Q3

State of the Market Report for PJM

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

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Preface

The PJM Market Monitoring Plan provides:

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

Accordingly, Monitoring Analytics, LLC, which serves as the Market Monitoring Unit (MMU) for PJM Interconnection, L.L.C. (PJM),[2] and is also known as the Independent Market Monitor for PJM (IMM), submits this *2014 Quarterly State of the Market Report for PJM: January through September*.[3]

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).
3 All references to this report should refer to the source as Monitoring Analytics, LLC, and should include the complete name of the report: *2014 Quarterly State of the Market Report for PJM: January through September.*

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Introduction

Q3 2014 in Review

The state of the PJM markets in the first nine months of 2014 reflected the extreme winter weather conditions in January and a return to more typical weather conditions in the second and third quarters. The stress on the markets during the winter weather was a reminder that markets must work during extreme conditions as well as more normal conditions. PJM markets did work during the extreme conditions but the experience highlighted areas of market design that need improvement. The results of the energy market, the results of the capacity market and the results of the regulation market were competitive in the first three quarters of 2014.

The PJM market design must be robust to stress. Markets that only work under normal conditions are not effective markets. 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. Despite the complex rules, these are markets not administrative constructs, and have all the potential efficiency benefits of markets. There are 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 overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units offering at, or close to, their marginal costs, although this was not always the case during the high demand hours in January. This is evidence of generally competitive behavior, although the behavior of some participants during the high demand periods in January raises concerns about economic withholding. The performance of the PJM markets under scarcity conditions raised a number of concerns related to capacity market incentives, participant offer behavior in the energy market under tight market conditions, natural gas availability and pricing, demand response and interchange transactions. In particular, there are issues related to the ability to increase markups substantially in tight market conditions, to the uncertainties about the pricing and availability of natural gas, and to the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel and generate power rather than take an outage.

The energy market reflected the combination of increased, weather related, demand, and higher fuel costs in higher energy market prices. The load-weighted average LMP was 47.4 percent higher in the first nine months of 2014 than in the first nine months of 2013, $58.60 per MWh versus $39.75 per MWh.

The increase in prices was a combined result of higher fuel prices and higher demand. If fuel costs in the first nine months of 2014 had been the same as in the first nine months of 2013, holding everything else constant, there would have an average increase in load-weighted LMP of 27.4 percent rather than the actual increase of 47.4 percent. The load-weighted LMP would have been $50.62 per MWh instead of the actual $58.60 per MWh in the first nine months of 2014.

In the first nine months of 2014, the averages concealed dramatically different outcomes in the first quarter compared to the second and third quarters. For example, despite higher average prices for the first nine months of 2014, the real-time, load-weighted, average LMP for the third quarter of 2014 was 15.4 percent lower than for the third quarter of 2013. While uplift was up substantially in the first quarter of 2014, uplift decreased in the second and third quarters of 2014.

Net revenue is a key measure of overall market performance as well as a measure of the incentive to invest in new generation to serve PJM markets. Energy net revenues are affected by fuel prices and energy prices. Natural gas prices and energy prices were significantly higher in the first three months of 2014 than in the first three months of 2013, resulting in large increases in net revenues in the first three months of 2014. For the first three months of 2014, energy net revenues increased by 1,444 percent for a new combustion turbine, 377 percent for a new combined cycle, 637 percent for a new coal plant, and 188 percent for a new nuclear plant. The net result was substantial increases in net revenues for all technology types in the first nine months of 2014 compared to the first nine months of 2013. For the first nine months, energy net revenues increased by an average of 275 percent for a new combustion turbine peaking unit, 114 percent for a new combined cycle, 202 percent for a new coal plant, and 58 percent for a new nuclear plant.

The impact of a relatively short period of high loads on net revenues illustrates how scarcity pricing can work to address the missing money issue in wholesale power markets. The net revenue impacts of a short period of unpredictable high load were substantial. But the question is whether relying on such revenues for the incentive to invest in new and existing resources is a preferred alternative to relying on more predictable revenues from a capacity market which is tightly linked to scarcity pricing in the energy market through a functional net revenue offset.

Particularly in times of stress on markets and when some flaws in markets are revealed, non-market solutions may appear attractive. Top down, integrated resource planning approaches are tempting because it is easy to think that experts know exactly the right mix and location of generation resources and the appropriate definition of resource diversity and therefore which technologies should be favored through exceptions to market rules. The provision of subsidies to favored technologies, whether solar, wind or nuclear, is tempting for those who would benefit but subsidies are a form of integrated resource planning that is not consistent with markets. Subsidies to existing units are no different in concept than subsidies to planned units and are equally inconsistent with markets. Cost of service regulation is tempting because guaranteed rates of return and fixed prices may look attractive to asset owners in uncertain markets and because cost of service regulation incorporates integrated resource planning.

But the market paradigm and the non-market paradigm are mutually exclusive. Once the decision is made that market outcomes must be fundamentally modified, it will be virtually impossible to return to markets.

Much of the reason that market outcomes are subject to legitimate criticism is that the markets have not been permitted to reveal the underlying supply and demand fundamentals in prices. Before market outcomes are rejected in favor of non-market choices, markets should be permitted to work.

It is more critical than ever to get capacity market prices correct. A number of capacity market design elements have resulted in a substantial suppression of capacity market prices for multiple years. The impact of continued inclusion of limited DR products in the capacity market was $2.2 billion in the 2017/2018 Base Residual Auction, a price reduction of 22.9 percent, holding everything else constant. The impact of the 2.5 percent offset to demand was $2.4 billion, a price reduction of 24.5 percent, holding everything else constant. The impact of continued inclusion of limited DR products combined with the impact of the 2.5 percent offset to demand, was $3.4 billion, a price reduction of 31.3 percent, holding everything else constant.

These market design choices have substantial impacts. PJM is addressing the fundamental issues of the capacity market design in its Capacity Performance proposal, including price formation, product definition and performance incentives.

The price of energy must also reflect supply and demand fundamentals. While the rules on gas procurement and the inclusion of gas costs in energy market offers need clarification, cost-based offer caps should be increased to ensure that offer caps reflect actual marginal costs, even when those marginal costs are well in excess of $1,000 per MWh. But when cost based offers are greater than $1,000 per MWh, price based offers should not exceed cost based offers and cost based offers should not include a ten percent adder. PJM's reserve requirements should reflect dispatchers' actual need for reserves to maintain reliability and those reserve requirements should be reflected in prices and should trigger scarcity pricing when they are not met. Better energy market pricing will help reduce uplift and a broader allocation of uplift to all participants, including UTCs, will help reduce uplift to the level of noise rather than the significant friction on markets that it is today.

There was a sharp decrease in UTC activity in September, as a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[1] To date, there have not been negative impacts on market outcomes as a result of the approximately 85 percent reduction in UTC volume and there have been some positive impacts. The MMU will continue to evaluate the market results and to report on them.

In a panel decision issued May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit vacated in its entirety Order No. 745, which provided for payment of full LMP to demand-side resources.[2] The decision calls into question the jurisdictional foundation for all demand response programs currently subject to FERC oversight, and, in particular, those in the energy and capacity markets.

While it is difficult to predict all the ramifications of this decision, the decision does create an opportunity to rethink the ways in which demand side resources can most effectively participate in wholesale power markets based on market principles. Demand response should be on the demand side of the capacity market rather than on the supply side. Customers would avoid paying for capacity by interrupting designated load when PJM indicates that it is a critical hour. Customers would pay for actual load on the system during PJM-defined critical hours, e.g. maximum generation alerts, rather than relying on flawed measurement and verification methods. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these critical hours. Demand resources should be provided a fair opportunity to compete, but demand resources should no longer be provided special advantages inconsistent with competitive markets.

The PJM markets and PJM market participants from all sectors face significant challenges, some of which were clearly revealed in January and some of which continue to be revealed. PJM and its market participants will need to continue to work constructively to address these challenges to ensure the continued effectiveness of PJM markets. A successful redesign of the PJM capacity market to address its identified flaws is the most critical initiative currently being considered by PJM stakeholders.

PJM Market Summary Statistics

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

Table 1-1 PJM Market Summary Statistics, January through September, 2013 and 2014[3]

	2013 (Jan - Sep)	2014 (Jan - Sep)	Percent Change
Load	592,209 GWh	602,533 GWh	1.7%
Generation	600,784 GWh	614,863 GWh	2.3%
Net Actual Interchange	3,474 GWh	(331) GWh	(109.5%)
Losses	13,218 GWh	13,241 GWh	0.2%
Regulation Requirement*	702 MW	664 MW	(5.4%)
RTO Primary Reserve Requirement	2,063 MW	2,063 MW	0.0%
Total Billing	$25.16 Billion	$40.76 Billion	62.0%
Peak	Jul 18, 2013 16:00	Jun 17, 2014 16:00	
Peak Load	157,508 MW	141,673 MW	(10.1%)
Load Factor	0.57	0.65	13.1%
Installed Capacity	As of 09/30/2013	As of 09/30/2014	
Installed Capacity	185,085 MW	184,400 MW	(0.4%)

* This is an hourly average stated in effective MW.

PJM Market Background

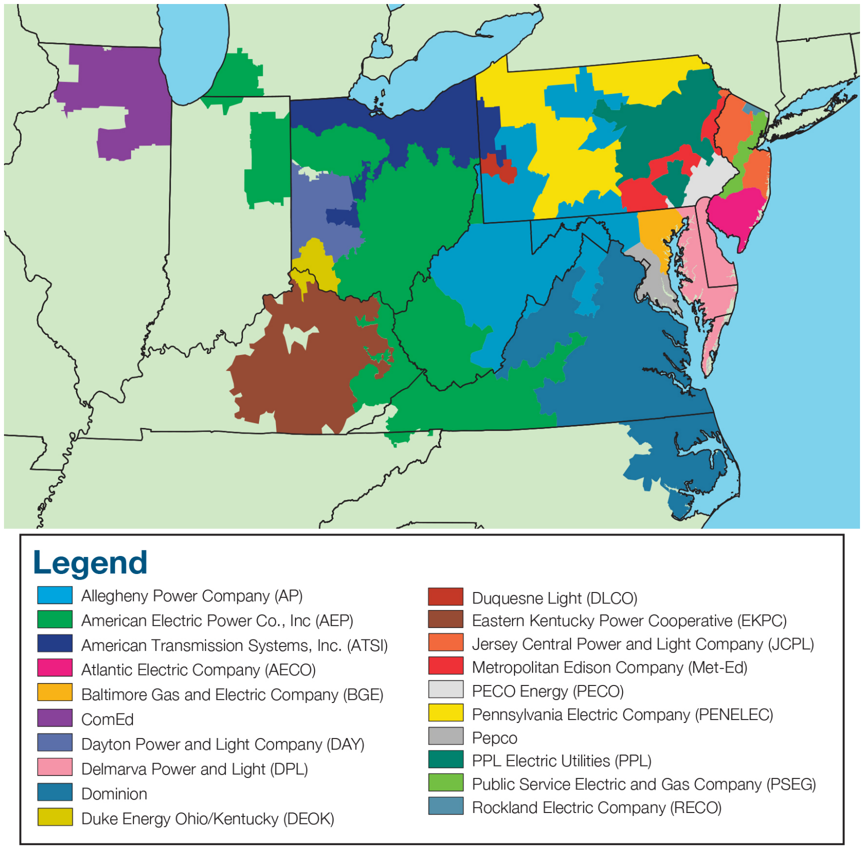
The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of September 30, 2014, had installed generating capacity of 184,400 megawatts (MW) and 915 members including market buyers, sellers and traders of electricity in a region including more than 61 million people in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia (Figure 1-1).[4,5,6]

1 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).
2 Electric Power Supply Association v. FERC, No. 11-1486, *petition for en banc review denied*; *see Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶ 31,322 (2011); *order on reh'g*, Order No. 745-A, 137 FERC ¶ 61,215 (2011); *order on reh'g*, Order No. 745-B, 138 FERC 61,148 (2012).

3 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 3, "Energy Market."
4 See PJM's "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
5 See PJM's "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
6 See the *2013 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2014.

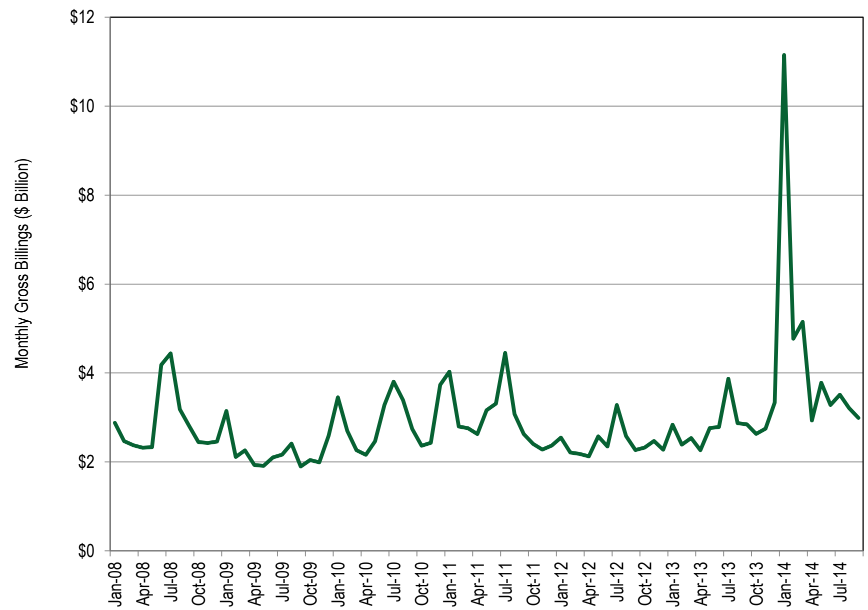
As part of the market operator function, PJM coordinates and directs the operation of the transmission grid and plans transmission expansion improvements to maintain grid reliability in this region.

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



In the first nine months of 2014, PJM had total billings of $40.76 billion, up from $25.16 billion in the first nine months of 2013 (Figure 1-2).[7] The highest total annual billing to date was in 2011, when PJM had gross billings of $35.89 billion. The increase in billings in 2014 resulted from high demand and high prices as a result of the extreme cold weather early in the year. In the second and third quarters of 2014, billings returned to prior levels.

Figure 1-2 PJM reported monthly billings ($ Billions): January 2008 through September 2014



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

7 Monthly billing values are provided by PJM.

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.[8,9]

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 nine months of 2014, 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, the market structure is evaluated as competitive or not competitive, and participant behavior is evaluated as competitive or not competitive. Most important, the outcome of each market, market performance, is evaluated as competitive or not competitive.

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

Market structure refers to the ownership structure of the market. The three pivotal supplier (TPS) test is the most relevant measure of market structure because it accounts for both the ownership of assets and the relationship between the pattern of ownership among multiple entities and the market demand 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 referred to 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 outcomes, 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.

8 See also the *2013 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."

9 Analysis of 2014 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 *2013 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

The MMU concludes for the first nine months of 2014:

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 nine months of 2014 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1154 with a minimum of 930 and a maximum of 1468 in the first nine months of 2014.
- 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, although the behavior of some participants during periods of high demand raises concerns about economic withholding.
- 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. The expanding role of UTCs in the Day-Ahead Energy Market continues to cause concerns. Issues related to the definition of gas costs includable in offers and the impact of the uncertainty around gas costs during high demand periods also need to be addressed.

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.[10] 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.[11] There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are extremely tight.

10 OATT Attachment M.

11 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.

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.[12]
- 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.[13]
- 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, the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the inclusion of imports which are not substitutes for internal capacity resources and inadequate performance incentives.

12 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.
13 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.

Table 1-4 The Regulation Market results were competitive

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

- 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 97 percent of the hours in the first nine months of 2014.
- Participant behavior in the Regulation Market was evaluated as competitive for the first nine months of 2014 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 competitive, after the introduction of the new market design, despite significant issues with the market design.
- Market design was evaluated as flawed. While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market results continue to include the incorrect definition of opportunity cost. Further, the market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement.

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	Mixed

- The Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration.
- 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 participant behavior with the market design results in competitive prices.
- Market design was evaluated as mixed. Market power mitigation rules result in competitive outcomes despite high levels of supplier concentration. However, Tier 1 reserves are inappropriately compensated when the non-synchronized reserve market clears with a non-zero price.

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, a significant proportion 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 ARR/FTR design including a wide range of options for market participants to acquire FTRs and a competitive auction mechanism, there are several problematic features of the ARR/FTR design which need to be addressed. The market design incorporates widespread cross subsidies which are not consistent with an efficient market design and the market design as implemented results in overselling FTRs. FTR funding levels are reduced as a result of these factors.

Role of MMU

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

Reporting

The MMU performs its reporting function primarily 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. 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 also issues reports on specific topics in depth. The MMU regularly issues reports on RPM auctions. In other ad hoc reports, the MMU responds to the needs of FERC, state regulators, or other authorities, in order to assist policy development, decision making in regulatory proceedings, and in support of investigations.

Monitoring

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

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

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

14 18 CFR § 35.28(g)(3)(ii); see also *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, FERC Stats. & Regs. ¶31,281 (2008) ("Order No. 719"), *order on reh'g*, Order No. 719-A, FERC Stats. & Regs. ¶31,292 (2009), *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).
15 OATT Attachment M § IV; 18 CFR § 1c.2.
16 OATT Attachment M § IV.
17 OATT Attachment M § IV.K.3.
18 OATT Attachment M § IV.H.
19 OATT Attachment M § II(d)&(q) ("FERC Market Rules" mean the market behavior rules and the prohibition against electric energy market manipulation codified by the Commission in its Rules and Regulations at 18 CFR §§ 1c.2 and 35.37, respectively; the Commission-approved PJM Market Rules and any related proscriptions or any successor rules that the Commission from time to time may issue, approve or otherwise establish… "PJM Market Rules" mean the rules, standards, procedures, and practices of the PJM Markets set forth in the PJM Tariff, the PJM Operating Agreement, the PJM Reliability Assurance Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Manuals, the PJM Regional Practices Document, the PJM-Midwest Independent Transmission System Operator Joint Operating Agreement or any other document setting forth market rules.")
20 The FERC defines manipulation as engaging "in any act, practice, or course of business that operates or would operate as a fraud or deceit upon any entity." 18 CFR § 1c.2(a)(3). Manipulation may involve behavior that is consistent with the letter of the rules, but violates their spirit. An example is market behavior that is economically meaningless, such as equal and opposite transactions, which may entitle the transacting party to a benefit associated with volume. Unlike market power or rule violations, manipulation must be intentional. The MMU must build its case, including an inference of intent, on the basis of market data.
21 OATT Attachment M § II(h-1).
22 OATT Attachment M § IV.C.
23 OATT Attachment M § IV.I.1.
24 *Id.*
25 *Id.*

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

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

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

The MMU reviews offers and inputs in order to evaluate whether those offers raise market power concerns.[32] 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.[33] 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.

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.[34] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[35] 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.[36] 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.[37] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[38]

New 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,"[39] 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 *2014 Quarterly State of the Market Report for PJM: January through September*, the MMU is making four new recommendations for the third quarter of 2014.

26 See OATT Attachment M–Appendix § II.A.
27 OATT Attachment M–Appendix § II.E.
28 OATT Attachment M–Appendix § II.B.
29 OATT Attachment M–Appendix § II.C.
30 OATT Attachment M–Appendix § IV.
31 OATT Attachment M–Appendix § VII.
32 OATT Attachment M § IV.
33 OATT § 12A.
34 OATT Attachment M § IV.D.
35 *Id.*
36 *Id.*
37 *Id.*
38 OATT Attachment M § VI.A.
39 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

From Section 9, Interchange Transactions

- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. New recommendation.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1200 day-prior to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be utilized to meet load in the most economic manner. (Priority: Medium. New recommendation.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized joint dispatch approach that treats seams between balancing authorizes as a constraint, similar to any other constraint within an LMP market. (Priority: Medium. New recommendation.)

From Section 10, Ancillary Services

- The MMU recommends that the amount of tier 1 MW paid when the non-synchronized reserve market clearing price (NSRMCP) goes above $0 be equal to the tier 1 MW estimated by the RT-SCED market solution, to the extent that PJM continues to pay tier 1 synchronized reserve the SRMCP when the non-synchronized reserve market clearing price is above $0 (e.g. the MMU recommendation to eliminate these payments is not implemented). (Priority: High. New recommendation.)

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 1-8 provides the average price and total revenues paid, by component, for the first nine months of 2013 and the first nine months of 2014.

Table 1-8 shows that Energy, Capacity and Transmission Service Charges are the three largest components of the total price per MWh of wholesale power, comprising 95.1 percent of the total price per MWh in the first nine months of 2014.

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.[40]
- The Energy Uplift (Operating Reserves) component is the average price per MWh of day-ahead, balancing and synchronous condensing charges.[41]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[42]

40 OATT §§ 13.7, 14.5, 27A & 34.
41 OA Schedules 1 §§ 3.2.3 & 3.3.3.
42 OATT Schedule 2 and OA Schedule 1 § 3.2.3B. The line item in Table 1-9 includes all reactive services charges.

- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[43]
- 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.[44]
- The Capacity (FRR) component is the average cost per MWh under the Fixed Resource Requirement (FRR) Alternative for an eligible LSE to satisfy its Unforced Capacity obligation.[45]
- The Emergency Load Response component is the average cost per MWh of the PJM Emergency Load Response Program.[46]
- 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.[47]
- 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.[48]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[49]
- The Black Start component is the average cost per MWh of black start service.[50]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[51]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[52]
- The Economic Load Response component is the average cost per MWh of day ahead and real time economic load response program charges to LSEs.[53]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[54]
- The Non-Synchronized Reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[55]
- The Emergency Energy component is the average cost per MWh of emergency energy.[56]

43 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
44 OATT Schedule 12.
45 Reliability Assurance Agreement Schedule 8.1.
46 OATT PJM Emergency Load Response Program.
47 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.
48 OATT Schedule 1A.
49 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
50 OATT Schedule 6A. The line item in Table 1-9 includes all Energy Uplift (Operating Reserves) charges for Black Start.
51 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
52 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
53 OA Schedule 1 § 3.6.
54 OA Schedule 1 § 5.3b.
55 OA Schedule 1 § 3.2.3A.001.
56 OA Schedule 1 §3.2.6.

Table 1-8 Total price per MWh by category: January through September, 2013 and 2014

Category	Jan-Sep 2013 $/MWh	Jan-Sep 2014 $/MWh	Percent Change Totals	Jan-Sep 2013 Percent of Total	Jan-Sep 2014 Percent of Total
Load Weighted Energy	$39.75	$58.60	47.4%	73.1%	76.9%
Capacity	$6.56	$8.76	33.4%	12.1%	11.5%
Transmission Service Charges	$5.09	$5.13	0.8%	9.4%	6.7%
Energy Uplift (Operating Reserves)	$0.66	$1.43	115.1%	1.2%	1.9%
Transmission Enhancement Cost Recovery	$0.39	$0.41	4.6%	0.7%	0.5%
PJM Administrative Fees	$0.43	$0.40	(7.1%)	0.8%	0.5%
Reactive	$0.69	$0.36	(47.6%)	1.3%	0.5%
Regulation	$0.27	$0.34	27.3%	0.5%	0.5%
Synchronized Reserves	$0.04	$0.25	509.2%	0.1%	0.3%
Capacity (FRR)	$0.12	$0.14	13.8%	0.2%	0.2%
Transmission Owner (Schedule 1A)	$0.08	$0.08	(4.1%)	0.1%	0.1%
Emergency Load Response	$0.00	$0.07	NA	0.0%	0.1%
Black Start	$0.14	$0.06	(55.8%)	0.3%	0.1%
Day Ahead Scheduling Reserve (DASR)	$0.08	$0.06	(20.1%)	0.1%	0.1%
Emergency Energy	$0.00	$0.05	NA	0.0%	0.1%
Load Response	$0.01	$0.02	79.2%	0.0%	0.0%
NERC/RFC	$0.02	$0.02	(5.5%)	0.0%	0.0%
Non-Synchronized Reserves	$0.00	$0.02	703.8%	0.0%	0.0%
RTO Startup and Expansion	$0.01	$0.01	(19.9%)	0.0%	0.0%
Transmission Facility Charges	$0.00	$0.00	(23.0%)	0.0%	0.0%
Total	$54.36	$76.21	40.2%	100.0%	100.0%

Section Overviews

Overview: Section 3, "Energy Market"

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. Average offered real-time generation decreased by 4,934 MW, or 2.8 percent, from 175,960 MW in the first nine months of 2013 to 171,026 MW in the first nine months of 2014.[57] In the first nine months of 2014, 2,515 MW of new capacity were added to PJM. This new generation was more than offset by the deactivation of 12 units (1,526 MW) since January 1, 2014.

PJM average real-time generation in the first nine months of 2014 increased by 2.2 percent from the first nine months of 2013, from 90,432 MW to 92,449 MW. The PJM average real-time generation in the first nine months of 2014 would have increased by 1.4 percent from the first nine months of 2013, from 90,432 MW to 91,701 MW, if the EKPC Transmission Zone had not been included.[58]

PJM average day-ahead supply in the first nine months of 2014, including INCs and up-to congestion transactions, increased by 8.5 percent from the first nine months of 2013, from 148,489 MW to 161,137 MW. The PJM average day-ahead supply, including INCs and up-to congestion transactions, would have increased by 7.8 percent from the first nine months of 2013, from 148,489 MW to 160,078 MW, if the EKPC Transmission Zone had not been included. The day-ahead supply growth was 286.4 percent higher than the real-time generation growth as a result of the continued growth, until September 8, 2014, of up-to congestion transactions.

- **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.

- **Generation Fuel Mix.** During the first nine months of 2014, coal units provided 44.4 percent, nuclear units 33.7 percent and gas units 17.1 percent of total generation. Compared to the first nine months of 2013, generation from coal units increased 2.3 percent, generation from gas units increased 6.0 percent and generation from nuclear units remained the same.

- **Marginal Resources.** In the PJM Real-Time Energy Market, during the first nine months of 2014, coal units were 49.8 percent of marginal resources and natural gas units were 42.4 percent of marginal resources. In the first

57 Calculated values shown in Section 3, "Energy Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

58 The EKPC Zone was integrated on June 1, 2013.

nine months of 2013, coal units were 57.6 percent and natural gas units were 34.1 percent of the marginal resources.

In the PJM Day-Ahead Energy Market, during the first nine months of 2014, up-to congestion transactions were 93.6 percent of marginal resources, INCs were 1.6 percent of marginal resources, DECs were 2.2 percent of marginal resources, and generation resources were 2.5 percent of marginal resources in the first nine months of 2014.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM system peak load during the first nine months of 2014 was 141,673 MW in the HE 1700 on June 17, 2014, which was 15,835 MW, or 10.1 percent, lower than the PJM peak load for the first nine months of 2013, which was 157,508 MW in the HE 1700 on July 18, 2013.

  PJM average real-time load in the first nine months of 2014 increased by 1.6 percent from the first nine months of 2013, from 89,123 MW to 90,567 MW. The PJM average real-time load in the first nine months of 2014 would have increased by 0.7 percent from the first nine months of 2013, from 89,123 MW to 89,707 MW, if the EKPC Transmission Zone had not been included.

  PJM average day-ahead demand in the first nine months of 2014, including DECs and up-to congestion transactions, increased by 7.9 percent from the first nine months of 2013, from 145,139 MW to 156,542 MW. The PJM average day-ahead demand, including DECs and up-to congestion transactions, would have increased by 7.1 percent from the first nine months of 2013, from 145,139 MW to 155,420 MW, if the EKPC Transmission Zone had not been included. The day-ahead demand growth was 393.8 percent higher than the real-time load growth as a result of the continued growth, until September 8, 2014, of up-to congestion transactions.

- **Supply and Demand: 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. For the first nine months of 2014, 10.2 percent of real-time load was supplied by bilateral contracts, 27.4 percent by spot market purchases and 62.5 percent by self-supply. Compared with 2013, reliance on bilateral contracts decreased 0.4 percentage points, reliance on spot market purchases increased by 2.4 percentage points and reliance on self-supply decreased by 1.9 percentage points.

- **Supply and Demand: Scarcity.** In the first nine months of 2014, shortage pricing was triggered on two days in PJM. On January 6, shortage pricing was triggered by a voltage reduction action that was issued at 1950 EPT and terminated at 2045. On January 7, shortage pricing was triggered by shortage of primary and synchronized reserves starting in the hour beginning 0700 EPT and was in effect until 1220 during the morning peak as well as between 1755 and 1810 during the evening peak.

Market Behavior

- **Offer Capping for Local Market Power.** 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 Day-Ahead Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours remained at 0.2 percent in the first nine months of 2013 and 2014. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.4 percent in the first nine months of 2013 to 0.5 percent in the first nine months of 2014.

  In the first nine months of 2014, 13 control zones experienced congestion resulting from one or more constraints binding for 75 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.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 3.0 percent in the first nine months of 2013 to 0.3 percent in the first nine months of 2014. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 2.5 percent in the first nine months of 2013 to 0.3 percent in the first nine months of 2014.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the PJM Real-Time Energy Market in the first nine months of 2014, 73.9 percent of marginal units had an average markup index less than or equal to 0.0. Nonetheless, some marginal units do have substantial markups. In the first nine months of 2014, 9.0 percent of units had average dollar markups greater than or equal to $150. Only 4.5 percent of units had average dollar markups greater than or equal to $150 in the first nine months of 2013. Markups increased during the high demand days in January.

  In the PJM Day-Ahead Energy Market in the first nine months of 2014, 94.8 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.02. Nonetheless, some marginal units do have substantial markups.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 104 units eligible for FMU or AU status in at least one month during the first nine months of 2014, 46 units (44.2 percent) were FMUs or AUs for all nine months, and 16 units (15.4 percent) qualified in only one month.

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up-to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. While up-to congestion transactions (UTC) continued to displace increment offers and decrement bids, there was a sharp decrease in UTCs in September as a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[59]

- **Generator Offers.** Generator offers are categorized as dispatchable and self scheduled. Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are categorized as self scheduled must run. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are categorized as self scheduled and dispatchable. Of all generator offers in the first nine months of 2014, 55.9 percent were offered as available for economic dispatch, 22.8 percent were offered as self scheduled, and 21.3 percent were offered as self scheduled and dispatchable.

Market Performance

- **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 Market prices in the first nine months of 2014 were between $800 and $900 for 4 hours, between $900 and $1,000 for one hour, greater than $1,000 for six hours, and greater than $1,800 for one hour.

  PJM Real-Time Energy Market prices increased in the first nine months of 2014 compared to the first nine months of 2013. The load-weighted average LMP was 47.4 percent higher in the first nine months of 2014 than in the first nine months of 2013, $58.60 per MWh versus $39.75 per MWh.

  PJM Day-Ahead Energy Market prices increased in the first nine months of 2014 compared to the first nine months of 2013. The load-weighted average LMP was 49.6 percent higher in the first nine months of 2014 than in the first nine months of 2013, $59.09 per MWh versus $39.49 per MWh.[60]

- **Components of LMP.** LMPs result from the operation of a market based on security-constrained, economic (least-cost) dispatch in which marginal units determine system LMPs, based on their offers. Those offers can

59 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

60 Tables reporting zonal and jurisdictional load and prices are in the *2013 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

be decomposed into fuel costs, emission costs, variable operation and maintenance costs, markup, FMU adder and the 10 percent cost adder and it is possible to decompose PJM system's load-weighted LMP by the components of unit offers.

In the PJM Real-Time Energy Market, for the first nine months of 2014, 29.8 percent of the load-weighted LMP was the result of coal costs, 36.9 percent was the result of gas costs and 0.65 percent was the result of the cost of emission allowances.

In the PJM Day-Ahead Energy Market, for the first nine months of 2014, 23.3 percent of the load-weighted LMP was the result of the cost of gas, 18.5 percent was the result of the cost of coal, 13.6 percent was the result of the cost of up-to congestion transactions and 15.8 percent was the result of the cost of DEC.

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

  In the PJM Real-Time Energy Market for the first nine months of 2014, the adjusted markup component of LMP was positive, $3.65 per MWh or 6.2 percent of the PJM real-time, load-weighted average LMP. The real-time load-weighted average LMP for the month of March had the highest markup component, $12.33 per MWh using adjusted cost offers, or 16.25 percent of the real-time load-weighted average LMP in March, a substantial increase over 2013. For the first nine months of 2013, the adjusted markup was $0.85 per MWh or 2.1 percent of the PJM real-time load-weighted average LMP.

  In the PJM Day-Ahead Energy Market, marginal INC, DEC and transactions have zero markups. In the first nine months of 2014, the adjusted markup component of LMP resulting from generation resources was -$0.93 per MWh.

  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, although the behavior of some participants during the high demand periods in January raises concerns about economic withholding.

- **Price Convergence.** Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. The difference between the average day-ahead and real-time prices was -$0.20 per MWh in the first nine months of 2013 and -$1.04 per MWh in the first nine months of 2014. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

- In the first nine months of 2014, shortage pricing was triggered on two days in January. On January 6, shortage pricing was triggered by a voltage reduction action that was issued at 1950 EPT and terminated at 2045. On January 7, shortage pricing was triggered by a shortage of primary and synchronized reserves starting in the hour beginning 0700 EPT and was in effect until 1220 during the morning peak as well as between 1755 and 1810 during the evening peak.
- The performance of the PJM markets under scarcity conditions raised a number of concerns including concerns related to capacity market incentives, participant offer behavior under tight market conditions, natural gas availability and pricing, demand response and interchange transactions.

Section 3 Recommendations

- The MMU has recommended the elimination of FMU and AU adders. Since the implementation of FMU adders, 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. (Priority: Medium. First reported 2012.)

The MMU and PJM proposed, and on October 31, 2014, the Commission approved, a compromise that maintained the ability of certain generating units to qualify for FMU adders but limiting FMU adders to units with net revenues less than unit going forward costs or ACR.[61]

The MMU considers this recommendation accepted and will review the results of the Commission order on FMU status for at least 12 months prior to considering any additional recommendation related to FMUs.

- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules. (Priority: Low. First reported Q2, 2014.)
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[62] (Priority: Medium. First reported 2012.)
- The MMU recommends that PJM not use the ATSI closed loop interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013.)

61 149 FERC ¶ 61,091 (2014).
62 PJM OATT, 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.

- The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule physical power. (Priority: Low. First reported 2013.)
- There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[63] The MMU recommends that PJM include in the appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[64] (Priority: Low. First reported 2013.)
- 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. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013.)
- The LMPs in excess of $1,800 per MWh on January 7, 2014, were potentially a result of the way in which PJM modeled zonal (not nodal) demand response as a marginal resource. The MMU recommends that PJM explain how LMPs are calculated when demand response is marginal. (Priority: Low. First reported Q1, 2014.)

63 The general definition of a hub can be found in "Manual 35: Definitions and Acronyms," Revision 23 (April 11, 2014).
64 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.

- The MMU recommends that PJM create and implement clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. (Priority: Medium. First reported Q1, 2014.)

Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first nine months of 2014, including aggregate supply and demand, concentration ratios, three pivotal supplier test results, offer capping, participation in demand response programs, loads and prices.

Average real-time offered generation decreased by 4,934 MW in the first nine months of 2014 compared to the first nine months of 2013, while peak load decreased by 15,835 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 the impact of the price elasticity of demand on prices. Energy market results for the first nine months of 2014 generally reflected supply-demand fundamentals, although the behavior of some participants during the high demand periods in January raises concerns about economic withholding. These issues relate to the ability to increase markups substantially in tight market conditions, to the uncertainties about the pricing and availability of natural gas, and to the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel and operate rather than take an outage.

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

PJM also offer caps units that are committed for reliability reasons in addition to units committed to provide constraint relief. Specifically, units that are committed to provide reactive support and black start service are offer capped in the energy market. These units are committed manually in both the Day-Ahead and Real-Time Energy Markets. Before 2011, these units were generally economic in the energy market. Since 2011, the percentage of hours when these units were not economic in the Real-Time Energy Market has steadily increased. In the Day-Ahead Energy Market, PJM started to commit these units

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

as offer capped in September 2012, as part of a broader effort to maintain consistency between Real-Time and Day-Ahead Energy Markets.

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 scarcity pricing rules in 2012. There are significant issues with the scarcity pricing net revenue true up mechanism in the PJM scarcity pricing design, which will create issues when scarcity pricing occurs.

The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case during the high demand hours in January. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods in January raises concerns about economic withholding. Given the structure of the Energy Market, the tighter markets and the change in some participants' behavior are sources of concern in the Energy Market. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2014.

Overview: Section 4, "Energy Uplift"

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges increased by $258.8 million or 40.2 percent in the first nine months of 2014 compared to the first nine months of 2013, from $644.2 million to $902.9 million. The increase of $258.8 million in the first nine months of 2014 is comprised of an increase of $12.9 million in day-ahead operating reserve charges, an increase of $444.6 million in balancing operating reserve charges, a decrease of $156.1 million in reactive services charges, a decrease of $0.3 million in synchronous condensing charges and a decrease of $42.3 million in black start services charges.
- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.139 per MWh. The balancing operating reserve reliability rates averaged $0.702, $0.023 and $0.010 per MWh for the RTO, Eastern and Western regions. The balancing operating reserve deviation rates averaged $1.491, $0.425 and $0.159 per MWh for the RTO, Eastern and Western regions. The lost opportunity cost rate averaged $1.481 per MWh and the canceled resources rate averaged $0.013 per MWh.
- **Reactive Services Rates.** The DPL, ATSI and PENELEC control zones had the three highest reactive local voltage support rates: $0.499, $0.229 and $0.210 per MWh. The reactive transfer interface support rate averaged $0.001 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 38.8 percent of all day-ahead generator credits and 56.6 percent of all balancing generator credits. Combustion turbines and diesels received 68.2 percent of the lost opportunity cost credits. Coal units received 83.8 percent of all reactive services credits.

- **Concentration of Energy Uplift Credits:** The top 10 units receiving energy uplift credits received 35.5 percent of all credits. The top 10 organizations received 81.8 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 4622, balancing operating reserves HHI was 2959, lost opportunity cost HHI was 3838 and reactive services HHI was 6964.
- **Economic and Noneconomic Generation.** In the first nine months of 2014, 87.5 percent of the day-ahead generation eligible for operating reserve credits was economic and 72.7 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability:** In the first nine months of 2014, 4.3 percent of the total day-ahead generation was scheduled as must run by PJM, of which 32.2 percent received energy uplift payments.

Geography of Charges and Credits

- In the first nine months of 2014, 90.7 percent of all charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones or buses within a control zone, demand and generators, 2.1 percent by transactions at hubs and aggregates and 7.2 percent by transactions at interfaces.

Energy Uplift Issues

- **Lost Opportunity Cost Credits:** In the first nine months of 2014, lost opportunity cost credits increased by $62.9 million compared to the first nine months of 2013. In the first nine months of 2014, resources in the top three control zones receiving lost opportunity cost credits, AEP, Dominion and PENELEC accounted for 56.5 percent of all lost opportunity cost credits, 44.1 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 51.7 percent of all day-ahead generation not committed in real time by PJM from those unit types and 61.2 percent of all day-ahead generation not committed in real time by PJM and receiving lost opportunity cost credits from those unit types.
- **Black Start Service Units:** Certain units located in the AEP Control Zone are relied on for their black start capability on a regular basis during periods when the units are not economic. These black start units provide black start service under the ALR option, which means that the units must be running in order to provide black start services even if the units are not economic. In the first nine months of 2014, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $26.4 million.
- **Con Edison – PJM Transmission Service Agreements Support:** Certain units located near the boundary between New Jersey and New York City have been operated to support the transmission service agreements between Con Ed and PJM, formerly known as the Con Ed – PSEG Wheeling Contracts. These units are often run out of merit and received substantial balancing operating reserves credits.

Energy Uplift Recommendations

- **Impact of Quantifiable Recommendations:** The impact of implementing the recommendations related to energy uplift proposed by the MMU on the rates paid by participants would be significant. For example, in the first nine months of 2014, the average rate paid by a DEC in the Eastern Region would have been $0.324 per MWh, which is $2.632 per MWh less than the actual average rate paid.

Section 4 Recommendations

- The MMU recommends that PJM clearly identify, classify all reasons for incurring operating reserves in the Day-Ahead and the Real-Time Energy Markets and the associated operating reserve charges in order for all market participants be aware of the reason of these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves. (Priority: Medium. First reported 2012.)
- The MMU recommends that PJM be transparent in the formulation of closed loop interfaces with adjustable limits and develop rules to reduce

the levels of subjectivity around the creation and implementation of these interfaces. (Priority: Medium. First reported 2013.)

- The MMU recommends that PJM estimate the impact such interfaces could have on additional uplift payments inside closed loops, transmission planning, offer capping, FTR and ARR revenue, ancillary services markets and the capacity market to avoid unintended consequences. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of operating reserve charges by unit and the detailed reasons for the level of operating reserve payments by unit in the PJM region. (Priority: High. First reported 2013.)
- The MMU recommends the elimination of the day-ahead operating reserve category to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2013.)
- The MMU recommends not compensating self-scheduled units for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours. (Priority: Low. First reported 2013.)
- 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. (Priority: High. First reported 2012.)
  - 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 committed in real time. (Priority: Medium. First reported 2012.)
  - 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 committed in real time. (Priority: Medium. First reported 2012.)
  - The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost. (Priority: Medium. First reported 2012.)
- The MMU recommends that up-to congestion transactions be required to pay operating reserve charges. (Priority: High. First reported 2013.)
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. (Priority: High. First reported 2013.)
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements. (Priority: Medium. First reported 2013.)
- 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 the operating reserve credits calculation. (Priority: Medium. First reported 2012.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above which is currently allocated to real-time RTO load. (Priority: Low. First reported Q2, 2014.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves and the timing of commitment decisions. (Priority: High. First reported Q1, 2014.).

Section 4 Conclusion

Energy uplift is 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. Referred to in PJM as day-ahead operating reserves, balancing operating reserves, energy lost opportunity cost credits, reactive services credits, synchronous condensing credits or black start services credits, 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, reactive services charges, synchronous condensing charges or black start charges.

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

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 energy uplift payments. When units receive substantial revenues through energy uplift payments, these payments are not transparent to the market because of the current confidentiality rules. As a result other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations has persisted for more than ten years.

The level of energy uplift 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. Energy uplift payments 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. The balance of these costs not covered by energy revenues are collected as energy uplift rather than reflected in price as a result of the rules governing the determination of LMP.

PJM has recognized the importance of addressing the issues that result in large amounts of energy uplift charges. In 2013, PJM stakeholders created the Energy Market Uplift Senior Task Force (EMUSTF).[66] The main goals of the EMUSTF are to evaluate the causes of energy uplift payments, develop ways to minimize energy uplift payments while maintaining prices that are consistent with operational reliability needs, and explore the allocation of such payments. In December 2013, PJM stakeholders created the Market Implementation Committee – Energy/Reserve Pricing and Interchange Volatility group to address issues such as improving the incorporation of operators' actions in LMP.[67]

The MMU recommended and supports PJM in the reexamination of the allocation of uplift charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges. For example, up-to congestion transactions continue to pay no energy uplift charges, which means that all others who pay these charges are paying too much. In addition, the netting of transactions against internal bilateral transactions should be eliminated.

- PJM's goal should be to minimize the total level of energy uplift 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 energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets

66 See "Problem Statement – Energy Market Uplift Costs," Energy Market Uplift Senior Task Force (July 30, 2013) <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20130730/20130730-problem-statement-energy-market-uplift-costs.ashx>.

67 See "Problem Statement – Energy/Reserve Pricing and Interchange Volatility," Market Implementation Committee (December 11, 2013) <http://www.pjm.com/~/media/committees-groups/committees/mic/20131212/20131212-item-01b-energy-reserve-problem-statement-updated.ashx>.

Overview: Section 5, "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.[68]

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.[69] 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.[70] 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.[71]

RPM prices are locational and may vary depending on transmission constraints.[72] 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, although the performance incentives are inadequate. 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 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 first nine months of 2014, PJM installed capacity increased 1,304.8 MW or 0.7 percent from 183,095.2 MW on January 1 to 184,400.0 MW on September 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 September 30, 2014, 40.5 percent was coal; 30.1 percent was gas; 17.8 percent was nuclear; 5.9 percent was oil; 4.8 percent was hydroelectric; 0.4 percent was wind; 0.4 percent was solid waste; and 0.1 percent was solar.
- **Market Concentration.** In the 2015/2016 RPM Second Incremental Auction and 2016/2017 RPM First Incremental Auction, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[73] 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.[74,75,76]

68 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2014 Quarterly State of the Market Report for PJM: January through September*, Section 5, "Capacity Market," and include all capacity within the PJM footprint.
69 See 126 FERC ¶ 61,275 (2009) at P 86.
70 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
71 See 126 FERC ¶ 61,275 (2009) at P 88.
72 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.
73 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given Delivery Year using the rules defined in OATT Attachment DD (Reliability Pricing Model) § 5.10(a)(ii).
74 See OATT Attachment DD § 6.5.
75 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.
76 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).

- **Imports and Exports.** Of the 324.0 MW of imports offered in the 2015/2016 RPM Second Incremental Auction, 324.0 MW cleared. Of the cleared imports, 323.8 MW (99.9 percent) were from MISO. Of the 210.8 MW of imports in the 2016/2017 RPM First Incremental Auction, 199.8 MW cleared. Of the cleared imports, none were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 9,493.6 MW for June 1, 2014 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2014/2015 Delivery Year (16,020.7 MW) less replacement capacity (6,527.1 MW).

Market Conduct

- **2015/2016 RPM Second Incremental Auction.** Of the 80 generation resources which submitted offers, unit-specific offer caps were calculated for 16 generation resources (20.0 percent). The MMU calculated offer caps for 25 generation resources (31.3 percent), of which nine were based on the technology specific default (proxy) ACR values.
- **2016/2017 RPM First Incremental Auction.** Of the 115 generation resources which submitted offers, unit-specific offer caps were calculated for 37 generation resources (32.2 percent). The MMU calculated offer caps for 62 generation resources (53.9 percent), of which 25 were based on the technology specific default (proxy) ACR values.

