Load
Silver Lake – Cherry Valley	BASE	Line	COMED	139	Load
Waukegan – Zion	BASE	Line	COMED	129	Load
Zion	Cherry Valley – Silver Lake	Transformer	COMED	121	Load
Zion – Lakeview	Cherry Valley – Silver Lake	Line	COMED	121	Load
Lakeview	Cherry Valley – Silver Lake	Transformer	MISO	121	Load
Electric Junction – Nelson	BASE	Line	COMED	113	Load
Waukegan – Zion	Cherry Valley – Silver Lake	Line	COMED	106	Load
Roseland – Whippany	Roseland – Readington	Line	PSEG	103	Outages
Roseland – Whippany	BASE	Line	PSEG	93	Outages
Kenney – Mount Olive	New Church – Piney Grove	Line	DPL	70	Outages
Prairie State – W. Mt. Vernon	St Francis – Lutesville	Flowgate	MISO	60	Load
Kenney – Stockton	New Church – Piney Grove	Line	DPL	59	Outages
Mount Olive – Piney	New Church – Piney Grove	Line	DPL	54	Outages
Belvidere – Woodstock	Cherry Valley – Silver Lake	Line	COMED	51	Load
Belvidere – Chrysler Corp.	Cherry Valley – Silver Lake	Line	COMED	51	Load
Dixon – Stillman Valley	Nelson – Electric Junction	Line	COMED	45	Load
Pleasant Valley – Belvidere 2	Cherry Valley – Silver Lake	Line	COMED	41	Load
McGirr Road – Steward	Nelson – Electric Junction	Line	COMED	37	Load
Athenia – Saddlebrook	BASE	Line	PSEG	24	Outages
Mazon – Mazon	Kickapoo Creek – Lasalle	Line	COMED	16	Load
Pleasant Valley – Belvidere 1	Cherry Valley – Silver Lake	Line	COMED	13	Load

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 total 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 total 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 received a projected $626.7 million in credits from the FTR auctions during the 2012 to 2013 planning period, with a projected average hourly ARR credit of $0.66 per MW. During the comparable 2011 to 2012 planning period, ARR holders received $1,055.9 million in ARR credits with an average hourly ARR credit of $1.06 per MW.

Table 12-34 lists projected ARR target allocations from the Annual ARR Allocation, and net revenue sources from the Annual and Monthly Balance of Planning Period FTR Auctions for the 2011 to 2012 and the 2012 to 2013 planning periods.

Table 12-34 Projected ARR revenue adequacy (Dollars (Millions)): Planning periods 2012 to 2013 and 2013 to 2014

	2012/2013	2013/2014
Total FTR auction net revenue	$626.7	$559.5
Annual FTR Auction net revenue	$602.9	$558.4
Monthly Balance of Planning Period FTR Auction net revenue*	$23.9	$1.1
ARR target allocations	$570.5	$502.4
ARR credits	$570.5	$502.4
Surplus auction revenue	$56.2	$57.1
ARR payout ratio	100%	100%
FTR payout ratio*	67.8%	74.7%

* Shows twelve months for 2012/2013 and one month for 2013/2014.

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 12-14 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone for the 2012 to 2013 planning period. The day-ahead and real-time congestion are based on the difference between zonal congestion prices and Western Hub congestion prices.