Market Performance

- The 2015/2016 RPM Second Incremental Auction and 2016/2017 RPM First Incremental Auction were conducted in the third quarter of 2014. In the 2015/2016 RPM Second Incremental Auction, the RTO clearing price for Annual Resources was $136.00 per MW-day. The weighted average capacity price for the 2015/2016 Delivery Year is $159.99 per MW-day, including all RPM Auctions for the 2015/2016 Delivery Year held through the first nine months of 2014. In the 2016/2017 RPM First Incremental Auction, the RTO clearing price for Annual Resources was $60.00 per MW-day. The weighted average capacity price for the 2016/2017 Delivery Year is $89.46, including all RPM Auctions for the 2016/2017 Delivery Year held through the first nine months of 2014.
- The Delivery Year weighted average capacity price was $116.55 per MW-day in 2013/2014 and $126.40 per MW-day in 2014/2015.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for the first nine months of 2014 was 9.7 percent, an increase from 8.2 percent for the first nine months of 2013.[77]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for the first nine months of 2014 was 83.1 percent, a decrease from 84.1 percent for the first nine months of 2013.
- **Outages Deemed Outside Management Control (OMC).** In the first nine months of 2014, 7.0 percent of forced outages were classified as OMC outages, and 5.3 percent of OMC outages were due to lack of fuel. 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 5 Recommendations[78]

The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant Delivery Year. The requirement to be a physical resource should be applied to all resource types,

77 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 capacity resources in RPM. Data is for the nine months ending September 30, 2014, as downloaded from the PJM GADS database on October 27, 2014. 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.

78 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.

including planned generation, demand resources and imports.[79] [80] (Priority: High. First reported 2013.)

- The MMU recommends that the definition of demand side resources be modified in order to ensure that such resources be fully substitutable for other generation capacity resources. Both the Limited and the Extended Summer DR products should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as generation capacity resources. (Priority: High. First reported 2013.)
- The MMU recommends that the use of the 2.5 percent demand adjustment (Short Term Resource Procurement Target) be terminated immediately. The 2.5 percent should be added back to the overall market demand curve. (Priority: Medium. First reported 2013.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013.)
- The MMU recommends that there be an explicit requirement that Capacity Resource offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013.)
- The MMU recommends that clear, explicit operational protocols be defined for recalling the energy output of Capacity Resources when PJM is in an emergency condition. PJM has modified these protocols, but they need additional clarification and operational details. (Priority: Low. First reported 2013.)
- The MMU recommends improvements to the performance incentive requirements of RPM:
  - The MMU recommends that Generation Capacity Resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. One hundred percent of capacity market revenue should be at risk rather than only fifty percent. (Priority: High. First reported 2013.)
  - The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage. (Priority: Medium. First reported 2013.)
  - 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. (Priority: Medium. First reported 2013.)
  - The MMU recommends that PJM eliminate the broad exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.[81] (Priority: Medium. First reported 2013.)

Section 5 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 nine months of 2014. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive in the first nine months of 2014.[82]

79 See also Comments of the Independent Market Monitor for PJM. Docket No. ER14-503-000 (December 20, 2013).
80 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013," <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf> (September 13, 2013).
81 For more on this issue and related incentive issues, see the MMU'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).
82 For more complete conclusions, see *2013 State of the Market Report for PJM*, Section 4, "Capacity Market."

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[83,84,85,86,87] In 2013 and 2014, the MMU prepared a number of RPM-related reports and testimony, shown in Table 5-2.

As an example of such reports, the MMU prepared a report that addresses and quantifies the impact on market outcomes in the Base Residual Auction (BRA) for the 2017/2018 Delivery Year of the Short-Term Resource Procurement Target (2.5 percent offset) and demand side resources both separately and together. (Demand side resources include Demand Resources, DR, and Energy Efficiency resources, EE.) The report demonstrates that the limited DR product and the 2.5 percent offset significantly suppress prices.[88]

The MMU continues to recommend that the use of the 2.5 percent demand adjustment be terminated immediately.[89] The 2.5 percent demand reduction is a barrier to entry in the capacity market. The logic of reducing demand in a market design that looks three years forward, to permit other resources to clear in Incremental Auctions, is not supportable and has no basis in economics. There are tradeoffs in using a one year forward or a three year forward design, but the design should be implemented on a consistent basis. Removing a portion of demand affects prices at the margin, which is where the critical signal to the market is determined.

The results of the report show that even when all DR is removed and the 2.5 percent offset is eliminated and holding everything else constant, prices would have risen to greater than net CONE but less than the maximum price and PJM's reliability target would have been maintained. This a measure of the impact of the removal of DR and the 2.5 percent offset and is also a measure of the price suppression effect of DR and the 2.5 percent offset.

The fact that this set of sensitivity analyses holds everything else constant is important for considering the actual impacts of the simultaneous elimination of DR and the 2.5 percent offset. The results of these sensitivity analyses are worst case, in the sense that the increases in prices and reductions in quantities cleared are the maximum levels, because they do not include any market response which would mitigate the impact on prices and cleared quantities of eliminating DR. If both these adjustments had been made prior to the 2017/2018 BRA, it is likely that additional generation resources would have entered the market, that prices would likely have been lower than the prices in these sensitivity analyses and that reliability would have been greater than in these sensitivity analyses.

Overview: Section 6, "Demand Response"

- **Demand Response Jurisdiction.** In a panel decision issued May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit vacated in its entirety Order No. 745, which provided for payment of demand-side resources at full LMP.[90] The decision calls into question the jurisdictional foundation for all demand response programs currently subject to FERC oversight, and, in particular, for those programs that involve FERC regulated payments to demand resources. A motion for stay was granted until at least December 16, 2014, by the United States Court of Appeals. The FERC is now deciding whether to petition the Supreme Court for review. If a petition is filed, the stay will remain in effect until the Supreme Court's final disposition. FirstEnergy filed an amended complaint on September 22, 2014, that seeks to extend *EPSA v. FERC* to the PJM capacity markets, and would, if granted, eliminate tariff provisions that provide for the compensation of Demand Resources as a form of supply effective May 23, 2014, and require a rerun of the 2017/2018 Base Residual Auction.[91]

83 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).
84 See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).
85 See "Analysis of the 2015/2016 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2013/Analysis_of_2015_2016_RPM_Base_Residual_Auction_20130924.pdf> (September 24, 2013).
86 See "Analysis of the 2016/2017 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_20162017_RPM_Base_Residual_Auction_20140418.pdf> (April 18, 2014).
87 See "Analysis of the 2017/2018 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_2017_2018_RPM_Base_Residual_Auction_20141006.pdf> (October 6, 2014).
88 See "The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses Revised," <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_20172018_RPM_BRA_Sensitivity_Analyses_Revised_20140826.pdf> (August 26, 2014).
89 See also the *Protest of the Independent Market Monitor for PJM*, Docket No. ER12-513 (December 22, 2011).
90 Electric Power Supply Association v. FERC, No. 11-1486, *petition for en banc review denied*; *see Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶ 31,322 (2011); *order on reh'g*, Order No. 745-A, 137 FERC ¶ 61,215 (2011); *order on reh'g*, Order No. 745-B, 138 FERC 61,148 (2012).
91 See FirstEnergy Service Company complaint, FERC Docket No. EL14-55-000, amending the complaint filed May 23, 2014.

- **Demand Response Activity.** Demand response is split into two main categories; economic and emergency. The emergency program revenue consists of both capacity and energy revenue. The capacity market is still the primary source of revenue to participants in PJM demand response programs. In the first nine months of 2014, capacity market revenue increased by $162.7 million, or 54.7 percent, from $297.4 million in the first nine months of 2013 to $460.1 million in the first nine months of 2014.[92] Emergency energy revenue increased by $6.2 million, from $36.7 million in the first nine months of 2013 to $43.0 million compared to the first nine months of 2014. The economic program only consists of energy revenue. Economic program credits increased by $7.9 million, from $7.4 million in the first nine months of 2013 to $16.3 million in the first nine months of 2014, a 121 percent increase.[93] Due to the cold winter, economic DR credits increased 1,075 percent in the first three months of 2014. In contrast, economic DR credits in the third quarter of 2014 decreased by 57.5 percent, from $4.8 million in the third quarter of 2013 to $2.0 million in the third quarter of 2014. Not all DR activities in the third quarter of 2014 have been reported to PJM at the time of this report.

  All demand response energy payments are uplift. LMP does not cover demand response energy payments. Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the real-time market. Economic demand response energy costs are assigned to real-time exports from the PJM Region and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than the price determined under the net benefits test for that month.[94]

- **Demand Response Market Concentration.** Economic demand response had high market concentration in the first nine months of 2013 and 2014. The HHI for economic demand response reductions decreased 472 points, from 8260 in the first nine months of 2013 to 7788 in the first nine months of 2014. Emergency demand response had moderate market concentration in the first nine months of 2014. The HHI for emergency demand response registrations increased 231 points, from 1529 in the first nine months of 2013 to 1760 in the first nine months of 2014. In the first nine months of 2014, the four largest companies contributed 65.3 percent of all registered emergency demand response resources.

- **Locational Dispatch of Demand Resources.** PJM dispatches demand resources on a zonal or subzonal basis, but subzonal dispatches are only on a voluntary basis during the 2013/2014 Delivery Year. Beginning with the 2014/2015 Delivery Year, demand resources are dispatchable for mandatory reduction on a subzonal basis, defined by zip codes. More locational dispatch of demand resources in a nodal market improves market efficiency. The goal should be nodal dispatch of demand resources.

- **Emergency Event Day Analysis.** PJM's calculations overstate participants' compliance during emergency load management events. In PJM's calculations, load increases are not netted against load decreases for dispatched demand resources across hours or across registrations within hours for compliance purposes, but are treated as zero. This skews the compliance results towards showing apparent higher compliance since poorly performing demand resources are not used in the compliance calculation. Considering all reported positive and negative values, the observed average load reduction of the eight events in the first nine months of 2014 should have been 2,198.6 MW, rather than the 2,840.9 MW calculated using PJM's method. The observed compliance is 29.2 percent rather than PJM's calculated 37.7 percent. This does not include locations that did not report their load during the emergency event days. All locations should be required to report their load.

Section 6 Recommendations

- The MMU recommends that there be only one demand response product, with an obligation to respond when called for all hours of the year, and that the demand response be on the demand side of the capacity market. (Priority: High. First reported 2013.)
- The MMU recommends that the emergency load response program be classified as an economic program, responding to economic price signals

92 The total credits and MWh numbers for demand resources were calculated as of October 15, 2014 and may change as a result of continued PJM billing updates.
93 Economic credits are synonymous with revenue received for reductions under the economic load response program.
94 PJM: "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), p 70.

and not an emergency program responding only after an emergency is called. (Priority: High. First reported 2012.)

- The MMU recommends that a daily must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[95] (Priority: High. First reported 2013.)
- The MMU recommends that demand response programs adopt an offer cap equal to the offer cap applicable to energy offers from generation capacity resources, currently $1,000 per MWh.[96] (Priority: High. First reported 2013.)
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. This recommendation has been adopted. (Priority: Medium. First reported 2013.)
- The MMU recommends that demand resources be required to provide their nodal location on the electricity grid. (Priority: High. First reported 2013.)
- The MMU recommends that measurement and verification methods for demand resources be further modified to more accurately reflect compliance. (Priority: Medium. First reported 2012.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[97] (Priority: Medium. First reported 2013.)
- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance. (Priority: Medium. First reported 2013.)
- The MMU recommends that demand resources whose load drop method is designated as "Other" explicitly record the method of load drop. (Priority: Low. First reported 2013.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately resemble the conditions of an emergency event. (Priority: Low. First reported 2013.)

Section 6 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.

With exception of large wholesale customers in some areas, most customers in PJM are not on retail rates that directly expose them to the wholesale price of energy or capacity. As a result, most customers in PJM do not have the direct ability to see, respond to or benefit from a response to price signals in PJM's markets. PJM's demand side programs are generally designed to allow customers (or their intermediaries in the form of load serving entities (LSEs) or curtailment service providers (CSPs)) to either directly, or through intermediaries, be paid as if they were directly paying the wholesale price of energy and capacity and avoiding those prices when reducing load. PJM's demand side programs are designed to provide direct incentives for load

95 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

96 *Id* at 1.

97 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed November 11, 2013) ISO-NE requires that DR have an interval meter with five minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

resources to respond, via load reductions, to wholesale market price signals and/or system emergency events.

If retail markets reflected hourly wholesale locational prices and customers or their intermediaries 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, as long as there are demand side programs, 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.

If demand resources are to continue competing directly with generation capacity resources in the PJM Capacity Market, the product must be defined such that it can actually serve as a substitute for generation. That is a prerequisite to a functional market design.

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources should be required to offer in the day ahead market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year and not be limited to a small number of hours.

In order to be a substitute for generation, demand resources should provide a nodal location and should be dispatched nodally to enhance the effectiveness of demand resources and to permit the efficient functioning of the energy market.

In order to be a substitute for generation, compliance by demand resources to PJM dispatch instructions should include both increases and decreases in load. The current method applied by PJM simply ignores increases in load and thus artificially overstates compliance.

As a preferred alternative, demand response would be on the demand side of the capacity market rather than on the supply side. Customers would avoid paying for capacity by interrupting designated load when PJM indicates that it is a critical hour. Customers would pay for actual load on the system during PJM-defined critical hours, e.g. maximum generation alerts, rather than relying on flawed measurement and verification methods. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these critical hours.

Overview: Section 7, "Net Revenue"

Net Revenue

- The net revenues reported are theoretical energy and ancillary net revenues and do not include capacity market revenues.
- Energy net revenues are affected by fuel prices and energy prices. Natural gas prices and energy prices were significantly higher in the first three months of 2014 than in the first three months of 2013, resulting in large increases in net revenues in the first three months of 2014. Eastern natural gas prices were 160.3 percent higher and Western natural gas prices were 81.1 percent higher in the first quarter of 2014 compared to the first quarter of 2013. Energy prices were 131.6 percent higher in the first quarter of 2014 compared to the first quarter of 2013. Eastern natural gas prices were 13.9 percent lower and Western natural gas prices were 1.6 percent higher for the second and third quarters of 2014 compared to the same period of 2013. Energy prices were 2.6 percent lower for the second and third quarters of 2014 compared to the same period of 2013.[98]
- Increases in average net revenues for the first nine months of 2014 were primarily the result of substantial increases in net revenues for the first three months of 2014 as a result of significantly higher energy prices which offset higher fuel costs.
- For the first three months of 2014, energy net revenues increased by 1,444 percent for a new CT, 377 percent for a new CC, 637 percent for a new CP, 9,293 percent for a new DS, 188 percent for a new nuclear plant,

98 Percentage increase is the percentage increase of the average zonal LMP.

54 percent for a new wind installation, and 33 percent for a new solar installation.

- Average net revenues increased for the second and third quarters of 2014 compared to the same period of 2013 by 7.3 percent for a new CT, increased by 15.9 percent for a new CC, decreased by 1.8 percent for a new CP, decreased by 72.1 percent for a new DS, decreased by 3.9 percent for a new nuclear plant, increased by 6.1 percent for a new wind installation, and increased by 2.2 percent for a new solar installation.
- Average net revenues increased for the first nine months of 2014 by 275 percent for a new CT, 114 percent for a new CC, 202 percent for a new CP, 1,173 percent for a new DS, 58 percent for a new nuclear plant, 28 percent for a new wind installation, and 10 percent for a new solar installation.

Section 7 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.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. High loads that result in high prices tend to increase energy market net revenues for all unit types. Even a relatively small number of high price hours can significantly increase net revenues. This illustrates the potential role of scarcity pricing as a source of net revenues and also makes it more important to address the appropriate net revenue offset mechanism in the capacity market.

Overview: Section 8, "Environmental and Renewables"

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.** 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.[99] 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 (PM). On March 28, 2013, the EPA issued a rule that raised the new source limits for new coal- and oil-fired power plants based on new information and analysis.[100]

99 *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).

100 *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).

- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine PM and ozone national ambient air quality standards (NAAQS). Much recent regulatory activity concerning emissions has concerned the development and implementation of a transport rule to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[101]

  On April 29, 2014, the U.S. Supreme Court upheld EPA's Cross-State Air Pollution Rule (CSAPR) and on October 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit lifted the stay imposed on CSAPR, clearing the way for the EPA to implement this rule and to replace the Clean Air Interstate Rule (CAIR) now in effect.[102,103]

- **National Emission Standards for Reciprocating Internal Combustion Engines.** On January 14, 2013, the EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[104] 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.

  Pending initiatives in Pennsylvania and the District of Columbia would reverse the EPA's exception in those jurisdictions and apply comparable regulatory standards to generation with similar operational characteristics.[105]

  In PJM's filing to improve its ability to dispatch DR prior to emergency system conditions, PJM proposed to retain the PJM Emergency Load Response Program which would allow RICE to continue to use the EPA's exception.[106] The MMU protested retention of the emergency program, particularly for the purpose of according discriminatory preference to resources that are not good for reliability, the markets or the environment.[107] An order from the Commission in this matter is now pending.

- **Greenhouse Gas Emissions Rule.** On September 20, 2013, the EPA proposed standards placing national limits on the amount of CO_2 that new power plants would be allowed to emit.[108] Once GHG NSPS standards for CO_2 are in place, the CAA permits the EPA to take the much more significant step of regulating CO_2 emissions from existing sources.[109] In anticipation of timely issuance of a final GHG NSPS, the EPA issued a proposed rule for regulating CO_2 from certain existing power generation facilities on June 2, 2014, the Existing Stationary Sources Notice of Proposed Rulemaking ("ESS NOPR").[110] The ESS NOPR established interim and final emissions goals for each state that must be met, respectively, by 2020 and 2030. States have flexibility to meet these goals, including through participation in multistate CO_2 credit trading programs.

- **Cooling Water Intakes.** Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. A final rule implementing this requirement was issued May 19, 2014.[111]

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.[112] New Jersey's HEDD rule, which became

101 CAA § 110(a)(2)(D)(i)(I).
102 See EPA et al. v. EME Homer City Generation, L.P. et al., No. 12-1182.
103 Order, No. 11-1302.
104 *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).
105 See Pennsylvania House of Representatives, House Bill No. 1699; Council of the District of Columbia Bill 20-569.
106 PJM Tariff filing, FERC Docket No. ER14-822 (December 24, 2013).
107 Comments, Complaint and Motion to Consolidate of the Independent Market Monitor for PJM, FERC Docket No. ER14-822 (January 14, 2014) at 3–6.
108 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, Propose Rule*, EPA-HQ-OAR-2013-0495 ("GHG NSPS").
109 See CAA § 111(b)&(d).
110 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, 79 Fed. Reg. 34830 (June 18, 2014).
111 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667.
112 N.J.A.C. § 7:27–19.

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.[113]

- **Illinois Air Quality Standards (NOX, SO2 and Hg).** The State of Illinois has promulgated its own standards for NOX, SO2 and Hg (mercury) known as Multi-Pollutant Standards ("MPS") and Combined Pollutants Standards ("CPS").[114] MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as EPA's MATS.

  The Illinois Pollution Control Board has granted variances with conditions for compliance with MPS/CPS for Illinois units included in or potentially included in PJM markets that may have impacted PJM markets.[115] In order to obtain variances, companies in PJM, such as Midwest Generation LLC, agreed to terms with the Illinois Pollution Control Board that may have resulted in investments in the installation of environmental pollution control equipment at units and deactivation of Illinois units that differ from what would have occurred had only Federal regulations applied.[116]

- **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 2014 for the 2012-2014 compliance period were $5.02 per ton, above the price floor for 2014. The clearing price is equivalent to a price of $5.53 per metric tonne, the unit used in other carbon markets.

Emissions Controls in PJM Markets

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. On June 30, 2014, 71.1 percent of coal steam MW had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions, while 98.7 percent of coal steam MW had some type of particulate control, and 92.2 percent of fossil fuel fired capacity in PJM had NO_x emission control technology.

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, 2014, 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 not enacted renewable portfolio standards. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 2015.

Renewable energy credits (RECs) and federal production tax credits provide out of market payments to qualifying resources, primarily wind and solar, which create an incentive to generate MWh until the LMP is equal to the marginal cost of producing power minus the credit received for each MWh. The credits provide an incentive to make negative energy offers when the net of marginal cost and credits is negative. These subsidies affect the offer behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources. During the first nine months of 2014, there were 6,065 intervals with negative LMPs as a result of negative offers from wind units.

Section 8 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. Attempts to extend the definition of renewable energy to include nuclear power in order to provide subsidies to nuclear power

113 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective non-catalytic reduction (SNCR).
114 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).
115 See, e.g., Midwest Generation, LLC, Opinion and Order of the Board, Docket No. PCB 13-24 (Variance-Air) (April 4, 2013); Midwest Generation, LLC, Opinion and Order of the Board, Docket No. PCB 12-121 (Variance-Air) (August 23, 2012).
116 See *Id.*

could increase this impact if successful. Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation unless bundled with a wholesale sale of electric energy.[117] REC markets are not transparent. Data on RECs prices and markets are not publicly available. 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. Costs for environmental controls are part of bids for capacity resource in the PJM capacity market. The costs of environmental permits are included in energy offers. PJM markets also provide a flexible mechanism that incorporates renewable resources and renewable energy credit markets, and ensure 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 9, "Interchange Transactions"

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first nine months of 2014, PJM was a net importer of energy in the Real-Time Energy Market in January, May, June and August, and a net exporter of energy in the remaining five months.[118] During the first nine months of 2014, the real-time net interchange of -982.1 GWh was lower than net interchange of 4,706.7 GWh in the first nine months of 2013.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first nine months of 2014, PJM was a net exporter of energy in the Day-Ahead Energy Market in all months. During the first nine months of 2014, the total day-ahead net interchange of -12,142.4 GWh was lower than net interchange of -12,727.7 GWh during the first nine months of 2013.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first nine months of 2014, gross imports in the Day-Ahead Energy Market were 113.9 percent of gross imports in the Real-Time Energy Market (150.8 percent during the first nine months of 2013), gross exports in the Day-Ahead Energy Market were 141.5 percent of the gross exports in the Real-Time Energy Market (218.5 percent during the first nine months of 2013).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first nine months of 2014, there were net scheduled exports at 12 of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first nine months of 2014, there were net scheduled exports at 12 of PJM's 18 interface pricing points eligible for real-time transactions.[119]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first nine months of 2014, there were net scheduled exports at 12 of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first nine months of 2014, there were net scheduled exports at 11 of PJM's 19 interface pricing points eligible for day-ahead transactions.
- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Market, for the first nine months of 2014, up-to congestion transactions were net exports at six of PJM's 19 interface pricing points eligible for day-ahead transactions.
- **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

117 See 139 FERC ¶ 61,061 at PP 18, 22 (2012) ("[W]e conclude that unbundled REC transactions fall outside of the Commission's jurisdiction under sections 201, 205 and 206 of the FPA. We further conclude that bundled REC transactions fall within the Commission's jurisdiction under sections 201, 205 and 206 of the FPA,… [A]lthough a transaction may not directly involve the transmission or sale of electric energy, the transaction could still fall under the Commission's jurisdiction because it is "in connection with" or "affects" jurisdictional rates or charges.").

118 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

119 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

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 nine months of 2014, net scheduled interchange was -1,081 GWh and net actual interchange was -331 GWh, a difference of 750 GWh. For the first nine months of 2013, net scheduled interchange was 3,316 GWh and net actual interchange was 3,474 GWh, a difference of 158 GWh. This difference is inadvertent interchange.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first nine months of 2014, the direction of the average hourly flow was consistent 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 53.0 percent of the hours in the first nine months of 2014.

- **PJM and New York ISO Interface Prices.** In the first nine months of 2014, 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 56.0 percent of the hours in the first nine months of 2014.

- **Neptune Underwater Transmission Line to Long Island, New York.** In the first nine months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus.[120] The direction of flow was consistent with price differentials in 58.9 percent of the hours in the first nine month of 2014.

- **Linden Variable Frequency Transformer (VFT) Facility.** In the first nine months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO Linden Bus.[121] The direction of flow was consistent with price differentials in 56.2 percent of the hours in the first nine months of 2014.

- **Hudson DC Line.** In the first nine months of 2014, the average hourly flow (PJM to NYISO) was inconsistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO Hudson Bus.[122] The direction of flow was consistent with price differentials in 59.3 percent of the hours in the first nine months of 2014.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued five TLRs of level 3a or higher during the first nine months of 2014, compared to 45 such TLRs issued during the first nine months of 2013.

- **Up-To Congestion.** The average number of up-to congestion bids submitted in the Day-Ahead Energy Market increased by 80.1 percent, from 105,472 bids per day in the first nine months of 2013 to 189,997 bids per day in the first nine months of 2014. The average cleared volume of up-to congestion bids increased by 22.6 percent, from 1,221,114 MWh per day in the first nine months of 2013 to 1,496,675 MWh per day in the first nine months of 2014. But the increases all occurred prior to September 8, 2014, after which the number and volume of bids declined sharply.

  On August 29, 2014, FERC issued an Order which, among other things, created an obligation for UTCs to pay any uplift determined to be appropriate in the Commission review, effective September 8, 2014.[123] The average number of up-to congestion bids submitted in the Day-Ahead Energy Market decreased by 79.5 percent, from 192,097 bids per day in three week period prior to the September 8, 2014 refund effective date to 39,429 bids per day in three week period following the September 8, 2014 refund effective date. The average cleared volume of up-to congestion bids decreased by 79.9 percent, from 1,633,746 MWh per day in the three week period prior to the September 8, 2014 refund effective date to

120 In the first nine months of 2014, there were 590 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 $58.04 while the NYISO LMP at the Neptune Bus during non-zero flows was $66.75, a difference of $8.71.

121 In the first nine months of 2014, there were 1,510 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 $63.82 while the NYISO LMP at the Neptune Bus during non-zero flows was $66.24, a difference of $2.42.

122 In the first nine months of 2014, there were 4,840 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $111.11 while the NYISO LMP at the Hudson Bus during non-zero flows was $114.83, a difference of $3.72.

123 *Order Instituting Section 206 Proceeding and Establishing Procedures*, 148 FERC ¶ 61,144 (2014).

328,041 MWh per day in the three week period following the September 8, 2014 refund effective date (Figure 9-13).

- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule to become compliant with Order No. 764.[124,125] PJM and the MMU issued a statement indicating that both remain concerned about market participants' scheduling behavior, and will continue to monitor and address any scheduling behavior that raises operational or market manipulation concerns.[126]

Section 9 Recommendations

- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. New recommendation.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1200 day-prior to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be utilized to meet load in the most economic manner. (Priority: Medium. New recommendation.)

124 *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).
125 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).
126 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, which can be accessed at: <http://www.pjm.com/~/media/documents/reports/20140729-pjm-imm-joint-statement-on-interchange-scheduling.ashx>.

- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized joint dispatch approach that treats seams between balancing authorizes as a constraint, similar to any other constraint within an LMP market. (Priority: Medium. New recommendation.)
- The MMU recommends 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. (Priority: Medium. First reported 2012.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction. (Priority: Medium. First reported 2013.)
- The MMU recommends that the validation also require market participants to submit transactions on market paths that reflect the expected actual flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU's proposed validation rules would address sham scheduling. (Priority: High. First reported 2012.)
- The MMU recommends that PJM eliminate the NIPSCO and Southeast interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM immediately provide the required 12-month notice to PEC to unilaterally terminate the Joint Operating Agreement. (Priority: Low. First reported 2013.)

- The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number of external buses and selecting buses in close proximity on either side of the border with comparable bus weights. (Priority: Medium. First reported 2012.)

Section 9 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 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's recommendations related to transactions with external balancing authorities all share the goal of improving the economic efficiency of interchange transactions. The standard of comparison is an LMP market. In an LMP market, redispatch based on LMP and generator offers results in an efficient dispatch and efficient prices.

Overview: Section 10, "Ancillary Services"

Primary Reserve

Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement. PJM's primary reserves are made up of resources, both synchronized and non-synchronized, that can provide energy within ten minutes.

Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (generation or demand response currently synchronized to the grid and available within ten minutes), and non-synchronized reserve (generation currently off-line but can be started and provide energy within ten minutes).
- **Demand.** The PJM primary reserve requirement is 150 percent of the largest contingency. The primary reserve requirement in the RTO Reserve Zone is currently 2,063 MW of which at least 1,700 MW must be available within the Mid-Atlantic Dominion (MAD) subzone. Adjustments to the primary reserve requirement can occur when grid maintenance or outages change the largest contingency. The actual demand for primary reserve in the RTO for the first nine months of 2014 was 2,078 MW. The actual demand for primary reserve in the MAD subzone in the first nine months of 2014 was 1,700 MW.

Tier 1 Synchronized Reserve

Synchronized reserve is energy or demand reduction synchronized to the grid and capable of increasing output or decreasing load within ten minutes. Synchronized reserve is of two distinct types, tier 1 and tier 2. Tier 1 synchronized reserve is part of primary reserve and is comprised of all on-line resources following economic dispatch and able to ramp up from their current output in response to a synchronized reserve event.

- **Supply.** In the first nine months of 2014, an average supply of 1,442.0 MW of tier 1 was identified hourly for the entire RTO synchronized reserve zone, and an average supply of 568.5 MW of tier 1 was identified hourly for the Mid-Atlantic Dominion subzone.
- **Demand.** There is no fixed required amount of tier 1 synchronized reserve. Tier 1 synchronized reserve is estimated and not assigned.
- **Price and Cost.** The price for tier 1 synchronized reserves is typically zero, as there is no incremental cost associated with providing the ability to ramp up from the current economic dispatch point. However, a tariff change included in the shortage pricing tariff changes (October 1, 2012) modified the pricing of tier 1 so that tier 1 synchronized reserve is paid the tier 2 synchronized reserve market clearing price whenever the non-synchronized reserve market clearing price rises above zero. The rationale

for this change was and is unclear but it has had a significant impact on the cost of tier 1 synchronized reserves, resulting in a windfall payment of $85,069,062 to tier 1 resources between January 1 and September 30, 2014.

The additional payments to tier 1 synchronized reserves can be considered a windfall because the additional payment does not create an incentive to provide more tier 1 synchronized reserves and the additional payment is not a payment for performance as there is no requirement to perform and all estimated tier 1 synchronized reserves receive the payment regardless of whether they provided any response.

- **Tier 1 Synchronized Reserve Spinning Event Response.** Tier 1 synchronized reserve is awarded credits when a spinning event occurs and it responds. These spinning event response credits for tier 1 response are independent of the tier 1 estimated, independent of the synchronized reserve market clearing price, and independent of the non-synchronized reserve market clearing price.

  Only 29.5 percent of tier 1 synchronized reserve identified as available for both synchronized reserve and primary reserve actually responded to spinning events.

Tier 2 Synchronized Reserve Market

Tier 2 synchronized reserve is part of primary reserve (ten minute availability) and is comprised of resources that are synchronized to the grid, that incur costs to synchronized and that must be dispatched in order to satisfy the synchronized reserve requirement. When the synchronized reserve requirement cannot be filled with tier 1 synchronized reserve, PJM conducts a market to satisfy the requirement with tier 2 synchronized reserve. The Tier 2 Synchronized Reserve Market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve subzone (MAD).

Market Structure

- **Supply.** In the first nine months of 2014, the supply of offered and eligible synchronized reserve was sufficient to cover the requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone, except for two hours on January 6, 2014, and eight hours on January 7, 2014.
- **Demand.** The default hourly required synchronized reserve requirement is 1,375 MW in the RTO Reserve Zone and 1,300 MW for the Mid-Atlantic Dominion Reserve subzone.
- **Market Concentration.** In the first nine months of 2014, the weighted average HHI for cleared inflexible tier 2 synchronized reserve in the Mid-Atlantic Dominion subzone was 5427 which is classified as highly concentrated. The HHI for flexible synchronized reserve cleared during real-time market solutions (which was only 11.6 percent of all tier 2 synchronized reserve) was 8643. The MMU calculates that during the first nine months of 2014, 38.7 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion subzone and 33.1 percent of hours would have failed a three pivotal supplier test in the RTO Synchronized Reserve Zone.

  The MMU concludes from these results that both the Mid-Atlantic Dominion subzone Tier 2 Synchronized Reserve Market and the RTO Synchronized Reserve Zone Market were characterized by structural market power in the first nine months of 2014.

Market Conduct

- **Offers.** Synchronized reserve offers from generating units are subject to an offer cap of marginal cost plus $7.50 per MW, plus opportunity cost, which is calculated by PJM. As of September 30, 2014, 3.4 percent of eligible resources had no tier 2 synchronized reserve offer. This is an improvement over the same period in 2013 when 14.0 percent of eligible resources had no tier 2 synchronized reserve offer.

Market Performance

- **Price.** The cleared synchronized reserve weighted average price for tier 2 synchronized reserve in the Mid-Atlantic Dominion (MAD) subzone was $15.42 per MW in the first nine months of 2014, an increase of $8.31 (85.6 percent) from the first nine months of 2013.

The cleared synchronized reserve weighted average price for tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was $13.40 per MW in the first nine months of 2014, an increase of $6.54 (95.3 percent) over the first nine months of 2013.

Non-Synchronized Reserve Market

Non-synchronized reserve is a component of primary reserve and includes the same two markets, the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone (MAD). After the hour ahead market solution satisfies the requirement for synchronized reserve the remainder of the primary reserve requirement is satisfied with non-synchronized reserve. Non-synchronized reserve is comprised of non-emergency energy resources not currently synchronized to the grid that can provide energy within ten minutes at the direction of PJM dispatch.

Market Structure

- **Supply.** In the first nine months of 2014, the supply of eligible non-synchronized reserve was sufficient to cover the primary reserve requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone, except for two hours on January 6, 2014, and eight hours on January 7, 2014.
- **Demand.** In the RTO Zone, the market cleared an hourly average of 680.9 MW of non-synchronized reserve during the first nine months of 2014. In 95.9 percent of hours the market clearing price was $0. In the MAD subzone, the market cleared an hourly average of 683.0 MW of non-synchronized reserve. In 93.7 percent of hours the market clearing price was $0.

Market Conduct

- **Offers.** No offers are made for non-synchronized reserve. Non-emergency generation resources that are available to provide energy and can start in 10 minutes or less are considered available for non-synchronized reserves by the market solution software.

Market Performance

- **Price.** Prices are a function of the opportunity costs of any resources taken for non-synchronized reserves. The cleared non-synchronized reserve weighted average price in the RTO Reserve Zone was $0.57 per MW for the first nine months of 2014, compared to $0.03 for the first nine months of 2013. The cleared non-synchronized reserve weighted average price in the Mid-Atlantic Dominion (MAD) subzone was $11.65 per MW, compared to $10.17 over the same period in 2013.

Secondary Reserve

PJM maintains a day-ahead, offer based market for 30-minute secondary reserve, designed to provide price signals that encourage resources to provide 30-minute reserve.[127] The DASR Market has no performance obligations.

Market Structure

- **Concentration.** In the first nine months of 2014, zero hours in the DASR Market would have failed the three pivotal supplier test.
- **Supply.** The DASR Market is a must offer market. Any resources that do not make an offer have their offer set to $0 per MW. DASR is calculated by the day-ahead market solution as the lesser of the thirty minute energy ramp rate or the emergency maximum MW minus the day-ahead dispatch point for all on-line units. For the first nine months of 2014, the average available hourly DASR was 45,282 MW.
- **Demand.** The DASR requirement in 2014 is 6.27 percent of peak load forecast, down from 6.91 percent in 2013. The average DASR MW purchased was 6,419 MW per hour for the first nine months of 2014.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. All offers greater than zero constitute economic withholding. As of September 30, 2014, 9.8 percent of resources offered DASR at levels above $5 per MW,

127 See PJM. "Manual 35, Definitions and Acronyms," Revision 35, (April 11, 2014), p. 89.

compared to 11.5 percent of resources offering above $5.00 at the same time in 2013.

- **DR.** Demand resources are eligible to participate in the DASR Market. As of September 30, 2014, six demand resources have entered offers for DASR.

Market Performance

- **Price.** The weighted average DASR market clearing price in the first nine months of 2014 was $1.02 per MW. This is a $0.09 per MW (9.7 percent) increase from the first nine months of 2013, which had a weighted price of $0.93 per MW.

Regulation Market

The PJM Regulation Market is a single market for the RTO. Regulation is provided by demand response and generation resources that must qualify to follow a regulation signal (RegA or RegD). PJM jointly optimizes regulation with synchronized reserve and energy to provide all three of these services at least cost. The PJM Regulation Market design includes three clearing price components (capability, performance, and lost opportunity cost), the rate of substitution between RegA and RegD resources (marginal benefit factor) and a measure of the quality of response (performance score) by a regulation resource to a regulation signal. The marginal benefit factor and performance score translate a resource's capability (actual) MW into effective MW.

Market Structure

- **Supply.** In the first nine months of 2014, the average hourly eligible supply of regulation was 1,300 actual MW (938 effective MW). This is a decrease of 152 actual MW (214 effective MW) from the first nine months of 2013, when the average hourly eligible supply of regulation was 1,453 actual MW (1,152 effective MW).
- **Demand.** The average hourly regulation demand was 664 actual MW in the first nine months of 2014. This is a 127 actual MW (38 effective MW) decrease in the average hourly regulation demand of 791 actual MW (702 effective MW) in the same period of the first nine months of 2013.
- **Supply and Demand.** The ratio of offered and eligible regulation to regulation required averaged 1.96. This is a 6.4 percent increase over the first nine months of 2013 when the ratio was 1.84.
- **Market Concentration.** In the first nine months of 2014, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 1836 which is classified as highly concentrated. In the first nine months of 2014, the three pivotal supplier test was failed in 97 percent of hours.

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. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.[128] In the first nine months of 2014, there were 290 resources following the RegA signal and 43 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $49.77 per MW of regulation in the first nine months of 2014, an increase of $17.05 per MW of regulation, or 52.1 percent, from the first nine months of 2013. The cost of regulation in the first nine months of 2014 was $60.42 per MW of regulation, an increase of $23.07 per MW of regulation, or 61.8 percent, from the first nine months of 2013.
- **RMCP Credits.** RegD resources continue to be underpaid relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment, pricing, and settlement processes. In the first nine months of 2014, RegA resources received RMCP credits per effective MW on average 1.9 times higher than RegD resources. If the

128 See the *2013 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

Regulation Market were functioning correctly, RegD and RegA resources would be paid equally per effective MW.

Black Start Service

Black start service is required for 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.[129]

In the first nine months of 2014, total black start charges were $44.6 million with $18.0 million in revenue requirement charges and $26.6 million in operating reserve charges. Black start revenue requirements for black start units consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor. Black start operating reserve charges are paid for scheduling in the Day-Ahead Energy Market or committing in real time units that provide black start service. Black start zonal charges in the first nine months of 2014 ranged from $0.03 per MW-day in the ATSI Zone (total charges were $123,375) to $4.09 per MW-day in the AEP Zone (total charges were $25,535,875).

Reactive

Reactive service, reactive supply and voltage control from generation or other sources service, is provided by generation and other sources of reactive power (measured in VAR). Reactive power helps maintain appropriate voltages on the transmission system and is essential to the flow of real power (measured in MW).

In the first nine months of 2014, total reactive service charges were $237.9 million with $210.5 million in revenue requirement charges and $27.4 million in operating reserve charges. Reactive service revenue requirements are based on FERC-approved filings. Reactive service operating reserve charges are paid for scheduling in the Day-Ahead Energy Market and committing in real time units that provide reactive service. Total charges in the first nine months of 2014 ranged from $1,700 in the RECO Zone to $30.7 million in the AEP Zone.

129 OATT Schedule 1 § 1.3BB.

Section 10 Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor throughout the optimization, assignment and settlement process. (Priority: High. First reported 2013.)
- The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately. (Priority: High. First reported 2013.)
- The MMU recommends that the amount of tier 1 MW paid when the non-synchronized reserve market clearing price (NSRMCP) goes above $0 be equal to the tier 1 MW estimated by the RT-SCED market solution, to the extent that PJM continues to pay tier 1 synchronized reserve the SRMCP when the non-synchronized reserve market clearing price is above $0 (e.g. the MMU recommendation to eliminate these payments is not implemented). (Priority: High. New recommendation.)
- The MMU recommends that the tier 2 synchronized reserve must-offer provision of scarcity pricing be enforced. As of the end of September 2014 compliance with the tier 2 must-offer provision is 96.6 percent. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM be more explicit about why tier 1 biasing is used in the optimized solution to the Tier 2 Synchronized Reserve Market. 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. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM determine why secondary reserve was either unavailable or not dispatched on September 10, 2013, January 6, 2014, and January 7, 2014, and that PJM replace the DASR Market with a

real time secondary reserve product that is available and dispatchable in real time. (Priority: Low. First reported 2013.)

- The MMU recommends that 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. (Priority: Low. First reported 2013.)
- The MMU recommends that the three pivotal supplier test be incorporated in the DASR Market. (Priority: Low. First reported 2012.)

Section 10 Conclusion

While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market results continue to include the incorrect definition of opportunity cost. Further, the market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. Instead, the market design makes use of the marginal benefit factor in the optimization and pricing, but a mileage ratio multiplier in settlement. This failure to correctly incorporate marginal benefit factor into the current Regulation Market design is causing effective MW provided by RegD resources to be underpaid per effective MW. These issues have led to the MMU's conclusion that the Regulation Market design, as currently implemented, is flawed.

The structure of each Tier 2 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. 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 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.

The MMU concludes that the new Regulation Market results were competitive. The MMU concludes that the Synchronized Reserve Market results were competitive. The MMU concludes that the DASR Market results were competitive.

Overview: Section 11, "Congestion and Marginal Losses"

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $1,195.7 million or 234.6 percent, from $509.6 million in the first nine months of 2013 to $1,705.3 million in the first nine months of 2014. Total congestion costs increased because of the cold weather in January 2014, but congestion was also much higher in March 2014 than in March 2013 and congestion was higher in each of the first nine months of 2014 than in the first nine months of 2013 except July.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $1,163.2 million or 145.1 percent, from $801.4 million in the first nine months of 2013 to $1,964.6 million in the first nine months of 2014.
- **Balancing Congestion.** Balancing congestion costs increased by $32.5 million or 11.1 percent, from -$291.8 million in the first nine months of 2013 to -$259.3 million in the first nine months of 2014.
- **Monthly Congestion.** Monthly total congestion costs in the first nine months of 2014 ranged from $54.3 million in April to $825.1 million in January.

- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the AP South Interface, the West Interface, the Bagley – Graceton line, the Bedington - Black Oak Interface, and the Breed – Wheatland flowgate.

- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy Market in the first nine months of 2014. The number of congestion event hours in the Day-Ahead Energy Market was about 15 times higher than the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion frequency increased by 25.3 percent from 261,702 congestion event hours in the first nine months of 2013 to 327,824 congestion event hours in the first nine months of 2014.

  Real-time congestion frequency increased by 44.0 percent from 14,677 congestion event hours in the first nine months of 2013 to 21,139 congestion event hours in the first nine months of 2014.

- **Congested Facilities.** Day-ahead, congestion-event hours increased on all types of congestion facilities. Real-time, congestion-event hours increased on all types of congestion facilities.

  The AP South Interface was the largest contributor to congestion costs in the first nine months of 2014. With $475.3 million in total congestion costs, it accounted for 27.9 percent of the total PJM congestion costs in the first nine months of 2014.

- **Zonal Congestion.** AEP had the largest total congestion costs among all control zones in the first nine months of 2014. AEP had $410.2 million in total congestion costs, comprised of -$761.1 million in total load congestion payments, -$1,225.6 million in total generation congestion credits and -$54.3 million in explicit congestion costs. The AP South Interface, the West Interface, the Breed – Wheatland, Monticello - East Winamac and the Benton Harbor - Palisades flowgates contributed $286.6 million, or 78.0 percent of the total AEP control cone congestion costs.

- **Ownership.** In the first nine months of 2014, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. UTCs are in the explicit cost category and comprise most of that category. Explicit costs are the primary source of congestion credits to financial entities. In the first nine months of 2014, financial companies received $196.4 million in congestion credits, an increase of $114.9 million or 141.1 percent compared to the first nine months of 2013. In the first nine months of 2014, physical companies paid $1,901.7 million in congestion charges, an increase of $1,310.7 million or 221.7 percent compared to the first nine months of 2013.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $446.2 million or 56.0 percent, from $797.0 million in the first nine months of 2013 to $1,243.1 million in the first nine months of 2014. Total marginal loss costs increased because of the cold weather in January, but marginal loss costs were also significantly higher in February and March 2014 than in February and March 2013. Marginal loss costs were lower in July, August, and September of 2014 than in July, August, and September of 2013. The loss component of LMP remained constant, $0.02 in the first nine months of 2013 and $0.02 in the first nine months of 2014. The loss MW in PJM increased 0.2 percent, from 13,218 GWh in the first nine months of 2013 to 13,241 GWh in the first nine months of 2014.

- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $476.3 million or 54.6 percent, from $871.6 million in the first nine months of 2013 to $1,347.9 million in the first nine months of 2014.

- **Balancing Marginal Loss Costs.** Balancing marginal loss costs decreased by $30.2 million or 40.4 percent, from -$74.6 million in the first nine months of 2013 to -$104.8 million in the first nine months of 2013.

- **Monthly Total Marginal Loss Costs.** Marginal loss costs in the first nine months of 2014 increased compared to the first nine months of 2013, by 310.2 percent in January, 114.4 percent in February, 95.4 percent in March, 7.9 percent in April, 0.9 percent in May, and 9.1 percent in June but decreased in July, August, and September. Monthly total marginal loss costs in the first nine months of 2014 ranged from $68.7 million in May to $414.6 million in January.

- **Marginal Loss Credits.** Marginal loss credits are calculated as total energy costs plus total marginal loss costs 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.[130] The marginal loss credits increased in the first nine months of 2014 by $136.4 million or 51.0 percent, from $267.3 million in the first nine months of 2013, to $404.1 million in the first nine months of 2014.

Energy Cost

- **Total Energy Costs.** Total energy costs decreased by $306.7 million or 58.2 percent, from -$527.2 million in the first nine months of 2013 to -$833.9 million in the first nine months of 2014.
- **Day-Ahead Energy Costs.** Day-ahead energy costs decreased by $573.2 million or 95.3 percent, from -$601.3 million in the first nine months of 2013 to -$1,174.5 million in the first nine months of 2014.
- **Balancing Energy Costs.** Balancing energy costs increased by $266.0 million or 339.9 percent, from $78.2 million in the first nine months of 2013 to $344.2 million in the first nine months of 2014.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first nine months of 2014 ranged from -$272.7 million in January to -$44.6 million in September.

Section 11 Conclusion

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, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

ARRs and FTRs served as an effective, but not total, offset against congestion for the first four months of the 2014 to 2015 planning period. ARR and FTR revenues offset 80.4 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the first four months of the 2014 to 2015 planning period. In the entire 2013 to 2014 planning period, total ARR and FTR revenues offset 98.2 percent of the congestion costs.

Overview: Section 12, "Planning"

Planned Generation and Retirements

- **Planned Generation.** As of September 30, 2014, 60,573.8 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 199,531.9 MW as of September 30, 2014. Of the capacity in queues, 6,617.64 MW, or 10.9 percent, are uprates and the rest are new generation. Wind projects account for 15,549.3 MW of nameplate capacity or 25.7 percent of the capacity in the queues. Combined-cycle projects account for 37,797.2 MW of capacity or 62.4 percent of the capacity in the queues.
- **Generation Retirements.** As shown in Table 12-6, 26,342.1 MW are, or are planned to be, retired between 2011 and 2019, with all but 2,050.5 MW planned to be retired by the end of 2015. The AEP Zone accounts for 6,024.0 MW, or 22.9 percent, of all MW planned for retirement from 2014 through 2019.
- **Generation Mix.** A significant change in the distribution of unit types within the PJM footprint is likely as natural gas fired units continue to be developed and steam units continue to be retired. While only 282.5 MW of coal fired steam capacity are currently in the queue, 10,475.8 MW of coal fired steam capacity are slated for deactivation. Most of these retirements, 9,147 MW, are scheduled to take place by June 1, 2015, in large part due to the EPA's Mercury and Air Toxics Standards (MATS)

130 See PJM. "Manual 28: Operating Agreement Accounting," Revision 65 (April 24, 2014), pp 64-66. Note that the overcollection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

set to go into effect at that time. In contrast, 39,287.9 MW of gas fired capacity are in the queue, while only 1,793.0 MW of natural gas units are planned to retire. The replacement of steam units by units burning natural gas could significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a new 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.[131] 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. These projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.
- Many feasibility, impact and facilities studies are delayed for reasons including disputes with developers, circuit and network issues, retooling as a result of projects being withdrawn, and an accumulated backlog in completing studies.
- Where the transmission owner is a vertically integrated company that also owns generation, there is a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is a competitor to the generation of its parent company. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company.

131 OATT Parts IV & VI.

Regional Transmission Expansion Plan (RTEP)

- Artificial Island is an area in southern New Jersey that includes nuclear units at Salem and at Hope Creek. On April 29, 2013, PJM issued a request for proposal (RFP), seeking technical solutions to improve stability issues, operational performance under a range of anticipated system conditions, and the elimination of potential planning criteria violations in this area. PJM received 26 individual proposals from seven entities, including proposals from the incumbent transmission owner, PSE&G, and from non-incumbents. After the results of the initial selection process prompted a significant amount of feedback from market participants, PJM deferred the selection of a winner. In response to the feedback, PJM allowed the developers for five of the proposals to submit updated cost estimates, which they have done.

Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects intended to resolve a wide range of reliability criteria violations and congestion issues and which have substantial impacts on energy and capacity markets. The current backbone projects are Mount Storm-Doubs, Jacks Mountain, Susquehanna-Roseland, and Surry Skiffes Creek 500kV.

Section 12 Recommendations

The MMU recommends additional improvements to the planning process.

- There is no mechanism to permit a direct comparison, or competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. The MMU recommends the creation of such a mechanism. (Priority: Low. First reported 2013.)

- The MMU recommends that rules be implemented to permit competition to provide financing of transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013.)
- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.[132] (Priority: Low. First reported 2013.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013.)
- The MMU recommends an analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. (Priority: Medium. First reported Q1, 2014.)

Section 12 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 the energy and capacity markets. But when generating units retire or load increases, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in the affected area. In addition, despite Order No. 1000, there is not yet a robust mechanism to permit competition to build transmission projects or to obtain least cost financing through the capital markets.

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 may effectively forestall the ability of generation to compete. But there is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

The PJM queue evaluation process should be improved to ensure that barriers to competition are not created. Issues that need to be addressed include the ownership rights to CIRs, whether transmission owners should perform interconnection studies, and improvements in queue management.

Overview: Section 13, "FTR and ARRs"

Financial Transmission Rights

Market Structure

- **Supply.** Market participants can sell FTRs. In the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2014 to 2015 planning period, total participant FTR sell offers were 1,431,101 MW, down from 2,217,995 MW for the same period during the 2013 to 2014 planning period.
- **Demand.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2014 to 2015

132 See "Comments of the Independent Market Monitor for PJM," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf>.

planning period increased 13.6 percent from 9,765,083 MW for the same time period of the prior planning period, to 11,096,054 MW.

- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 79.4 percent of prevailing flow and 87.8 percent of counter flow FTRs for January through September of 2014. Financial entities owned 69.4 percent of all prevailing and counter flow FTRs, including 60.2 percent of all prevailing flow FTRs and 85.0 percent of all counter flow FTRs during the period from January through September 2014.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the first four months of the 2014 to 2015 planning period were $53,740 for Increment Offers, Decrement Bids and UTC Transactions.

- **Credit Issues.** People's Power and Gas, LLC and CCES, LLC defaulted on their collateral calls and payment obligations in January 2014. Customers of these members have been reallocated accordingly, and neither company held any financial transmission rights. These two load-serving members accounted for 17 of the total 33 default events. People's Power and Gas, LLC defaulted on three collateral calls totaling approximately $687,000 and then defaulted on four related payment obligations totaling approximately $554,000. CCES, LLC defaulted on two collateral calls totaling approximately $308,000 and then defaulted on eight related payment obligations totaling approximately $2.6 million. On March 6, 2014, PJM filed with FERC to terminate membership of these two companies. The FERC authorized this request effective April 24, 2014 and PJM utilized the default allocation assessment to apply their defaulting charges of approximately $1.9 million (total defaults of these two members less collateral held) to PJM's non-defaulting members in accordance with section 15.2.2 of the OATT to non-defaulting members' March 2014 monthly invoices.[133]

  Of the remaining 16 defaults not from People's Power and Gas, LLC and CCES, LLC, in January through March 2014, 13 were from collateral defaults, averaging $822,493, and three were from payment defaults, averaging $2,328. These remaining defaults were all promptly cured. In April through June 2014, CCES, LLC defaulted again for a total of $59,899. The default allocation assessment was assigned to non-defaulting members resulting in 18 payment defaults in April 2014 totaling $4,017, nine of which were promptly cured. There were no collateral or payment defaults in May through September 2014. These defaults were not necessarily related to FTR positions.

Market Performance

- **Volume.** For the first four months of the 2014 to 2015 planning period Monthly Balance of Planning Period FTR Auctions 893,952 MW (8.1 percent) of FTR buy bids and 307,481 MW (21.5 percent) of FTR sell offers cleared.

- **Price.** The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period was $0.17, up from $0.10 per MW in the 2013 to 2014 planning period.

- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $4.2 million in net revenue for all FTRs for the first four months of the 2014 to 2015 planning period, down from $7.3 million for the same time period in the 2013 to 2014 planning period.

- **Revenue Adequacy.** FTRs were paid at 100 percent of the target allocation level for the first four months of the 2014 to 2015 planning period. Congestion revenues are allocated to FTR holders based on their portion of FTR target allocations. PJM collected $351.2 million of FTR revenues during the first four months of the 2014 to 2015 planning period and $1,819.5 million during the entire 2013 to 2014 planning period. For the 2014 to 2015 planning period, the top sink and top source with the highest positive FTR target allocations were the Western Hub and the PECO zone. Similarly, the top sink and top source with the largest negative FTR target allocations were the JCPL zone and the Western Hub.

  For the first nine months of 2014, total day-ahead congestion was $1,964.6 million while total day-ahead plus balancing congestion was

133 *See* Default Allocation Assessment. OATT Section 15.2.2

$1,705.3 million, compared to target allocations of $2,174.3 million in the same time period.

Target allocation values are based on FTR MW and the differences between FTR source and sink day ahead CLMPs, not on the actual congestion incurred on FTR paths. Actual congestion incurred is the overpayment by load compared to payments to generation which result from both day-ahead congestion and balancing congestion. Target allocations are therefore not a good measure of congestion incurred on FTR paths and FTR payouts relative to target allocations are not a good measure of the payout performance of FTRs. Target allocations are just a distribution mechanism for congestion collected.

- **ARR and FTR Offset.** ARRs and FTRs served as an effective, but not total, offset to congestion. ARR and FTR revenues offset 80.4 percent of the total congestion costs including the Day-Ahead Energy Market and the balancing energy market in PJM for the first four months of the 2014 to 2015 planning period. In the 2013 to 2014 planning period, total ARR and FTR revenues offset 98.2 percent of the congestion costs.
- **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 $780.4 million in profits for physical entities, of which $420.5 million was from self-scheduled FTRs, and $517.9 million for financial entities. FTRs were undervalued in the auctions compared to their returns from congestion revenue, despite the fact that the payout ratio was less than 1.0. Not every FTR was profitable. FTR profits were high for the first nine months of 2014 due in large part to very high January congestion prices and higher than normal congestion prices in February and March.

Auction Revenue Rights

Market Structure

- **ARR Allocations.** Due to more conservative treatment of transmission outages by PJM in the FTR Auction model designed to reduce revenue inadequacy, ARR allocation quantities were reduced. For the 2014 to 2015 planning period, Stage 1B and Stage 2 ARR allocations were reduced 84.9 percent and 88.1 percent from the 2013 to 2014 planning period.
- **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 first four months of the 2014 to 2015 planning period planning period, PJM allocated a total of 9,826.4 MW of residual ARRs with a total target allocation of $5,109,164.
- **ARR Reassignment for Retail Load Switching.** There were 64,086 MW of ARRs associated with $382,100 of revenue that were reassigned in the 2013 to 2014 planning period. There were 30,323 MW of ARRs associated with $302,600 of revenue that were reassigned for the first four months of the 2014 to 2015 planning period.

Market Performance

- **Revenue Adequacy.** For the first four months of the 2014 to 2015 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $732.2 million while PJM collected $752.9 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2013 to 2014 planning period, the ARR target allocations were $506.2 million while PJM collected $568.8 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.
- **ARRs as an Offset to Congestion.** ARRs served as an effective offset against congestion. The total revenues received by ARR holders, including self-scheduled FTRs, offset 100 percent of the total congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and

the balancing energy market for the first four months of the 2014 to 2015 planning period and for the 2013 to 2014 planning period.

Section 13 Recommendations

- Report correct monthly payout ratios to reduce understatement of payout ratios on a monthly basis. (Priority: Low. First reported 2013.)
- Eliminate portfolio netting to eliminate cross subsidies among FTR marketplace participants. (Priority: High. First reported 2013.)
- Eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2013.)
- Eliminate geographic cross subsidies. (Priority: High. First reported 2013.)
- Improve transmission outage modeling in the FTR auction models. (Priority: Low. First reported 2013.)
- Reduce FTR sales on paths with persistent overallocation of FTRs including clear rules for what defines persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013.)
- Implement a seasonal ARR and FTR allocation system to better represent outages. (Priority: Medium. First reported 2013.)
- Eliminate over allocation requirement of ARRs in the Annual ARR Allocation process. (Priority: High. First reported 2013.)
- Apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids. (Priority: High. First reported 2013.)
- The MMU recommends that PJM not use the ATSI Interface or create similar closed loop interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product. Market prices should be a function of market fundamentals. The MMU recommends that, in general, the implementation of closed loop interface constraints be studied in advance and, if there is good reason to implement, implemented so as to include them in the FTR Auction model to minimize their impact on FTR funding. (Priority: Medium. First reported 2013.)

Section 13 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.

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. Financial transmission rights and the associated revenues were directly provided to loads in recognition of the facts that loads pay for the transmission system which permits low cost generation to be delivered to load. Another way of describing the result is that FTRs and the associated revenues were directly provided to loads in recognition of the fact that load pays locational prices which result in load payments in excess of generation revenues which are the source of the funds available to offset congestion costs in an LMP market. In other words, load payments in excess of generation revenues are the source of the funds to pay FTRs. In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs to pay back to load the difference between the total load payments and the total generation revenues associated with congestion.

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.

For these reasons, load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested.[134] One form of recommended subsidies would ignore balancing congestion when calculating total congestion dollars available to fund FTRs. This approach

134 See "FirstEnergy Solutions Corp. Allegheny Energy Supply Company, LLC v PJM Interconnection, LLC" EL13-47(February 15, 2013).

would ignore the fact that loads must pay both day ahead and balancing congestion. To eliminate balancing congestion from the FTR revenue calculation would require load to pay twice for congestion. Load would have to continue paying for the physical transmission system, would have to continue paying in excess of generator revenues and not have balancing congestion included in the calculation of congestion in order to increase the payout to holders of FTRs who are not loads and who therefore did not receive an allocation of ARRs. In other words, load would have to continue providing all the funding of FTRs, while payments to FTR holders who did not receive ARRs exceed total congestion on their FTR paths.

Revenue adequacy has received a lot of attention in the PJM FTR Market. There are several factors that can affect the reporting, 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 balancing 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.

Reported FTR revenue sufficiency uses target allocations as the relevant benchmark. But target allocations are not the relevant benchmark. Target allocations are based on day-ahead congestion only, ignoring the other part of total congestion which is balancing congestion. The difference between the congestion payout using total congestion and the congestion payout using only day-ahead congestion illustrates the issue. For the first nine months of 2014, total day-ahead congestion was $1,964.6 million while total day-ahead plus balancing congestion was $1,705.3 million, compared to target allocations of $2,174.3 million in the same time period.

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, in the 2012 to 2013 planning period, the clearing price was $0.34 per MW, a 52 percent decrease, and in the 2013 to 2014 planning period, the clearing price was $0.30 per MW, a 13.3 percent decrease. For the 2014 to 2015 planning period, the Annual FTR Obligation price was $0.44, a 46.7 percent increase from the previous planning period. In the 2010 to 2011 planning period, the clearing price for FTR Obligation sell offers was $0.22 per MW, in the 2012 to 2013 planning period was $0.15 per MW, a 31.8 percent decrease, and in the 2013 to 2014 planning period the price was $0.05 per MW, a 66.7 percent decrease. For the 2014 to 2015 planning period, the Annual FTR Obligation sell offer price was $0.22, a 340 percent increase from the previous planning period.

The volume of cleared buy bids and self-scheduled bids in the Annual FTR Auctions decreased from 420,489 MW in the 2013 to 2014 planning period to 365,843 MW in the 2014 to 2015 planning period, a decrease of 54,646 MW or 13.0 percent. The volume of cleared sell offers increased from 37,821 MW in the 2013 to 2014 planning period to 41,213 MW in the 2014 to 2015 planning period, an increase of 9.0 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. The bid volume was 7,598,008.5 MW, 7,909,804.6 MW and 9,600,316 MW for June 2012, June 2013 and June 2014, increases of 95.1, 103.1 and 405.7 percent over June 2010. The net bid volume was 6,407,647.2 MW, 6,607,570.4 MW and 8,631,332 MW for June 2012, June 2013 and June 2014, increases of 101.7, 108.0 and 368.1 percent. The net bid volume to bid volume ratio was 0.82, 0.83, 0.84, 0.84 and 0.90 for June 2010, June 2012, June 2013 and June 2014.

The monthly payout ratio reported by PJM 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. PJM's reported monthly payout ratios are based on an estimate of the results for the entire year. The reported monthly payout ratio should be the actual monthly results including all revenue. 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. The FTR market cannot work efficiently if FTR buyers do not receive payments consistent with the performance of their FTRs. Eliminating the portfolio subsidy would be a good first step in that direction.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in the 2013 to 2014 planning period would have been 87.5 percent instead of the reported 72.8 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 impact of lower payouts 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 FTR market cannot work efficiently if FTR buyers do not receive payments consistent with the performance of their FTRs. Eliminating the counter flow subsidy would be another good step in that direction.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would have increased the calculated payout ratio in the 2013 to 2014 planning period from the reported 72.8 percent to 91.0 percent. The MMU recommends that counter flow and prevailing flow FTRs should be treated symmetrically with respect to the application of a payout ratio.

The result of removing portfolio netting, applying a payout ratio to counter flow FTRs and eliminating Stage 1A ARR over allocation would increase the payout ratio to 94.6 percent.

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 in the FTR auction model 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, which directly results in differences in congestion between day-ahead and real-time markets; 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, which directly results in differences in congestion between day–ahead and real-time markets; the overallocation of ARRs which directly results in a difference between congestion revenue and the payment obligation; the appropriateness of seasonal ARR allocations to better match actual market conditions with the FTR auction model; geographic subsidies from the holders of positively valued FTRs in some locations to the holders of consistently negatively valued FTRs in other locations; the contribution of up-to congestion transactions to the differences between day-ahead and balancing congestion and thus to FTR payout ratios; and the continued sale of FTR capability on pathways with a persistent difference between FTRs and total congestion revenue. The MMU recommends that these issues be reviewed and modifications implemented. Regardless of how these issues are addressed, funding issues that persist as a result of modeling differences and flaws in the design of the FTR market should be borne by FTR holders operating in the voluntary FTR market and not imposed on load through the mechanism of balancing congestion. The end result of all the modeling differences is that too many FTRs are sold. In addition to addressing the specific modeling issues, PJM should reduce the number of FTRs sold.

Recommendations

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.[1] The MMU initiates and proposes changes to the design of the markets and the PJM Market Rules in stakeholder and regulatory proceedings.[2] 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 and working groups regarding market design matters; publishes proposals, reports and studies on market design issues; and makes filings with the Commission on market design issues.[3] 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.[4] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[5]

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 or that it could be easily resolved.

1 OATT Attachment M § IV.D.
2 *Id.*
3 *Id.*
4 *Id.*
5 OATT Attachment M § VI.A.

New 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,"[6] 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 *2014 Quarterly State of the Market Report for PJM: January through September*, the MMU is making four new recommendations for the third quarter of 2014.

From Section 9, Interchange Transactions

- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. New recommendation.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1200 day-prior to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be utilized to meet load in the most economic manner. (Priority: Medium. New recommendation.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need

6 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

for market participants to schedule physical transactions across seams. Such a solution would include an optimized joint dispatch approach that treats seams between balancing authorizes as a constraint, similar to any other constraint within an LMP market. (Priority: Medium. New recommendation.)

From Section 10, Ancillary Services

- The MMU recommends that the amount of tier 1 MW paid when the non-synchronized reserve market clearing price (NSRMCP) goes above $0 be equal to the tier 1 MW estimated by the RT-SCED market solution, to the extent that PJM continues to pay tier 1 synchronized reserve the SRMCP when the non-synchronized reserve market clearing price is above $0 (e.g. the MMU recommendation to eliminate these payments is not implemented). (Priority: High. New recommendation.)

Complete List of MMU Recommendations

The following recommendations are explained in greater detail in each section of the report.

Section 3, Energy Market

- The MMU has recommended the elimination of FMU and AU adders. Since the implementation of FMU adders, 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. (Priority: Medium. First reported 2012.)

  The MMU and PJM proposed, and on October 31, 2014, the Commission approved, a compromise that maintained the ability of certain generating units to qualify for FMU adders but limiting FMU adders to units with net revenues less than unit going forward costs or ACR.

  The MMU considers this recommendation accepted and will review the results of the Commission order on FMU status for at least 12 months prior to considering any additional recommendation related to FMUs.

- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules. (Priority: Low. First reported Q2, 2014.)
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events. (Priority: Medium. First reported 2012.)
- The MMU recommends that PJM not use the ATSI closed loop interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013.)
- The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule physical power. (Priority: Low. First reported 2013.)

- The MMU recommends that PJM include in the appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed. There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed. (Priority: Low. First reported 2013.)
- 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. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM explain how LMPs are calculated when demand response is marginal. The LMPs in excess of $1,800 per MWh on January 7, 2014, were potentially a result of the way in which PJM modeled zonal (not nodal) demand response as a marginal resource. (Priority: Low. First reported Q1, 2014.)
- The MMU recommends that PJM create and implement clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. (Priority: Medium. First reported Q1, 2014.)

Section 4, Energy Uplift

- The MMU recommends that PJM clearly identify, classify all reasons for incurring operating reserves in the Day-Ahead and the Real-Time Energy Markets and the associated operating reserve charges in order for all market participants be aware of the reason of these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves. (Priority: Medium. First reported 2012.)
- The MMU recommends that PJM be transparent in the formulation of closed loop interfaces with adjustable limits and develop rules to reduce the levels of subjectivity around the creation and implementation of these interfaces. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM estimate the impact such interfaces could have on additional uplift payments inside closed loops, transmission planning, offer capping, FTR and ARR revenue, ancillary services markets and the capacity market to avoid unintended consequences. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of operating reserve charges by unit and the detailed reasons for the level of operating reserve payments by unit in the PJM region. (Priority: High. First reported 2013.)
- The MMU recommends the elimination of the day-ahead operating reserve category to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2013.)
- The MMU recommends not compensating self-scheduled units for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours. (Priority: Low. First reported 2013.)

- 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. (Priority: High. First reported 2012.)
  - 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 committed in real time. (Priority: Medium. First reported 2012.)
  - 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 committed in real time. (Priority: Medium. First reported 2012.)
  - The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost. (Priority: Medium. First reported 2012.)
- The MMU recommends that up-to congestion transactions be required to pay operating reserve charges. (Priority: High. First reported 2013.)
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. (Priority: High. First reported 2013.)
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements. (Priority: Medium. First reported 2013.)
- 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 the operating reserve credits calculation. (Priority: Medium. First reported 2012.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above which is currently allocated to real-time RTO load. (Priority: Low. First reported Q2, 2014.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves and the timing of commitment decisions. (Priority: High. First reported Q1, 2014.)

Section 5, Capacity[7]

- The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant Delivery Year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports. (Priority: High. First reported 2013.)
- The MMU recommends that the definition of demand side resources be modified in order to ensure that such resources be fully substitutable for other generation capacity resources. Both the Limited and the Extended Summer DR products should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as generation capacity resources. (Priority: High. First reported 2013.)
- The MMU recommends that the use of the 2.5 percent demand adjustment (Short Term Resource Procurement Target) be terminated immediately. The 2.5 percent should be added back to the overall market demand curve. (Priority: Medium. First reported 2013.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas in RPM be redefined. A detailed reliability analysis of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013.)
- The MMU recommends that there be an explicit requirement that Capacity Resource offers in the Day-Ahead Energy Market be competitive, where

7 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports.

competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013.)

- The MMU recommends that clear, explicit operational protocols be defined for recalling the energy output of Capacity Resources when PJM is in an emergency condition. PJM has modified these protocols, but they need additional clarification and operational details. (Priority: Low. First reported 2013.)
- The MMU recommends improvements to the performance incentive requirements of RPM:
  - The MMU recommends that Generation Capacity Resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. One hundred percent of capacity market revenue should be at risk rather than only fifty percent. (Priority: High. First reported 2013.)
  - The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage. (Priority: Medium. First reported 2013.)
  - 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. (Priority: Medium. First reported 2013.)
  - The MMU recommends that PJM eliminate the broad exception related to lack of gas during the winter period for single-fuel, natural gas-fired units. (Priority: Medium. First reported 2013.)

Section 6, Demand Response

- The MMU recommends that there be only one demand response product, with an obligation to respond when called for all hours of the year, and that the demand response be on the demand side of the capacity market. (Priority: High. First reported 2013.)
- The MMU recommends that the emergency load response program be classified as an economic program, responding to economic price signals and not an emergency program responding only after an emergency is called. (Priority: High. First reported 2012.)
- The MMU recommends that a daily must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources. (Priority: High. First reported 2013.)
- The MMU recommends that demand response programs adopt an offer cap equal to the offer cap applicable to energy offers from generation capacity resources, currently $1,000 per MWh. (Priority: High. First reported 2013.)
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. This recommendation has been adopted. (Priority: Medium. First reported 2013.)
- The MMU recommends that demand resources be required to provide their nodal location on the electricity grid. (Priority: High. First reported 2013.)
- The MMU recommends that measurement and verification methods for demand resources be further modified to more accurately reflect compliance. (Priority: Medium. First reported 2012.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions. (Priority: Medium. First reported 2013.)
- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance. (Priority: Medium. First reported 2013.)

- The MMU recommends that demand resources whose load drop method is designated as “Other” explicitly record the method of load drop. (Priority: Low. First reported 2013.)
- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately resemble the conditions of an emergency event. (Priority: Low. First reported 2013.)

Section 7, Net Revenue

There are no recommendations in this section.

Section 8, Environmental

There are no recommendations in this section.

Section 9, Interchange Transactions

- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. New recommendation.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1200 day-prior to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be utilized to meet load in the most economic manner. (Priority: Medium. New recommendation.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized joint dispatch approach that treats seams between balancing authorizes as a constraint, similar to any other constraint within an LMP market. (Priority: Medium. New recommendation.)
- The MMU recommends 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. (Priority: Medium. First reported 2012.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction. (Priority: Medium. First reported 2013.)
- The MMU recommends that the validation also require market participants to submit transactions on market paths that reflect the expected actual flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU’s proposed validation rules would address sham scheduling. (Priority: High. First reported 2012.)
- The MMU recommends that PJM eliminate the NIPSCO and Southeast interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM immediately provide the required 12-month notice to PEC to unilaterally terminate the Joint Operating Agreement. (Priority: Low. First reported 2013.)

- The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number of external buses and selecting buses in close proximity on either side of the border with comparable bus weights. (Priority: Medium. First reported 2012.)

Section 10, Ancillary Services

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor throughout the optimization, assignment and settlement process. (Priority: High. First reported 2013.)
- The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately. (Priority: High. First reported 2013.)
- The MMU recommends that the amount of tier 1 MW paid when the non-synchronized reserve market clearing price (NSRMCP) goes above $0 be equal to the tier 1 MW estimated by the RT-SCED market solution, to the extent that PJM continues to pay tier 1 synchronized reserve the SRMCP when the non-synchronized reserve market clearing price is above $0 (e.g. the MMU recommendation to eliminate these payments is not implemented). (Priority: High. New recommendation.)
- The MMU recommends that the tier 2 synchronized reserve must-offer provision of scarcity pricing be enforced. As of the end of September 2014 compliance with the tier 2 must-offer provision is 96.6 percent. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM be more explicit about why tier 1 biasing is used in the optimized solution to the Tier 2 Synchronized Reserve Market. 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. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM determine why secondary reserve was either unavailable or not dispatched on September 10, 2013, January 6, 2014, and January 7, 2014, and that PJM replace the DASR Market with a real time secondary reserve product that is available and dispatchable in real time. (Priority: Low. First reported 2013.)
- The MMU recommends that 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. (Priority: Low. First reported 2013.)
- The MMU recommends that the three pivotal supplier test be incorporated in the DASR Market. (Priority: Low. First reported 2012.)

Section 11, Congestion and Marginal Losses

There are no recommendations in this section.

Section 12, Planning

- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. (Priority: Low. First reported 2013.)
- The MMU recommends that rules be implemented to permit competition to provide financing of transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013.)
- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors. (Priority: Low. First reported 2013.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly

when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013.)

- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013.)
- The MMU recommends an analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. (Priority: Medium. First reported Q1, 2014.)

Section 13, FTRs and ARRs

- The MMU recommends that PJM report correct monthly payout ratios to reduce understatement of payout ratios on a monthly basis. (Priority: Low. First reported 2013.)
- The MMU recommends the elimination of portfolio netting to eliminate cross subsidies among FTR marketplace participants. (Priority: High. First reported 2013.)
- The MMU recommends the elimination of subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2013.)
- The MMU recommends the elimination of geographic cross subsidies. (Priority: High. First reported 2013.)
- The MMU recommends the improvement of transmission outage modeling in the FTR auction models. (Priority: Low. First reported 2013.)
- The MMU recommends the reduction of FTR sales on paths with persistent overallocation of FTRs including clear rules for what defines persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013.)
- The MMU recommends the implementation of a seasonal ARR and FTR allocation system to better represent outages. (Priority: Medium. First reported 2013.)
- The MMU recommends the elimination of the over allocation requirement of ARRs in the Annual ARR Allocation process. (Priority: High. First reported 2013.)
- The MMU recommends that the FTR forfeiture rule be applied to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids. (Priority: High. First reported 2013.)
- The MMU recommends that PJM not use the ATSI Interface or create similar closed loop interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product. Market prices should be a function of market fundamentals. The MMU recommends that, in general, the implementation of closed loop interface constraints be studied in advance and, if there is good reason to implement, implemented so as to include them in the FTR Auction model to minimize their impact on FTR funding. (Priority: Medium. First reported 2013.)

Energy Market

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for the first nine months of 2014, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM Energy Market results were competitive in the first nine months of 2014.

Table 3-1 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 nine months of 2014 was moderately concentrated. Based on the hourly Energy Market measure, average HHI was 1154 with a minimum of 930 and a maximum of 1468 in the first nine months of 2014.
- 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, although the behavior of some participants during periods of high demand raises concerns about economic withholding.
- 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. The expanding role of UTCs in the Day-Ahead Energy Market continues to cause concerns. Issues related to the definition of gas costs includable in offers and the impact of the uncertainty around gas costs during high demand periods also need to be addressed.

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

1 Analysis of 2014 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 *2013 State of the Market Report for PJM*, Appendix A, "PJM Geography."

2 OATT Attachment M.

basis for competitive outcomes) and on limiting market power mitigation to instances where the market structure is not competitive and thus where market design alone cannot mitigate market power. In the PJM Energy Market, this occurs only in the case of local market power. When a transmission constraint creates the potential for local market power, PJM applies a structural test to determine if the local market is competitive, applies a behavioral test to determine if generator offers exceed competitive levels and applies a market performance test to determine if such generator offers would affect the market price.[3] There are currently no market power mitigation rules in place that limit the ability to exercise market power when aggregate market conditions are extremely tight.

Overview

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. Average offered real-time generation decreased by 4,934 MW, or 2.8 percent, from 175,960 MW in the first nine months of 2013 to 171,026 MW in the first nine months of 2014.[4] In the first nine months of 2014, 2,515 MW of new capacity were added to PJM. This new generation was more than offset by the deactivation of 12 units (1,526 MW) since January 1, 2014.

  PJM average real-time generation in the first nine months of 2014 increased by 2.2 percent from the first nine months of 2013, from 90,432 MW to 92,449 MW. The PJM average real-time generation in the first nine months of 2014 would have increased by 1.4 percent from the first nine months of 2013, from 90,432 MW to 91,701 MW, if the EKPC Transmission Zone had not been included.[5]

  PJM average day-ahead supply in the first nine months of 2014, including INCs and up-to congestion transactions, increased by 8.5 percent from the first nine months of 2013, from 148,489 MW to 161,137 MW. The PJM average day-ahead supply, including INCs and up-to congestion transactions, would have increased by 7.8 percent from the first nine months of 2013, from 148,489 MW to 160,078 MW, if the EKPC Transmission Zone had not been included. The day-ahead supply growth was 286.4 percent higher than the real-time generation growth as a result of the continued growth, until September 8, 2014, of up-to congestion transactions.

- **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.

- **Generation Fuel Mix.** During the first nine months of 2014, coal units provided 44.4 percent, nuclear units 33.7 percent and gas units 17.1 percent of total generation. Compared to the first nine months of 2013, generation from coal units increased 2.3 percent, generation from gas units increased 6.0 percent and generation from nuclear units remained the same.

- **Marginal Resources.** In the PJM Real-Time Energy Market, during the first nine months of 2014, coal units were 49.8 percent of marginal resources and natural gas units were 42.4 percent of marginal resources. In the first nine months of 2013, coal units were 57.6 percent and natural gas units were 34.1 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market, during the first nine months of 2014, up-to congestion transactions were 93.6 percent of marginal resources, INCs were 1.6 percent of marginal resources, DECs were 2.2 percent of marginal resources, and generation resources were 2.5 percent of marginal resources in the first nine months of 2014.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM system peak load during the first nine months of 2014 was 141,673 MW in the HE 1700 on June 17, 2014, which was 15,835 MW, or 10.1 percent, lower than the PJM peak load for the first nine months of 2013, which was 157,508 MW in the HE 1700 on July 18, 2013.

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

5 The EKPC Zone was integrated on June 1, 2013.

PJM average real-time load in the first nine months of 2014 increased by 1.6 percent from the first nine months of 2013, from 89,123 MW to 90,567 MW. The PJM average real-time load in the first nine months of 2014 would have increased by 0.7 percent from the first nine months of 2013, from 89,123 MW to 89,707 MW, if the EKPC Transmission Zone had not been included.

PJM average day-ahead demand in the first nine months of 2014, including DECs and up-to congestion transactions, increased by 7.9 percent from the first nine months of 2013, from 145,139 MW to 156,542 MW. The PJM average day-ahead demand, including DECs and up-to congestion transactions, would have increased by 7.1 percent from the first nine months of 2013, from 145,139 MW to 155,420 MW, if the EKPC Transmission Zone had not been included. The day-ahead demand growth was 393.8 percent higher than the real-time load growth as a result of the continued growth, until September 8, 2014, of up-to congestion transactions.

- **Supply and Demand: 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. For the first nine months of 2014, 10.2 percent of real-time load was supplied by bilateral contracts, 27.4 percent by spot market purchases and 62.5 percent by self-supply. Compared with 2013, reliance on bilateral contracts decreased 0.4 percentage points, reliance on spot market purchases increased by 2.4 percentage points and reliance on self-supply decreased by 1.9 percentage points.

- **Supply and Demand: Scarcity.** In the first nine months of 2014, shortage pricing was triggered on two days in PJM. On January 6, shortage pricing was triggered by a voltage reduction action that was issued at 1950 EPT and terminated at 2045. On January 7, shortage pricing was triggered by shortage of primary and synchronized reserves starting in the hour beginning 0700 EPT and was in effect until 1220 during the morning peak as well as between 1755 and 1810 during the evening peak.

Market Behavior

- **Offer Capping for Local Market Power.** 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 Day-Ahead Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours remained at 0.2 percent in the first nine months of 2013 and 2014. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours increased from 0.4 percent in the first nine months of 2013 to 0.5 percent in the first nine months of 2014.

  In the first nine months of 2014, 13 control zones experienced congestion resulting from one or more constraints binding for 75 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.

- **Offer Capping for Reliability.** PJM also offer caps units that are committed for reliability reasons, specifically for black start service and reactive service. In the Day-Ahead Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 3.0 percent in the first nine months of 2013 to 0.3 percent in the first nine months of 2014. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours decreased from 2.5 percent in the first nine months of 2013 to 0.3 percent in the first nine months of 2014.

- **Markup Index.** The markup index is a summary measure of participant offer behavior for individual marginal units. In the PJM Real-Time Energy Market in the first nine months of 2014, 73.9 percent of marginal units had an average markup index less than or equal to 0.0. Nonetheless, some marginal units do have substantial markups. In the first nine months of 2014, 9.0 percent of units had average dollar markups greater than or equal to $150. Only 4.5 percent of units had average dollar markups greater than or equal to $150 in the first nine months of 2013. Markups increased during the high demand days in January.

In the PJM Day-Ahead Energy Market in the first nine months of 2014, 94.8 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.02. Nonetheless, some marginal units do have substantial markups.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** Of the 104 units eligible for FMU or AU status in at least one month during the first nine months of 2014, 46 units (44.2 percent) were FMUs or AUs for all nine months, and 16 units (15.4 percent) qualified in only one month.

- **Virtual Offers and Bids.** Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, up-to congestion transactions, import transactions and export transactions as financial instruments that do not require physical generation or load. While up-to congestion transactions (UTC) continued to displace increment offers and decrement bids, there was a sharp decrease in UTCs in September as a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[6]

- **Generator Offers.** Generator offers are categorized as dispatchable and self scheduled. Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are categorized as self scheduled must run. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are categorized as self scheduled and dispatchable. Of all generator offers in the first nine months of 2014, 55.9 percent were offered as available for economic dispatch, 22.8 percent were offered as self scheduled, and 21.3 percent were offered as self scheduled and dispatchable.

Market Performance

- **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 Market prices in the first nine months of 2014 were between $800 and $900 for 4 hours, between $900 and $1,000 for one hour, greater than $1,000 for six hours, and greater than $1,800 for one hour.

  PJM Real-Time Energy Market prices increased in the first nine months of 2014 compared to the first nine months of 2013. The load-weighted average LMP was 47.4 percent higher in the first nine months of 2014 than in the first nine months of 2013, $58.60 per MWh versus $39.75 per MWh.

  PJM Day-Ahead Energy Market prices increased in the first nine months of 2014 compared to the first nine months of 2013. The load-weighted average LMP was 49.6 percent higher in the first nine months of 2014 than in the first nine months of 2013, $59.09 per MWh versus $39.49 per MWh.[7]

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

  In the PJM Real-Time Energy Market, for the first nine months of 2014, 29.8 percent of the load-weighted LMP was the result of coal costs, 36.9 percent was the result of gas costs and 0.65 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market, for the first nine months of 2014, 23.3 percent of the load-weighted LMP was the result of the cost of gas, 18.5 percent was the result of the cost of coal, 13.6 percent was the result

6 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

7 Tables reporting zonal and jurisdictional load and prices are in the *2013 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

of the cost of up-to congestion transactions and 15.8 percent was the result of the cost of DEC.

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

  In the PJM Real-Time Energy Market for the first nine months of 2014, the adjusted markup component of LMP was positive, $3.65 per MWh or 6.2 percent of the PJM real-time, load-weighted average LMP. The real-time load-weighted average LMP for the month of March had the highest markup component, $12.33 per MWh using adjusted cost offers, or 16.25 percent of the real-time load-weighted average LMP in March, a substantial increase over 2013. For the first nine months of 2013, the adjusted markup was $0.85 per MWh or 2.1 percent of the PJM real-time load-weighted average LMP.

  In the PJM Day-Ahead Energy Market, marginal INC, DEC and transactions have zero markups. In the first nine months of 2014, the adjusted markup component of LMP resulting from generation resources was -$0.93 per MWh.

  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, although the behavior of some participants during the high demand periods in January raises concerns about economic withholding.

- **Price Convergence.** Hourly and daily price differences between the Day-Ahead and Real-Time Energy Markets fluctuate continuously and substantially from positive to negative. The difference between the average day-ahead and real-time prices was -$0.20 per MWh in the first nine months of 2013 and -$1.04 per MWh in the first nine months of 2014. The degree of convergence, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

- In the first nine months of 2014, shortage pricing was triggered on two days in January. On January 6, shortage pricing was triggered by a voltage reduction action that was issued at 1950 EPT and terminated at 2045. On January 7, shortage pricing was triggered by a shortage of primary and synchronized reserves starting in the hour beginning 0700 EPT and was in effect until 1220 during the morning peak as well as between 1755 and 1810 during the evening peak.
- The performance of the PJM markets under scarcity conditions raised a number of concerns including concerns related to capacity market incentives, participant offer behavior under tight market conditions, natural gas availability and pricing, demand response and interchange transactions.

Recommendations

- The MMU has recommended the elimination of FMU and AU adders. Since the implementation of FMU adders, 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. (Priority: Medium. First reported 2012.)

  The MMU and PJM proposed, and on October 31, 2014, the Commission approved, a compromise that maintained the ability of certain generating units to qualify for FMU adders but limiting FMU adders to units with net revenues less than unit going forward costs or ACR.[8]

  The MMU considers this recommendation accepted and will review the results of the Commission order on FMU status for at least 12 months prior to considering any additional recommendation related to FMUs.

8 149 FERC ¶ 61,091 (2014).

- The MMU recommends that PJM require all generating units to identify the fuel type associated with each of their offered schedules. (Priority: Low. First reported Q2, 2014.)
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[9] (Priority: Medium. First reported 2012.)
- The MMU recommends that PJM not use the ATSI closed loop interface or create similar interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM update the outage impact studies, the reliability analyses used in RPM for capacity deliverability and the reliability analyses used in RTEP for transmission upgrades to be consistent with the more conservative emergency operations (post contingency load dump limit exceedance analysis) in the energy market that were implemented in June 2013. (Priority: Low. First reported 2013.)
- The MMU recommends that the roles of PJM and the transmission owners in the decision making process to control for local contingencies be clarified, that PJM's role be strengthened and that the process be made transparent. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule physical power. (Priority: Low. First reported 2013.)
- There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[10] The MMU recommends that PJM include in the appropriate manual an explanation of the initial creation of hubs, the process for modifying hub definitions and a description of how hub definitions have changed.[11] (Priority: Low. First reported 2013.)
- 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. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013.)
- The LMPs in excess of $1,800 per MWh on January 7, 2014, were potentially a result of the way in which PJM modeled zonal (not nodal) demand response as a marginal resource. The MMU recommends that PJM explain how LMPs are calculated when demand response is marginal. (Priority: Low. First reported Q1, 2014.)
- The MMU recommends that PJM create and implement clear, explicit and detailed rules that define the conditions under which PJM will and will not recall energy from PJM capacity resources and prohibit new energy exports from PJM capacity resources. The MMU recommends that those rules define the conditions under which PJM will purchase emergency energy while at the same time not recalling energy exports from PJM capacity resources. (Priority: Medium. First reported Q1, 2014.)

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first nine months of 2014, including aggregate supply and demand, concentration ratios, three pivotal supplier test

9 PJM OATT, 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.
10 The general definition of a hub can be found in "Manual 35: Definitions and Acronyms," Revision 23 (April 11, 2014).
11 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.

results, offer capping, participation in demand response programs, loads and prices.

Average real-time offered generation decreased by 4,934 MW in the first nine months of 2014 compared to the first nine months of 2013, while peak load decreased by 15,835 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 the impact of the price elasticity of demand on prices. Energy market results for the first nine months of 2014 generally reflected supply-demand fundamentals, although the behavior of some participants during the high demand periods in January raises concerns about economic withholding. These issues relate to the ability to increase markups substantially in tight market conditions, to the uncertainties about the pricing and availability of natural gas, and to the lack of adequate incentives for unit owners to take all necessary actions to acquire fuel and operate rather than take an outage.

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

PJM also offer caps units that are committed for reliability reasons in addition to units committed to provide constraint relief. Specifically, units that are committed to provide reactive support and black start service are offer capped in the energy market. These units are committed manually in both the Day-Ahead and Real-Time Energy Markets. Before 2011, these units were generally economic in the energy market. Since 2011, the percentage of hours when these units were not economic in the Real-Time Energy Market has steadily increased. In the Day-Ahead Energy Market, PJM started to commit these units as offer capped in September 2012, as part of a broader effort to maintain consistency between Real-Time and Day-Ahead Energy Markets.

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

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

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 scarcity pricing rules in 2012. There are significant issues with the scarcity pricing net revenue true up mechanism in the PJM scarcity pricing design, which will create issues when scarcity pricing occurs.

The overall energy market results support the conclusion that energy prices in PJM are set, generally, by marginal units operating at, or close to, their marginal costs, although this was not always the case during the high demand hours in January. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods in January raises concerns about economic withholding. Given the structure of the Energy Market, the tighter markets and the change in some participants' behavior are sources of concern in the Energy Market. The MMU concludes that the PJM energy market results were competitive in the first nine months of 2014.

Market Structure

Market Concentration

Analyses of supply curve segments of the PJM Energy Market for the first nine months of 2014 indicate moderate concentration in the base load segment, but high concentration in the intermediate and peaking segments.[13] 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 nine months of 2014.

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 3-2).

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.[14]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM Energy Market during the first nine months of 2014 was moderately concentrated (Table 3-2).

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

14 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).

Table 3-2 PJM hourly Energy Market HHI: January through September, 2013 and 2014[15]

	Hourly Market HHI (Jan - Sep, 2013)	Hourly Market HHI (Jan - Sep, 2014)
Average	1180	1154
Minimum	871	930
Maximum	1610	1468
Highest market share (One hour)	31%	29%
Average of the highest hourly market share	22%	21%
# Hours	6,551	6,551
# Hours HHI > 1800	0	0
% Hours HHI > 1800	0%	0%

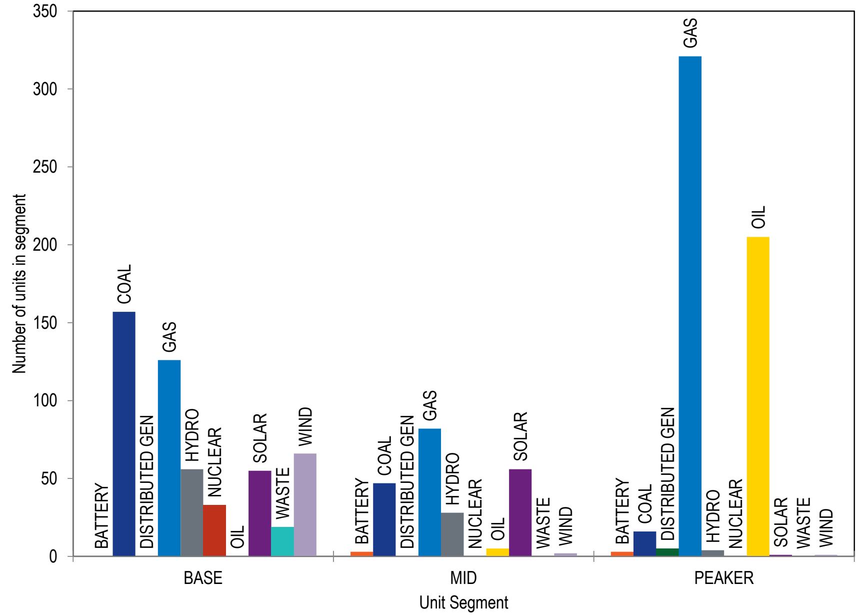
Table 3-3 includes HHI values by supply curve segment, including base, intermediate and peaking plants for the first nine months of 2013 and 2014.

Table 3-3 PJM hourly Energy Market HHI (By supply segment): 2013 and 2014

	Jan - Sep, 2013			Jan - Sep, 2014		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	901	1095	1484	1038	1181	1484
Intermediate	835	2266	8429	771	1914	6533
Peak	694	6329	10000	702	5940	10000

Figure 3-1 shows the number of units in the baseload, intermediate and peaking segments by fuel source in the first nine months of 2014.

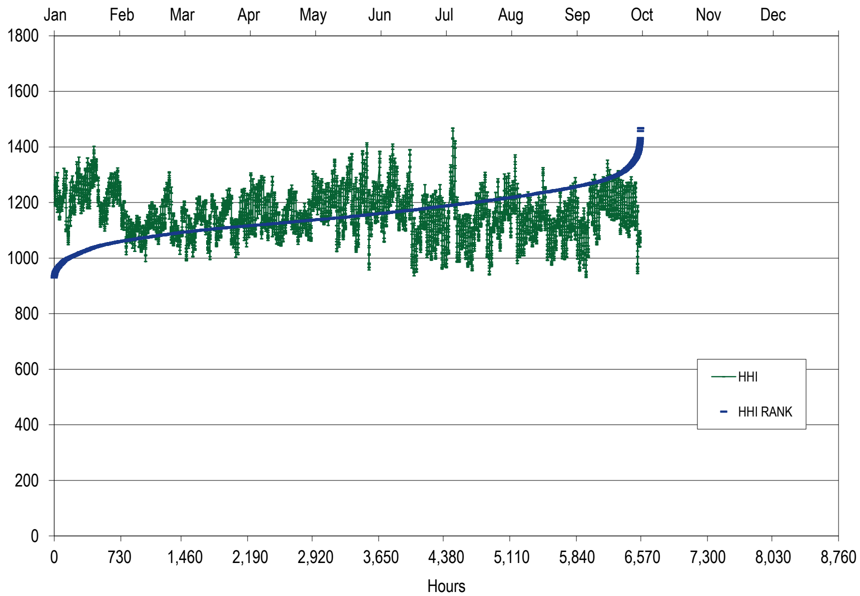
Figure 3-1 Fuel source distribution in unit segments: January through September, 2014



15 This analysis includes all hours in the first nine months of 2014, regardless of congestion.

Figure 3-2 presents the hourly HHI values in chronological order and an HHI duration curve for the first nine months of 2014.