Figure 12-14 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: 2012 to 2013 planning period
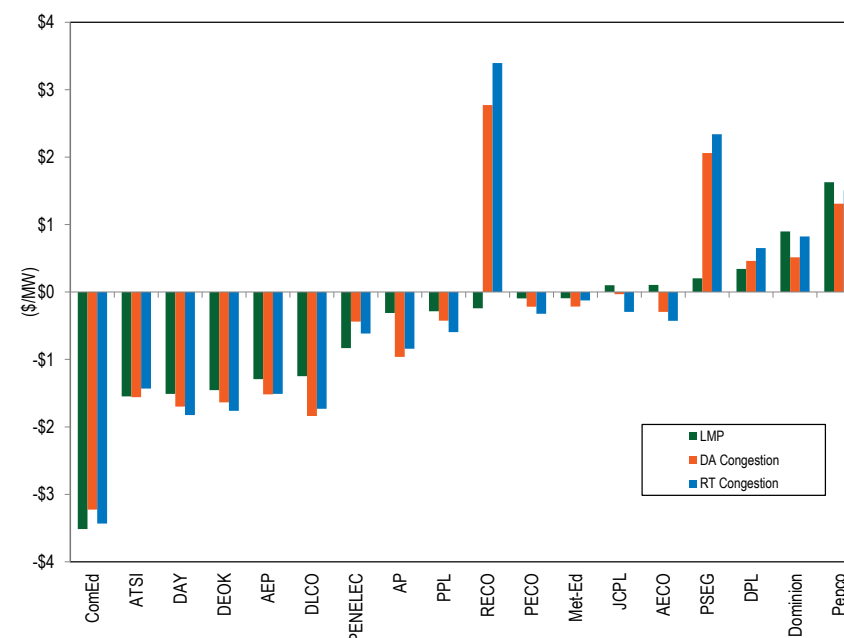
Effectiveness of ARRs as an Offset to Congestion

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 2012 to 2013 planning period, the total revenues received by the holders of all ARRs and FTRs offset 92.6 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 12-35. ARRs and self-scheduled FTRs that sink at an aggregate are assigned to a control zone if applicable.[23] 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 67.8 percent of the target allocation for the 2012 to 2013 planning period. The target allocation is not a guarantee of payment nor does it reflect congestion incurred on a particular FTR path. The target allocation is used to set a cap on path specific FTR payouts.

The Congestion column shows the amount of congestion in each control zone from the Day-Ahead Energy Market and the balancing energy market and includes only the congestion costs incurred by the organizations that hold ARRs or self-scheduled FTRs. The last column shows the difference between the total revenue and the congestion for each ARR control zone sink.

Table 12-35 ARR and self-scheduled FTR congestion offset (in millions) by control zone: 2012 to 2013 planning period[24]

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue – Congestion Difference	Percent Offset
AECO	$5.9	$0.0	$5.9	$6.8	($0.8)	87.5%
AEP	$25.3	$57.1	$82.4	$37.7	$71.9	>100%
APS	$40.6	$23.5	$64.1	$7.1	$68.2	>100%
ATSI	$4.1	$0.2	$4.3	($4.0)	$8.5	>100%
BGE	$30.3	$0.7	$31.0	$7.9	$23.4	>100%
ComEd	$101.8	$0.0	$101.8	($45.3)	$147.1	>100%
DAY	$1.5	$1.7	$3.2	($2.9)	$7.0	>100%
DEOK	$1.1	$0.1	$1.3	($5.1)	$6.5	>100%
DLCO	$5.9	$0.2	$6.1	($0.4)	$6.6	>100%
Dominion	$6.7	$56.5	$63.2	$13.9	$76.2	>100%
DPL	$11.4	$1.3	$12.8	$27.3	($13.9)	46.7%
External	$5.5	$0.5	$6.0	$2.5	$3.7	>100%
JCPL	$9.0	$0.2	$9.2	$9.7	($0.4)	95.0%
Met-Ed	$8.7	$0.1	$8.9	$5.1	$3.8	>100%
PECO	$16.9	$1.8	$18.8	$16.7	$2.9	>100%
PENELEC	$6.9	$4.9	$11.8	$6.4	$7.6	>100%
Pepco	$24.8	$1.6	$26.4	$25.1	$2.0	>100%
PPL	$18.8	$1.1	$20.0	$6.3	$14.2	>100%
PSEG	$26.1	$8.7	$34.8	($13.9)	$52.8	>100%
RECO	$0.0	$0.0	$0.0	$1.3	($1.3)	0.1%
Total	$351.4	$160.5	$511.9	$102.3	$505.3	>100%

Effectiveness of ARRs and FTRs as an Offset to Congestion

Table 12-36 compares the revenue for ARR and FTR holders and the congestion in both the Day-Ahead Energy Market and the balancing energy market for the 2012 to 2013 planning period. 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

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23 For Table 12-35 through Table 12-37, 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.