Figure 3-2 PJM hourly Energy Market HHI: January through September, 2014



Ownership of Marginal Resources

Table 3-4 shows the contribution to PJM real-time, load-weighted LMP by individual marginal resource owner.[16] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of the first nine months of 2014, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. The results show that in the first nine months of 2014, the offers of one company contributed 17.1. percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 53.8 percent of the real-time, load-weighted, average PJM system LMP. During the first nine months of 2013, the offers of one company contributed 21.7 percent of the real time, load-weighted PJM system LMP and offers of the top four companies contributed 60.3 percent of the real-time, load-weighted, average PJM system LMP.

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

Table 3-4 Marginal unit contribution to PJM real-time, load-weighted LMP (By parent company): January through September 2013 and 2014

2013 (Jan-Sep)		2014 (Jan-Sep)	
Company	Percent of Price	Company	Percent of Price
1	21.7%	1	17.7%
2	21.4%	2	16.1%
3	10.3%	3	12.2%
4	7.0%	4	7.7%
5	5.1%	5	6.2%
6	4.7%	6	5.5%
7	3.7%	7	5.3%
8	3.5%	8	3.7%
9	3.2%	9	3.4%
Other (58 companies)	19.5%	Other (60 companies)	22.1%

Table 3-5 shows the contribution to PJM day-ahead, load-weighted LMP by individual marginal resource owners.[17] The contribution of each marginal resource to price at each load bus is calculated hourly and summed by company. The marginal resource owner with the largest impact on PJM day-ahead, load-weighted LMP (20.6 percent), in the first nine months of 2013 also had the largest impact (13.8 percent) in the first nine months of 2014.

Table 3-5 Marginal resource contribution to PJM day-ahead, load-weighted LMP (By parent company): January through September 2013 and 2014

2013 (Jan - Sep)		2014 (Jan - Sep)	
Company	Percent of Price	Company	Percent of Price
1	20.6%	1	13.8%
2	10.4%	2	8.1%
3	8.4%	3	6.5%
4	7.9%	4	6.1%
5	7.4%	5	5.3%
6	4.9%	6	3.6%
7	4.0%	7	3.5%
8	3.4%	8	2.8%
9	3.1%	9	2.7%
Other (139 companies)	29.9%	Other (143 companies)	47.6%

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

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 in the Day-Ahead Energy Market. INC offers, DEC bids and up-to congestion transactions are dispatchable injections and withdrawals in the Day-Ahead Energy Market that can set price via their offers and bids.

Table 3-6 shows the type of fuel used by marginal resources in the Real-Time Energy Market. There can be more than one marginal resource in any given interval as a result of transmission constraints. In the first nine months of 2014, coal units were 49.77 percent and natural gas units were 42.40 percent of marginal resources. In the first nine months of 2013, coal units were 57.56 percent and natural gas units were 34.13 percent of the total marginal resources.

The results reflect the dynamics of an LMP market. When there is a single constraint, there are two marginal units. For example, a significant west to east constraint could be binding with a gas unit marginal in the east and a coal unit marginal in the west. As a result, although the dispatch of natural gas units has increased and gas units set price for more hours as marginal resources in the Real-Time Energy Market, this does not necessarily reduce the proportion of hours in which coal units are marginal.[18] In the first nine months of 2014, 75.24 percent of the wind marginal units had negative offer prices, 22.84 percent had zero offer prices and 1.74 percent had positive offer prices.

Table 3-6 Type of fuel used (By real-time marginal units): January through September 2013 and 2014

Type/Fuel	2013 (Jan-Sep)	2014 (Jan-Sep)
Coal	57.56%	49.77%
Gas	34.13%	42.40%
Wind	4.75%	3.86%
Oil	3.22%	3.46%
Other	0.21%	0.35%
Uranium	0.02%	0.06%
Emergency DR	0.03%	0.05%
Municipal Waste	0.08%	0.04%

Table 3-7 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first nine months of 2014, up-to congestion transactions were 93.57 percent of the total marginal resources. Up-to congestion transactions were 96.11 percent of the total marginal resources in the first nine months of 2013.[19]

Table 3-7 Day-ahead marginal resources by type/fuel: January through September 2013 and 2014

Type/Fuel	2013 (Jan - Sep)	2014 (Jan - Sep)
Up-to Congestion Transaction	96.11%	93.57%
DEC	1.24%	2.19%
INC	1.01%	1.59%
Coal	0.97%	1.43%
Gas	0.44%	0.95%
Wind	0.16%	0.12%
Dispatchable Transaction	0.06%	0.08%
Price Sensitive Demand	0.01%	0.01%
Municipal Waste	0.00%	0.00%
Oil	0.00%	0.02%
Import	0.00%	0.03%
Other	0.00%	0.02%
Total	100.00%	100.00%

18 For the generation units that are capable of using multiple fuel types, PJM does not require the participants to disclose the fuel type associated with their offer schedule. For these units, the cleared offer schedules on a given day were compared to the cost associated with each fuel to determine the fuel type most likely to have been the basis for the cleared schedule.

19 PJM acknowledged an error in identifying marginal up-to congestion transactions following April 2013 changes to the day-ahead solution software. The software incorrectly increased the volume of marginal up-to congestion transactions. The fix to the problem is expected to be in place in 2014.

Figure 3-3 shows, for the day-ahead market between January 1 and September 30 of 2014, the daily proportion of marginal resources that were up-to congestion transaction and/or generation units. The percentage of marginal up-to congestion transactions decreased significantly beginning on September 8, 2014, as a result of the FERC's UTC uplift refund notice which became effective on September 8, 2014.[20] The percentage of marginal up-to congestion transaction decreased and that of generation units increased. Figure 3-4 shows the percentage of marginal up-to congestion transaction and marginal generation units from August 18, 2014 through September 30, 2014. The percentage of marginal up-to congestion transaction decreased and that of generation units, INCs and DECs increased.

Figure 3-3 Day-ahead marginal up-to congestion transaction and generation units: January through September 2014

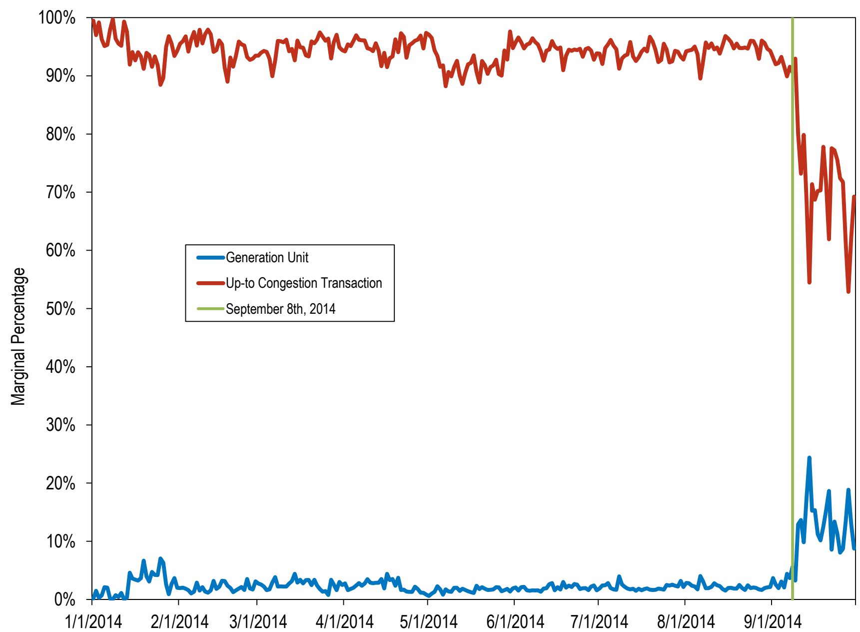
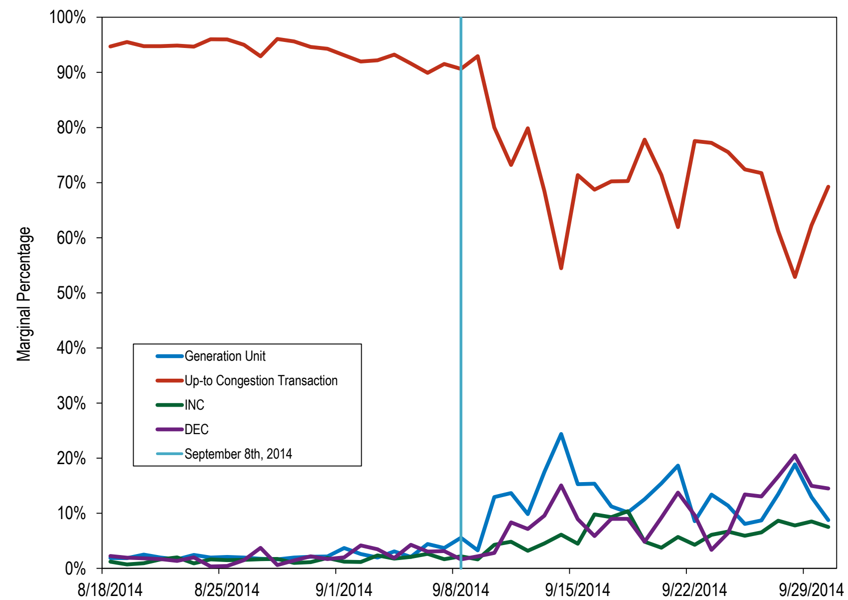


Figure 3-4 Day-ahead marginal up-to congestion transaction and generation units: August 18, 2014, through September 30, 2014



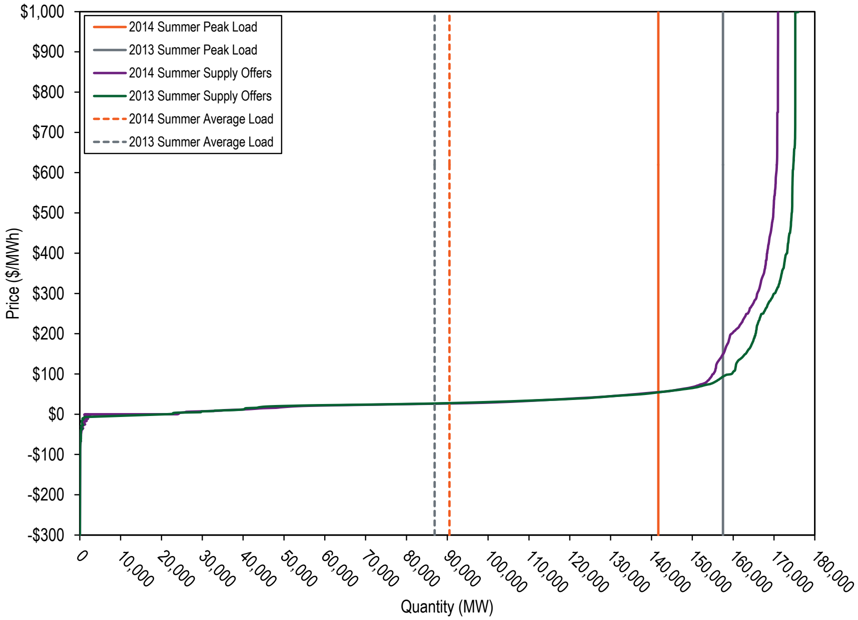
Supply

Supply includes physical generation and imports and virtual transactions.

Figure 3-5 shows the average PJM aggregate real-time generation supply curves, peak load and average load for the first nine months of 2013 and the first nine months of 2014. Total average PJM aggregate real-time generation supply decreased by 4,934 MW, or 2.8 percent, in the first nine months of 2014 from a maximum of 175,960 MW to 171,026 MW.

20 See 18 CFR § 385.213 (2014).

Figure 3-5 Average PJM aggregate real-time generation supply curves: January through September of 2013 and 2014



Energy Production by Fuel Source

Compared to the first nine months of 2013, generation from coal units increased 2.3 percent and generation from natural gas units increased 5.9 percent (Table 3-8).[21] Natural gas prices increased and coal prices remained relatively constant in the first nine months of 2014. Natural gas prices in the third quarter of 2014 were lower than the third quarter of 2013.

Table 3-8 PJM generation (By fuel source (GWh)): January through September of 2013 and 2014[22]

	2013 (Jan-Sep)		2014 (Jan-Sep)		Change in
	GWh	Percent	GWh	Percent	Output
Coal	267,112.3	44.5%	273,126.4	44.4%	2.3%
Standard Coal	259,835.6	43.2%	265,236.6	43.1%	2.0%
Waste Coal	7,276.7	1.2%	7,889.8	1.3%	0.2%
Nuclear	207,254.4	34.5%	207,170.7	33.7%	(0.0%)
Gas	99,264.9	16.5%	105,197.1	17.1%	6.0%
Natural Gas	97,550.2	16.2%	103,274.6	16.8%	5.9%
Landfill Gas	1,713.1	0.3%	1,786.6	0.3%	4.3%
Biomass Gas	1.7	0.0%	136.0	0.0%	8,000.1%
Hydroelectric	11,144.7	1.9%	11,601.1	1.9%	4.1%
Pumped Storage	5,277.1	0.9%	5,742.0	0.9%	8.8%
Run of River	5,867.6	1.0%	5,859.0	1.0%	(0.1%)
Wind	10,379.3	1.7%	10,723.0	1.7%	3.3%
Waste	3,719.2	0.6%	3,895.9	0.6%	4.8%
Solid Waste	3,111.9	0.5%	3,191.3	0.5%	2.6%
Miscellaneous	607.2	0.1%	704.6	0.1%	16.0%
Oil	1,620.5	0.3%	2,812.9	0.5%	73.6%
Heavy Oil	1,440.3	0.2%	2,351.0	0.4%	63.2%
Light Oil	152.4	0.0%	390.2	0.1%	156.1%
Diesel	14.1	0.0%	51.4	0.0%	264.4%
Kerosene	13.6	0.0%	20.2	0.0%	49.0%
Jet Oil	0.1	0.0%	0.1	0.0%	(56.0%)
Solar	288.4	0.0%	330.6	0.1%	14.6%
Battery	0.4	0.0%	5.8	0.0%	1,250.0%
Total	600,784.1	100.0%	614,863.3	100.0%	2.3%

21 Generation data are the sum of MWh for each fuel by source at every generation bus in PJM with positive output and reflect gross generation without offset for station use of any kind.

22 All generation is total gross generation output and does not net out the MWh withdrawn at a generation bus to provide auxiliary/parasitic power or station power, power to synchronous condenser motors, or power to run pumped storage pumps.

Table 3-9 Monthly PJM generation (By fuel source (GWh)): January through September of 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
Coal	37,833.4	34,845.0	34,350.8	25,940.4	24,165.0	29,969.9	31,489.1	29,277.6	25,255.1	273,126.4
Standard Coal	36,809.3	33,985.5	33,460.1	25,162.7	23,406.8	29,088.3	30,559.5	28,368.4	24,395.9	265,236.6
Waste Coal	1,024.1	859.5	890.7	777.7	758.2	881.6	929.7	909.2	859.2	7,889.8
Nuclear	25,189.6	21,737.8	22,504.1	20,862.6	21,331.1	23,329.3	24,511.9	24,853.1	22,851.2	207,170.7
Gas	11,597.9	9,772.2	11,053.4	8,392.8	10,715.9	12,489.6	13,858.4	14,158.4	13,158.5	105,197.1
Natural Gas	11,377.7	9,566.6	10,845.4	8,185.5	10,508.5	12,274.2	13,636.6	13,946.3	12,933.9	103,274.6
Landfill Gas	207.0	181.3	194.5	197.3	206.4	196.4	199.7	206.4	197.6	1,786.6
Biomass Gas	13.2	24.3	13.5	10.1	1.0	19.0	22.1	5.7	27.1	136.0
Hydroelectric	1,391.3	1,074.4	1,371.9	1,448.9	1,575.4	1,380.0	1,231.6	1,257.5	870.1	11,601.1
Pumped Storage	536.0	530.6	551.0	433.3	606.2	794.5	832.8	857.0	600.7	5,742.0
Run of River	855.3	543.7	821.0	1,015.6	969.2	585.5	398.8	400.6	269.4	5,859.0
Wind	1,918.4	1,342.1	1,661.4	1,697.7	1,238.1	820.3	757.2	566.4	721.4	10,723.0
Waste	407.6	336.6	433.7	421.9	445.8	464.3	469.4	485.2	431.5	3,895.9
Solid Waste	324.2	270.0	342.0	350.6	375.0	381.9	391.8	391.3	364.6	3,191.3
Miscellaneous	83.4	66.6	91.7	71.3	70.8	82.4	77.6	93.8	66.9	704.6
Oil	840.7	69.2	199.3	31.8	173.6	250.2	541.0	463.5	243.6	2,812.9
Heavy Oil	585.2	39.0	132.2	25.1	145.4	231.1	510.2	449.1	233.6	2,351.0
Light Oil	193.4	28.7	64.4	6.4	27.8	18.6	30.1	11.7	9.0	390.2
Diesel	47.3	0.5	1.0	0.0	0.2	0.2	0.2	1.1	0.8	51.4
Kerosene	14.9	1.0	1.6	0.3	0.1	0.2	0.4	1.6	0.2	20.2
Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Solar	16.0	20.2	31.5	42.8	41.4	45.8	48.8	45.3	38.8	330.6
Battery	0.2	0.1	0.2	4.6	0.2	0.1	0.1	0.1	0.1	5.8
Total	79,195.1	69,197.7	71,606.3	58,843.5	59,686.5	68,749.5	72,907.5	71,107.0	63,570.3	614,863.3

Net Generation and Load

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 zonal load-weighted LMP is calculated by weighting the zone's load bus LMPs by the zone's load bus accounting load. The definition of injections and withdrawals of energy as generation or load affects PJM's calculation of zonal load-weighted LMP.

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.

Real-Time Supply

Average offered real-time generation decreased by 4,934 MW, or 2.8 percent, from 175,960 MW in the first nine months of 2013 to 171,026 MW in the first nine months of 2014.[23] The decrease in offered supply was partly offset by the integration of the East Kentucky Power Cooperative (EKPC) Transmission Zone in the second quarter of 2013. In the first nine months of 2014, 1,030 MW of new capacity were added to PJM. This new generation was more than offset by the deactivation of 12 units (1,526MW) since January 1, 2014. The decrease in offered supply in the first nine months of 2014 was in part a result of a 992.8 MW reduction in net capacity between October 2013 and September 2014.[24]

PJM average real-time generation in the first nine months of 2014 increased by 2.2 percent from the first nine months of 2013, from 90,432 MW to 92,449 MW. PJM average real-time generation in the first nine months of 2014 would

23 Calculated values shown in Section 3, "Energy Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.

24 The net capacity additions are calculated by taking the difference between the new generation (1,622 MW) and the retired generation (3,808 MW) after July 1, 2013.

have increased by 1.4 percent from the first nine months of 2013, from 90,432 MW to 91,701 MW, if the EKPC Transmission Zone had not been included in the comparison.[25,26]

PJM average real-time supply, including imports, in the first nine months of 2014 increased by 2.4 percent from the first nine months of 2013, from 95,639 MW to 97,922 MW. PJM average real-time supply, including imports, in the first nine months of 2014 would have increased by 1.6 percent from the first nine months of 2013, from 95,639 MW to 97,175 MW, if the EKPC Transmission Zone had not been included in the comparison.

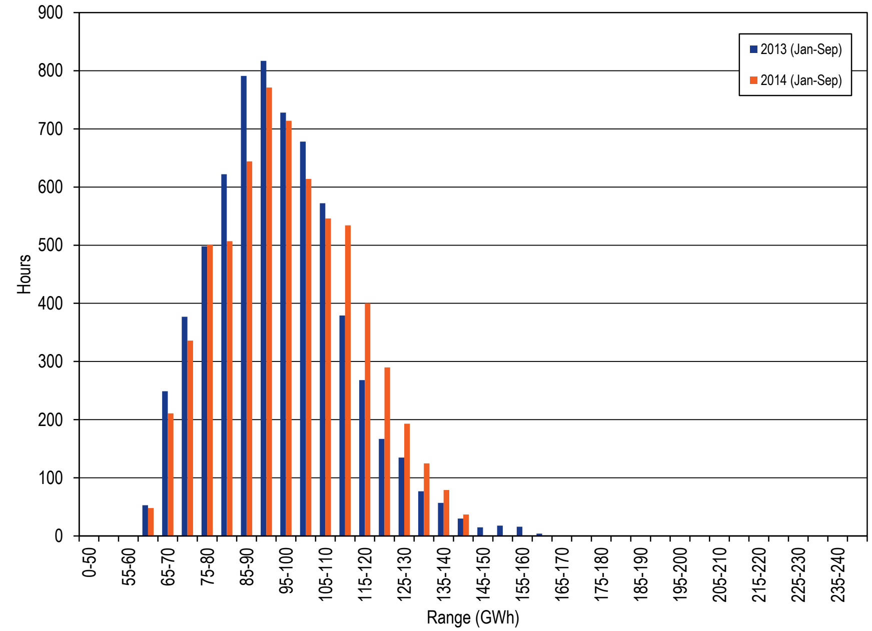
In the PJM Real-Time Energy Market, there are three types of supply offers:

- **Self-Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a specific unit.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. A real-time import must have a valid OASIS reservation when offered, must have available ramp room to support the import, must be accompanied by a NERC e-Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Supply Duration

Figure 3-6 shows the hourly distribution of PJM real-time generation plus imports for the first nine months of 2013 and the first nine months of 2014.

Figure 3-6 Distribution of PJM real-time generation plus imports: January through September of 2013 and 2014[27]



25 The EKPC Transmission Zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013 and 2014.
26 Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

27 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Real-Time, Average Supply

Table 3-10 presents summary real-time supply statistics for each year for the first nine months of each year for the 15-year period from 2000 through 2014.[28]

Table 3-10 PJM real-time average hourly generation and real-time average hourly generation plus average hourly imports: January through September of 2000 through 2014

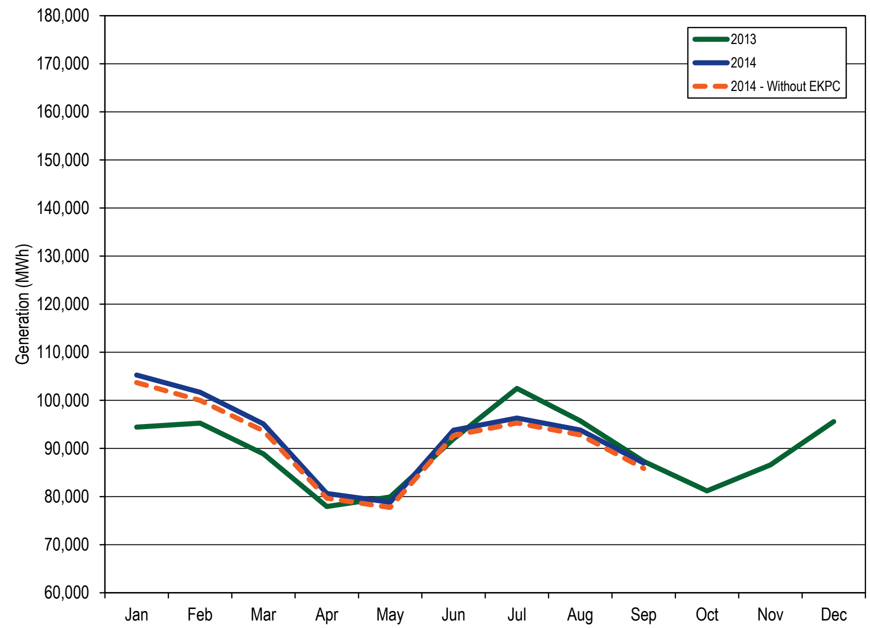
	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
(Jan-Sep)	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2000	30,989	5,216	33,855	5,966	NA	NA	NA	NA
2001	30,304	5,216	33,299	5,571	(2.2%)	0.0%	(1.6%)	(6.6%)
2002	34,467	8,217	38,207	8,540	13.7%	57.5%	14.7%	53.3%
2003	37,211	6,556	40,815	6,526	8.0%	(20.2%)	6.8%	(23.6%)
2004	45,888	11,035	49,990	11,185	23.3%	68.3%	22.5%	71.4%
2005	81,095	16,710	86,330	17,216	76.7%	51.4%	72.7%	53.9%
2006	84,260	14,696	88,621	15,399	3.9%	(12.1%)	2.7%	(10.5%)
2007	87,297	14,853	91,647	15,668	3.6%	1.1%	3.4%	1.7%
2008	85,241	14,203	90,621	14,646	(2.4%)	(4.4%)	(1.1%)	(6.5%)
2009	78,850	14,242	83,986	14,728	(7.5%)	0.3%	(7.3%)	0.6%
2010	84,086	16,346	88,876	17,001	6.6%	14.8%	5.8%	15.4%
2011	86,966	17,369	91,746	18,276	3.4%	6.3%	3.2%	7.5%
2012	90,367	16,893	95,726	17,810	3.9%	(2.7%)	4.3%	(2.5%)
2013	90,432	15,792	95,639	16,729	0.1%	(6.5%)	(0.1%)	(6.1%)
2014	92,449	16,002	97,922	17,064	2.2%	1.3%	2.4%	2.0%

28 The import data in this table is not available before June 1, 2000. The data that includes imports in 2000 is calculated from the last six months of that year.

PJM Real-Time, Monthly Average Generation

Figure 3-7 compares the real-time, monthly average hourly generation in 2013 to the first nine months of 2014 with and without EKPC.

Figure 3-7 PJM real-time average monthly hourly generation: January 2013 through September 2014



Day-Ahead Supply

PJM average day-ahead supply in the first nine months of 2014, including INCs and up-to congestion transactions, increased by 8.5 percent from the first nine months of 2013, from 148,489 MW to 161,137 MW. The PJM average day-ahead supply in the first nine months of 2014, including INCs and up-to congestion transactions, would have increased by 7.8 percent in the first nine months of 2014, from 148,489 MW to 160,078 MW, if the EKPC Transmission Zone had not been included in the comparison.

PJM average day-ahead supply in the first nine months of 2014, including INCs, up-to congestion transactions, and imports, increased by 8.4 percent from the first nine months of 2013, from 150,785 MW to 163,431 MW. PJM average day-ahead supply in the first nine months of 2014, including INCs, up-to congestion transactions, and imports, would have increased by 7.7 percent from the first nine months of 2013, from 150,785 MW to 162,373 MW, if the EKPC Transmission Zone had not been included in the comparison.

The day-ahead supply growth was 286.4 percent higher than the real-time generation growth in the first nine months of 2014, because of the continued growth, until September 8, 2014, of up-to congestion transactions. While up-to congestion transactions (UTC) continued to displace increment offers and decrement bids, there was a sharp decrease in UTCs in September as a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[29]

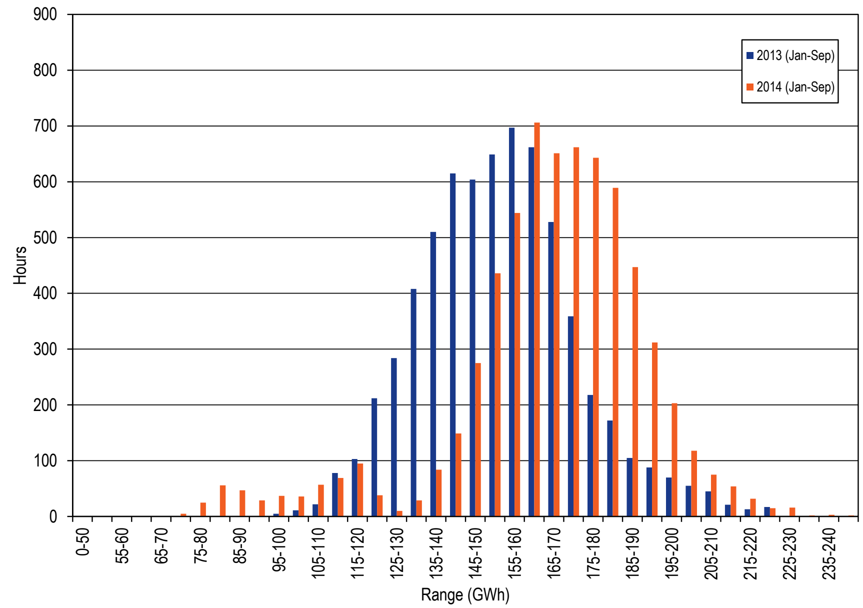
In the PJM Day-Ahead Energy Market, there are five types of financially binding supply offers:

- **Self-Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a unit.
- **Increment Offer (INC).** Financial offer to supply MWh and corresponding offer prices. INCs 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. 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.
- **Import.** An import is an external energy transaction scheduled to PJM from another balancing authority. An import must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An import energy transaction that clears the Day-Ahead Energy Market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an import energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the real-time energy market scheduling process.

PJM Day-Ahead Supply Duration

Figure 3-8 shows the hourly distribution of PJM day-ahead supply, including increment offers, up-to congestion transactions, and imports for the first nine months of 2013 and the first nine months of 2014.

Figure 3-8 Distribution of PJM day-ahead supply plus imports: January through September of 2013 and 2014[30]



29 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

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

PJM Day-Ahead, Average Supply

Table 3-11 presents summary day-ahead supply statistics for the first nine months of each year of the 15-year period from 2000 through 2014.[31]

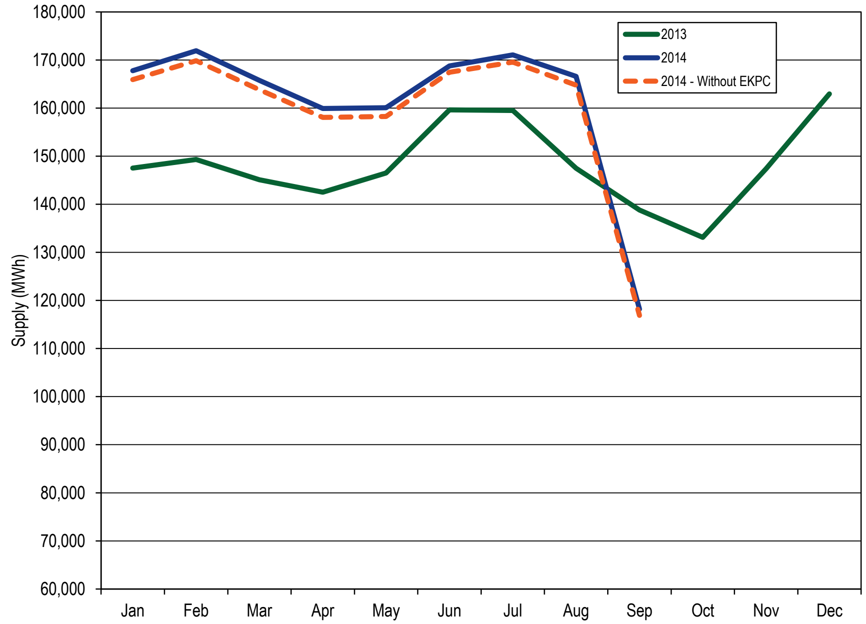
Table 3-11 PJM day-ahead average hourly supply and day-ahead average hourly supply plus average hourly imports: January through September of 2000 through 2014

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
(Jan-Sep)	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2000	27,853	5,340	28,233	5,395	NA	NA	NA	NA
2001	27,519	4,839	28,279	4,911	(1.2%)	(9.4%)	0.2%	(9.0%)
2002	30,080	10,982	30,629	10,992	9.3%	126.9%	8.3%	123.8%
2003	40,024	9,079	40,556	9,066	33.1%	(17.3%)	32.4%	(17.5%)
2004	56,103	13,380	56,799	13,349	40.2%	47.4%	40.0%	47.2%
2005	94,437	18,671	96,315	18,963	68.3%	39.5%	69.6%	42.1%
2006	100,888	18,061	103,029	18,071	6.8%	(3.3%)	7.0%	(4.7%)
2007	110,300	17,561	112,575	17,752	9.3%	(2.8%)	9.3%	(1.8%)
2008	107,367	16,601	109,811	16,717	(2.7%)	(5.5%)	(2.5%)	(5.8%)
2009	98,527	17,462	101,123	17,526	(8.2%)	5.2%	(7.9%)	4.8%
2010	108,309	23,295	111,059	23,464	9.9%	33.4%	9.8%	33.9%
2011	116,988	22,722	119,488	23,015	8.0%	(2.5%)	7.6%	(1.9%)
2012	135,213	18,553	137,670	18,788	15.6%	(18.3%)	15.2%	(18.4%)
2013	148,489	18,858	150,785	19,073	9.8%	1.6%	9.5%	1.5%
2014	161,137	23,922	163,431	24,080	8.5%	26.9%	8.4%	26.2%

PJM Day-Ahead, Monthly Average Supply

Figure 3-9 compares the day-ahead, monthly average hourly supply, including increment offers and up-to congestion transactions, in 2013 to the first nine months of 2014 with and without EKPC. The sharp decrease in UTC MW in September, which resulted in a corresponding decrease in day-ahead supply, was a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[32]

Figure 3-9 PJM day-ahead monthly average hourly supply: January 2013 through September 2014



Real-Time and Day-Ahead Supply

Table 3-12 presents summary statistics for the first nine months of 2013 and the first nine months of 2014, for day-ahead and real-time supply. The last two columns of Table 3-12 are the day-ahead supply minus the real-time supply. The first of these columns is the total day-ahead supply less the total real-time supply and the second of these columns is the total physical day-ahead generation less the total physical real-time generation. In the first nine months of 2014, up-to congestion transactions were 38.2 percent of the total day-ahead supply compared to 33.7 percent in the first nine months of 2013.

31 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

32 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

Table 3-12 Day-ahead and real-time supply (MWh): January through September of 2013 and 2014

		Day Ahead					Real Time		Day Ahead Less Real Time	
	(Jan-Sep)	Generation	INC Offers	Up-to Congestion	Imports	Total Supply	Generation	Total Supply	Total Supply	Total Generation
Average	2013	92,323	5,279	50,888	2,295	150,785	90,432	95,639	55,145	1,891
	2014	95,427	3,359	62,351	2,294	163,431	92,449	97,922	65,509	2,978
Median	2013	91,378	5,292	51,045	2,259	150,598	89,341	94,099	56,499	2,037
	2014	94,776	3,226	65,651	2,268	166,097	91,287	96,679	69,418	3,489
Standard Deviation	2013	16,953	868	10,509	459	19,073	15,792	16,729	2,344	1,160
	2014	16,852	881	17,350	428	24,080	16,002	17,064	7,016	849
Peak Average	2013	102,879	5,551	51,272	2,384	162,086	99,804	105,581	56,505	3,075
	2014	105,800	3,828	62,347	2,463	174,438	101,790	107,959	66,479	4,010
Peak Median	2013	100,661	5,620	52,023	2,368	159,932	98,051	103,561	56,371	2,610
	2014	105,384	3,816	66,186	2,406	177,198	101,266	107,135	70,063	4,119
Peak Standard Deviation	2013	13,985	776	9,793	401	15,937	13,518	14,474	1,463	467
	2014	13,485	800	16,853	389	21,930	13,183	14,063	7,868	302
Off-Peak Average	2013	83,093	5,040	50,552	2,218	140,903	82,238	86,947	53,956	856
	2014	86,357	2,948	62,355	2,147	153,806	84,281	89,146	64,660	2,076
Off-Peak Median	2013	81,594	5,001	50,254	2,129	139,972	80,728	85,235	54,737	866
	2014	85,081	2,851	65,234	2,107	157,517	82,531	87,177	70,340	2,549
Off-Peak Standard Deviation	2013	13,604	874	11,087	491	15,828	12,797	13,396	2,432	808
	2014	14,034	731	17,776	405	21,630	13,603	14,414	7,216	431

Figure 3-10 shows the average hourly cleared volumes of day-ahead supply and real-time supply. The day-ahead supply consists of day-ahead generation, imports, increment offers and up-to congestion transactions. The real-time generation includes generation and imports.

Figure 3-10 Day-ahead and real-time supply (Average hourly volumes): January through September of 2014

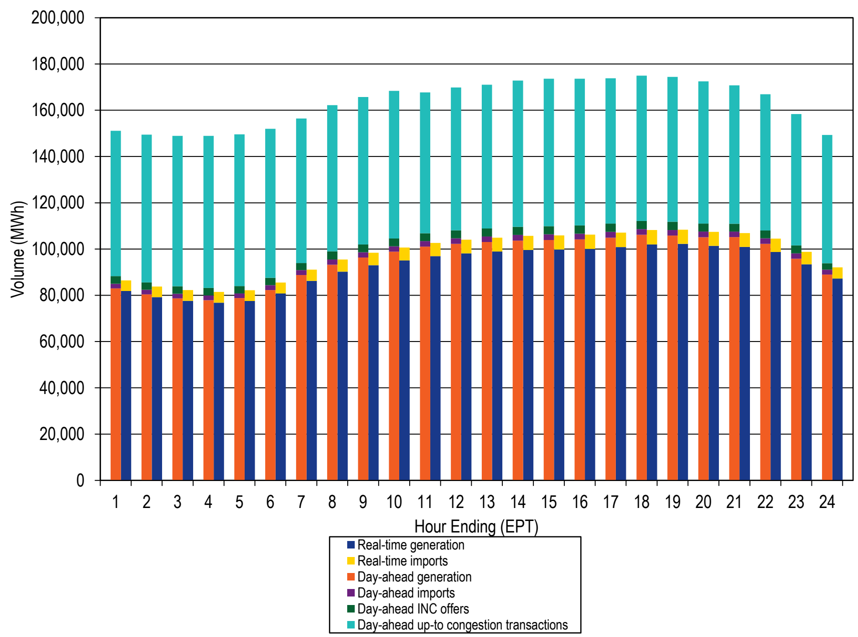


Figure 3-11 shows the difference between the day-ahead and real-time average daily supply in January 2013 through September of 2014.

Figure 3-11 Difference between day-ahead and real-time supply (Average daily volumes): January 2013 through September of 2014

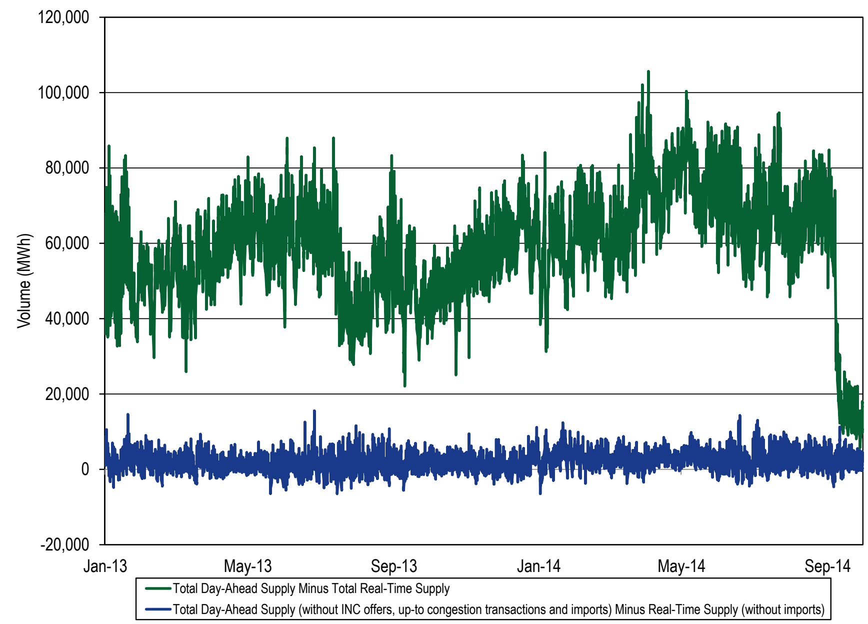
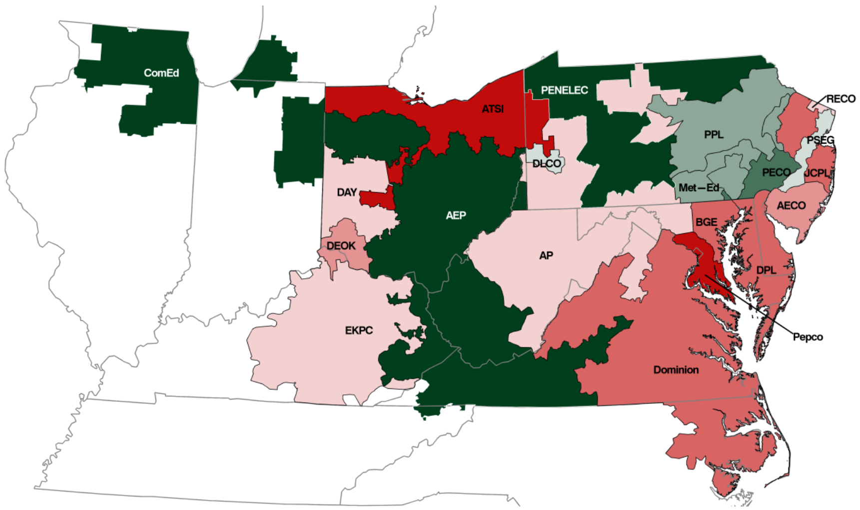


Figure 3-12 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2014. Table 3-13 shows the difference between the PJM real-time generation and real-time load by zone in the first nine months of 2013 and the first nine months of 2014. Figure 3-12 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 3-12 Map of PJM real-time generation less real-time load by zone: January through September of 2014[33]



Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)	Zone	Net Gen Minus Load (GWh)
AECO	(5,473)	ComEd	19,700	DPL	(8,316)	PENELEC	21,486
AEP	18,520	DAY	(1,759)	EKPC	(1,595)	Pepco	(13,865)
AP	(2,032)	DEOK	(5,908)	JCPL	(7,790)	PPL	6,562
ATSI	(10,979)	DLCO	2,042	Met-Ed	4,935	PSEG	729
BGE	(8,067)	Dominion	(9,990)	PECO	15,277	RECO	(1,148)

Table 3-13 PJM real-time generation less real-time load by zone (GWh): January through September of 2013 and 2014

	Zonal Generation and Load (GWh)					
	2013 (Jan - Sep)			2014 (Jan - Sep)		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	1,720.2	8,013.9	(6,293.7)	2,450.0	7,922.8	(5,472.8)
AEP	99,790.3	97,582.4	2,207.9	115,730.6	97,210.9	18,519.7
AP	42,595.9	35,282.2	7,313.7	34,345.1	36,376.7	(2,031.6)
ATSI	41,393.9	50,220.1	(8,826.2)	40,304.0	51,283.2	(10,979.2)
BGE	15,944.6	24,500.6	(8,556.0)	16,464.0	24,530.5	(8,066.5)
ComEd	94,423.0	74,585.7	19,837.4	94,155.0	74,455.2	19,699.8
DAY	12,891.4	12,587.0	304.4	11,122.1	12,881.1	(1,759.0)
DEOK	18,602.4	20,209.2	(1,606.8)	14,713.6	20,621.5	(5,907.9)
DLCO	13,962.7	11,109.6	2,853.1	13,073.4	11,031.7	2,041.8
Dominion	61,604.3	71,237.2	(9,633.0)	62,805.2	72,795.6	(9,990.4)
DPL	5,874.7	14,084.8	(8,210.2)	5,729.5	14,045.1	(8,315.6)
EKPC	3,420.7	3,937.2	(516.5)	8,030.0	9,624.9	(1,594.9)
JCPL	8,523.9	17,636.1	(9,112.2)	9,677.0	17,466.6	(7,789.6)
Met-Ed	15,490.1	11,332.1	4,158.0	16,395.7	11,460.4	4,935.4
PECO	45,148.4	30,480.7	14,667.8	45,657.6	30,380.1	15,277.4
PENELEC	32,773.1	12,889.7	19,883.4	34,448.5	12,962.8	21,485.8
Pepco	6,993.3	23,260.3	(16,266.9)	9,555.6	23,421.0	(13,865.5)
PPL	36,462.3	30,328.6	6,133.7	37,387.9	30,825.7	6,562.2
PSEG	34,804.9	33,390.7	1,414.2	33,586.9	32,857.8	729.1
RECO	0.0	1,177.6	(1,177.6)	0.0	1,148.2	(1,148.2)

Demand

Demand includes physical load and exports and virtual transactions.

Peak Demand

The PJM system load reflects the entire RTO. The PJM Energy Market includes the Real-Time Energy Market and the Day-Ahead Energy Market. In this section, demand refers to physical load and exports and in the Day-Ahead Energy Market also includes virtual transactions, which include decrement bids and up-to congestion transactions.

The PJM system real-time peak load for the first nine months of 2014 was 141,673 MW in the HE 1700 on June 17, 2014, which was 15,835 MW, or 10.1 percent, lower than the peak load for the first nine months of 2013, which

33 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/markets-and-operations/energy/lmp-model-info/bus-model-updates.aspx>. (Accessed on 10/8/2014)

was 157,508 MW in the HE 1700 on July 18, 2013. The EKPC Transmission Zone accounted for 2,128 MW in the peak hour of the first nine months of 2014. The peak load excluding the EKPC Transmission Zone was 139,545 MW, also occurring on June 17, 2014, HE 1700, a decrease of 17,964 MW, or 11.4 percent from the first nine months of 2013.

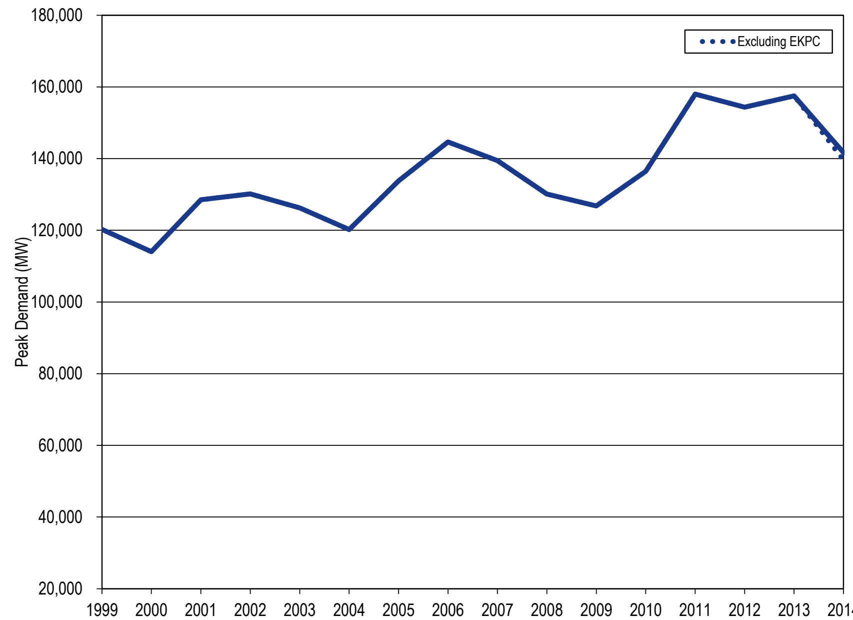
Table 3-14 shows the peak loads for the first nine months of the years 1999 through 2014.