24 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.

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 67.8 percent of the target allocation for the 2012 to 2013 planning period. 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 offset 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.[25] The last column shows the difference between the total ARR and FTR offset and the congestion cost for each control zone.

Table 12–36 ARR and FTR congestion offset (in millions) by control zone: 2012 to 2013 planning period

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset – Congestion Difference	Percent Offset
AECO	$5.9	($1.1)	$6.5	($1.7)	$2.9	($4.5)	0.0%
AEP	$104.1	$99.6	$123.0	$80.7	$96.5	($15.8)	83.6%
APS	$76.3	$28.0	$40.0	$64.3	$80.4	($16.1)	80.0%
ATSI	$4.3	$13.6	($0.9)	$18.8	($0.8)	$19.6	>100%
BGE	$31.6	$32.2	$43.5	$20.4	$27.8	($7.4)	73.3%
ComEd	$121.5	$86.0	$81.4	$126.0	$155.7	($29.7)	80.9%
DAY	$3.8	$6.0	$5.4	$4.5	$4.4	$0.0	>100%
DEOK	$1.4	$6.1	$4.1	$3.4	$0.5	$3.0	>100%
DLCO	$7.2	$0.5	$7.4	$0.4	$4.3	($3.9)	8.3%
Dominion	$79.3	$78.1	$109.9	$47.5	$75.8	($28.2)	62.7%
DPL	$12.3	$21.2	$19.8	$13.6	$16.8	($3.2)	80.9%
External	$6.7	($1.3)	$1.5	$3.9	($27.5)	$31.3	>100%
JCPL	$9.3	$24.3	$22.0	$11.6	$13.1	($1.5)	88.2%
Met-Ed	$9.1	$7.1	$16.0	$0.2	$2.3	($2.1)	9.0%
PECO	$20.1	$11.5	$17.5	$14.2	$1.2	$13.0	>100%
PENELEC	$11.8	$28.6	$30.3	$10.1	$39.6	($29.5)	25.5%
Pepco	$27.1	$44.6	$83.4	($11.6)	$37.6	($49.2)	0.0%
PPL	$21.5	$5.4	$9.4	$17.4	$13.2	$4.2	>100%
PSEG	$24.0	$117.6	$35.7	$105.9	$27.1	$78.8	>100%
RECO	$0.0	$2.1	($1.8)	$3.9	$4.9	($1.1)	78.1%
Total	$577.2	$610.3	$654.1	$533.4	$575.9	($42.5)	92.6%

Table 12-37 shows the total offset due to ARRs and FTRs for the entire 2011 to 2012 and 2012 to 2013 planning periods.

Table 12–37 ARR and FTR congestion hedging (in millions): Planning periods 2011 to 2012 and 2012 to 2013[26]

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset – Congestion Difference	Percent Offset
2011/2012	$982.9	$794.3	$1,092.4	$684.8	$771.2	($86.4)	88.8%
2012/2013	$577.2	$610.3	$654.1	$533.4	$575.9	($42.5)	92.6%

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25 The total zonal congestion numbers were calculated as of July 10, 2013 and may change as a result of continued PJM billing updates.

26 The FTR credits do not include after-the-fact adjustments. For the 2012 to 2013 planning period, the ARR credits were the total credits allocated to all ARR of this planning period, and the FTR Auction Revenue includes the net revenue in the Monthly Balance of Planning Period FTR Auctions for the planning period and the portion of Annual FTR Auction revenue distributed to the entire planning period.