Table 3-14 Actual PJM footprint peak loads: January through September of 1999 to 2014[34]

(Jan - Sep)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (%)
1999	Fri, July 30	17	120,227	NA	NA
2000	Wed, August 09	17	114,036	(6,191)	(5.1%)
2001	Wed, August 08	17	128,535	14,499	12.7%
2002	Thu, August 01	17	130,159	1,625	1.3%
2003	Thu, August 21	17	126,259	(3,900)	(3.0%)
2004	Wed, June 09	17	120,218	(6,041)	(4.8%)
2005	Tue, July 26	16	133,761	13,543	11.3%
2006	Wed, August 02	17	144,644	10,883	8.1%
2007	Wed, August 08	16	139,428	(5,216)	(3.6%)
2008	Mon, June 09	17	130,100	(9,328)	(6.7%)
2009	Mon, August 10	17	126,798	(3,302)	(2.5%)
2010	Tue, July 06	17	136,460	9,662	7.6%
2011	Thu, July 21	17	158,016	21,556	15.8%
2012	Tue, July 17	17	154,344	(3,672)	(2.3%)
2013	Thu, July 18	17	157,508	3,165	2.1%
2014 (with EKPC)	Tue, June 17	17	141,673	(15,835)	(10.1%)
2014 (without EKPC)	Tue, June 17	17	139,545	(17,964)	(11.4%)

Figure 3-13 shows the peak loads for the first nine months of the years 1999 through 2014.

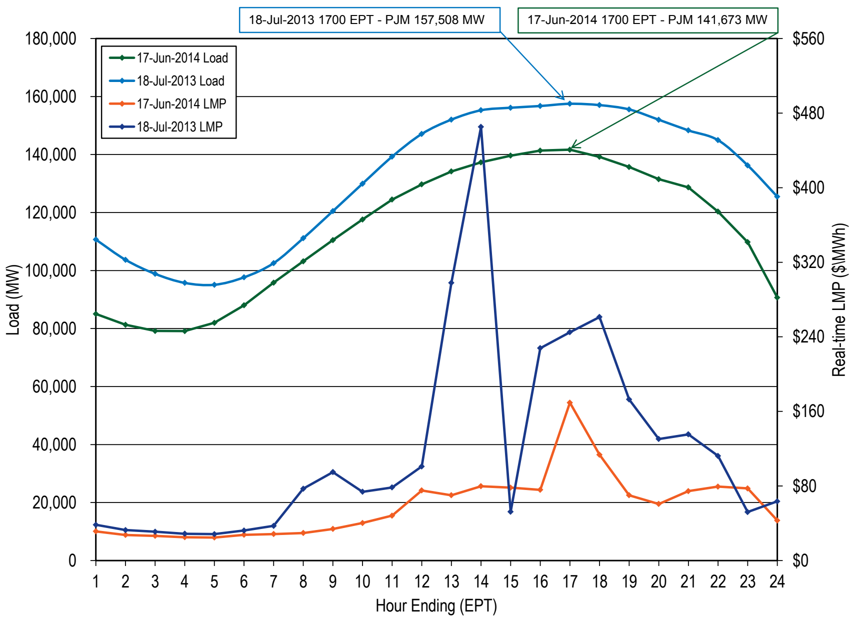
Figure 3-13 PJM footprint calendar year peak loads: January through September of 1999 to 2014



34 Peak loads shown are eMTR load. See the MMU Technical Reference for the PJM Markets, at "Load Definitions" for detailed definitions of load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Figure 3-14 compares the peak load days in the first nine months of 2013 and the first nine months of 2014. The average hourly real-time LMP peaked at $169.33 on June 17, 2014 and peaked at $465.18 on July 18, 2013.

Figure 3-14 PJM peak-load comparison: Tuesday, June 17, 2014, and Tuesday, July 18, 2013



Real-Time Demand

PJM average real-time load in the first nine months of 2014 increased by 1.6 percent from the first nine months of 2013, from 89,123 MW to 90,567 MW. PJM average real-time load in the first nine months of 2014 would have increased by 0.7 percent from the first nine months of 2013, from 89,123 MW to 89,707 MW, if the EKPC Transmission Zone had not been included in the comparison.[35,36]

PJM average real-time demand in the first nine months of 2014 increased 2.5 percent from the first nine months of 2013, from 93,647 MW to 96,015 MW. PJM average real-time demand in the first nine months of 2014 would have increased by 1.6 percent from the first nine months of 2013, from 93,647 MW to 95,155 MW, if the EKPC Transmission Zone had not been included in the comparison.

In the PJM Real-Time Energy Market, there are two types of demand:

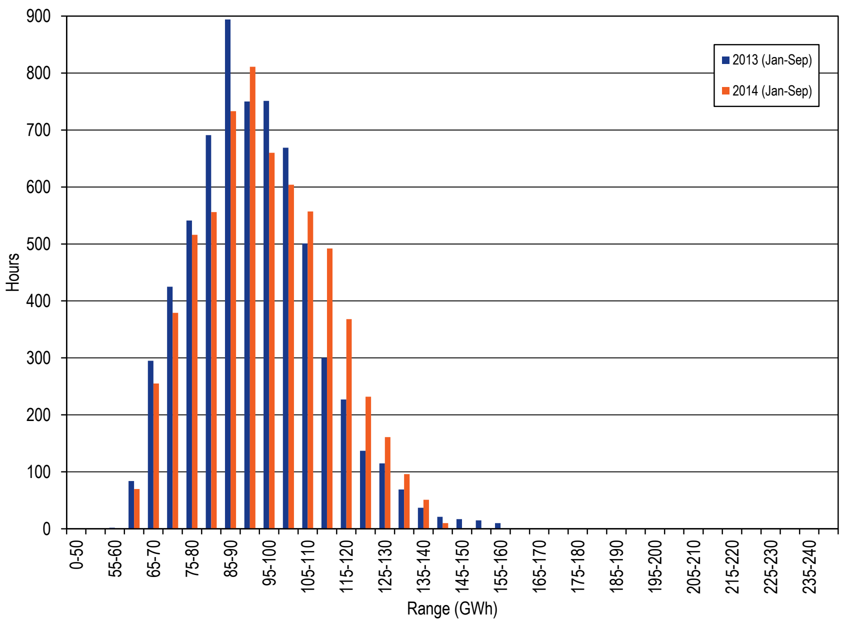
- **Load.** The actual MWh level of energy used.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. A real-time export must have a valid OASIS reservation when offered, must have available ramp room to support the export, must be accompanied by a NERC e-Tag, and must pass the neighboring balancing authority checkout process.

35 The EKPC Transmission Zone was integrated on June 1, 2013 and was not included in this comparison for January through May of 2013 and 2014.
36 Load data are the net MWh injections and withdrawals MWh at every load bus in PJM.

PJM Real-Time Demand Duration

Figure 3-15 shows the hourly distribution of PJM real-time load plus exports for the first nine months of 2013 and the first nine months of 2014.[37]

Figure 3-15 Distribution of PJM real-time accounting load plus exports: January through September of 2013 and 2014[38]



PJM Real-Time, Average Load

Table 3-15 presents summary real-time demand statistics for the first nine months of each year during the 17-year period 1998 to 2014. 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.[39]

Table 3-15 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: January through September of 1998 through 2014[40]

	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
(Jan-Sep)	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
1998	29,112	5,780	29,112	5,780	NA	NA	NA	NA
1999	30,236	6,306	30,236	6,306	3.9%	9.1%	3.9%	9.1%
2000	30,266	5,765	31,060	5,977	0.1%	(8.6%)	2.7%	(5.2%)
2001	31,060	6,156	32,900	5,861	2.6%	6.8%	5.9%	(2.0%)
2002	35,715	8,688	37,367	8,878	15.0%	41.1%	13.6%	51.5%
2003	37,996	7,187	39,965	7,120	6.4%	(17.3%)	7.0%	(19.8%)
2004	45,294	10,512	49,176	11,556	19.2%	46.3%	23.0%	62.3%
2005	78,235	17,541	85,295	17,794	72.7%	66.9%	73.4%	54.0%
2006	80,717	15,568	87,326	16,147	3.2%	(11.2%)	2.4%	(9.3%)
2007	83,114	15,386	89,390	16,008	3.0%	(1.2%)	2.4%	(0.9%)
2008	80,611	14,389	87,788	14,893	(3.0%)	(6.5%)	(1.8%)	(7.0%)
2009	76,954	13,879	82,118	14,360	(4.5%)	(3.5%)	(6.5%)	(3.6%)
2010	81,068	16,209	86,994	16,687	5.3%	16.8%	5.9%	16.2%
2011	83,762	17,604	89,628	17,799	3.3%	8.6%	3.0%	6.7%
2012	88,687	17,431	93,763	17,329	5.9%	(1.0%)	4.6%	(2.6%)
2013	89,123	16,384	93,647	16,254	0.5%	(6.0%)	(0.1%)	(6.2%)
2014	90,567	16,662	96,015	16,518	1.6%	1.7%	2.5%	1.6%

37 All real-time load data in Section 3, "Energy Market," "Market Performance: Load and LMP" are based on PJM accounting load. See the *Technical Reference for PJM Markets*, "Load Definitions," for detailed definitions of accounting load. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

38 Each range on the horizontal axis excludes the start value and includes the end value.

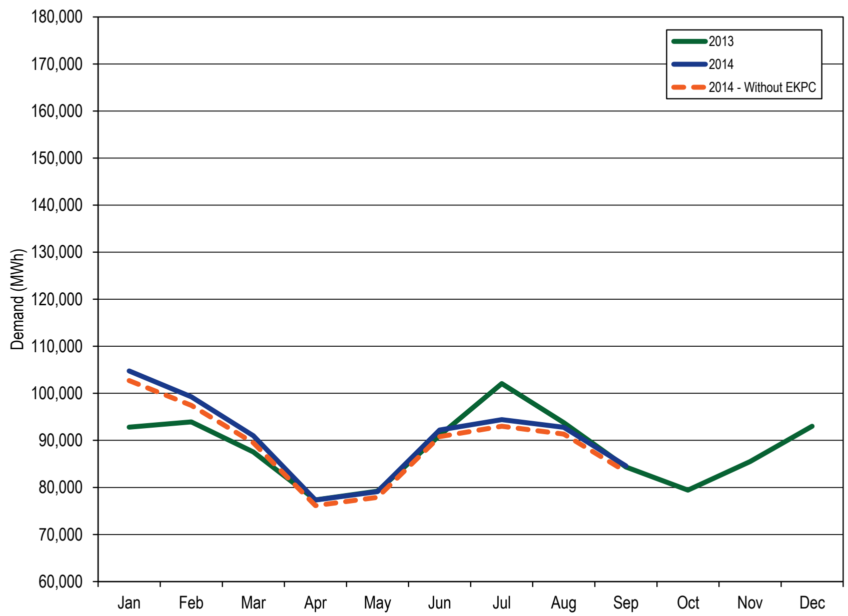
39 Accounting load is used here because PJM uses accounting load in the settlement process, which determines how much load customers pay for. In addition, the use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP, which excludes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

40 The export data in this table are not available before June 1, 2000. The export data for 2000 are for the last six months of 2000.

PJM Real-Time, Monthly Average Load

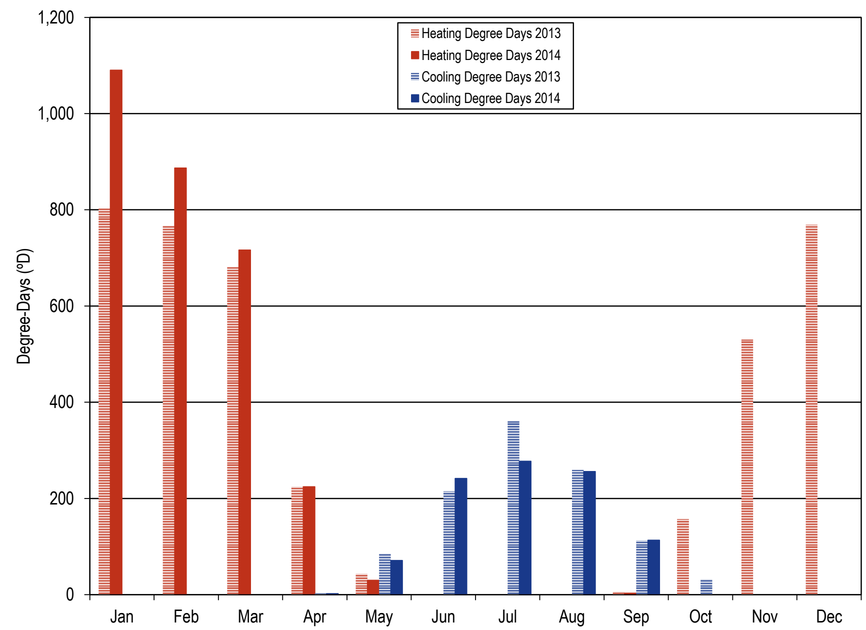
Figure 3-16 compares the real-time, monthly average hourly loads in 2013 to the first nine months of 2014 with and without EKPC.

Figure 3-16 PJM real-time monthly average hourly load: January 2013 through September 2014



PJM real-time load is significantly affected by temperature. Figure 3-17 and Table 3-16 compare the PJM monthly heating and cooling degree days in the first nine months of 2014 with those in the first nine months of 2013.[41] The figure and table show that in 2014, the heating degree days increased 35.8 percent in January, increased 15.6 percent in February, increased 5.2 percent in March, remained constant in April, decreased 31.1 percent in May, and decreased 47.2 percent in September compared to 2013. The figure shows that in 2014, the cooling degree days decreased 20.5 percent in April, decreased 16.7 percent in May, increased 12.5 percent in June, decreased 23.2 percent in July, decreased 1.2 percent in August, and increased 0.5 percent in September compared to 2013.

Figure 3-17 PJM heating and cooling degree days: January 2013 through September 2014



41 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, LEX, ORD, ORF, PHL, PIT, RIC, ROA, TOL and WAL.

Table 3-16 PJM heating and cooling degree days: January 2013 through September 2014

	2013		2014	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	803	0	1,090	0
Feb	767	0	887	0
Mar	681	0	716	0
Apr	224	3	224	2
May	43	86	30	71
Jun	0	215	0	242
Jul	0	361	0	277
Aug	0	259	0	256
Sep	6	113	3	113
Oct	157	32		
Nov	530	0		
Dec	769	0		
Total	3,982	1,069	2,951	962

Day-Ahead Demand

PJM average day-ahead demand in the first nine months of 2014, including DECs and up-to congestion transactions, increased by 7.9 percent from the first nine months of 2013, from 145,139 MW to 156,542 MW. The PJM average day-ahead demand in the first nine months of 2014, including DECs and up-to congestion transactions, would have increased 7.1 percent from the first nine months of 2013, from 145,139 MW to 155,420 MW, if the EKPC Transmission Zone had not been included in the comparison.

PJM average day-ahead demand in the first nine months of 2014, including DECs, up-to congestion transactions, and exports, increased by 8.1 percent from the first nine months of 2013, from 148,444 MW to 160,425 MW. The PJM average day-ahead demand in the first nine months of 2014, including DECs and up-to congestion transactions, and imports, would have increased 7.3 percent from the first nine months of 2013, from 148,444 MW to 159,303 MW, if the EKPC Transmission Zone had not been included in the comparison.

The day-ahead demand growth was 393.8 percent higher than the real-time load growth in the first nine months of 2014, because of the continued growth, until September 8, 2014, of up-to congestion transactions. While up-to congestion transactions (UTC) continued to displace increment offers and decrement bids, there was a sharp decrease in UTCs in September as a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[42]

In the PJM Day-Ahead Energy Market, five 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 DEC 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. 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.
- **Export.** An export is an external energy transaction scheduled from PJM to another balancing authority. An export must have a valid willing to pay congestion (WPC) OASIS reservation when offered. An export energy transaction that clears the Day-Ahead Energy Market is financially binding. There is no link between transactions submitted in the PJM Day-Ahead Energy Market and the PJM Real-Time Energy Market, so an export energy transaction approved in the Day-Ahead Energy Market will not physically flow in real time unless it is also submitted through the Real-Time Energy Market scheduling process.

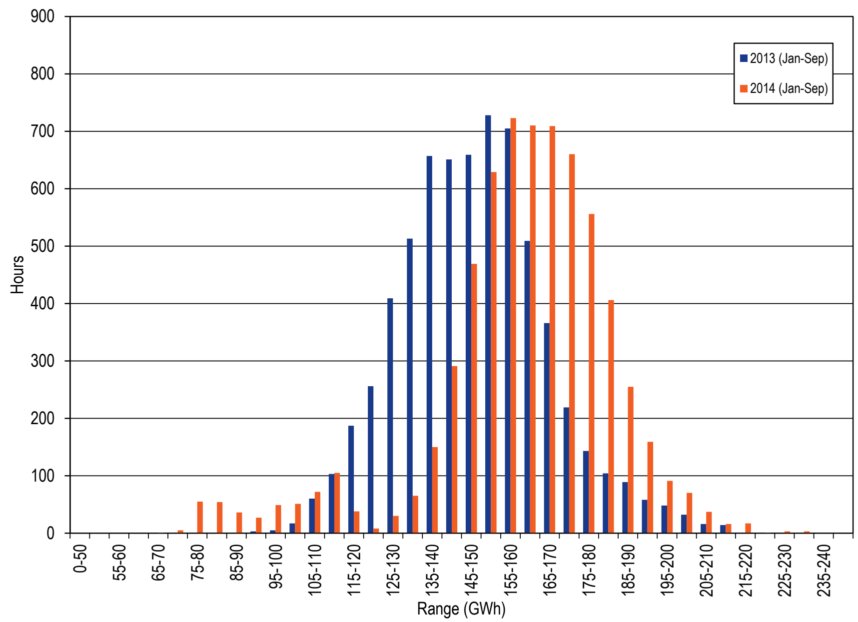
PJM day-ahead demand is the hourly total of the five types of cleared demand bids.

42 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

PJM Day-Ahead Demand Duration

Figure 3-18 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up-to congestion transactions, and exports for the first nine months of 2013 and the first nine months of 2014.

Figure 3-18 Distribution of PJM day-ahead demand plus exports: January through September of 2013 and 2014[43]



43 Each range on the horizontal axis excludes the start value and includes the end value.

PJM Day-Ahead, Average Demand

Table 3-17 presents summary day-ahead demand statistics for the first nine months of each year of the 15-year period 2000 to 2014.[44]

Table 3-17 PJM day-ahead average demand and day-ahead average hourly demand plus average hourly exports: January through September of 2000 through 2014

	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
(Jan-Sep)	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2000	34,064	7,649	34,268	7,553	NA	NA	NA	NA
2001	33,944	7,016	34,444	6,817	(0.4%)	(8.3%)	0.5%	(9.7%)
2002	41,634	11,073	41,726	11,120	22.7%	57.8%	21.1%	63.1%
2003	45,371	8,377	45,477	8,354	9.0%	(24.4%)	9.0%	(24.9%)
2004	55,830	13,319	56,558	13,753	23.1%	59.0%	24.4%	64.6%
2005	93,525	19,126	96,302	19,455	67.5%	43.6%	70.3%	41.5%
2006	99,403	18,165	102,520	18,687	6.3%	(5.0%)	6.5%	(3.9%)
2007	107,295	17,580	110,711	17,949	7.9%	(3.2%)	8.0%	(4.0%)
2008	103,586	16,618	107,169	16,810	(3.5%)	(5.5%)	(3.2%)	(6.3%)
2009	96,020	16,995	99,084	17,117	(7.3%)	2.3%	(7.5%)	1.8%
2010	105,018	22,972	109,113	23,286	9.4%	35.2%	10.1%	36.0%
2011	113,724	22,444	117,533	22,651	8.3%	(2.3%)	7.7%	(2.7%)
2012	132,494	18,115	135,840	18,235	16.5%	(19.3%)	15.6%	(19.5%)
2013	145,139	18,667	148,444	18,696	9.5%	3.1%	9.3%	2.5%
2014	156,542	23,584	160,425	23,533	7.9%	26.3%	8.1%	25.9%

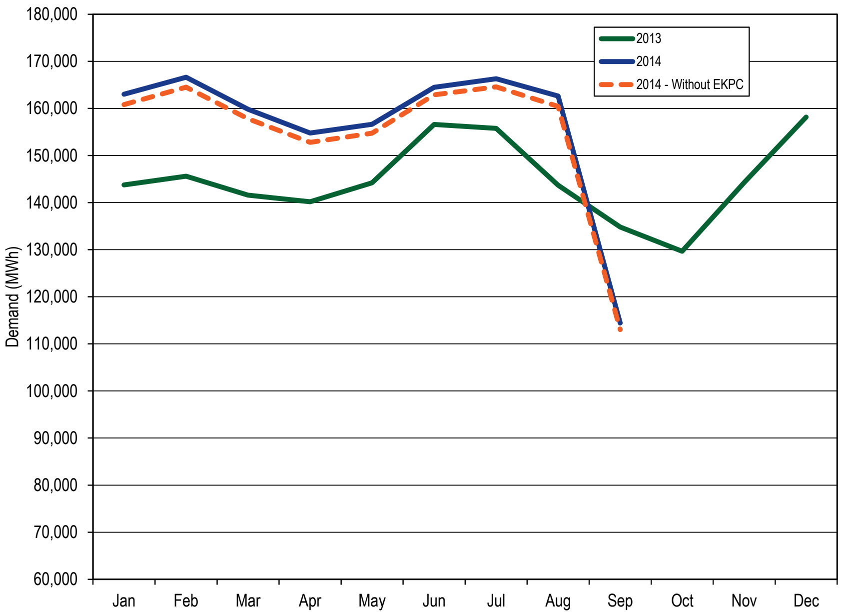
PJM Day-Ahead, Monthly Average Demand

Figure 3-19 compares the day-ahead, monthly average hourly demand, including decrement bids and up-to congestion transactions, in 2013 to the first nine months of 2014 with and without EKPC. The sharp decrease in UTC MW in September, which resulted in a corresponding decrease in day-ahead demand, was a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[45]

44 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

45 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

Figure 3-19 PJM day-ahead monthly average hourly demand: January 2013 through September 2014



Real-Time and Day-Ahead Demand

Table 3-18 presents summary statistics for the first nine months of 2013 and the first nine months of 2014 day-ahead and real-time demand. The last two columns of Table 3-18 are the day-ahead demand minus the real-time demand. The first such column is the total day-ahead demand less the total real-time demand and the second such column is the total physical day-ahead load (fixed demand plus price sensitive demand) less the physical real-time load.

Table 3-18 Cleared day-ahead and real-time demand (MWh): January through September of 2013 and 2014

		Day Ahead						Real Time		Day Ahead Less Real Time	
	(Jan-Sep)	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Total Demand	Total Load
Average	2013	85,893	1,156	7,204	50,888	3,304	148,444	89,123	93,647	54,797	(2,075)
	2014	86,518	1,240	6,432	62,351	3,883	160,425	90,567	96,015	64,410	(2,808)
Median	2013	84,729	1,184	6,925	51,045	3,242	148,180	87,586	92,198	55,982	(1,674)
	2014	85,321	1,229	6,148	65,651	3,779	162,809	88,957	94,758	68,051	(2,407)
Standard Deviation	2013	15,592	254	1,505	10,509	617	18,696	16,384	16,254	2,442	(537)
	2014	15,755	171	1,471	17,350	974	23,533	16,662	16,518	7,015	(735)
Peak Average	2013	95,790	1,248	7,956	51,272	3,272	159,538	99,025	103,333	56,205	(1,987)
	2014	96,415	1,317	7,228	62,347	3,869	171,177	100,493	105,782	65,395	(2,760)
Peak Median	2013	93,964	1,306	7,582	52,023	3,214	157,641	97,004	101,357	56,284	(1,734)
	2014	95,721	1,318	7,026	66,186	3,806	173,802	99,462	104,973	68,830	(2,423)
Peak Standard Deviation	2013	12,954	272	1,467	9,793	616	15,624	13,993	14,055	1,569	(767)
	2014	12,725	159	1,441	16,853	965	21,487	13,807	13,611	7,876	(923)
Off-Peak Average	2013	77,238	1,075	6,546	50,552	3,332	138,743	80,465	85,178	53,565	(2,152)
	2014	77,865	1,173	5,735	62,355	3,895	151,023	81,887	87,475	63,548	(2,849)
Off-Peak Median	2013	75,784	1,104	6,308	50,254	3,277	137,872	78,761	83,553	54,319	(1,874)
	2014	76,074	1,168	5,515	65,234	3,771	154,557	79,619	85,595	68,962	(2,377)
Off-Peak Standard Deviation	2013	12,184	206	1,199	11,087	615	15,493	13,087	12,990	2,503	(698)
	2014	12,775	152	1,096	17,776	981	21,095	13,865	13,897	7,198	(938)

Figure 3-20 shows the average hourly cleared volumes of day-ahead demand and real-time demand. The day-ahead demand includes day-ahead load, day-ahead exports, decrement bids and up-to congestion transactions. The real-time demand includes real-time load and real-time exports.

Figure 3-20 Day-ahead and real-time demand (Average hourly volumes): January through September of 2014

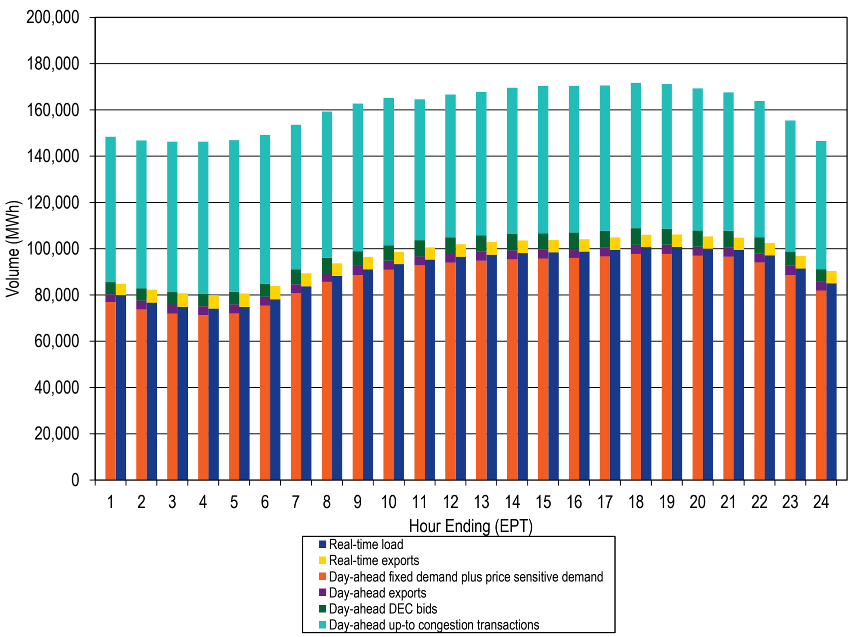
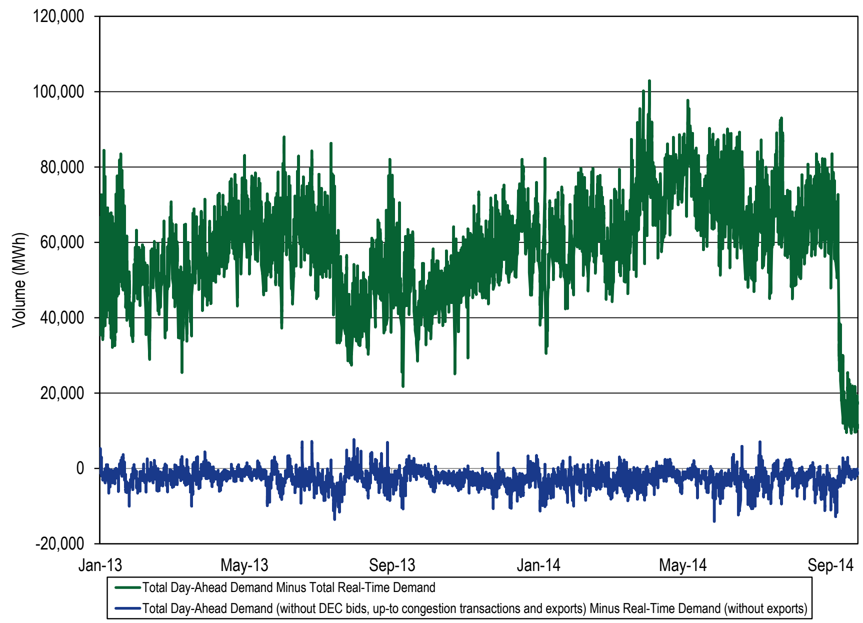


Figure 3-21 shows the difference between the day-ahead and real-time average daily demand in January 2013 through September 2014. The sharp decrease in UTC MW in September, which resulted in a corresponding decrease in day-ahead demand, was a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[46]

46 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

Figure 3-21 Difference between day-ahead and real-time demand (Average daily volumes): January 2013 through September 2014



Supply and Demand: 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 3-19 shows the monthly average share of real-time load served by self-supply, bilateral contracts and spot purchase in 2013 and 2014 based on parent company. For the first nine months of 2014, 10.2 percent of real-time load was supplied by bilateral contracts, 27.4 percent by spot market purchase and 62.5 percent by self-supply. Compared with 2013, reliance on bilateral contracts decreased 0.4 percentage points, reliance on spot supply increased by 2.4 percentage points and reliance on self-supply decreased by 1.9 percentage points.

Table 3-19 Monthly average percentage of real-time self-supply load, bilateral-supply load and spot-supply load based on parent companies: 2013 through 2014

	2013			2014			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	10.4%	22.3%	67.3%	9.5%	27.9%	62.6%	(0.9%)	5.7%	(4.7%)
Feb	10.5%	22.0%	67.5%	9.2%	27.3%	63.5%	(1.4%)	5.3%	(4.0%)
Mar	10.4%	24.2%	65.4%	9.7%	27.2%	63.0%	(0.7%)	3.1%	(2.4%)
Apr	10.7%	24.2%	65.1%	9.1%	29.7%	61.2%	(1.6%)	5.5%	(3.9%)
May	10.9%	25.4%	63.6%	9.7%	28.8%	61.5%	(1.2%)	3.4%	(2.1%)
Jun	10.7%	25.0%	64.3%	10.6%	29.0%	60.4%	(0.1%)	4.0%	(3.8%)
Jul	10.2%	25.2%	64.7%	11.2%	25.7%	63.1%	1.0%	0.6%	(1.6%)
Aug	10.2%	24.5%	65.3%	11.2%	25.4%	63.4%	1.0%	0.9%	(1.9%)
Sep	10.1%	24.2%	65.7%	11.2%	25.6%	63.2%	1.1%	1.3%	(2.4%)
Oct	11.1%	28.2%	60.7%						
Nov	10.6%	27.2%	62.2%						
Dec	11.3%	27.1%	61.7%						
Annual	10.6%	25.0%	64.4%	10.2%	27.4%	62.5%	(0.4%)	2.4%	(1.9%)

Day-Ahead Load and Spot Market

In the PJM Day-Ahead Energy Market, participants can not only use their own generation, bilateral contracts and spot market purchases to supply their load serving obligation, but can also use virtual resources to meet their load serving obligations in any hour. Virtual supply is treated as supply 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 demand (cleared fixed-demand, price-sensitive load and decrement bids) is calculated by summing across all the parent companies of PJM billing organizations that serve demand in the Day-Ahead Energy Market for each hour. Table 3-20 shows the monthly average share of day-ahead demand served by self-supply, bilateral contracts and spot purchases in 2013 and 2014, based on parent companies. For the first nine months of 2014, 9.1 percent of day-ahead demand was supplied by bilateral contracts, 26.9 percent by spot market purchases, and 64.0 percent by self-supply. Compared with 2013, reliance on bilateral contracts increased by 1.0

percentage points, reliance on spot supply increased by 2.4 percentage points, and reliance on self-supply decreased by 3.4 percentage points.

Table 3-20 Monthly average percentage of day-ahead self-supply demand, bilateral supply demand, and spot-supply demand based on parent companies: 2013 through 2014

	2013			2014			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	6.8%	22.1%	71.1%	10.9%	28.7%	60.4%	4.1%	6.7%	(10.7%)
Feb	7.0%	22.1%	71.0%	7.9%	27.0%	65.0%	1.0%	5.0%	(5.9%)
Mar	7.0%	23.6%	69.4%	8.6%	27.7%	63.7%	1.6%	4.1%	(5.7%)
Apr	7.1%	23.1%	69.8%	7.9%	29.9%	62.3%	0.7%	6.8%	(7.6%)
May	7.8%	23.5%	68.7%	8.0%	29.0%	63.0%	0.2%	5.5%	(5.7%)
Jun	8.2%	23.8%	68.0%	9.4%	28.5%	62.1%	1.2%	4.7%	(5.9%)
Jul	8.0%	24.1%	67.9%	9.6%	25.1%	65.3%	1.6%	1.0%	(2.6%)
Aug	8.1%	23.9%	68.0%	9.7%	24.5%	65.8%	1.6%	0.6%	(2.2%)
Sep	7.8%	23.9%	68.3%	9.3%	24.9%	65.8%	1.6%	1.0%	(2.6%)
Oct	9.8%	29.0%	61.3%						
Nov	9.3%	29.1%	61.7%						
Dec	9.9%	25.6%	64.5%						
Annual	8.0%	24.5%	67.5%	9.1%	26.9%	64.0%	1.0%	2.4%	(3.4%)

Market Behavior

Offer Capping for Local Market Power

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 as well as for conservative operations. 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 3-21. The offer capping percentages shown in Table 3-21 include units that are committed to provide constraint relief whose owners failed the TPS test in the Energy Market as well as units committed as part of conservative operations, excluding units that were committed for providing black start and reactive service. In January 2014, due to an increase in constrained hours, there was an increase in the offer capping percentages for units failing the TPS test and units committed for conservative operations while the number of units committed as offer capped for providing black start and reactive service decreased. In the first nine months of 2014, the percentage of hours in which black start and reactive service units were economic increased compared to the first nine months of 2013 and the percentage of hours they were committed as offer capped decreased as a result.

Table 3-21 Offer-capping statistics – Energy only: January through September, 2010 to 2014

	Real Time		Day Ahead	
(Jan-Sep)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2010	1.2%	0.3%	0.3%	0.1%
2011	0.7%	0.3%	0.0%	0.0%
2012	1.1%	0.6%	0.1%	0.1%
2013	0.4%	0.1%	0.2%	0.0%
2014	0.5%	0.2%	0.2%	0.1%

Table 3-22 shows the offer capping percentages including units committed to provide constraint relief and units committed to provide black start service and reactive support. The units that are committed and offer capped for reliability reasons have been increasing since 2011. Before 2011, the units that ran to provide black start service and reactive support were generally economic in the energy market. Since 2011, the percentage of hours when these units were not economic (and are therefore committed on their cost schedule for reliability reasons) has steadily increased. This trend reversed in the first nine months of 2014 because higher LMPs resulted in the increased economic dispatch of black start and reactive service resources.

Table 3-22 Offer-capping statistics for energy and reliability: January through September, 2010 to 2014

	Real Time		Day Ahead	
(Jan-Sep)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2010	1.2%	0.3%	0.3%	0.1%
2011	1.5%	0.6%	0.0%	0.0%
2012	1.4%	0.8%	0.2%	0.2%
2013	2.9%	2.3%	3.2%	2.1%
2014	0.8%	0.6%	0.5%	0.4%

Table 3-23 presents data on the frequency with which units were offer capped in the first nine months of 2013 and the first nine months of 2014, for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market.

Table 3-23 Real-time offer-capped unit statistics: January through September, 2013 and 2014

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	(Jan - Sep)	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2014	0	0	0	0	0	0
	2013	0	0	0	0	0	0
80% and < 90%	2014	0	1	1	0	2	0
	2013	0	0	0	1	1	1
75% and < 80%	2014	1	1	0	0	1	0
	2013	0	0	0	1	1	3
70% and < 75%	2014	0	0	0	0	1	0
	2013	0	0	0	0	0	3
60% and < 70%	2014	0	0	0	0	6	4
	2013	0	0	0	0	0	6
50% and < 60%	2014	0	0	0	0	3	8
	2013	0	0	0	0	0	9
25% and < 50%	2014	0	0	9	1	10	43
	2013	0	0	6	0	5	50
10% and < 25%	2014	0	0	0	1	8	42
	2013	2	0	0	0	3	45

Table 3-23 shows that four units were offer capped for 80 percent or more of their run hours in the first nine months of 2014 compared to three units in the first nine months of 2013.

Offer Capping for Local Market Power

In the first nine months of 2014, the AEP, AP, ATSI, BGE, ComEd, DLCO, Dominion, DPL, PECO, PENELEC, Pepco, PPL and PSEG control zones experienced congestion resulting from one or more constraints binding for 75 or more hours. The AECO, DAY, DEOK, EKPC, JCPL, Met-Ed and RECO control zones did not have constraints binding for 75 or more hours in the first nine months of 2014. Table 3-24 shows that AEP, BGE, ComEd, Dominion, PPL, and PSEG were the only control zones with 75 or more hours of congestion or with an interface constraint that was binding for one or more hours in every year in the first nine months of 2009 through 2014. In the first nine months of 2014, the BGE Pepco interface (BCPEP) constraint was binding in Pepco for 41 hours.

Table 3-24 Numbers of hours when control zones experienced congestion for 75 or more hours: January through September, 2009 through 2014

	2009 (Jan - Sep)	2010 (Jan - Sep)	2011 (Jan - Sep)	2012 (Jan - Sep)	2013 (Jan - Sep)	2014 (Jan - Sep)
AECO	149	163	234	NA	NA	NA
AEP	1,005	975	2,197	178	1,210	1,474
AP	1,297	3,344	1,805	89	NA	170
ATSI	140	NA	NA	208	68	481
BGE	127	274	368	1,582	1,192	4,416
ComEd	784	2,108	872	1,808	3,169	1,928
DEOK	NA	NA	NA	185	NA	NA
DLCO	156	393	NA	209	NA	223
Dominion	456	889	1,593	559	1,148	179
DPL	NA	111	NA	382	783	542
Met-Ed	NA	168	NA	NA	NA	NA
PECO	247	NA	276	NA	390	1,826
PENELEC	80	96	77	NA	NA	2,147
Pepco	149	NA	76	143	200	41
PPL	176	117	40	146	609	148
PSEG	379	515	1,132	259	1,993	2,132

The local market structure in the Real-Time Energy Market associated with each of the frequently binding constraints was analyzed using the three pivotal supplier results for the first nine months of 2014.[47] The three pivotal supplier (TPS) 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 3-25 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 3-25 Three pivotal supplier test details for interface constraints: January through September, 2014

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	379	373	13	1	12
	Off Peak	396	399	12	1	11
AEP - DOM	Peak	376	254	8	0	8
	Off Peak	323	211	7	0	7
AP South	Peak	398	464	9	0	9
	Off Peak	427	517	9	0	9
BC/PEPCO	Peak	582	585	7	0	6
	Off Peak	482	468	6	0	6
Bedington - Black Oak	Peak	162	191	13	3	10
	Off Peak	200	163	11	1	10
Central	Peak	422	63	6	0	6
	Off Peak	1,070	657	11	0	11
Eastern	Peak	426	295	8	0	8
	Off Peak	457	400	9	1	8
Western	Peak	951	887	14	1	13
	Off Peak	894	937	13	1	12

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 3-26 provides, for the identified interface constraints, information on total tests applied, the subset of three pivotal supplier tests that could have resulted in the offer capping of uncommitted units and the portion of those tests that did result in offer capping uncommitted units.

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

Table 3-26 Summary of three pivotal supplier tests applied for interface constraints: January through September, 2014

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	991	84	8%	8	1%	10%
	Off Peak	887	82	9%	2	0%	2%
AEP - DOM	Peak	79	5	6%	0	0%	0%
	Off Peak	238	29	12%	0	0%	0%
AP South	Peak	4607	189	4%	2	0%	1%
	Off Peak	3546	176	5%	4	0%	2%
BC/PEPCO	Peak	246	26	11%	0	0%	0%
	Off Peak	112	8	7%	0	0%	0%
Bedington - Black Oak	Peak	1201	106	9%	13	1%	12%
	Off Peak	358	39	11%	0	0%	0%
Central	Peak	2	0	0%	0	0%	0%
	Off Peak	6	0	0%	0	0%	0%
Eastern	Peak	48	2	4%	0	0%	0%
	Off Peak	60	4	7%	0	0%	0%
Western	Peak	1158	132	11%	2	0%	2%
	Off Peak	627	35	6%	0	0%	0%

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.[48] 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 Markup

Table 3-27 shows the average markup index of marginal units in the Real-Time Energy Market, by offer price category. The markup is negative if the cost-based offer of the marginal unit exceeds its price-based offer at its operating point. In the first nine months of 2014, 73.9 percent of marginal units had average dollar markups less than zero and 73.9 percent of units had an average markup index less than or equal to 0.0. The data show that some marginal units did have substantial markups. The average data do not show the high markups that occurred for the very high load days in January. Using the unadjusted cost offers, the highest markup in the first nine months of 2014 was $922.3 whereas the highest markup in the first nine months of 2013 was $ 355.9.

48 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.

Table 3-27 Average, real-time marginal unit markup index (By offer price category): January through September 2013 and 2014

	2013 (Jan - Sep)			2014 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	0.02	($3.25)	21.4%	(0.10)	($2.18)	16.5%
$25 to $50	(0.01)	($1.25)	62.5%	(0.01)	($1.14)	57.4%
$50 to $75	0.01	($1.53)	8.6%	0.05	$2.12	8.6%
$75 to $100	0.06	$3.41	1.5%	0.10	$8.01	2.5%
$100 to $125	0.13	$13.66	0.7%	0.04	$3.72	4.8%
$125 to $150	0.09	$11.51	0.8%	0.11	$13.78	1.2%
>= $150	0.04	$9.33	4.5%	0.09	$22.16	9.0%

Day-Ahead Markup

Table 3-28 shows the average markup index of marginal units in Day-Ahead Energy Market, by offer price category. In the first nine months of 2014, 94.8 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.02. The data show that some marginal units did have substantial markups. The average markup index increased significantly, for example, from 0.00 in the first nine months of 2013, to 0.14 in the first nine months of 2014 in the offer price category from $100 to $125. There were five hours when the generating resources had offer prices of $100 or above in the first nine months of 2013. However, in the first nine months of 2014, there were 442 hours when the marginal units had offer prices of $100 or above and the highest markup was $392 per MWh.

Table 3-28 Average day-ahead marginal unit markup index (By offer price category): January through September of 2013 and 2014

	2013 (Jan - Sep)			2014 (Jan - Sep)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.06)	($1.76)	18.9%	(0.08)	($2.07)	14.3%
$25 to $50	(0.04)	($2.41)	75.4%	(0.02)	($2.22)	69.2%
$50 to $75	0.00	($2.72)	4.6%	0.02	($2.00)	10.2%
$75 to $100	0.08	$7.07	0.4%	0.07	$4.31	1.5%
$100 to $125	0.00	$0.00	0.1%	0.14	$15.81	1.1%
$125 to $150	0.00	$0.00	0.0%	0.02	($2.02)	1.1%
>= $150	0.75	$118.80	0.0%	0.06	$12.12	2.5%

Frequently Mitigated Units and Associated Units

An FMU is a frequently mitigated unit. The results reported here include units that were mitigated for any reason, including both structural market power in the energy market and units called on for reliability reasons, including reactive and black start service.

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.[49] These categories are designated Tier 1, Tier 2 and Tier 3.[50,51]

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 based on the number of run-hours the unit is offer capped. 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 3 FMU. If the second unit were capped for 30 percent of its run hours, that unit would be an AU and receive the same Tier 3 adder as the FMU at the site. The AU designation was implemented to ensure that the associated unit is not dispatched in place of the FMU, resulting in no effective adder for the FMU. In the absence of the AU designation, the associated unit would be an FMU after its dispatch and the FMU would be dispatched in its place after losing its FMU designation.

FMUs and AUs are designated monthly, and a unit's capping percentage is based on a rolling 12-month average, effective with a one-month lag.[52]

Table 3-29 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 2013 and the first nine months of 2014. Of the 104 units eligible in at least one month during the first nine months of 2014, 46 units (44.2 percent) were FMUs or AUs for all nine months, and 16 units (15.4 percent) qualified in only one month in the first nine months of 2014.

49 OA, Schedule 1 § 6.4.2.
50 114 FERC ¶ 61, 076 (2006).
51 See "Settlement Agreement," Docket Nos. EL03-236-006, EL04-121-000 (consolidated) (November 16, 2005).
52 OA, Schedule 1 § 6.4.2. In 2007, the FERC approved OA revisions to clarify the AU criteria.

Table 3-29 Frequently mitigated units and associated units total months eligible: 2013 and January through September, 2014

Months Adder-Eligible	2013	2014
1	10	16
2	22	7
3	14	0
4	10	3
5	5	4
6	8	17
7	7	1
8	3	10
9	1	46
10	2	
11	8	
12	22	
Total	112	104

Figure 3-22 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, 2014, there have been 351 unique units that have qualified for an FMU adder in at least one month. Of these 351 units, no unit qualified for an adder in all potential months. Two units qualified in 104 of the 105 possible months, and 93 of the 351 units (26.5 percent) have qualified for an adder in more than half of the possible months.

Figure 3-22 Frequently mitigated units and associated units total months eligible: February, 2006 through September, 2014

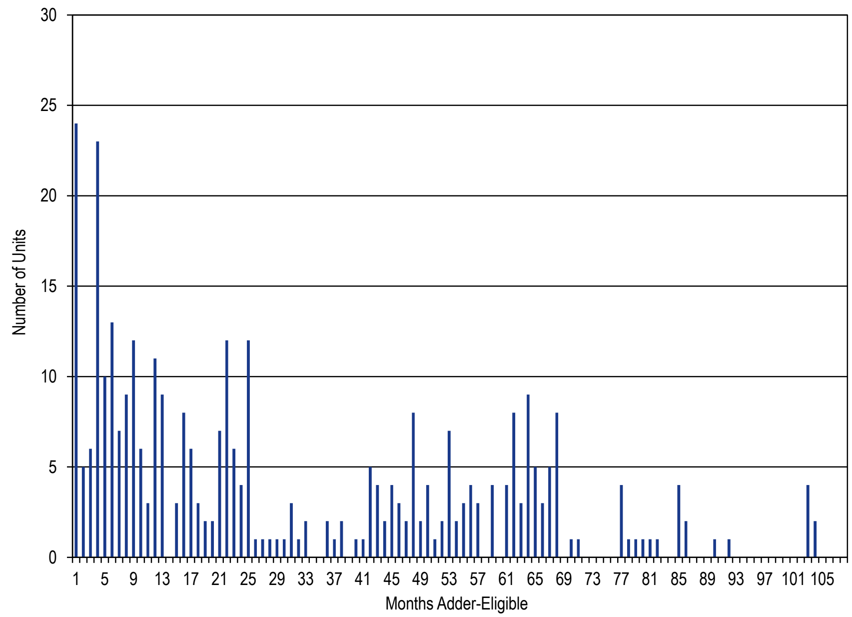


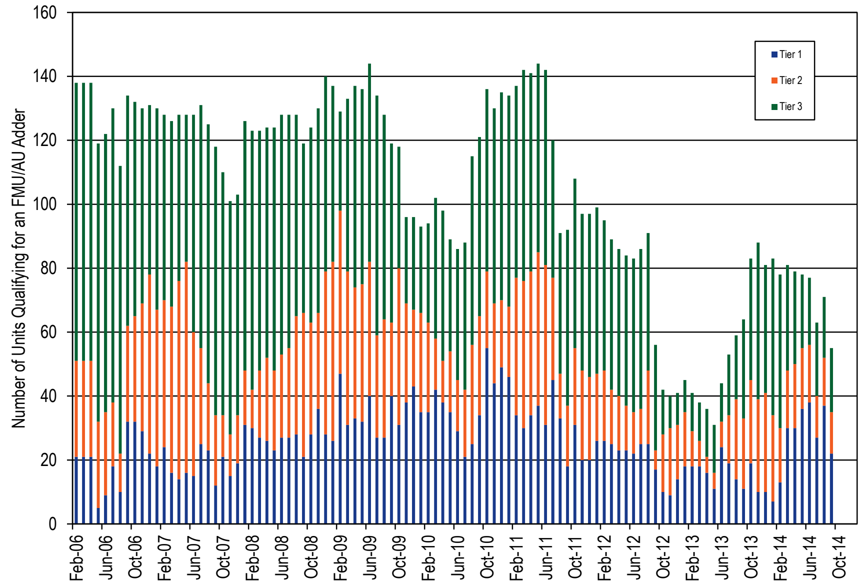
Table 3-30 shows, by month, the number of FMUs and AUs in 2013 and the first nine months of 2014. For example, in January 2014, there were 7 FMUs and AUs in Tier 1, 27 FMUs and AUs in Tier 2, and 49 FMUs and AUs in Tier 3.

Table 3-30 Number of frequently mitigated units and associated units (By month): 2013 and January through September, 2014

	FMUs and AUs							
	2013				2014			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	18	17	10	45	7	27	49	83
February	18	11	12	41	13	17	48	78
March	18	8	12	38	30	18	33	81
April	16	5	15	36	30	20	29	79
May	11	5	15	31	36	19	23	78
June	24	8	12	44	38	18	21	77
July	19	15	19	53	27	13	23	63
August	14	25	20	59	37	15	19	71
September	11	22	31	64	22	13	20	55
October	19	26	38	83				
November	10	29	49	88				
December	10	31	40	81				

Figure 3-23 shows the total number of FMUs and AUs that qualified for an adder since the inception of the business rule in February 2006. The reduction in the total number of units qualifying for an FMU or AU adder in 2012 resulted from the decrease in congestion, which was in turn the result of changes in fuel costs, changes in the generation mix and changes in system topology. The increase in the total number of units qualifying for an FMU or AU adder in the first quarter of 2013 was the result of modifications to commitment of black start and reactive units in the Day-Ahead Energy Market. In September 2012, PJM began to schedule units in the Day-Ahead Energy Market for black start and reactive that otherwise would not clear the market based on economics. Whenever these units are scheduled in the Day-Ahead Energy Market for black start and reactive, they are offer capped for all run hours in day ahead and real time. As FMU status is determined on a rolling 12-month period, this change started to affect the number of eligible FMU units in the first six months of 2013 and has continued to affect the number of FMU eligible units through the first nine months of 2014.

Figure 3-23 Frequently mitigated units and associated units (By month): February, 2006 through September, 2014



The PJM Tariff defines offer capped units as those capped to maintain system reliability as a result of limits on transmission capability.[53] Offer capping for providing black start service does not meet this criterion. The MMU recommends that black start units not be given FMU status under the current rules.

The goal of the FMU adders was to ensure that units that were offer capped for most of their run hours could cover their going forward or avoidable costs (also known as ACR in the capacity market). The relevant units were all CTs, typically running less than 500 hours per year and the adders were specifically

53 PJM OATT. Attachment K – Appendix §6.4 Offer Price Caps., (Effective Date August 9, 2013), p. 1912.

designed to cover ACR for such units. The FMU adders were not designed for baseload units like those providing reactive service. If the FMU adders are not eliminated, adders must be specifically designed for such baseload units.

The FMU adder was filed with FERC in 2005, and approved effective February 2006.[54] The goal, in 2005, was to ensure that units that were offer capped for most of their run hours could cover their going forward or avoidable costs (also known as ACR in the capacity market). That function became unnecessary with the introduction of the RPM capacity market design in 2007. Under the RPM design, units can make offers in the capacity market that include their ACR net of net revenues. Thus if there is a shortfall in ACR recovery, that shortfall is included in the RPM offer. If the unit clears in RPM, it covers its shortfall in ACR costs. If the unit does not clear, then the market result means that PJM can provide reliability without the unit and no additional revenue is needed.

The MMU has recommended the elimination of FMU and AU adders. Since the implementation of FMU adders, 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. The MMU and PJM proposed a compromise that maintained the ability of certain generating units to qualify for FMU adders but limiting FMU adders to units with net revenues less than unit going forward costs or ACR. At the June 26, 2014, meeting of the PJM Members Committee, the proposal received 65.6 percent of votes in favor of the joint MMU/PJM proposal, but failed to receive the 66.7 percent majority vote necessary to revise the PJM Operating Agreement. At the July 23, 2014, meeting of the PJM Board of Managers, the Board directed PJM staff to file the proposal, and on August 26, 2014, PJM submitted the joint MMU/PJM proposal to the Commission pursuant to section 206 of the Federal Power Act.[55] On October 31, 2014, the Commission conditionally approved the filing effective November 1, 2014.[56]

In 2013, of the 112 units that received FMU payments in 2013, 28 units did not cover ACR. Of those 28 units, 22 units are scheduled to retire (Table 3-31).

Table 3-31 Frequently mitigated units at risk of retirement: 2013

	No. of Units	MW
Units that received FMU payments in 2013	112	14,763
FMUs that did not cover ACR in 2013	28	5,342
FMUs that did not cover ACR in 2013 that are scheduled to retire	22	3,908
FMUs that did not cover ACR in 2013 that are not scheduled to retire	6	1,434

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, up-to congestion transactions, import transactions and export 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. Up-to congestion transactions may be submitted between any two buses on a list of 437 buses, eligible for up-to congestion transaction bidding.[57] Financial Transaction Rights (FTRs) bids may be submitted at any bus on a list of 1,915 buses, eligible for FTRs. Import and export transactions may be submitted at any interface pricing point, where an import is equivalent to a virtual offer that is injected into PJM and an export is equivalent to a virtual bid that is withdrawn from PJM.

54 110 FERC ¶ 61,053 (2005).

55 See *PJM Interconnection, L.L.C* Docket No. EL14-95-000 (August 26, 2014).

56 149 FERC ¶ 61,091 (2014).

57 Market participants were required to specify an interface pricing point as the source for imports, an interface pricing point as the sink for exports or an interface pricing point as both the source and sink for transactions wheeling through PJM. On November 1, 2012, PJM eliminated this requirement. For the list of eligible sources and sinks for up-to congestion transactions, see www.pjm.com "*OASIS-Source-Sink-Link.xls*," <http://www.pjm.com/~/media/etools/oasis/references/oasis-source-sink-link.ashx>.

Figure 3-24 shows the PJM day-ahead daily aggregate supply curve of increment offers, the system aggregate supply curve of imports, the system aggregate supply curve without increment offers and imports, the system aggregate supply curve with increment offers, and the system aggregate supply curve with increment offers and imports for an example day in the first nine months of 2014.

Figure 3-24 PJM day-ahead aggregate supply curves: 2014 example day

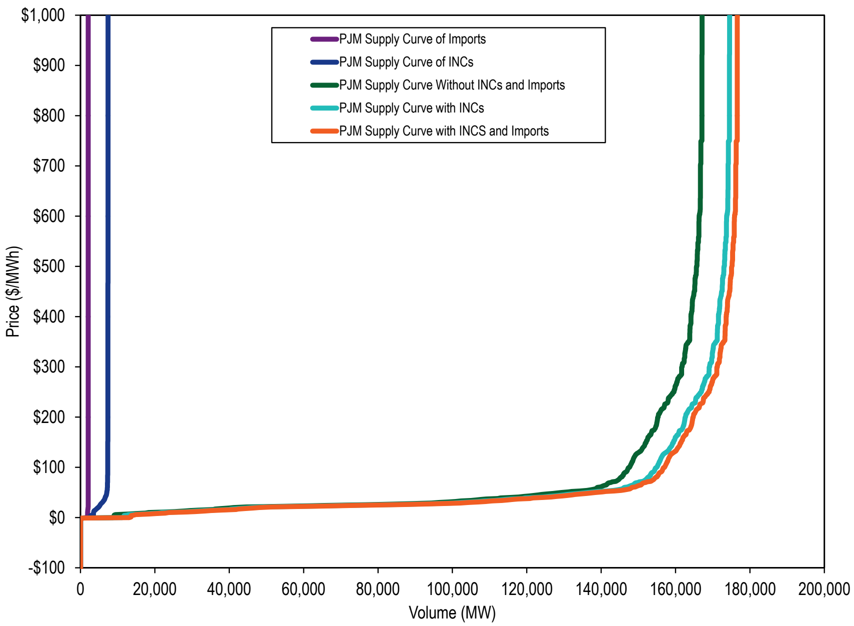


Table 3-32 shows the average hourly number of increment offers and decrement bids and the average hourly MW for 2013 and the first nine months of 2014. In the first nine months of 2014, the average hourly submitted and cleared increment offer MW decreased 26.4 and 36.4 percent, and the average hourly submitted and cleared decrement bid MW increased 0.9 and decreased 10.7 percent, compared to the first nine months of 2013.

Table 3-32 Hourly average number of cleared and submitted INCs, DECs by month: January 2013 through September of 2014

		Increment Offers				Decrement Bids			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
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	6,595	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	Jul	5,374	6,710	60	173	7,566	9,786	89	267
2013	Aug	4,633	6,169	62	179	6,819	8,295	78	195
2013	Sep	4,262	5,464	60	191	6,646	8,400	82	233
2013	Oct	4,375	5,642	70	215	6,694	8,899	93	287
2013	Nov	4,906	6,803	81	304	7,202	10,200	105	386
2013	Dec	4,803	6,123	75	278	7,700	10,650	98	393
2013	Annual	5,131	6,451	65	182	7,202	9,088	83	239
2014	Jan	3,086	4,165	69	214	5,844	8,372	81	322
2014	Feb	3,085	3,985	64	171	5,981	9,108	82	286
2014	Mar	2,942	3,890	66	179	6,702	9,455	96	291
2014	Apr	2,837	3,722	69	181	5,693	7,720	86	279
2014	May	3,981	6,008	73	248	6,042	10,238	104	418
2014	Jun	3,486	5,101	62	219	6,716	8,806	105	324
2014	Jul	3,892	6,350	66	305	7,331	9,514	146	402
2014	Aug	3,465	4,981	66	293	6,540	7,967	155	331
2014	Sep	3,416	5,020	69	356	6,996	8,839	198	417
2014	Annual	3,359	4,814	67	241	6,432	8,893	117	342

In the first nine months of 2014, up-to congestion transactions continued to displace increment offers and decrement bids, until September 8, 2014. While up-to congestion transactions (UTC) continued to displace increment offers and decrement bids, there was a sharp decrease in UTCs in September as a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[58] Table 3-33 shows the average hourly number of up-to congestion transactions and the average hourly MW for 2013 and the first nine months of 2014. In the first nine months of 2014, the average hourly up-to congestion submitted MW increased 19.4 percent and

58 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

cleared MW increased 22.5 percent, compared to the first nine months of 2013.

Table 3-33 Hourly average of cleared and submitted up-to congestion bids by month: January 2013 through September of 2014

		Up-to Congestion			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2013	Jan	44,844	157,229	1,384	4,205
2013	Feb	46,351	144,066	1,419	3,862
2013	Mar	49,003	163,178	1,467	3,745
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	Jul	49,674	201,630	1,658	5,300
2013	Aug	44,765	157,748	1,477	3,923
2013	Sep	45,412	136,813	1,408	3,507
2013	Oct	45,918	145,026	1,705	4,267
2013	Nov	54,643	171,439	2,108	5,365
2013	Dec	60,588	197,092	2,204	5,948
2013	Annual	51,598	175,255	1,682	4,596
2014	Jan	55,969	199,708	2,436	7,056
2014	Feb	64,123	229,256	3,262	9,020
2014	Mar	65,829	243,469	3,521	10,920
2014	Apr	73,453	224,924	3,216	8,390
2014	May	73,853	251,463	3,057	8,860
2014	Jun	69,050	235,590	2,781	8,221
2014	Jul	66,800	212,485	2,855	7,856
2014	Aug	66,272	214,713	3,003	7,933
2014	Sep	25,370	86,237	1,210	2,979
2014	Annual	62,351	210,979	2,815	7,918

Table 3-34 shows the average hourly number of import and export transactions and the average hourly MW for 2013 and the first nine months of 2014. In the first nine months of 2014, the average hourly submitted and cleared import transaction MW decreased 2.7 and 0.8 percent, and the average hourly submitted and cleared export transaction MW increased 16.2 and 14.1 percent, compared to the first nine months of 2013.[59]

Table 3-34 Hourly average number of cleared and submitted import and export transactions by month: January 2013 through September of 2014

		Imports				Exports			
Year		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2013	Jan	2,071	2,177	10	11	3,278	3,293	21	21
2013	Feb	2,098	2,244	11	13	3,275	3,288	19	19
2013	Mar	1,997	2,097	12	13	3,326	3,329	18	18
2013	Apr	2,004	2,097	12	13	2,691	2,691	16	16
2013	May	2,160	2,316	12	13	2,824	2,838	18	19
2013	Jun	2,712	2,818	15	16	3,420	3,507	19	20
2013	Jul	2,930	3,019	15	16	3,621	3,720	19	20
2013	Aug	2,577	2,656	13	15	3,734	3,766	20	20
2013	Sep	2,089	2,135	9	10	3,561	3,567	19	19
2013	Oct	2,191	2,216	10	10	3,215	3,225	18	18
2013	Nov	2,182	2,196	10	11	2,531	2,564	16	16
2013	Dec	2,243	2,315	10	10	3,774	3,889	21	22
2013	Annual	2,273	2,359	12	13	3,273	3,309	19	19
2014	Jan	2,347	2,515	14	15	3,495	3,887	21	24
2014	Feb	2,419	2,616	13	15	4,299	4,584	24	26
2014	Mar	2,450	2,496	15	15	5,069	5,293	27	29
2014	Apr	2,017	2,045	13	13	4,164	4,171	22	22
2014	May	2,162	2,168	13	13	2,664	2,674	18	18
2014	Jun	2,527	2,536	13	14	3,643	3,645	22	22
2014	Jul	2,236	2,279	12	12	3,786	3,787	21	21
2014	Aug	2,224	2,236	11	12	3,138	3,140	18	18
2014	Sep	2,114	2,123	11	11	3,744	3,755	23	23
2014	Annual	2,276	2,333	13	13	3,771	3,874	22	22

59 For more information about imports and exports, see the *2014 Quarterly State of the Market Report for PJM: January through September*, Section 9, "Interchange Transactions," Interchange Transaction Activity.

Table 3-35 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 3-35 Type of day-ahead marginal units: January through September of 2014

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	2.9%	0.1%	94.4%	1.4%	1.1%	0.0%
Feb	2.0%	0.3%	94.7%	1.9%	1.1%	0.0%
Mar	2.6%	0.2%	94.7%	1.5%	1.0%	0.0%
Apr	2.3%	0.0%	95.1%	1.4%	1.2%	0.0%
May	1.6%	0.0%	92.0%	4.0%	2.4%	0.0%
Jun	2.0%	0.0%	94.6%	2.0%	1.4%	0.0%
Jul	2.1%	0.0%	93.9%	2.1%	1.9%	0.0%
Aug	2.2%	0.0%	94.7%	1.5%	1.6%	0.0%
Sep	7.2%	0.1%	83.9%	5.5%	3.4%	0.0%
Annual	2.5%	0.1%	93.7%	2.2%	1.6%	0.0%

Figure 3-25 shows the monthly volume of bid and cleared INC, DEC and up-to congestion bids by month for the period from January 2005 through September 2014. Figure 3-26 shows the daily volume of bid and cleared INC, DEC and up-to congestion bids for the period from January 2013 through September 2014 in order to show the drop off in UTC volumes compared to volumes in the last two years. Figure 3-27 shows the daily volume of bid and cleared INC, DEC and up-to congestion bids for the period from July 2014 through September 2014 in order to show the drop off in UTC volumes in more detail.

Figure 3-25 Monthly bid and cleared INCs, DECs, and UTCs (MW): January 2005 through September 2014

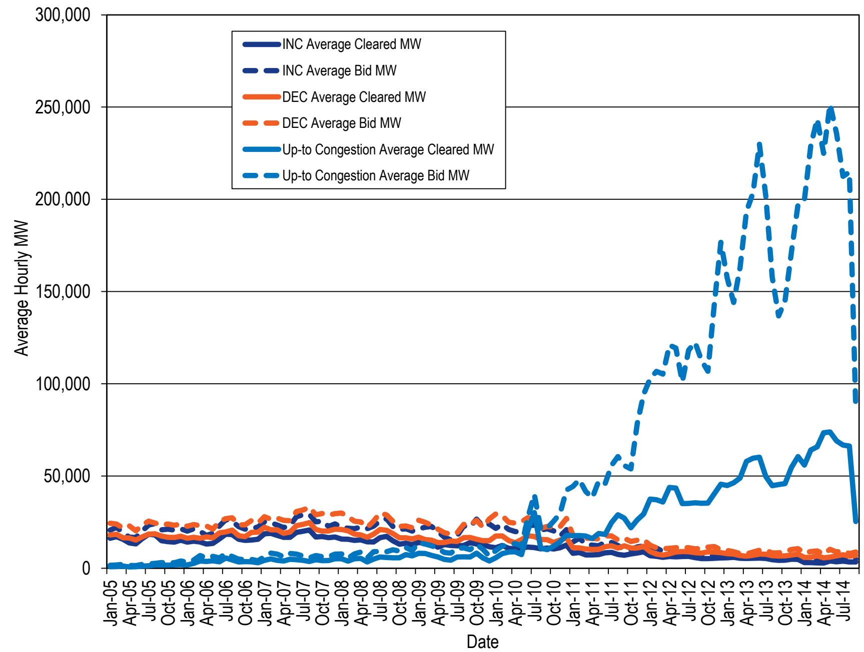


Figure 3-26 Daily bid and cleared INCs, DECs, and UTCs (MW): January 2013 through September 2014

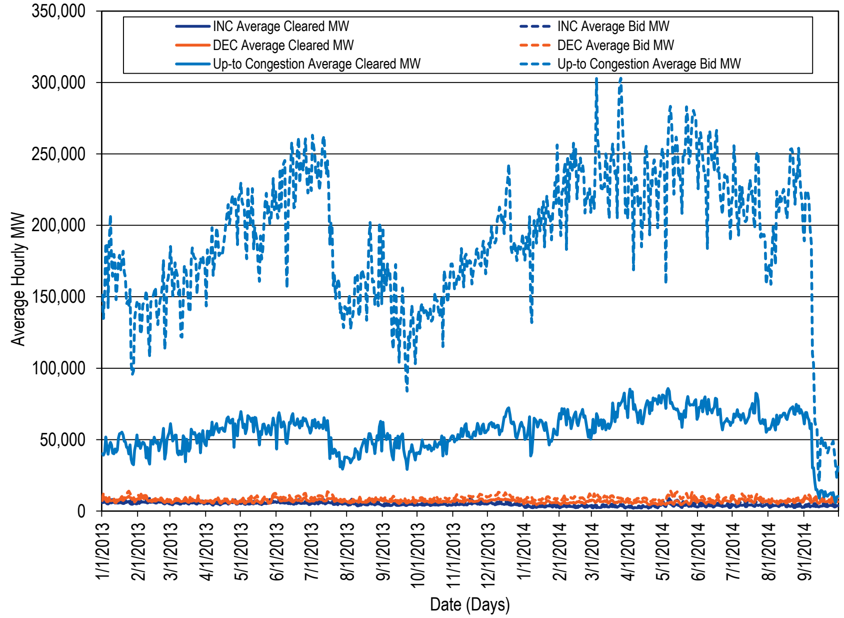
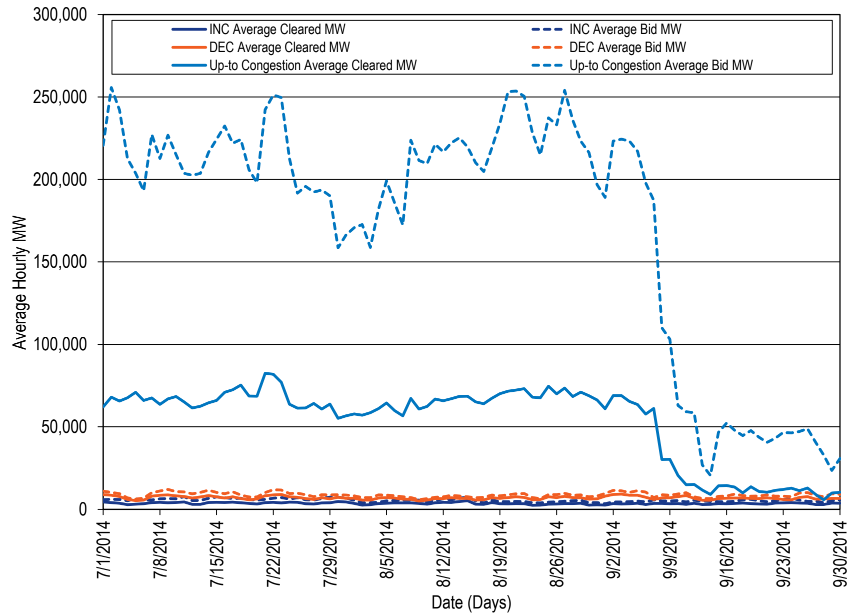


Figure 3-27 Daily bid and cleared INCs, DECs, and UTCs (MW): July 2014 through September 2014



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 3-36 shows, for the first nine months of 2013 and the first nine months of 2014, the total increment offers and decrement bids by whether the parent organization is financial or physical. Table 3-37 shows, for the first nine months of 2013 and the first nine months of 2014, the total up-to congestion transactions by the type of parent organization. Table 3-38 shows, for the first nine months of 2013 and the first nine months of 2014, the total import and export transactions by whether the parent organization is financial or physical.

The top five companies with cleared up-to congestion transactions are financial and account for 63.9 percent of all the cleared up-to congestion MW in PJM in the first nine months of 2014, which is lower than the 65.1 percent in the first nine months of 2013. The cleared up-to congestion MW from financial companies increased 28.8 percent in the first nine months of 2014 compared to the first nine months of 2013. At the same time, the cleared up-to congestion MW from physical companies decreased by 31.7 percent decrease in the first nine months of 2014 compared to the first nine months for 2013.

Table 3-36 PJM INC and DEC bids by type of parent organization (MW): January through September of 2013 and 2014

	2013 (Jan - Sep)		2014 (Jan - Sep)	
Category	Total Virtual Bids MW	Percentage	Total Virtual Bids MW	Percentage
Financial	26,288,812	26.1%	34,951,487	38.9%
Physical	74,283,033	73.9%	54,842,824	61.1%
Total	100,571,845	100.0%	89,794,311	100.0%

Table 3-37 PJM up-to congestion transactions by type of parent organization (MW): January through September of 2013 and 2014

	2013 (Jan - Sep)		2014 (Jan - Sep)	
Category	Total Up-to Congestion MW	Percentage	Total Up-to Congestion MW	Percentage
Financial	308,437,367	94.9%	397,253,998	97.3%
Physical	16,406,890	5.1%	11,208,929	2.7%
Total	324,844,257	100.0%	408,462,927	100.0%

Table 3-38 PJM import and export transactions by type of parent organization (MW): January through September of 2013 and 2014

	2013 (Jan - Sep)		2014 (Jan - Sep)	
Category	Total Import and Export MW	Percentage	Total Import and Export MW	Percentage
Financial	15,685,768	42.8%	15,806,252	39.1%
Physical	20,998,911	57.2%	24,661,550	60.9%
Total	36,684,679	100.0%	40,467,801	100.0%

Table 3-39 shows increment offers and decrement bids bid by top ten locations for the first nine months of 2013 and the first nine months of 2014.

Table 3-39 PJM virtual offers and bids by top ten locations (MW): January through September of 2013 and 2014

2013 (Jan - Sep)					2014 (Jan - Sep)				
Aggregate/Bus Name	Aggregate/ Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/ Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	18,260,786	20,364,245	38,625,031	WESTERN HUB	HUB	9,894,171	10,863,829	20,758,000
N ILLINOIS HUB	HUB	2,021,992	3,654,688	5,676,680	MISO	INTERFACE	343,925	5,474,143	5,818,068
SOUTHIMP	INTERFACE	5,631,492	0	5,631,492	PPL	ZONE	176,875	4,896,410	5,073,284
AEP-DAYTON HUB	HUB	2,617,334	2,689,122	5,306,456	SOUTHIMP	INTERFACE	4,663,488	0	4,663,488
IMO	INTERFACE	4,541,532	48,272	4,589,804	PECO	ZONE	216,231	4,185,850	4,402,081
PPL	ZONE	61,736	3,971,407	4,033,143	AEP-DAYTON HUB	HUB	1,802,758	1,888,119	3,690,877
MISO	INTERFACE	339,371	2,691,928	3,031,299	IMO	INTERFACE	3,198,562	172,008	3,370,570
PECO	ZONE	84,716	2,790,978	2,875,694	N ILLINOIS HUB	HUB	763,057	2,005,553	2,768,610
BGE	ZONE	26,503	1,524,108	1,550,611	BGE	ZONE	19,929	2,315,241	2,335,170
DOMINION HUB	HUB	241,575	1,292,010	1,533,584	MIAMIFOR22 KV MI7	GEN	0	1,096,814	1,096,814
Top ten total		33,827,037	39,026,758	72,853,795			21,078,997	32,897,966	53,976,963
PJM total		42,857,882	57,713,964	100,571,845			31,534,992	58,259,319	89,794,311
Top ten total as percent of PJM total		78.9%	67.6%	72.4%			66.8%	56.5%	60.1%

Table 3-40 shows up-to congestion transactions by import bids for the top ten locations for the first nine months of 2013 and the first nine months of 2014.[60]

Table 3-40 PJM cleared up-to congestion import bids by top ten source and sink pairs (MW): January through September of 2013 and 2014

2013 (Jan - Sep)				
Imports				
Source	Source Type	Sink	Sink Type	MW
OVEC	INTERFACE	DEOK	ZONE	939,254
OVEC	INTERFACE	STUART 1	AGGREGATE	882,562
OVEC	INTERFACE	MIAMI FORT 7	AGGREGATE	805,645
NYIS	INTERFACE	HUDSON BC	AGGREGATE	762,162
NORTHWEST	INTERFACE	ZION 1	AGGREGATE	656,470
NORTHWEST	INTERFACE	BYRON 1	AGGREGATE	496,011
OVEC	INTERFACE	BECKJORD 6	AGGREGATE	455,771
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	452,895
OVEC	INTERFACE	SPORN 2	AGGREGATE	447,182
MISO	INTERFACE	112 WILTON	EHVAGG	399,528
Top ten total				6,297,480
PJM total				32,351,220
Top ten total as percent of PJM total				19.5%
2014 (Jan - Sep)				
Imports				
Source	Source Type	Sink	Sink Type	MW
HUDSONTP	INTERFACE	LEONIA 230 T-2	AGGREGATE	962,423
SOUTHEAST	INTERFACE	EDANVILL T1	AGGREGATE	759,991
MISO	INTERFACE	COOK	EHVAGG	620,933
OVEC	INTERFACE	BIG SANDY CT1	AGGREGATE	586,836
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	494,224
NEPTUNE	INTERFACE	SOUTHRIV 230	AGGREGATE	428,251
MISO	INTERFACE	AEP-DAYTON HUB	HUB	425,824
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	395,391
OVEC	INTERFACE	DEOK	ZONE	374,463
HUDSONTP	INTERFACE	LEONIA 230 T-1	AGGREGATE	373,872
Top ten total				5,422,207
PJM total				26,605,983
Top ten total as percent of PJM total				20.4%

Table 3-41 shows up-to congestion transactions by export bids for the top ten locations for the first nine months of 2013 and the first nine months of 2014.

Table 3-41 PJM cleared up-to congestion export bids by top ten source and sink pairs (MW): January through September of 2013 and 2014

2013 (Jan - Sep)				
Exports				
Source	Source Type	Sink	Sink Type	MW
JEFFERSON	EHVAGG	OVEC	INTERFACE	1,901,810
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	1,074,478
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	1,055,665
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	949,703
TANNERS CRK 4	AGGREGATE	OVEC	INTERFACE	875,503
GAVIN	EHVAGG	OVEC	INTERFACE	641,654
ROCKPORT	EHVAGG	OVEC	INTERFACE	571,378
EAST BEND 2	AGGREGATE	OVEC	INTERFACE	556,385
SPORN 3	AGGREGATE	OVEC	INTERFACE	545,195
F387 CHICAGOH	AGGREGATE	NIPSCO	INTERFACE	533,133
Top ten total				8,704,904
PJM total				38,431,224
Top ten total as percent of PJM total				22.7%
2014 (Jan - Sep)				
Exports				
Source	Source Type	Sink	Sink Type	MW
JEFFERSON	EHVAGG	OVEC	INTERFACE	2,072,977
TANNERS CRK 4	AGGREGATE	SOUTHWEST	INTERFACE	1,679,588
TANNERS CRK 4	AGGREGATE	OVEC	INTERFACE	809,023
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	663,858
ROCKPORT	EHVAGG	OVEC	INTERFACE	537,417
JEFFERSON	EHVAGG	SOUTHWEST	INTERFACE	530,747
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	508,396
BECKJORD 6	AGGREGATE	OVEC	INTERFACE	412,879
UNIV PARK 1-6	AGGREGATE	NIPSCO	INTERFACE	410,199
LINDEN A	AGGREGATE	LINDENVFT	INTERFACE	397,475
Top ten total				8,022,558
PJM total				28,341,400
Top ten total as percent of PJM total				28.3%

60 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 3-42 shows up-to congestion transactions by wheel bids for the top ten locations for the first nine months of 2013 and the first nine months of 2014.

Table 3-42 PJM cleared up-to congestion wheel bids by top ten source and sink pairs (MW): January through September of 2013 and 2014

2013 (Jan - Sep)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	685,232
NORTHWEST	INTERFACE	MISO	INTERFACE	396,607
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	300,204
IMO	INTERFACE	NYIS	INTERFACE	272,426
MISO	INTERFACE	NIPSCO	INTERFACE	259,584
OVEC	INTERFACE	IMO	INTERFACE	109,350
MISO	INTERFACE	SOUTHEXP	INTERFACE	104,052
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	88,280
MISO	INTERFACE	OVEC	INTERFACE	79,810
NORTHWEST	INTERFACE	OVEC	INTERFACE	78,419
Top ten total				2,373,962
PJM total				3,144,557
Top ten total as percent of PJM total				75.5%
2014 (Jan - Sep)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
NORTHWEST	INTERFACE	MISO	INTERFACE	757,930
OVEC	INTERFACE	SOUTHEXP	INTERFACE	325,649
MISO	INTERFACE	NORTHWEST	INTERFACE	281,282
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	255,598
MISO	INTERFACE	NIPSCO	INTERFACE	113,990
NYIS	INTERFACE	IMO	INTERFACE	96,966
MISO	INTERFACE	SOUTHEXP	INTERFACE	94,359
IMO	INTERFACE	NYIS	INTERFACE	89,338
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	84,922
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	71,509
Top ten total				2,171,543
PJM total				2,761,587
Top ten total as percent of PJM total				78.6%

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.[61] Up-to congestion transactions can now be made at internal buses. The top ten internal up-to congestion transaction locations were 10.2 percent of the PJM total internal up-to congestion transactions in the first nine months of 2014.

Table 3-43 shows up-to congestion transactions by internal bids for the top ten locations for the first nine months of 2013 and 2014.

Table 3-43 PJM cleared up-to congestion internal bids by top ten source and sink pairs (MW): January through September of 2013 and 2014

2013 (Jan - Sep)				
Internal				
Source	Source Type	Sink	Sink Type	MW
SUNBURY 1-3	AGGREGATE	CITIZENS	AGGREGATE	3,248,461
ATSI GEN HUB	HUB	ATSI	ZONE	3,180,687
MT STORM	EHVAGG	GREENLAND GAP	EHVAGG	3,060,670
FE GEN	AGGREGATE	ATSI	ZONE	1,778,421
AEP-DAYTON HUB	HUB	WESTERN HUB	HUB	1,690,443
CORDOVA	AGGREGATE	QUAD CITIES 2	AGGREGATE	1,519,249
WYOMING	EHVAGG	BROADFORD	EHVAGG	1,417,822
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	1,371,354
WHITPAIN	EHVAGG	ELROY	EHVAGG	1,313,998
NAPERVILLE	AGGREGATE	WINNETKA	AGGREGATE	1,189,073
Top ten total				19,770,178
PJM total				250,917,257
Top ten total as percent of PJM total				7.9%
2014 (Jan - Sep)				
Internal				
Source	Source Type	Sink	Sink Type	MW
MOUNTAINEER	EHVAGG	GAVIN	EHVAGG	6,614,543
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	5,207,634
MOUNTAINEER	EHVAGG	FLATLICK	EHVAGG	4,294,199
ATSI GEN HUB	HUB	ATSI	ZONE	3,921,656
VERNON BK 4	AGGREGATE	AEC - JC	AGGREGATE	3,733,527
FE GEN	AGGREGATE	ATSI	ZONE	3,324,975
DUMONT	EHVAGG	COOK	EHVAGG	2,370,640
JEFFERSON	EHVAGG	COOK	EHVAGG	2,291,396
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	2,035,779
TANNERS CRK 4	AGGREGATE	STUART DIESEL	AGGREGATE	1,810,214
Top ten total				35,604,562
PJM total				350,753,957
Top ten total as percent of PJM total				10.2%

61 For more information, see the *2013 State of the Market Report for PJM*, Volume II, Section 9, "Interchange Transactions," Up-to Congestion.

Table 3-44 shows the number of source-sink pairs that were offered and cleared monthly in January of 2012 through the first nine months of 2014. The annual row in Table 3-44 is the average hourly number of offered and cleared source-sink pairs for the year for the average columns and the maximum hourly number of offered and cleared source-sink pairs for the year for the maximum columns. The increase in average offered and cleared source-sink pairs beginning in November and December of 2012 and continuing through the first nine months of 2014 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.

Table 3-44 Number of PJM offered and cleared source and sink pairs: January 2012 through September 2014

		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	2,827	13,009	1,800	8,071
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	9,064	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	Jul	5,955	9,006	3,242	4,938
2013	Aug	6,215	9,751	3,642	5,117
2013	Sep	3,496	4,222	2,510	3,082
2013	Oct	4,743	7,134	3,235	4,721
2013	Nov	8,605	14,065	5,419	8,069
2013	Dec	8,346	11,728	6,107	7,415
2013	Annual	5,996	14,065	3,620	8,069
2014	Jan	7,977	11,191	5,179	7,714
2014	Feb	10,087	11,688	7,173	8,463
2014	Mar	11,360	14,745	7,284	9,943
2014	Apr	11,487	14,106	8,589	10,253
2014	May	11,215	13,477	7,734	9,532
2014	Jun	10,613	14,112	7,374	10,143
2014	Jul	10,057	12,304	7,202	8,486
2014	Aug	10,877	12,863	7,609	9,254
2014	Sep	5,618	11,269	4,281	8,743
2014	Annual	9,927	14,745	6,935	10,253

Table 3-45 and Figure 3-28 show total cleared up-to congestion transactions by type for the first nine months of 2013 and the first nine months of 2014. Internal up-to congestion transactions in the first nine months of 2014 were 85.9 percent of all up-to congestion transactions for the first nine months of 2014.

Table 3-45 PJM cleared up-to congestion transactions by type (MW): January through September of 2013 and 2014

	2013 (Jan - Sep)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	6,297,480	8,704,904	2,373,962	19,770,178	20,482,915
PJM total (MW)	32,351,220	38,431,224	3,144,557	250,917,257	324,844,257
Top ten total as percent of PJM total	19.5%	22.7%	75.5%	7.9%	6.3%
PJM total as percent of all up-to congestion transactions	10.0%	11.8%	1.0%	77.2%	100.0%
	2014 (Jan - Sep)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	5,422,207	8,022,558	2,171,543	35,604,562	35,867,325
PJM total (MW)	26,605,983	28,341,400	2,761,587	350,753,957	408,462,927
Top ten total as percent of PJM total	20.4%	28.3%	78.6%	10.2%	8.8%
PJM total as percent of all up-to congestion transactions	6.5%	6.9%	0.7%	85.9%	100.0%

Figure 3-28 shows the initial increase and continued rise of internal up-to congestion transactions by month following the November 1, 2012 rule change permitting such transactions, until September 8, 2014. There was a sharp decrease in UTCs in September as a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[62] Figure 3-29 shows the daily cleared up-to congestion MW by transaction type for the period from January 2013 through September 2014 in order to show the drop off in UTC volumes compared to volumes in the last two years. Figure 3-30 shows the daily cleared up-to congestion MW by transaction type for the period from July 2014 through September 2014 in order to show the drop off in UTC volumes in more detail.

62 See "PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date," Docket No. EL14-37-000 (September 8, 2014).

Figure 3-28 PJM cleared up-to congestion transactions by type (MW): January 2005 through September 2014

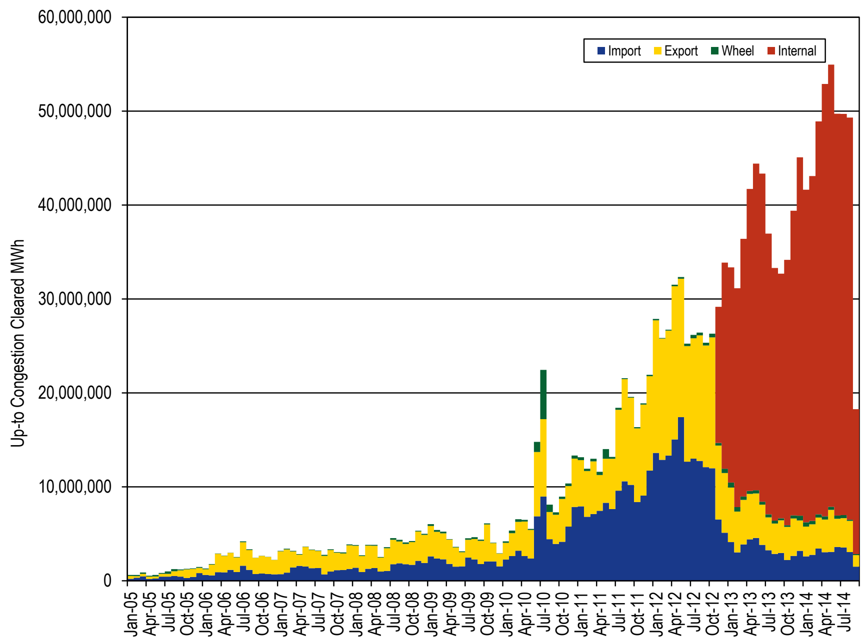


Figure 3-29 PJM daily cleared up-to congestion transaction by type (MW): January 2013 through September 2014

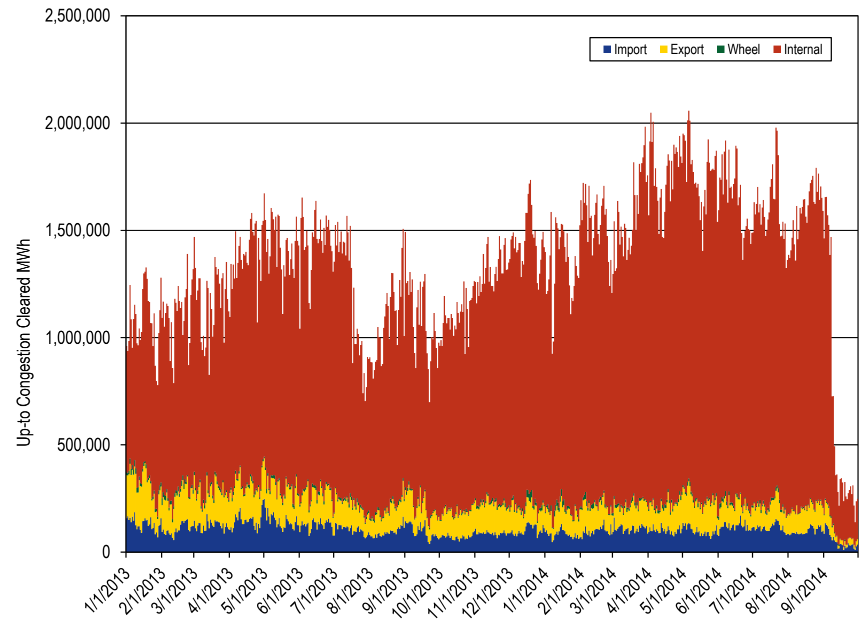
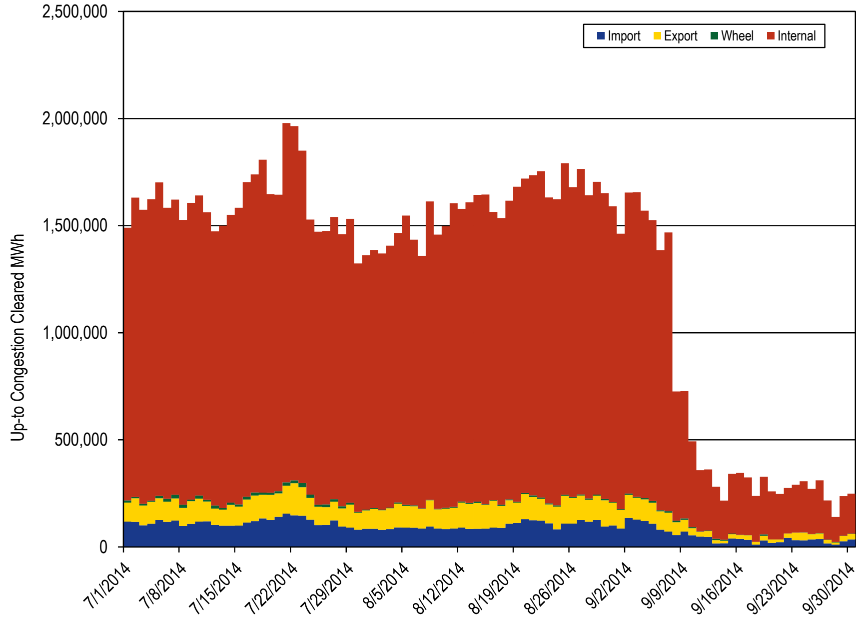


Figure 3-30 PJM daily cleared up-to congestion transaction by type (MW): July through September 2014



Generator Offers

Generator offers are categorized as dispatchable (Table 3-46) or self scheduled (Table 3-47).[63] Units which are available for economic dispatch are dispatchable. Units which are self scheduled to generate fixed output are self scheduled and must run. Units which are self scheduled at their economic minimum and are available for economic dispatch up to their economic maximum are self scheduled and dispatchable. Table 3-46 and Table 3-47 do not include units that did not indicate their offer status and units that were offered as available to run only during emergency events. The MW offered beyond the economic range of a unit, i.e. MW range between the specified economic maximum and emergency maximum, are categorized as emergency MW. The emergency MW are included in both tables.

Table 3-46 shows the proportion of MW offers by dispatchable units, by unit type and by offer price range, for the first nine months of 2014. For example, 66.4 percent of CC offers were dispatchable and in the $0 to $200 per MWh price range. The Total column is the proportion of all MW offers by unit type that were dispatchable. For example, 80.6 percent of all CC MW offers were dispatchable, including the 7.7 percent of emergency MW offered by CC units. The All Dispatchable Offers row is the proportion of MW that were offered as available for economic dispatch within a given range by all unit types. For example, 41.4 percent of all dispatchable offers were in the $0 to $200 per MWh price range. The Total column in the All Dispatchable Offers row is the proportion of all MW offers that were offered as available for economic dispatch, including emergency MW. Among all the generator offers in the first nine months of 2014, 55.9 percent were offered as available for economic dispatch.

Table 3-46 Distribution of MW for dispatchable unit offer prices: January through September of 2014

	Dispatchable (Range)							
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	0.1%	66.4%	3.6%	1.6%	0.4%	0.8%	7.7%	80.6%
CT	0.1%	52.2%	26.1%	6.6%	1.9%	0.9%	11.4%	99.2%
Diesel	3.0%	14.4%	25.0%	8.9%	2.0%	1.7%	15.5%	70.4%
Run of River	0.0%	11.0%	0.0%	0.0%	0.0%	0.0%	0.0%	11.0%
Nuclear	8.6%	36.6%	0.0%	0.0%	0.0%	0.0%	11.9%	57.1%
Pumped Storage	0.0%	0.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Solar	0.7%	6.7%	0.0%	0.0%	0.0%	0.0%	0.1%	7.5%
Steam	0.0%	45.7%	2.1%	0.3%	0.1%	0.2%	3.5%	51.9%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	40.1%	7.5%	0.0%	0.0%	0.0%	0.0%	0.6%	48.2%
All Dispatchable Offers	0.9%	41.4%	6.2%	1.6%	0.4%	0.4%	5.0%	55.9%

63 Each range in the tables is greater than or equal to the lower value and less than the higher value. The unit type battery is not included in these tables because batteries do not make energy offers. The unit type fuel cell is not included in these tables because of the small number owners and the small number of units of this type of generation.

Table 3-47 Distribution of MW for self scheduled offer prices: January through September of 2014

	Self Scheduled		Self Scheduled and Dispatchable (Range)							
Unit Type	Must Run	Emergency	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	0.8%	0.3%	0.2%	16.4%	0.3%	0.1%	0.0%	0.0%	1.3%	19.4%
CT	0.4%	0.0%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%
Diesel	25.7%	3.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	29.6%
Hydro	83.2%	5.4%	0.0%	0.3%	0.0%	0.0%	0.0%	0.0%	0.1%	89.0%
Nuclear	21.1%	10.1%	2.8%	1.9%	0.0%	0.0%	0.0%	0.0%	6.9%	42.9%
Pumped Storage	60.7%	15.4%	5.0%	12.9%	0.0%	0.0%	0.0%	1.7%	4.1%	99.8%
Solar	67.9%	23.9%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	92.5%
Steam	4.6%	1.2%	0.2%	39.0%	0.1%	0.0%	0.0%	0.0%	2.8%	48.1%
Transaction	79.6%	20.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
Wind	5.6%	4.6%	33.6%	2.6%	0.0%	0.0%	0.0%	0.0%	5.4%	51.8%
All Self-Scheduled Offers	20.6%	2.2%	0.7%	18.7%	0.1%	0.0%	0.0%	0.0%	1.7%	44.1%

Table 3-47 shows the proportion of MW offers by unit type that were self scheduled to generate fixed output and by unit type and price range for self-scheduled and dispatchable units, for the first nine months of 2014. For example, 16.4 percent of CC offers were self scheduled and dispatchable and in the $0 to $200 price range. The Total column is the proportion of all MW offers by unit type that were self scheduled to generate fixed output and are self scheduled and dispatchable. For example, 19.4 percent of all CC MW offers were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including the 1.6 percent of emergency MW offered by CC units. The All Self-Scheduled Offers row is the proportion of MW that were offered as either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum within a given range by all unit types. For example, units that were self scheduled to generate at fixed output accounted for 20.6 percent of all offers and self-scheduled and dispatchable units accounted for 19.6 percent of all offers. The Total column in the All Self-Scheduled Offers row is the proportion of all MW offers that were either self scheduled to generate at fixed output or self scheduled to generate at economic minimum and dispatchable up to economic maximum, including emergency MW. Among all the generator offers in the first nine months of 2014, 22.8 percent were offered as self scheduled and 21.3 percent were offered as self scheduled and dispatchable.

Market Performance

The PJM average locational marginal price (LMP) reflects the configuration of the entire RTO. The PJM Energy Market includes the Real-Time Energy Market and the Day-Ahead Energy Market.

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.[64]

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

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

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 the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units.

Table 3-48 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 3-48 on the system-wide load-weighted LMP. The negative markup components of LMP reflect the negative markups shown in the Table 3-27.

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 exclude 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. Even the adjusted markup underestimates the markup because coal units facing increased competitive pressure have excluded both the ten percent adder and some or all components of operating and maintenance cost. While both these elements are permitted under the definition of cost-based offers in the relevant PJM manual, they are not part of a competitive offer for a coal unit because they are not actually marginal costs, and market behavior reflected that fact.[65]

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, markup is the difference between the active offer of the marginal unit and the cost offer. In the second approach, the 10 percent markup is removed from the cost offers of coal units because coal units do not face the same cost uncertainty as gas-fired CTs. The adjusted markup is calculated as the difference between the active offer and the cost offer excluding the 10 percent adder. The unadjusted markup is calculated as the difference between the active offer and the cost offer including the 10 percent adder in the cost offer.

Table 3-48 shows the mark-up component of the load-weighted LMP by fuel type and unit type using unadjusted and adjusted offers. The adjusted markup component of LMP increased from $0.85 in the first nine months of 2013 to $3.65 in the first nine months of 2014. The adjusted markup contribution of coal units in the first nine months of 2014 was $1.99. The adjusted mark-up component of all gas-fired units in the first nine months of 2014 was minus $1.05. Coal units accounted for 40 percent of the increased markup

65 See *PJM Manual 15: Cost Development Guidelines*, Revision: 25 (Effective July 28, 2014).

component of LMP in the first nine months of 2014 while gas units accounted for 37 percent. The markup component of wind units was 0.04. If a price-based offer is negative but less negative than a cost-based offer, the markup is positive. In the first nine months of 2014, among the wind units that were marginal, 1.74 percent had positive offer prices.

Table 3-48 Markup component of the overall PJM real-time, load-weighted, average LMP by primary fuel type and unit type: January through September 2013 and 2014[66]

		2013 (Jan-Sep)		2014 (Jan-Sep)	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($0.65)	$0.86	$0.66	$1.99
Gas	CC	($0.01)	($0.01)	$0.72	$0.72
Gas	CT	$0.17	$0.17	$0.33	$0.33
Gas	Diesel	$0.06	$0.06	$0.03	$0.03
Gas	Steam	($0.35)	($0.35)	($0.03)	($0.03)
Municipal Waste	Steam	($0.01)	($0.01)	$0.20	$0.20
Oil	CC	$0.02	$0.02	$0.12	$0.12
Oil	CT	$0.02	$0.02	$0.12	$0.12
Oil	Diesel	$0.00	$0.00	$0.09	$0.09
Oil	Steam	$0.09	$0.10	$0.05	$0.05
Other	Steam	($0.02)	($0.02)	($0.00)	($0.00)
Uranium	Steam	($0.00)	($0.00)	$0.01	$0.01
Wind	Wind	$0.00	$0.00	$0.04	$0.04
Total		($0.67)	$0.85	$2.32	$3.65

Markup Component of Real-Time Price

Table 3-49 shows the markup component, calculated using unadjusted offers, of average prices and of average monthly on-peak and off-peak prices. Table 3-50 shows the markup component, calculated using adjusted offers, of average prices and of average monthly on-peak and off-peak prices. In the first nine months of 2014, when using unadjusted cost offers, $2.32 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-offers, $3.65 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first nine months of 2014, the peak markup component was highest in March, $11.48 per MWh using unadjusted cost offers and $12.33 per MWh using adjusted cost offers. This corresponds to 15.13 percent and 16.25 percent of the real time load-weighted average LMP in March.

Table 3-49 Monthly markup components of real-time load-weighted LMP (Unadjusted): January through September 2013 and 2014

	2013			2014		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($3.10)	($3.87)	($2.38)	$5.84	$3.91	$7.69
Feb	($1.84)	($2.95)	($0.76)	$3.02	$0.88	$5.08
Mar	$0.67	($0.90)	$2.30	$7.27	$3.24	$11.48
Apr	($1.95)	($3.04)	($1.02)	($0.43)	($2.16)	$1.07
May	($1.16)	($2.92)	$0.32	$1.51	($1.27)	$4.18
Jun	($0.42)	($1.58)	$0.74	$2.22	($0.06)	$4.18
Jul	$3.86	($0.20)	$7.44	($0.01)	($0.88)	$0.74
Aug	($1.49)	($1.89)	($1.15)	($1.08)	($1.91)	($0.29)
Sep	($1.41)	($2.35)	($0.48)	$1.51	($0.13)	$3.01
Total	($0.66)	($2.13)	$0.70	$2.32	$0.35	$4.16

Table 3-50 Monthly markup components of real-time load-weighted LMP (Adjusted): January through September 2013 and 2014

	2013			2014		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	($1.32)	($1.97)	($0.71)	$7.22	$5.48	$8.90
Feb	($0.05)	($1.04)	$0.91	$3.94	$1.97	$5.84
Mar	$2.28	$0.89	$3.71	$8.37	$4.59	$12.33
Apr	($0.69)	($1.39)	($0.10)	$0.86	($0.45)	$2.00
May	$0.22	($1.17)	$1.39	$2.66	$0.09	$5.12
Jun	$1.05	($0.04)	$2.14	$3.44	$1.45	$5.15
Jul	$5.22	$1.32	$8.65	$1.61	$0.69	$2.40
Aug	($0.06)	($0.36)	$0.19	$0.50	($0.29)	$1.25
Sep	$0.13	($0.58)	$0.83	$3.18	$1.65	$4.59
Total	$0.85	($0.42)	$2.04	$3.65	$1.85	$5.33

66 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 gas from municipal waste.

Markup Component of Real-Time Zonal Prices

The unit markup component of average real-time price using unadjusted offers is shown for each zone for the first nine months of 2014 and the first nine months of 2013 in Table 3-51 and for adjusted offers in Table 3-52. The smallest zonal all hours average markup component using unadjusted offers for the first nine months of 2014 was in the ComEd Zone, $1.40 per MWh, while the highest was in the Dominion Control Zone, $3.75 per MWh. The smallest zonal on peak average markup was in the ComEd Control Zone, $2.88 per MWh, while the highest was in the Dominion Control Zone, $5.98 per MWh.

Table 3-51 Average real-time zonal markup component (Unadjusted): January through September, 2013 and 2014

	2013 (Jan - Sep)			2014 (Jan -Sep)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	($0.58)	($2.01)	$0.78	$2.19	$0.01	$4.23
AEP	($0.83)	($2.20)	$0.46	$1.93	($0.03)	$3.80
APS	($0.80)	($2.27)	$0.59	$2.15	$0.34	$3.87
ATSI	($0.66)	($2.16)	$0.72	$1.52	($0.20)	$3.13
BGE	($0.53)	($2.09)	$0.95	$3.64	$1.48	$5.66
ComEd	($0.76)	($2.20)	$0.53	$1.40	($0.19)	$2.88
DAY	($0.78)	($2.20)	$0.49	$1.65	($0.25)	$3.39
DEOK	($0.82)	($2.16)	$0.42	$1.62	($0.35)	$3.47
DLCO	($0.86)	($2.13)	$0.32	$1.66	$0.11	$3.11
DPL	($0.71)	($2.12)	$0.63	$3.37	$1.50	$5.11
Dominion	($0.42)	($2.11)	$1.19	$3.75	$1.37	$5.98
EKPC	$0.04	($1.74)	$1.71	$2.09	$0.24	$3.91
JCPL	($0.45)	($1.80)	$0.76	$1.88	($0.01)	$3.55
Met-Ed	($0.66)	($2.13)	$0.68	$1.99	$0.25	$3.58
PECO	($0.73)	($2.08)	$0.53	$2.28	$0.27	$4.14
PENELEC	($0.94)	($2.26)	$0.28	$2.48	$0.22	$4.56
PPL	($0.80)	($2.03)	$0.33	$2.61	$0.38	$4.66
PSEG	($0.34)	($1.97)	$1.15	$2.69	$0.47	$4.71
Pepco	($0.41)	($2.11)	$1.15	$3.42	$1.29	$5.36
RECO	$0.03	($1.78)	$1.56	$2.42	$0.61	$3.93

Table 3-52 Average real-time zonal markup component (Adjusted): January through September, 2013 and 2014

	2013			2014		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$0.90	($0.32)	$2.05	$3.42	$1.32	$5.39
AEP	$0.73	($0.46)	$1.86	$3.30	$1.56	$4.97
APS	$0.74	($0.53)	$1.95	$3.49	$1.84	$5.06
ATSI	$0.93	($0.41)	$2.17	$2.89	$1.36	$4.32
BGE	$1.02	($0.30)	$2.26	$5.22	$3.27	$7.03
ComEd	$0.73	($0.58)	$1.91	$2.75	$1.35	$4.05
DAY	$0.81	($0.43)	$1.93	$3.07	$1.37	$4.63
DEOK	$0.71	($0.46)	$1.80	$2.99	$1.21	$4.66
DLCO	$0.68	($0.44)	$1.73	$3.08	$1.70	$4.38
DPL	$0.80	($0.42)	$1.96	$4.55	$2.79	$6.19
Dominion	$1.07	($0.40)	$2.47	$5.12	$2.90	$7.19
EKPC	$1.52	($0.12)	$3.07	$3.45	$1.79	$5.08
JCPL	$0.85	($0.11)	$1.71	$3.06	$1.30	$4.60
Met-Ed	$0.80	($0.47)	$1.95	$3.15	$1.54	$4.61
PECO	$0.76	($0.43)	$1.87	$3.45	$1.56	$5.19
PENELEC	$0.63	($0.52)	$1.70	$3.76	$1.63	$5.73
PPL	$0.71	($0.35)	$1.68	$3.77	$1.67	$5.71
PSEG	$1.09	($0.28)	$2.35	$3.87	$1.75	$5.79
Pepco	$1.09	($0.36)	$2.41	$4.89	$2.95	$6.65
RECO	$1.43	($0.11)	$2.73	$3.68	$1.93	$5.14

Markup by Real Time Price Levels

Table 3-53 shows the average markup component of observed prices, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM average LMP was in the identified price range.

Table 3-53 Average real-time markup component (By price category, unadjusted): January through September 2013 and 2014

	2013 (Jan - Sep)		2014 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($1.05)	73.5%	$2.17	74.2%
$25 to $50	($0.23)	22.1%	($0.42)	21.9%
$50 to $75	$0.05	2.9%	$0.32	2.8%
$75 to $100	$0.12	0.7%	$0.12	0.7%
$100 to $125	$0.11	0.3%	$0.09	0.3%
$125 to $150	$0.08	0.2%	$0.07	0.1%
>= $150	$0.25	0.3%	$0.01	0.0%

Table 3-54 Average real-time markup component (By price category, adjusted): January through September, 2013 and 2014

	2013 (Jan - Sep)		2014 (Jan -Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$0.05	73.5%	$3.05	74.2%
$25 to $50	$0.16	22.1%	($0.01)	21.9%
$50 to $75	$0.07	2.9%	$0.36	2.8%
$75 to $100	$0.14	0.7%	$0.13	0.7%
$100 to $125	$0.11	0.3%	$0.09	0.3%
$125 to $150	$0.07	0.2%	$0.07	0.1%
>= $150	$0.27	0.3%	$0.01	0.0%

Day-Ahead Markup

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

The markup component of the PJM day-ahead, load-weighted average LMP by primary fuel and unit type is shown in Table 3-55. INC, DEC and up-to congestion transactions have zero markups. Up-to congestion transactions were marginal for 93.6 percent of marginal resources in the first nine months of 2014. INCs were marginal for 1.6 percent of marginal resources and DECs were marginal for 2.2 percent of marginal resources in the first nine months of 2014. The percentage of marginal up-to congestion transactions decreased significantly beginning on September 8, 2014, as a result of the FERC's UTC uplift refund notice which became effective on September 8, 2014.[67] The adjusted markup of coal units is calculated as the difference between the price offer and the cost offer excluding the 10 percent adder. Table 3-55 shows the markup component of LMP for marginal generating resources. Generating resources were marginal in only 2.5 percent of marginal resources in the first nine months of 2014. The markup component of LMP for marginal generating resources increased in all categories but gas-fired steam units. The markup component of LMP for coal units increased from -$0.52 in the first nine months of 2013 to -$0.10 in the first nine months of 2014. The markup component of LMP for gas-fired CCs increased from -$0.49 in the first nine months of 2013 to -$0.24 in the first nine months of 2014.

Table 3-55 Markup component of the annual PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through September of 2013 and 2014

		2013 (Jan - Sep)		2014 (Jan - Sep)	
Fuel Type	Unit Type	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)	Markup Component of LMP (Unadjusted)	Markup Component of LMP (Adjusted)
Coal	Steam	($0.52)	$0.13	($0.10)	$0.71
Gas	CC	($0.49)	($0.49)	($0.24)	($0.24)
Gas	CT	$0.00	$0.00	$0.03	$0.03
Gas	Diesel	$0.00	$0.00	$0.00	$0.00
Gas	Steam	$0.01	$0.01	($1.52)	($1.52)
Municipal Waste	Steam	$0.00	$0.00	($0.00)	($0.00)
Oil	CC	$0.00	$0.00	$0.01	$0.01
Oil	CT	$0.00	$0.00	$0.04	$0.05
Oil	Steam	$0.00	$0.00	$0.02	$0.02
Other	Steam	$0.00	$0.00	($0.02)	($0.01)
Total		($1.00)	($0.35)	($1.78)	($0.96)

67 See 18 CFR § 385.213 (2014).

Markup Component of Day-Ahead Price

The markup component of price is the difference between the system price, when the system price is determined by the active offers of the marginal units, whether price or cost-based, and the system price, based on the cost-based offers of those marginal units. Only hours when generating units were marginal on either priced based offers or on cost based offers were included in the markup calculation.

Table 3-56 shows the markup component of average prices and of average monthly on-peak and off-peak prices using unadjusted offers. Table 3-57 shows the markup component of average prices and of average monthly on-peak and off-peak prices using adjusted offers.

Table 3-56 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January through September of 2013 and 2014

	2013 (Jan - Sep)			2014 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($3.77)	($3.99)	($3.54)	$0.67	$2.17	($0.90)
Feb	($2.53)	($1.43)	($3.67)	$0.34	$2.07	($1.47)
Mar	($1.84)	($0.18)	($3.45)	$0.11	($0.33)	$0.53
Apr	($0.11)	($0.01)	($0.22)	($1.81)	($1.32)	($2.37)
May	($0.10)	($0.04)	($0.17)	($3.38)	($4.12)	($2.60)
Jun	($0.05)	$0.03	($0.14)	($3.06)	($4.43)	($1.45)
Jul	($0.08)	($0.01)	($0.15)	($3.19)	($3.92)	($2.33)
Aug	($0.06)	($0.01)	($0.11)	($4.27)	($4.33)	($4.19)
Sep	($0.27)	($0.13)	($0.42)	($1.55)	($1.47)	($1.64)
Annual	($1.00)	($0.66)	($1.37)	($1.75)	($1.72)	($1.78)

Table 3-57 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: January through September of 2013 and 2014

	2013 (Jan - Sep)			2014 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	($2.03)	($2.33)	($1.72)	$1.44	$2.72	$0.09
Feb	($0.74)	$0.41	($1.93)	$1.40	$2.81	($0.08)
Mar	($0.26)	$1.29	($1.78)	$1.28	$0.52	$2.01
Apr	$0.07	$0.16	($0.03)	($0.38)	($0.34)	($0.42)
May	$0.02	$0.06	($0.02)	($2.14)	($3.32)	($0.90)
Jun	$0.07	$0.15	($0.02)	($1.72)	($3.44)	$0.29
Jul	($0.01)	$0.06	($0.08)	($2.96)	($3.65)	($2.16)
Aug	$0.01	$0.03	($0.01)	($4.09)	($4.13)	($4.05)
Sep	($0.12)	($0.02)	($0.22)	($1.37)	($1.20)	($1.55)
Annual	($0.35)	($0.05)	($0.67)	($0.93)	($1.10)	($0.74)

Markup Component of Day-Ahead Zonal Prices

The markup component of annual average day-ahead price using unadjusted offers is shown for each zone in Table 3-58. The markup component of annual average day-ahead price using adjusted offers is shown for each zone in Table 3-59. The markup component of the average day-ahead price increased in all zones from the first nine months of 2013 to the first nine months of 2014.

Table 3-58 Day-ahead, average, zonal markup component (Unadjusted): January through September of 2013 and 2014

	2013 (Jan - Sep)			2014 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($1.00)	($0.71)	($1.30)	($2.27)	($2.65)	($1.85)
AEP	($1.01)	($0.62)	($1.42)	($1.53)	($1.29)	($1.78)
AP	($1.10)	($0.71)	($1.50)	($1.64)	($1.42)	($1.86)
ATSI	($1.01)	($0.63)	($1.42)	($1.65)	($1.42)	($1.89)
BGE	($1.00)	($0.71)	($1.33)	($1.78)	($1.84)	($1.72)
ComEd	($0.91)	($0.55)	($1.31)	($1.47)	($1.33)	($1.63)
DAY	($1.02)	($0.62)	($1.47)	($1.65)	($1.47)	($1.84)
DEOK	($0.96)	($0.56)	($1.39)	($1.70)	($1.63)	($1.78)
DLCO	($0.95)	($0.60)	($1.33)	($1.64)	($1.52)	($1.76)
DPL	($1.05)	($0.65)	($1.46)	($2.44)	($3.16)	($1.65)
Dominion	($0.98)	($0.67)	($1.32)	($1.91)	($1.93)	($1.88)
EKPC	($0.10)	($0.02)	($0.20)	($1.36)	($1.18)	($1.55)
JCPL	($1.18)	($1.05)	($1.34)	($2.17)	($2.43)	($1.87)
Met-Ed	($1.09)	($0.78)	($1.43)	($1.89)	($2.02)	($1.75)
PECO	($1.01)	($0.66)	($1.38)	($1.99)	($2.22)	($1.74)
PENELEC	($1.02)	($0.67)	($1.39)	($1.90)	($1.90)	($1.90)
PPL	($1.14)	($0.83)	($1.48)	($1.99)	($2.19)	($1.78)
PSEG	($0.96)	($0.64)	($1.33)	($2.06)	($2.25)	($1.84)
Pepco	($1.00)	($0.71)	($1.31)	($1.78)	($1.79)	($1.78)
RECO	($0.92)	($0.58)	($1.32)	($2.08)	($2.23)	($1.89)

Table 3-59 Day-ahead, average, zonal markup component (Adjusted): January through September of 2013 and 2014

	2013 (Jan - Sep)			2014 (Jan - Sep)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	($0.39)	($0.15)	($0.65)	($1.50)	($2.07)	($0.87)
AEP	($0.33)	$0.01	($0.69)	($0.68)	($0.67)	($0.70)
AP	($0.37)	($0.04)	($0.72)	($0.80)	($0.81)	($0.78)
ATSI	($0.34)	($0.01)	($0.71)	($0.79)	($0.78)	($0.81)
BGE	($0.32)	($0.07)	($0.58)	($0.92)	($1.19)	($0.62)
ComEd	($0.31)	$0.01	($0.67)	($0.64)	($0.70)	($0.57)
DAY	($0.35)	($0.00)	($0.75)	($0.79)	($0.83)	($0.74)
DEOK	($0.32)	$0.03	($0.70)	($0.88)	($1.02)	($0.73)
DLCO	($0.33)	($0.01)	($0.67)	($0.81)	($0.92)	($0.70)
DPL	($0.39)	($0.06)	($0.74)	($1.64)	($2.55)	($0.64)
Dominion	($0.33)	($0.07)	($0.61)	($1.10)	($1.33)	($0.84)
EKPC	($0.01)	$0.05	($0.08)	($0.53)	($0.58)	($0.49)
JCPL	($0.53)	($0.41)	($0.68)	($1.37)	($1.80)	($0.87)
Met-Ed	($0.44)	($0.18)	($0.72)	($1.08)	($1.41)	($0.73)
PECO	($0.38)	($0.08)	($0.69)	($1.21)	($1.63)	($0.75)
PENELEC	($0.31)	$0.01	($0.65)	($1.10)	($1.29)	($0.89)
PPL	($0.47)	($0.20)	($0.75)	($1.18)	($1.57)	($0.76)
PSEG	($0.36)	($0.09)	($0.67)	($1.31)	($1.66)	($0.91)
Pepco	($0.31)	($0.06)	($0.58)	($0.97)	($1.17)	($0.74)
RECO	($0.35)	($0.07)	($0.69)	($1.34)	($1.64)	($0.99)

Markup by Day-Ahead Price Levels

Table 3-60 and Table 3-61 show the average markup component of observed prices, based on the unadjusted cost-based offers and adjusted cost-based offers of the marginal units, when the PJM system LMP was in the identified price range. Table 3-60 shows that the average day-ahead markup increased significantly when day-ahead price is greater or equal to $150 from the first nine months of 2013 to the first nine months of 2014. There were 12 hours when generating resources were marginal in this category in the first nine months of 2013. However, there were 202 hours when generating resources were marginal in this category in the first nine months of 2014. The highest average markup was $437.10 in hour ending 1400 on January 28.

Table 3-60 Average, day-ahead markup (By LMP category, unadjusted): January through September of 2013 and 2014

	2013 (Jan - Sep)		2014 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($1.89)	5.1%	($2.72)	9.2%
$25 to $50	($2.97)	83.9%	($2.53)	66.6%
$50 to $75	$0.75	8.9%	($3.70)	15.1%
$75 to $100	$0.03	1.2%	($1.93)	3.3%
$100 to $125	$0.01	0.4%	($6.78)	1.1%
$125 to $150	$0.00	0.1%	$3.31	0.9%
>= $150	($0.30)	0.4%	$10.26	3.8%

Table 3-61 Average, day-ahead markup (By LMP category, adjusted): January through June of 2013 and 2014

	2013 (Jan - Sep)		2014 (Jan - Sep)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.71)	5.1%	($2.36)	9.2%
$25 to $50	($1.23)	83.9%	($1.28)	66.6%
$50 to $75	$1.31	8.9%	($2.69)	15.1%
$75 to $100	$0.13	1.2%	($1.58)	3.3%
$100 to $125	$0.03	0.4%	($6.44)	1.1%
$125 to $150	$0.01	0.1%	$3.74	0.9%
>= $150	($0.29)	0.4%	$11.15	3.8%

Prices

The conduct of individual market entities within a market structure is reflected in market prices.[68] PJM locational marginal prices (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 47.4 percent and 49.6 percent higher in the first nine months of 2014 than in the first nine months of 2013 as a result of higher fuel costs and higher demand.[69] Natural gas prices were higher, particularly in eastern zones, while coal prices were relatively constant. Natural gas prices in the first nine months of 2014 were higher than the first nine month of 2013, particularly in eastern zones.

PJM real-time energy market prices increased in the first nine months of 2014 compared to the first nine months of 2013. The average LMP was 41.3 percent higher in the first nine months of 2014 than in the first nine months of 2013, $57.72 per MWh versus $37.30 per MWh. The load-weighted average LMP was 47.4 percent higher in the first nine months of 2014 than in the first nine months of 2013, $58.60 per MWh versus $39.75 per MWh.

The fuel-cost adjusted, load-weighted, average LMP for the first nine months of 2014 was 13.6 percent lower than the load-weighted, average LMP for the first nine months of 2014. If fuel costs in the first nine months of 2014 had been the same as in the first nine months of 2013, holding everything else constant, the load-weighted LMP would have been lower, $50.62 per MWh instead of the observed $58.60 per MWh in the first nine months of 2014.

PJM day-ahead energy market prices increased in the first nine months of 2014 compared to the first nine months of 2013. The average LMP was 43.4 percent higher in the first nine months of 2014 than in the first nine months of 2013, $53.76 per MWh versus $37.50 per MWh. The load-weighted average LMP was 49.6 percent higher in the first nine months of 2014 than in the first nine months of 2013, $59.09 per MWh versus $39.49 per MWh.[70]

Real-Time LMP

Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[71]

68 See the *2013 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*, at "Calculating Locational Marginal Price" for more information on how bus LMPs are aggregated to system LMPs. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

69 There was an average increase of 1.6 heating degree days and average decrease of 0.3 cooling degree days in the first nine months of 2014 compared to the first nine months of 2013, which meant overall increased demand.

70 Tables reporting zonal and jurisdictional load and prices are in the *2013 State of the Market Report for PJM*, Volume II, Appendix C, "Energy Market."

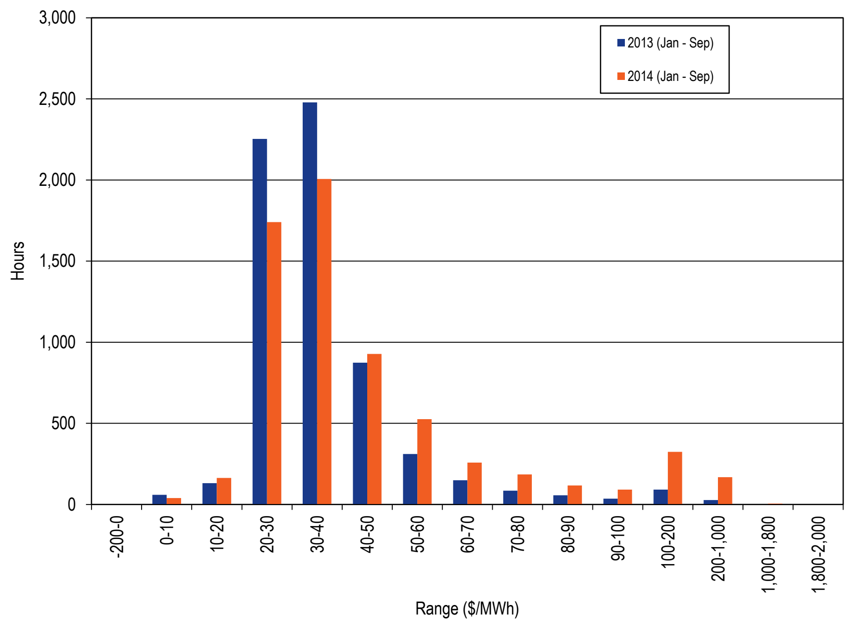
71 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price," for detailed definition of Real-Time LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 3-31 shows the hourly distribution of PJM real-time average LMP for the first nine months of 2013 and the first nine months of 2014. There was one hour in the first nine months of 2013 and 2014 in which the real-time LMP for the entire system was negative. Negative LMPs in the PJM Real-Time Market were primarily the result of marginal wind units with negative offer prices but may also result within a constrained area when inflexible generation exceeds the forecasted load. There were two hours in the first nine months of 2013 and eight hours in the first nine months of 2014 in which the PJM real-time LMP was $0.00. In 2014, there were six hours in January in which PJM real-time average LMP was greater than $1,000 and one hour that was greater $1,800.

Figure 3-31 Average LMP for the PJM Real-Time Energy Market: January through September of 2013 and 2014[72]



72 The data used in the version of this table in the *2014 Quarterly State of the Market Report for PJM: January through March* did not include LMP values greater than $1,000, but this table reflects those LMP values.

PJM Real-Time, Average LMP

Table 3-62 shows the PJM real-time, average LMP for the first nine months of each year of the 17-year period 1998 to 2014.[73]

Table 3-62 PJM real-time, average LMP (Dollars per MWh): January through September of 1998 through 2014

	Real-Time LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$23.18	$16.86	$36.00	NA	NA	NA
1999	$31.65	$18.77	$83.28	36.6%	11.3%	131.3%
2000	$25.88	$18.22	$23.70	(18.2%)	(2.9%)	(71.5%)
2001	$36.00	$25.48	$51.30	39.1%	39.9%	116.4%
2002	$28.13	$20.70	$23.92	(21.9%)	(18.8%)	(53.4%)
2003	$40.42	$33.68	$26.00	43.7%	62.7%	8.7%
2004	$43.85	$39.99	$21.82	8.5%	18.7%	(16.1%)
2005	$54.69	$44.53	$33.67	24.7%	11.4%	54.3%
2006	$51.79	$43.50	$34.93	(5.3%)	(2.3%)	3.7%
2007	$57.34	$49.40	$35.52	10.7%	13.6%	1.7%
2008	$71.94	$61.33	$41.64	25.4%	24.2%	17.2%
2009	$37.42	$33.00	$17.92	(48.0%)	(46.2%)	(57.0%)
2010	$46.13	$37.89	$26.99	23.3%	14.8%	50.6%
2011	$45.79	$37.05	$32.25	(0.7%)	(2.2%)	19.5%
2012	$32.45	$28.78	$21.94	(29.1%)	(22.3%)	(32.0%)
2013	$37.30	$32.44	$22.84	15.0%	12.7%	4.1%
2014	$52.72	$36.06	$74.17	41.3%	11.2%	224.8%

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 3-63 shows the PJM real-time, load-weighted, average LMP for the first nine months of each year of the 17-year period 1998 to 2014.

73 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 3-63 PJM real-time, load-weighted, average LMP (Dollars per MWh): January through September of 1998 through 2014

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$26.06	$18.20	$44.65	NA	NA	NA
1999	$38.65	$20.02	$104.17	48.3%	10.0%	133.3%
2000	$28.49	$19.30	$26.89	(26.3%)	(3.6%)	(74.2%)
2001	$40.96	$28.18	$64.57	43.8%	46.0%	140.1%
2002	$31.95	$23.09	$29.14	(22.0%)	(18.1%)	(54.9%)
2003	$43.57	$38.17	$26.53	36.3%	65.3%	(9.0%)
2004	$46.44	$43.03	$21.89	6.6%	12.7%	(17.5%)
2005	$60.44	$50.10	$36.52	30.2%	16.4%	66.9%
2006	$56.39	$46.82	$40.70	(6.7%)	(6.5%)	11.4%
2007	$61.83	$55.12	$37.98	9.7%	17.7%	(6.7%)
2008	$77.27	$66.73	$43.80	25.0%	21.1%	15.3%
2009	$39.57	$34.57	$19.04	(48.8%)	(48.2%)	(56.5%)
2010	$49.91	$40.33	$29.65	26.2%	16.7%	55.7%
2011	$49.48	$38.72	$37.02	(0.9%)	(4.0%)	24.8%
2012	$35.02	$29.84	$25.44	(29.2%)	(22.9%)	(31.3%)
2013	$39.75	$33.61	$26.47	13.5%	12.6%	4.0%
2014	$58.60	$37.93	$86.22	47.4%	12.8%	225.8%

Table 3-64 shows zonal real-time, and real-time, load-weighted, average LMP for the first nine months of 2013 and 2014. The real-time, load-weighted, average LMP increased by 47.4 percent compared to the first nine months of 2013.

Table 3-64 Zone real-time and real-time, load-weighted, average LMP (Dollars per MWh): January through September 2013 and 2014

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	(Jan-Sep) 2013 Average	(Jan-Sep) 2014 Average	Percentage Change	(Jan-Sep) 2013 Average	(Jan-Sep) 2014 Average	Percentage Change
AECO	$38.66	$57.16	47.8%	$42.09	$62.02	47.4%
AEP	$34.78	$47.07	35.3%	$36.31	$51.76	42.5%
AP	$36.58	$51.93	42.0%	$38.52	$58.66	52.3%
ATSI	$40.41	$48.95	21.1%	$44.63	$52.74	18.2%
BGE	$41.18	$65.16	58.2%	$44.55	$75.84	70.2%
ComEd	$32.02	$41.98	31.1%	$34.01	$44.79	31.7%
Day	$35.08	$46.82	33.5%	$36.91	$51.13	38.5%
DEOK	$33.42	$44.57	33.4%	$35.02	$48.45	38.4%
DLCO	$34.47	$44.05	27.8%	$36.44	$47.04	29.1%
Dominion	$38.97	$60.29	54.7%	$41.77	$70.61	69.1%
DPL	$39.93	$61.10	53.0%	$43.13	$72.28	67.6%
EKPC	$32.72	$44.65	36.4%	$35.06	$52.51	49.8%
JCPL	$39.89	$56.96	42.8%	$44.45	$62.59	40.8%
Met-Ed	$38.10	$55.42	45.5%	$40.70	$63.19	55.3%
PECO	$37.75	$56.16	48.8%	$40.44	$62.83	55.4%
PENELEC	$37.60	$52.20	38.8%	$39.51	$57.50	45.5%
Pepco	$40.49	$63.85	57.7%	$43.72	$73.53	68.2%
PPL	$37.87	$55.46	46.4%	$40.19	$64.58	60.7%
PSEG	$42.08	$59.98	42.5%	$45.47	$64.49	41.8%
RECO	$43.31	$58.85	35.9%	$47.74	$62.69	31.3%
PJM	$37.30	$52.72	41.3%	$39.75	$58.60	47.4%

Figure 3-32 and Figure 3-33 are contour maps of the real-time, load-weighted, average LMP for the first nine months of 2013 and 2014. Green represents the system marginal price (SMP) for January through September with each color to the right of green containing 5 percent of the pricing nodes above SMP and each color to the left of green containing 25 percent of pricing nodes below SMP. Prices in Eastern MAAC were all higher, on average, than the SMP for January through September of 2014.

Figure 3-32 PJM real-time, load-weighted, average LMP: January through September 2013

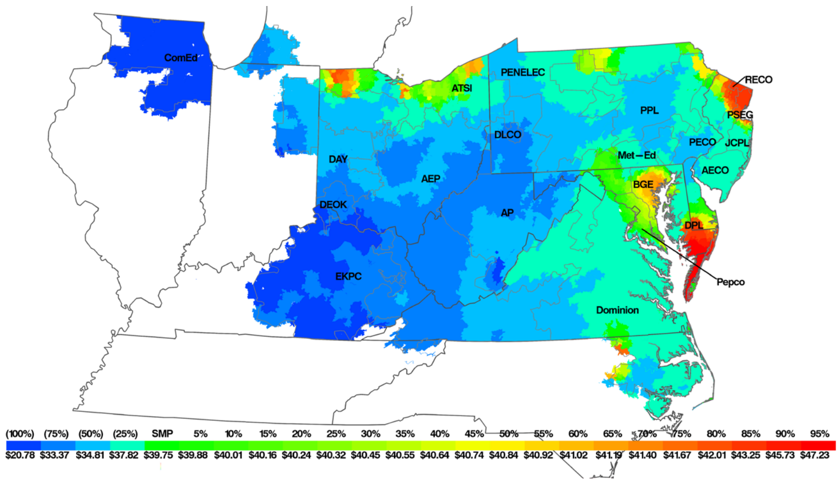


Figure 3-33 PJM real-time, load-weighted, average LMP: January through September 2014

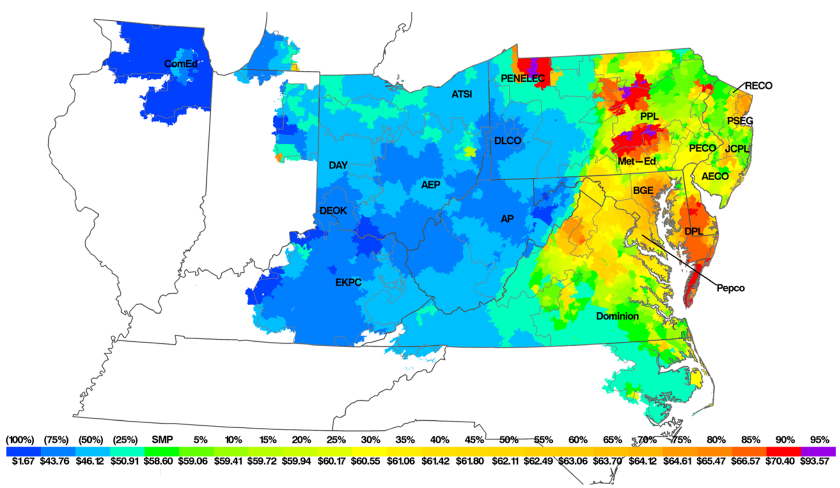


Table 3-65 shows zonal real-time, and real-time, load-weighted, average LMP for July through September of 2013 and 2014. The real-time, load-weighted, average LMP decreased by 15.4 percent compared to July through September of 2013.

Table 3-65 Zone real-time and real-time, load-weighted, average LMP (Dollars per MWh): July through September 2013 and 2014

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	(Jul-Sep) 2013 Average	(Jul-Sep) 2014 Average	Percentage Change	(Jul-Sep) 2013 Average	(Jul-Sep) 2014 Average	Percentage Change
AECO	$40.44	$34.30	(15.2%)	$46.27	$38.21	(17.4%)
AEP	$34.47	$33.11	(3.9%)	$36.98	$34.70	(6.2%)
AP	$37.27	$34.19	(8.3%)	$40.61	$36.16	(11.0%)
ATSI	$49.27	$34.24	(30.5%)	$58.99	$36.32	(38.4%)
BGE	$42.04	$40.38	(4.0%)	$47.22	$43.25	(8.4%)
ComEd	$33.05	$31.51	(4.7%)	$36.51	$33.33	(8.7%)
Day	$34.92	$33.92	(2.9%)	$38.03	$35.82	(5.8%)
DEOK	$33.20	$32.32	(2.6%)	$35.85	$34.10	(4.9%)
DLCO	$35.69	$31.93	(10.5%)	$39.27	$33.76	(14.0%)
Dominion	$39.89	$36.44	(8.7%)	$43.96	$38.87	(11.6%)
DPL	$42.70	$36.38	(14.8%)	$47.98	$41.12	(14.3%)
EKPC	$32.70	$32.20	(1.5%)	$35.18	$34.15	(2.9%)
JCPL	$42.37	$33.32	(21.4%)	$50.35	$37.42	(25.7%)
Met-Ed	$39.67	$32.29	(18.6%)	$44.19	$34.92	(21.0%)
PECO	$39.38	$33.01	(16.2%)	$44.03	$36.24	(17.7%)
PENELEC	$38.58	$34.35	(11.0%)	$41.97	$36.15	(13.9%)
Pepco	$41.24	$37.99	(7.9%)	$46.02	$40.63	(11.7%)
PPL	$39.47	$32.31	(18.1%)	$43.56	$34.72	(20.3%)
PSEG	$41.14	$33.58	(18.4%)	$46.65	$36.84	(21.0%)
RECO	$41.03	$33.28	(18.9%)	$48.22	$37.25	(22.7%)
PJM	$38.76	$34.20	(11.8%)	$43.01	$36.38	(15.4%)

Figure 3-34 and Figure 3-35 are contour maps of the real-time, load-weighted, average LMP for July through September of 2013 and for July through September of 2014. Green represents the system marginal price (SMP) for July through September with each color to the right of green containing 5 percent of the pricing nodes above SMP and each color to the left of green containing 25 percent of pricing nodes below SMP.

Figure 3-34 PJM real-time, load-weighted, average LMP: July through September 2013

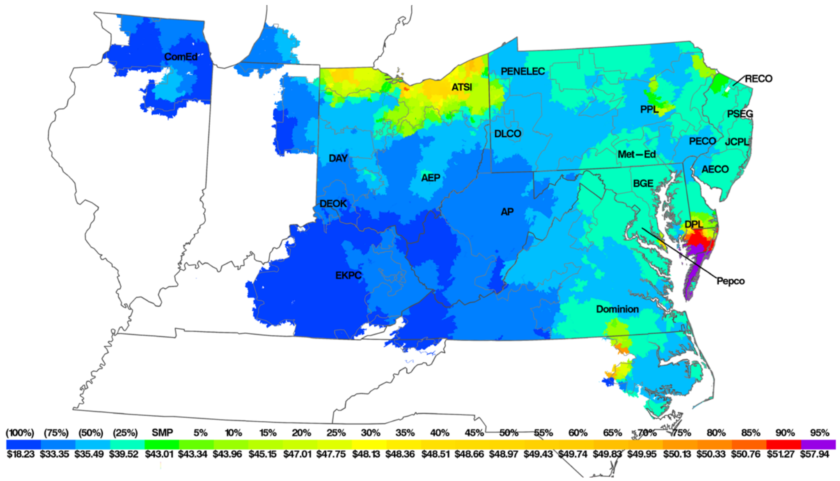
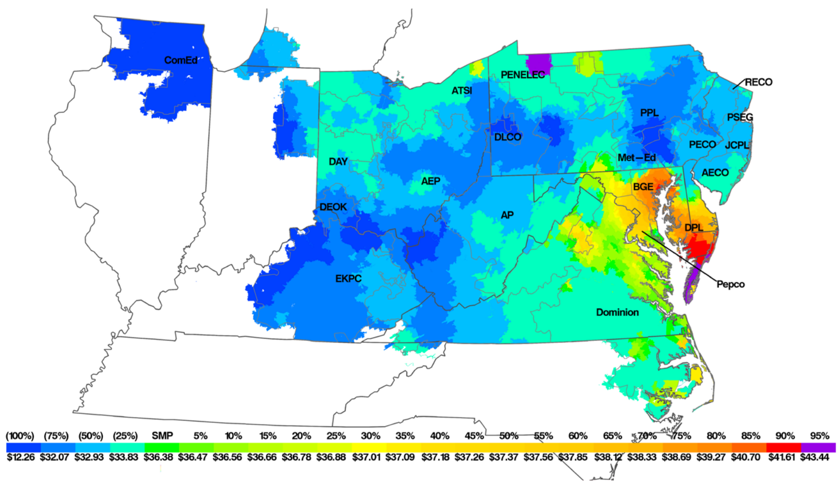


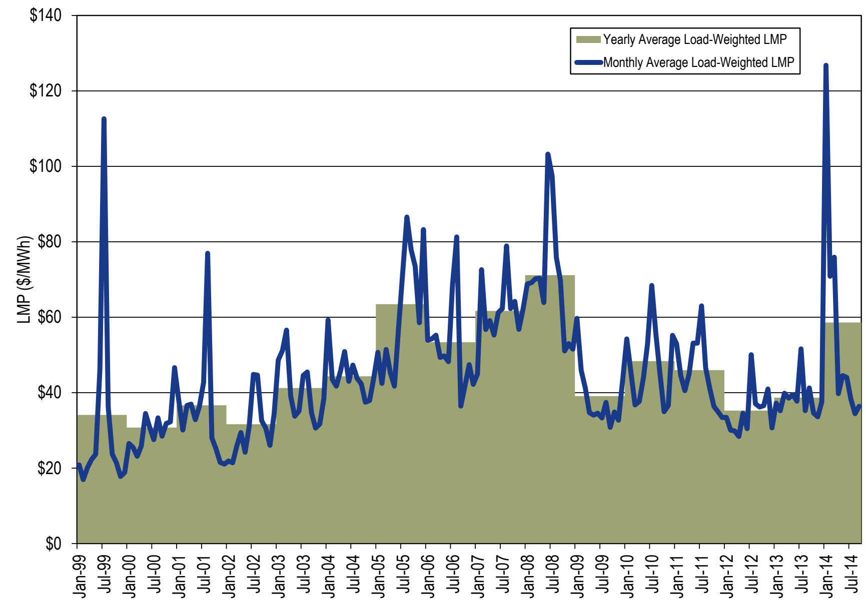
Figure 3-35 PJM real-time, load-weighted, average LMP: July through September 2014



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

Figure 3-36 shows the PJM real-time monthly and annual load-weighted LMP from 1999 through the first nine months of 2014.

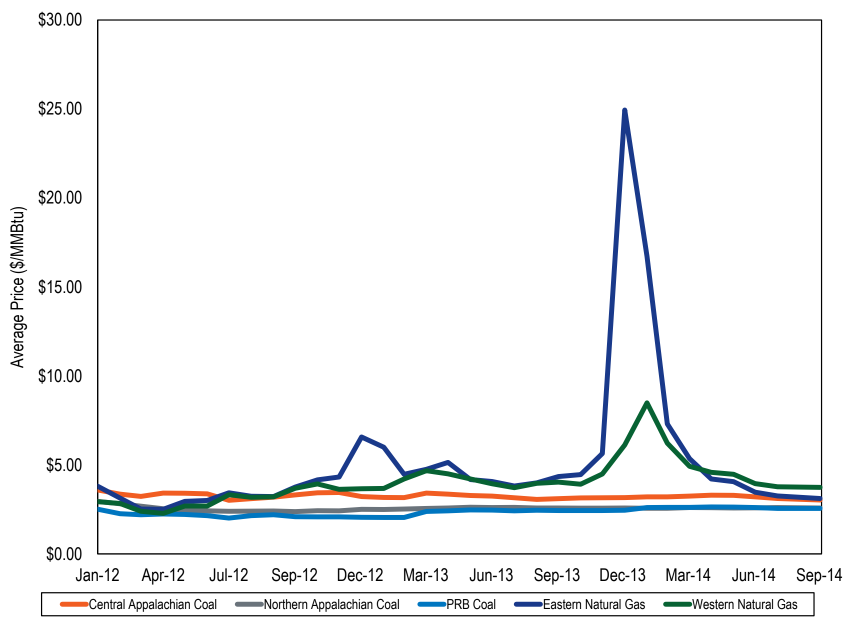
Figure 3-36 PJM real-time, monthly and annual, load-weighted, average LMP: 1999 through September of 2014



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 nine months of 2014. Comparing fuel prices in the first nine months of 2014 to the first nine months of 2013, the price of Northern Appalachian coal was 0.5 percent higher; the price of Central Appalachian coal was 2.9 percent lower; the price of Powder River Basin coal was 10.1 percent higher; the price of eastern natural gas was 54.9 percent higher; and the price of western natural gas was 27.0 percent higher. Figure 3-37 shows monthly average spot fuel prices for the first nine months of 2013 and the first nine months of 2014.[74] Natural gas prices were above coal prices in the first nine months of 2014.

Figure 3-37 Spot average fuel price comparison with fuel delivery charges: 2012 through 2014 ($/MMBtu)



74 Eastern natural gas consists of the average of Texas M3, Transco Zone 6 non-NY, Transco Zone 6 NY and Transco Zone 5 daily fuel price indices. Western natural gas prices are the average of Dominion North Point, Columbia Appalachia and Chicago Citygate daily fuel price indices. 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.

Table 3-66 compares the first nine months of 2014 PJM real time fuel-cost adjusted, load-weighted, average LMP to the first nine months of 2013 load-weighted, average LMP. The real time fuel-cost adjusted, load-weighted, average LMP for the first nine months of 2014 was 13.6 percent lower than the real time load-weighted, average LMP for the first nine months of 2014. The real-time, fuel-cost adjusted, load-weighted, average LMP for the first nine months of 2014 was 27.4 percent higher than the real time load-weighted LMP for the first nine months of 2013. If fuel costs in the first nine months of 2014 had been the same as in the first nine months of 2013, holding everything else constant, the real time load-weighted LMP in the first nine months of 2014 would have been lower, $50.62 per MWh instead of the observed $58.60 per MWh.

Table 3-66 PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): nine months over nine months

	2014 Load-Weighted LMP	2014 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$58.60	$50.62	(13.6%)
	2013 Load-Weighted LMP	2014 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$39.75	$50.62	27.4%
	2013 Load-Weighted LMP	2014 Load-Weighted LMP	Change
Average	$39.75	$58.60	47.4%

Table 3-67 shows the impact of each fuel type on the difference between the fuel-cost adjusted, load-weighted average LMP and the load-weighted LMP in the first nine months of 2014. Table 3-67 shows that higher natural gas prices explain almost all of the fuel-cost related increase in the real time annual load-weighted average LMP in the first nine months of 2014.

Table 3-67 Change in PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh) by Fuel-type: nine months over nine months

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Coal	$0.12	1.5%
Gas	$7.89	98.8%
Oil	($0.03)	(0.3%)
Other	$0.00	0.0%
Uranium	$0.00	0.0%
Wind	($0.00)	(0.0%)
Total	$7.98	100.0%

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 forecasts of system conditions. Those offers can be decomposed into components including 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 LMP by the components of unit offers.

Cost offers of marginal units are separated 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, emission rates for NO_x, emission rates for SO_2 and emission rates for CO_2. The CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware and Maryland.[75] 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.

Since the implementation of scarcity pricing on October 1, 2012, PJM jointly optimizes the commitment and dispatch of energy and ancillary services. In periods when generators providing energy have to be dispatched down from their economic operating level to meet reserve requirements, the joint optimization of energy and reserves takes into account the opportunity cost of the reduced generation and the associated incremental cost to maintain reserves. If a unit incurring such opportunity costs is a marginal resource in the energy market, this opportunity cost contributes to LMP. In addition, in periods when generators providing energy cannot meet the reserve requirements, PJM can invoke shortage pricing. PJM invoked shortage pricing on January 6 and January 7 of 2014.[76] During the shortage conditions, the LMPs of marginal generators reflect the cost of not meeting the reserve requirements, the scarcity adder, which is defined by the operating reserve demand curve.

The components of LMP are shown in Table 3-68, including markup using unadjusted cost offers.[77] Table 3-68 shows that for the first nine months of 2014, 29.8 percent of the load-weighted LMP was the result of coal costs, 36.9 percent was the result of gas costs and 0.65 percent was the result of the cost of emission allowances. Markup was $2.32 per MWh. The fuel-related components of LMP reflect the degree to which the cost of the identified fuel affects LMP and does not reflect the other components of the offers of units burning that fuel. The component NA is the unexplainable portion of load-weighted LMP. Occasionally, PJM fails to provide all the data needed to accurately calculate generator sensitivity factors. As a result, the LMP for those intervals cannot be decomposed into component costs. The cumulative effect of excluding those five-minute intervals is the component NA. In the first nine months of 2014, nearly six percent of all five-minute intervals had insufficient data. The percent column is the difference in the proportion of LMP represented by each component between the first nine months of 2014 and the first nine months of 2013.

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

76 PJM triggered shortage pricing on January 6 following a RTO-wide voltage reduction action. PJM triggered shortage pricing on January 7, due to RTO-wide shortage of synchronized reserve.

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

Table 3-68 Components of PJM real-time (Unadjusted), annual, load-weighted, average LMP: January through September, 2013 and 2014

	2013 (Jan - Sep)		2014 (Jan - Sep)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Gas	$9.31	23.4%	$21.63	36.9%	13.5%
Coal	$15.42	38.8%	$17.46	29.8%	(9.0%)
Ten Percent Adder	$3.46	8.7%	$4.03	6.9%	(1.8%)
Oil	$0.67	1.7%	$3.64	6.2%	4.5%
VOM	$1.88	4.7%	$2.75	4.7%	(0.0%)
Emergency DR Adder	$0.11	0.3%	$2.40	4.1%	3.8%
Markup	($0.66)	(1.7%)	$2.32	4.0%	5.6%
NA	$1.33	3.4%	$1.94	3.3%	(0.0%)
Increase Generation Adder	$0.16	0.4%	$0.87	1.5%	1.1%
FMU Adder	$0.37	0.9%	$0.76	1.3%	0.4%
Ancillary Service Redispatch Cost	$0.21	0.5%	$0.54	0.9%	0.4%
CO2 Cost	$0.08	0.2%	$0.22	0.4%	0.2%
NOx Cost	$0.08	0.2%	$0.15	0.3%	0.1%
Scarcity Adder	$0.00	0.0%	$0.13	0.2%	0.2%
Other	($0.00)	(0.0%)	$0.03	0.1%	0.1%
Municipal Waste	$0.00	0.0%	$0.02	0.0%	0.0%
SO2 Cost	$0.01	0.0%	$0.01	0.0%	(0.0%)
Market-to-Market Adder	$0.01	0.0%	($0.01)	(0.0%)	(0.0%)
LPA-SCED Differential	($0.05)	(0.1%)	($0.01)	(0.0%)	0.1%
Wind	($0.00)	(0.0%)	($0.01)	(0.0%)	(0.0%)
Uranium	$0.00	0.0%	($0.01)	(0.0%)	(0.0%)
LPA Rounding Difference	$7.53	18.9%	($0.07)	(0.1%)	(19.1%)
Decrease Generation Adder	($0.16)	(0.4%)	($0.19)	(0.3%)	0.1%
Total	$39.75	100.0%	$58.60	100.0%	0.0%

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 3-68 and Table 3-72) markup is simply the difference between the price offer and the cost offer. In the second approach, (Table 3-69 and Table 3-73) the 10 percent markup is removed from the cost offers of coal units.

The components of LMP are shown in Table 3-69, including markup using adjusted cost offers.

Table 3-69 Components of PJM real-time (Adjusted), annual, load-weighted, average LMP: January through September, 2013 and 2014

	2013 (Jan - Sep)		2014 (Jan - Sep)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Gas	$9.31	23.4%	$21.63	36.9%	13.5%
Coal	$15.46	38.9%	$17.46	29.8%	(9.1%)
Markup	$0.85	2.1%	$3.65	6.2%	4.1%
Oil	$0.67	1.7%	$3.64	6.2%	4.5%
VOM	$1.89	4.7%	$2.75	4.7%	(0.1%)
Ten Percent Adder	$1.93	4.8%	$2.69	4.6%	(0.3%)
Emergency DR Adder	$0.11	0.3%	$2.40	4.1%	3.8%
NA	$1.33	3.4%	$1.94	3.3%	(0.0%)
Increase Generation Adder	$0.16	0.4%	$0.87	1.5%	1.1%
FMU Adder	$0.35	0.9%	$0.76	1.3%	0.4%
Ancillary Service Redispatch Cost	$0.21	0.5%	$0.54	0.9%	0.4%
CO2 Cost	$0.08	0.2%	$0.22	0.4%	0.2%
NOx Cost	$0.08	0.2%	$0.15	0.3%	0.1%
Scarcity Adder	$0.00	0.0%	$0.13	0.2%	0.2%
Other	($0.00)	(0.0%)	$0.03	0.1%	0.1%
Municipal Waste	$0.00	0.0%	$0.02	0.0%	0.0%
SO2 Cost	$0.01	0.0%	$0.01	0.0%	(0.0%)
Market-to-Market Adder	$0.01	0.0%	($0.01)	(0.0%)	(0.0%)
LPA-SCED Differential	($0.05)	(0.1%)	($0.01)	(0.0%)	0.1%
Wind	($0.00)	(0.0%)	($0.01)	(0.0%)	(0.0%)
Uranium	$0.00	0.0%	($0.01)	(0.0%)	(0.0%)
LPA Rounding Difference	$7.53	18.9%	($0.07)	(0.1%)	(19.0%)
Decrease Generation Adder	($0.16)	(0.4%)	($0.19)	(0.3%)	0.1%
Total	$39.75	100.0%	$58.60	100.0%	0.0%

Day-Ahead LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[78]

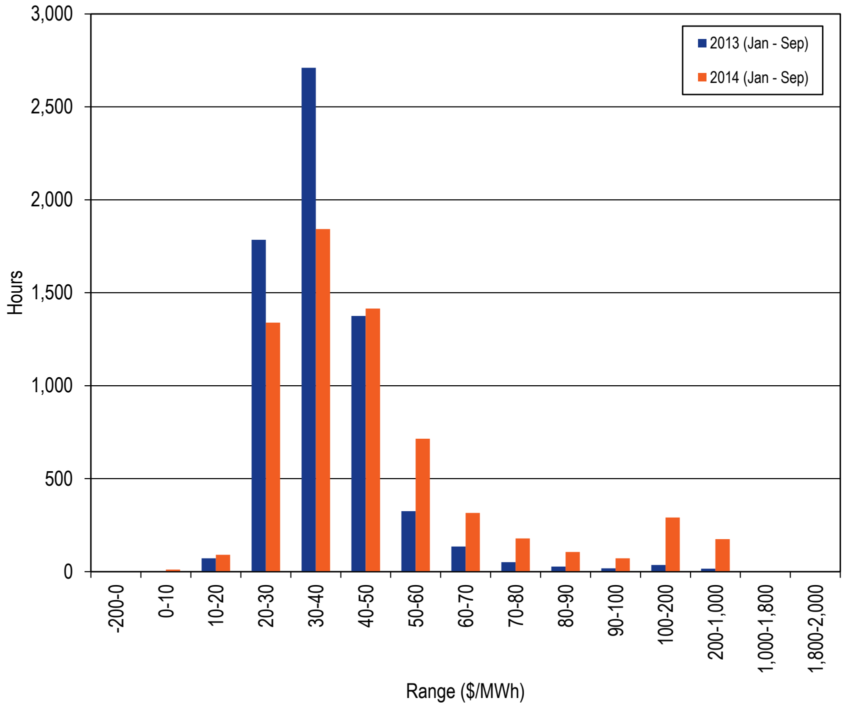
Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-38 shows the hourly distribution of PJM day-ahead average LMP for the first nine months of 2013 and the first nine months of 2014.

78 See the *MMU Technical Reference for the PJM Markets*, at "Calculating Locational Marginal Price" for a detailed definition of Day-Ahead LMP. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.

Figure 3-38 Average LMP for the PJM Day-Ahead Energy Market: January through September of 2013 and 2014



PJM Day-Ahead, Average LMP

Table 3-70 shows the PJM day-ahead, average LMP for the first nine months of each year of the 14-year period 2001 to 2014.

Table 3-70 PJM day-ahead, average LMP (Dollars per MWh): January through September of 2001 through 2014

	Day-Ahead LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$36.07	$30.02	$34.25	NA	NA	NA
2002	$28.29	$22.54	$19.09	(21.6%)	(24.9%)	(44.3%)
2003	$41.20	$38.24	$22.02	45.6%	69.7%	15.4%
2004	$42.64	$42.07	$17.47	3.5%	10.0%	(20.7%)
2005	$54.48	$46.67	$28.83	27.8%	10.9%	65.1%
2006	$50.45	$46.32	$24.93	(7.4%)	(0.8%)	(13.5%)
2007	$54.24	$51.40	$24.95	7.5%	11.0%	0.1%
2008	$71.43	$66.38	$33.11	31.7%	29.2%	32.7%
2009	$37.35	$35.29	$14.32	(47.7%)	(46.8%)	(56.8%)
2010	$45.81	$41.03	$19.59	22.7%	16.3%	36.8%
2011	$45.14	$40.20	$22.68	(1.5%)	(2.0%)	15.7%
2012	$32.16	$30.10	$14.54	(28.8%)	(25.1%)	(35.9%)
2013	$37.50	$34.70	$16.96	16.6%	15.3%	16.6%
2014	$53.76	$39.92	$58.98	43.4%	15.0%	247.8%

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 3-71 shows the PJM day-ahead, load-weighted, average LMP for the first nine months of each year of the 14-year period 2001 to 2014.

Table 3-71 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through September of 2001 through 2014

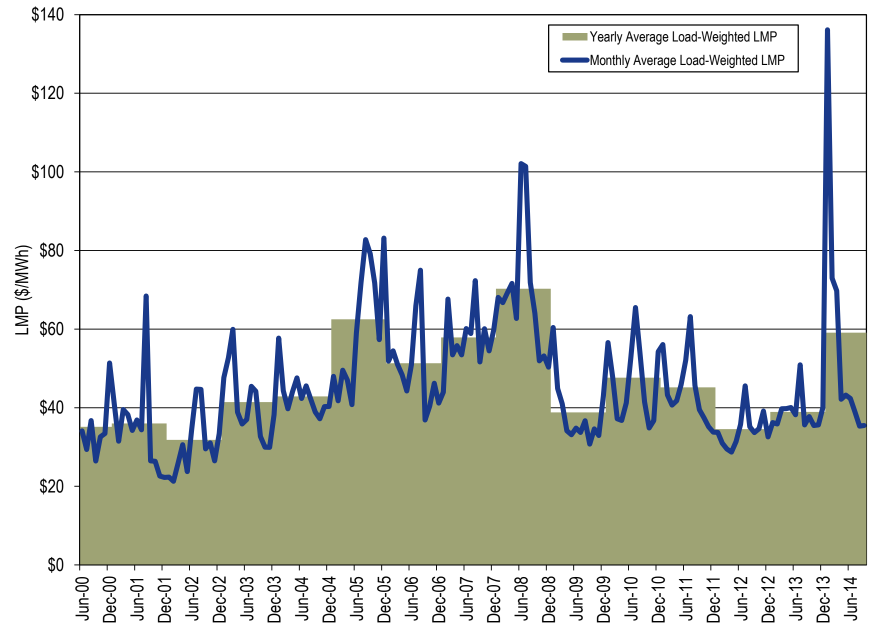
	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Sep)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$39.88	$32.68	$42.01	NA	NA	NA
2002	$32.29	$25.22	$22.81	(19.0%)	(22.8%)	(45.7%)
2003	$44.11	$41.51	$22.34	36.6%	64.6%	(2.1%)
2004	$44.59	$44.47	$17.40	1.1%	7.1%	(22.1%)
2005	$59.51	$51.33	$31.13	33.5%	15.4%	78.9%
2006	$54.19	$48.87	$28.35	(8.9%)	(4.8%)	(8.9%)
2007	$57.79	$55.62	$26.07	6.6%	13.8%	(8.0%)
2008	$75.96	$70.35	$35.19	31.5%	26.5%	35.0%
2009	$39.35	$36.92	$14.98	(48.2%)	(47.5%)	(57.4%)
2010	$49.12	$43.33	$21.35	24.8%	17.4%	42.6%
2011	$48.34	$42.35	$26.54	(1.6%)	(2.3%)	24.3%
2012	$34.29	$31.17	$17.12	(29.1%)	(26.4%)	(35.5%)
2013	$39.49	$35.96	$19.90	15.1%	15.4%	16.3%
2014	$59.09	$42.08	$67.27	49.6%	17.0%	238.0%

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

Figure 3-39 shows the PJM day-ahead, monthly and annual, load-weighted LMP from 2000 through the first nine months of 2014.[79]

79 Since the Day-Ahead Energy Market did not start until June 1, 2000, the day-ahead data for 2000 only includes data for the last six months of that year.

Figure 3-39 Day-ahead, monthly and annual, load-weighted, average LMP: 2000 through September of 2014



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 their components including 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 with an offer price that 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.

Cost offers of marginal units are separated 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, emission rates for $NO_{X,}$ emission rates for SO_2 and emission rates for CO_2. CO_2 emission costs are applicable to PJM units in the PJM states that participate in RGGI: Delaware and Maryland.[80] 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. 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.

The components of day-ahead LMP are shown in Table 3-72, including markup using unadjusted cost offers. Table 3-72 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In the first nine months of 2014, 23.3 percent of the load-weighted LMP was the result of gas, 13.6 percent was the result of the up-to congestion transactions and 15.8 percent was the result of DEC bids.

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

Table 3-72 Components of PJM day-ahead, (unadjusted) annual, load-weighted, average LMP (Dollars per MWh): January through September of 2013 and 2014[81]

	2013 (Jan - Sep)		2014 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$2.83	7.2%	$13.77	23.3%	16.2%
Coal	$5.94	15.0%	$10.93	18.5%	3.5%
DEC	$2.31	5.8%	$9.33	15.8%	9.9%
INC	$1.50	3.8%	$8.75	14.8%	11.0%
Up-to Congestion Transaction	$25.87	65.5%	$8.01	13.6%	(52.0%)
Dispatchable Transaction	$0.17	0.4%	$2.84	4.8%	4.4%
Ten Percent Cost Adder	$0.94	2.4%	$2.78	4.7%	2.3%
VOM	$0.63	1.6%	$1.56	2.6%	1.1%
Price Sensitive Demand	$0.06	0.2%	$1.09	1.8%	1.7%
Oil	$0.00	0.0%	$1.05	1.8%	1.8%
FMU Adder	$0.02	0.1%	$0.41	0.7%	0.6%
Import	$0.00	0.0%	$0.16	0.3%	0.3%
CO2	$0.02	0.0%	$0.13	0.2%	0.2%
Other	$0.00	0.0%	$0.10	0.2%	0.2%
NOx	$0.02	0.1%	$0.10	0.2%	0.1%
DASR Offer Adder	$0.00	0.0%	$0.06	0.1%	0.1%
SO2	$0.00	0.0%	$0.01	0.0%	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%	0.0%
Municipal Waste	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.00)	(0.0%)	($0.01)	(0.0%)	(0.0%)
DASR LOC Adder	$0.02	0.0%	($0.04)	(0.1%)	(0.1%)
Markup	($1.00)	(2.5%)	($1.75)	(3.0%)	(0.4%)
NA	$0.15	0.4%	($0.19)	(0.3%)	(0.7%)
Total	$39.49	100.0%	$59.09	100.0%	0.0%

81 PJM acknowledged an error in identifying marginal up-to congestion transactions following April 2013 changes to the day-ahead solution software. The software incorrectly increased the volume of marginal up-to congestion transactions. The fix to the problem is expected to be in place in 2014.

Table 3-73 shows the components of the PJM day ahead, annual, load-weighted average LMP including the adjusted markup calculated by excluding the 10 percent adder from the coal units.

Table 3-73 Components of PJM day-ahead, (adjusted) annual, load-weighted, average LMP (Dollars per MWh): January through September of 2013 and 2014

	2013 (Jan - Sep)		2014 (Jan - Sep)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Gas	$2.83	7.2%	$13.77	23.3%	16.2%
Coal	$5.94	15.0%	$10.90	18.4%	3.4%
DEC	$2.31	5.8%	$9.33	15.8%	9.9%
INC	$1.50	3.8%	$8.75	14.8%	11.0%
Up-to Congestion Transaction	$25.87	65.5%	$8.01	13.6%	(52.0%)
Dispatchable Transaction	$0.17	0.4%	$2.84	4.8%	4.4%
Ten Percent Cost Adder	$0.29	0.7%	$1.99	3.4%	2.6%
VOM	$0.63	1.6%	$1.56	2.6%	1.0%
Price Sensitive Demand	$0.06	0.2%	$1.09	1.8%	1.7%
Oil	$0.00	0.0%	$1.05	1.8%	1.8%
FMU Adder	$0.02	0.1%	$0.41	0.7%	0.6%
Import	$0.00	0.0%	$0.16	0.3%	0.3%
CO2	$0.02	0.0%	$0.13	0.2%	0.2%
Other	$0.00	0.0%	$0.10	0.2%	0.2%
NOx	$0.02	0.1%	$0.10	0.2%	0.1%
DASR Offer Adder	$0.00	0.0%	$0.06	0.1%	0.1%
SO2	$0.00	0.0%	$0.01	0.0%	0.0%
Constrained Off	$0.00	0.0%	$0.00	0.0%	0.0%
Municipal Waste	$0.00	0.0%	$0.00	0.0%	0.0%
Wind	($0.00)	(0.0%)	($0.01)	(0.0%)	(0.0%)
DASR LOC Adder	$0.02	0.0%	($0.04)	(0.1%)	(0.1%)
Markup	($0.35)	(0.9%)	($0.93)	(1.6%)	(0.7%)
NA	$0.15	0.4%	($0.19)	(0.3%)	(0.7%)
Total	$39.49	100.0%	$59.09	100.0%	0.0%

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 Energy 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 on a day to day basis is not a realistic expectation as a result of uncertainty, lags in response time and modeling differences, such as differences in modeled contingencies and marginal loss calculations, between the Day-Ahead and Real-Time Energy Market.

Where arbitrage opportunities are created by differences between Day-Ahead and Real-Time Energy Market expectations, the resulting behavior can lead to more efficient market outcomes by improving day-ahead commitments relative to real-time system requirements.

But there is no guarantee that the results of virtual bids and offers will result in more efficient market outcomes.

Where arbitrage incentives are created by systematic modeling differences, such as differences between the day-ahead and real-time modeled transmission contingencies and marginal loss calculations, virtual bids and offers cannot result in more efficient market outcomes. Such offers may be profitable but cannot change the underlying reason for the price difference. The virtual transactions will continue to profit from the activity for that reason. This is termed false arbitrage.

INCs, DECs and UTCs allow participants to arbitrage price differences between the Day-Ahead and Real-Time Energy Market. Absent a physical position in real time, the seller of an INC must buy energy in the Real-Time Energy Market to fulfill the financial obligation to provide energy. If the day-ahead price for energy is higher than the real-time price for energy, the INC makes a profit. Absent a physical position in real time, the buyer of a DEC must sell energy in the Real-Time Energy Market to fulfill the financial obligation to buy energy. If the day-ahead price for energy is lower than the real-time price for energy, the DEC makes a profit.

While the profitability of an INC or DEC position is an indicator that the INC or DEC, all else held equal, contributed to price convergence at the specific bus, unprofitable INCs and DECs may also contribute to price convergence.

Profitability is a less reliable indicator of whether a UTC contributes to price convergence than for INCs and DECs. The profitability of a UTC transaction is the net of the separate profitability of the component INC and DEC. A UTC can be net profitable if the profit on one side of the UTC transaction exceeds the losses on the other side. A profitable UTC can contribute to both price divergence on one side and to price convergence on the other side.

Table 3-74 shows the number of cleared UTC transactions, the number of profitable cleared UTCs, the number of cleared UTCs that were profitable at their source point and the number of cleared UTCs that were profitable at their sink point in the first nine months of 2013 and the first nine months of 2014. In the first nine months of 2014, 55.3 percent of all cleared UTC transactions were net profitable, with 67.5 percent of the source side profitable and 33.6 percent of the sink side profitable (Table 3-74).

Table 3-74 Cleared UTC profitability by source and sink point: January through September of 2013 and 2014[82]

(Jan-Sep)	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	Profitable UTC	Profitable Source	Profitable Sink
2013	10,309,092	5,637,485	6,663,751	3,734,928	54.7%	64.6%	36.2%
2014	18,442,292	10,204,493	12,449,206	6,195,177	55.3%	67.5%	33.6%

There are incentives to use virtual transactions to arbitrage price differences between the Day-Ahead and Real-Time Energy Markets, but there is no guarantee that such activity will result in price convergence and no data to support that claim. As a general matter, virtual offers and bids are based on expectations about both Day-Ahead and Real-Time Energy Market conditions and reflect the uncertainty about conditions in both markets and the fact that these conditions change hourly and daily. PJM markets do not provide a mechanism that could result in immediate convergence after a change in system conditions as there is at least a one day lag after any change in system conditions before offers could reflect such changes.

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 3-41).

Table 3-75 shows that the difference between the average real-time price and the average day-ahead price was -$0.20 per MWh in the first nine months of 2013 and -$1.04 per MWh in the first nine months of 2014. The difference between average peak real-time price and the average peak day-ahead price was $0.16 per MWh in the first nine months of 2013 and -$1.72 per MWh in the first nine months of 2014.

82 Calculations exclude PJM administrative charges.

Table 3-75 Day-ahead and real-time average LMP (Dollars per MWh): January through September of 2013 and 2014[83]

	2013 (Jan - Sep)				2014 (Jan - Sep)			
	Day Ahead	Real Time	Difference	Percent of Real Time	Day Ahead	Real Time	Difference	Percent of Real Time
Average	$37.50	$37.30	($0.20)	(0.5%)	$53.76	$52.72	($1.04)	(2.0%)
Median	$34.70	$32.44	($2.26)	(7.0%)	$39.92	$36.06	($3.86)	(10.7%)
Standard deviation	$16.96	$22.84	$5.88	25.7%	$58.98	$74.17	$15.18	20.5%
Peak average	$44.58	$44.74	$0.16	0.4%	$67.11	$65.39	($1.72)	(2.6%)
Peak median	$40.32	$37.41	($2.91)	(7.8%)	$47.70	$42.97	($4.73)	(11.0%)
Peak standard deviation	$21.37	$28.77	$7.40	25.7%	$73.24	$93.17	$19.94	21.4%
Off peak average	$31.31	$30.80	($0.51)	(1.7%)	$42.09	$41.64	($0.45)	(1.1%)
Off peak median	$30.07	$28.44	($1.63)	(5.7%)	$32.85	$30.34	($2.52)	(8.3%)
Off peak standard deviation	$7.58	$12.77	$5.19	40.7%	$39.24	$49.58	$10.34	20.9%

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 3-76 shows the difference between the Real-Time and the Day-Ahead Energy Market prices for the first nine months of each year of the 14-year period 2001 to 2014.

Table 3-76 Day-ahead and real-time average LMP (Dollars per MWh): January through September of 2001 through 2014

(Jan-Sep)	Day Ahead	Real Time	Difference	Percent of Real Time
2001	$36.07	$36.00	($0.07)	(0.2%)
2002	$28.29	$28.13	($0.16)	(0.6%)
2003	$41.20	$40.42	($0.77)	(1.9%)
2004	$42.64	$43.85	$1.22	2.9%
2005	$54.48	$54.69	$0.21	0.4%
2006	$50.45	$51.79	$1.34	2.7%
2007	$54.24	$57.34	$3.10	5.7%
2008	$71.43	$71.94	$0.51	0.7%
2009	$37.35	$37.42	$0.08	0.2%
2010	$45.81	$46.13	$0.32	0.7%
2011	$45.14	$45.79	$0.65	1.4%
2012	$32.16	$32.45	$0.29	0.9%
2013	$37.50	$37.30	($0.20)	(0.5%)
2014	$53.76	$52.72	($1.04)	(1.9%)

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

Table 3-77 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for the first nine months of 2007 through 2014.

Table 3-77 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): January through September of 2007 through 2014

	2007		2008		2009		2010		2011		2012		2013		2014	
LMP	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent	Frequency	Cumulative Percent
< ($1,000)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%
($1,000) to ($750)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	2	0.03%
($750) to ($500)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	3	0.08%
($500) to ($450)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.09%
($450) to ($400)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	6	0.18%
($400) to ($350)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	5	0.26%
($350) to ($300)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	5	0.34%
($300) to ($250)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	6	0.43%
($250) to ($200)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%	1	0.02%	14	0.64%
($200) to ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%	4	0.08%	3	0.06%	14	0.85%
($150) to ($100)	0	0.00%	1	0.02%	0	0.00%	0	0.00%	2	0.05%	6	0.17%	5	0.14%	45	1.54%
($100) to ($50)	26	0.40%	88	1.35%	3	0.05%	13	0.20%	49	0.79%	17	0.43%	9	0.27%	89	2.90%
($50) to $0	3,385	52.07%	3,730	58.08%	3,776	57.69%	4,091	62.65%	4,011	62.02%	4,112	62.97%	4,338	66.49%	4,301	68.55%
$0 to $50	2,914	96.55%	2,448	95.32%	2,736	99.45%	2,288	97.57%	2,290	96.98%	2,343	98.60%	2,112	98.73%	1,871	97.11%
$50 to $100	193	99.50%	264	99.33%	34	99.97%	130	99.56%	169	99.56%	61	99.53%	58	99.62%	97	98.60%
$100 to $150	21	99.82%	37	99.89%	2	100.00%	20	99.86%	21	99.88%	14	99.74%	12	99.80%	37	99.16%
$150 to $200	4	99.88%	4	99.95%	0	100.00%	8	99.98%	2	99.91%	10	99.89%	10	99.95%	18	99.44%
$200 to $250	1	99.89%	2	99.98%	0	100.00%	1	100.00%	3	99.95%	4	99.95%	1	99.97%	9	99.57%
$250 to $300	3	99.94%	0	99.98%	0	100.00%	0	100.00%	0	99.95%	1	99.97%	2	100.00%	8	99.69%
$300 to $350	2	99.97%	1	100.00%	0	100.00%	0	100.00%	0	99.95%	2	100.00%	0	100.00%	3	99.74%
$350 to $400	0	99.97%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%	0	100.00%	3	99.79%
$400 to $450	1	99.98%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%	0	100.00%	2	99.82%
$450 to $500	1	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.95%	0	100.00%	0	100.00%	0	99.82%
$500 to $750	0	100.00%	0	100.00%	0	100.00%	0	100.00%	3	100.00%	0	100.00%	0	100.00%	7	99.92%
$750 to $1,000	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.92%
$1,000 to $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	1	99.94%
>= $1,250	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	100.00%	4	100.00%

Figure 3-40 shows the hourly differences between day-ahead and real-time hourly LMP in the first nine months of 2014.

Figure 3-40 Real-time hourly LMP minus day-ahead hourly LMP: January through September of 2014

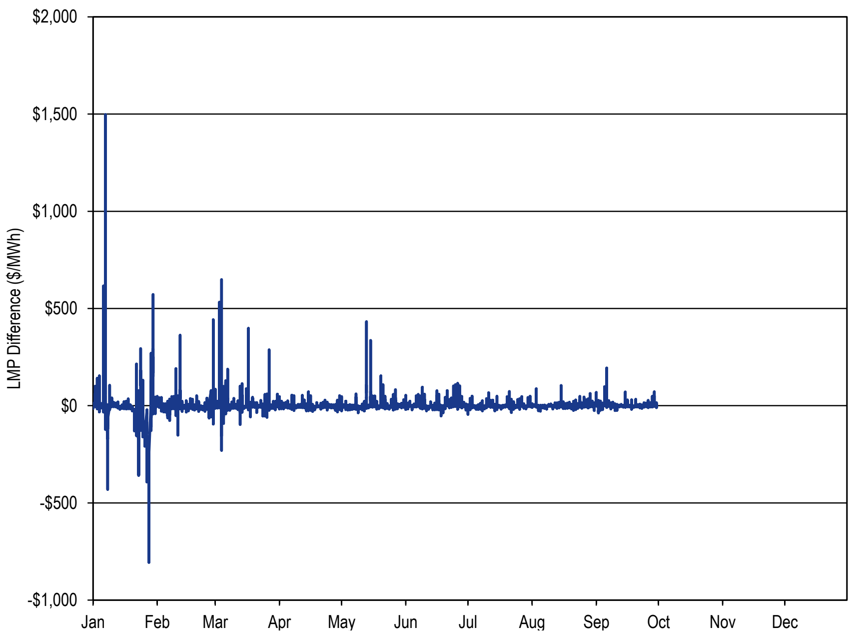


Figure 3-41 shows the monthly average differences between the day-ahead and real-time LMP in the first nine months of 2014.

Figure 3-41 Monthly average of real-time minus day-ahead LMP: January through September of 2014

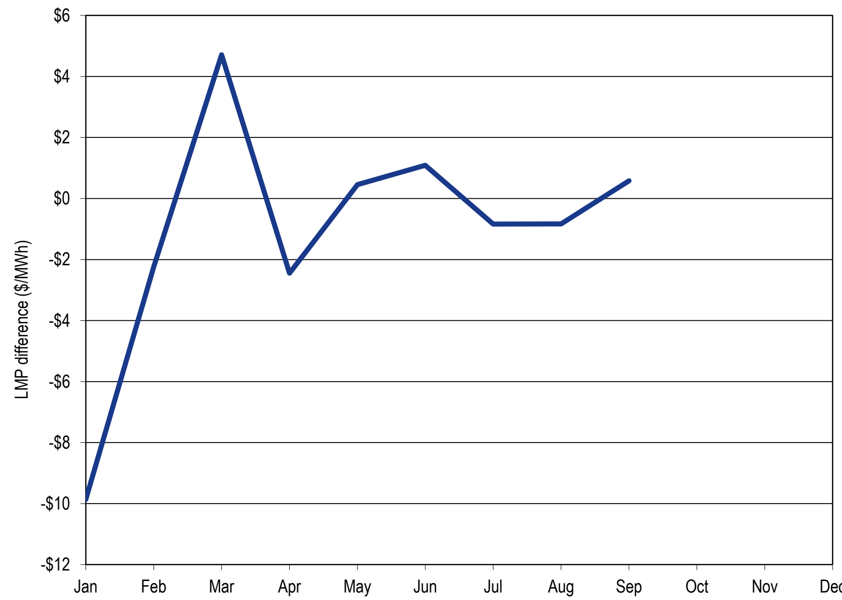
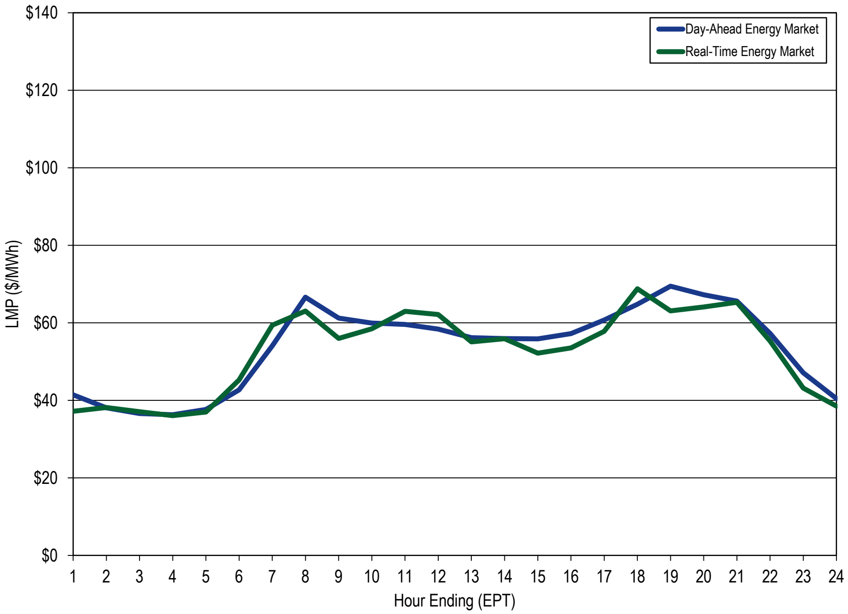


Figure 3-42 shows day-ahead and real-time LMP on an average hourly basis for the first nine months of 2014.

Figure 3-42 PJM system hourly average LMP: January through September of 2014



Scarcity

PJM's Energy Market experienced shortage pricing events on two days in January 2014. Extreme cold weather conditions in January resulted in record winter peak loads. The high demand combined with high forced outage rates, and supply interruptions for natural gas fueled generation resulted in low reserve margins and associated shortage pricing events, and high uplift payments in January. Table 3-78 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in the first nine months of 2013 and 2014.

Table 3-78 Summary of emergency events declared January through September, 2013 and 2014

	Number of days events declared	
Event Type	Jan - Sep, 2013	Jan - Sep, 2014
Cold Weather Alert	4	25
Hot Weather Alert	17	7
Maximum Emergency Generation Alert	4	6
Primary Reserve Alert	0	2
Voltage Reduction Alert	0	2
Primary Reserve Warning	0	1
Voltage Reduction Warning	1	4
Emergency Load Management Long Lead Time	5	6
Emergency Load Management Short Lead Time	1	6
Maximum Emergency Action	5	8
Emergency Energy Bids Requested	0	3
Voltage Reduction Action	0	1
Shortage Pricing	0	2
Energy export recalls from PJM capacity resources	0	0

Emergency procedures

PJM declares alerts at least a day prior to the operating day to warn members of possible emergency actions that could be taken during the operating day. In real time on the operating day, PJM issues warnings notifying members of system conditions that could result in emergency actions during the operating day.

PJM declared cold weather alerts on 25 days in the first nine months of 2014 compared to only four days in the first nine months of 2013.[84] The purpose of a cold weather alert is to prepare personnel and facilities for expected extreme cold weather conditions, generally when temperatures are forecast to approach minimums or fall below ten degrees Fahrenheit.

PJM declared hot weather alerts on seven days in the first nine months of 2014 compared to 17 days in the first nine months of 2013.[85] The purpose of a hot weather alert is to prepare personnel and facilities for expected extreme hot and humid weather conditions, generally when temperatures are forecast to exceed 90 degrees Fahrenheit with high humidity.

84 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), Section 3.3 Cold Weather Alert, p. 41.
85 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), Section 3.3 Cold Weather Alert, p. 41.

PJM declared maximum emergency generation alerts on six days in the first nine months of 2014 compared to four days in the first nine months of 2013. All the maximum emergency generation alerts in 2014 were associated with cold weather conditions in the period from January through March. In 2013, the maximum emergency generation alerts were associated with hot weather conditions in the period from July through September. The purpose of a maximum emergency generation alert is to provide an alert at least one day prior to the operating day that system conditions may require use of PJM emergency actions. It is called to alert PJM members that maximum emergency generation may be requested in the operating capacity.[86] This means that if PJM directs members to load maximum emergency generation during the operating day, the resources must be able to increase generation above the maximum economic level of their offer.

PJM declared a primary reserve alert on two days in the first nine months of 2014. The purpose of a primary reserve alert is to alert members at least one day prior to the operating day that available primary reserves are anticipated to be short of the primary reserve requirement on the operating day. It is issued when the estimated primary reserves are less than the forecast primary reserve requirement.

PJM declared a voltage reduction alert on two days in the first nine months of 2014. The purpose of a voltage reduction alert is to alert members at least one day prior to the operating day that a voltage reduction may be required on the operating day. It is issued when the estimated operating reserve is less than the forecast synchronized reserve requirement.

PJM declared a primary reserve warning on one day in the first nine months of 2014. The purpose of a primary reserve warning is to warn members that available primary reserves are less than the primary reserve requirement but greater than the synchronized reserve requirement.

PJM declared a voltage reduction warning and reduction of non-critical plant load on four days in the first nine months of 2014 compared to one day in the first nine months of 2013. The purpose of a voltage reduction warning and reduction of non-critical plant load is to warn members that available synchronized reserves are less than the synchronized reserve requirement and that a voltage reduction may be required. It can be issued for the RTO or for specific control zones.

PJM declared emergency mandatory load management reductions (long lead time and short lead time) in all or parts of the PJM service territory on six days in the first nine months of 2014 compared to five days in the first nine months of 2013 (short lead time load reductions were declared on only one of the five days). The purpose of emergency mandatory load management is to request curtailment service providers (CSP) to implement load reductions from demand resources registered in PJM demand response programs that have a lead time of between one and two hours (long lead time) and a lead time of up to one hour (short lead time). Despite that the formal name of PJM's action, load reductions (both long lead time and short lead time) during the first nine months of 2014 are voluntary and not mandatory, because they occurred outside of the mandatory summer compliance period of June 1 through September 30. Load reductions during these events are not counted for performance assessment.

PJM declared maximum emergency generation actions on eight days in the first nine months of 2014 compared to five days in the first nine months of 2013. The purpose of a maximum emergency generation action is to request generators to increase output to the maximum emergency level which unit owners may define at a level above the maximum economic level. A maximum emergency generation action can be issued for the RTO, for specific control zones or for parts of control zones. Maximum emergency generation action was declared for the RTO on four days in the first nine months of 2013 (January 6, 7, 8 and March 4); for the BGE and Pepco control zones on January 22; for the Mid-Atlantic and Dominion regions on January 23, 24 and 30; and for the AP zone on January 23 and 24.

PJM requested bids for emergency energy purchases on three days in the first nine months of 2014. On January 7, PJM requested bids for emergency

86 See PJM. "Manual 13: Emergency Operations," Revision 55 (January 1, 2014), Section 2.3.1 Day-Ahead Emergency Procedures: Alerts, p. 16.

energy between 0600 and 1100 and again between hours 1700 to 2100. PJM also requested bids for emergency energy on January 8 and January 23, but did not purchase any emergency energy.

PJM did not recall energy from PJM capacity resources that were exporting energy during emergency conditions in the first nine months of 2014.

PJM issued a voltage reduction action on one day (January 6) in the first nine months of 2014. The purpose of a voltage reduction is to reduce load to provide sufficient reserves, to maintain tie flow schedules, and to preserve limited energy sources. When a voltage reduction action is issued for a reserve zone or sub-zone, the primary reserve penalty factor and synchronized reserve penalty factor are incorporated into the synchronized and non-synchronized reserve market clearing prices and locational marginal prices until the voltage reduction action has been terminated.

There were 29 spinning events in the first nine months of 2014 compared to 15 in the first nine months of 2013.[87] Of the 29, 19 were classified as system disturbances (caused by unit trips or line trip).

Table 3-79 provides a description of PJM declared emergency procedures.

Table 3-79 Description of Emergency Procedures

Emergency Procedure	Purpose
Cold Weather Alert	To prepare personnel and facilities for extreme cold weather conditions, generally when forecast weather conditions approach minimum or temperatures fall below ten degrees Fahrenheit.
Hot Weather Alert	To prepare personnel and facilities for extreme hot and/or humid weather conditions, generally when forecast temperatures exceed 90 degrees with high humidity.
Maximum Emergency Generation Alert	To provide an early alert at least one day prior to the operating day that system conditions may require the use of the PJM emergency procedures and resources must be able to increase generation above the maximum economic level of their offers.
Primary Reserve Alert	To alert members of a projected shortage of primary reserve for a future period. It is implemented when estimated primary reserve is less than the forecast requirement.
Voltage Reduction Alert	To alert members thjat a voltage reduction may be required during a future critical period. It is implemented when estimated reserve capacity is less than forecasted synchronized reserve requirement.
Primary Reserve Warning	To warn members that available primary reserve is less than required and present operations are becoming critical. It is implemented when available primary reserve is less than the primary reserve requirement but greater than the synchronized reserve requirement.
Voltage Reduction Warning & Reduction of Non-Critical Plant Load	To warn members that actual synchronized reserves are less than the synchronized reserve requiremtn and that voltage reduction may be required.
Emergency Mandatory Load Management Reductions (Long Lead Time)	To request end-use customers registered in the PJM demand response program as a demand resource (DR) that need between one to two hours lead time to make reductions.
Emergency Mandatory Load Management Reductions (Short Lead Time)	To request end-use customers registered in the PJM demand response program as a demand resource (DR) that need up to one hour lead time to make reductions.
Maximum Emergency Generation Action	To provide real time notice to increase generation above the maximum economic level. It is implemented whenever generation is needed that is greater than the maximum economic level.
Voltage Reduction	To reduce load to provide sufficient reserve capacity to maintain tie flow schedules and preserve limited energy sources. It is implemented when load relief is needed to maintain tie schedules.

87 See *2014 Quarterly State of the Market Report for PJM: January through September*, Section 10: Ancillary Service Markets for details on the spinning events.

Table 3-80 shows the dates on which emergency alerts and warnings were declared as well as emergency actions were implemented in the first nine months of 2014.

Table 3-80 PJM declared emergency alerts, warnings and actions: January through September, 2014

Dates	Cold Weather Alert	Hot Weather Alert	Maximum Emergency Generation Alert	Primary Reserve Alert	Voltage Reduction Alert	Primary Reserve Warning	Voltage Reduction Warning and Reduction of Non-Critical Plant Load	Maximum Emergency Generation Action	Emergency Load Management Long Lead Time	Emergency Load Management Short Lead Time	Voltage Reduction
1/1/2014	ComEd										
1/2/2014	ComEd										
1/3/2014	PJM except Southern region										
1/6/2014	PJM except Mid-Atlantic and Dominion						PJM	PJM			PJM
1/7/2014	PJM		PJM			PJM	PJM	PJM	PJM	PJM	
1/8/2014	PJM		PJM					PJM	PJM	PJM	
1/21/2014	PJM except Mid-Atlantic and Dominion										
1/22/2014	PJM							BGE, Pepco	BGE, Pepco	BGE, Pepco	
1/23/2014	PJM		Mid-Atlantic region, AP and Dominion control zones		BGE, Pepco			Mid-Atlantic region, AP and Dominion control zones	Mid-Atlantic region, AP and Dominion control zones	Mid-Atlantic region, AP and Dominion control zones	
1/24/2014	PJM		Mid-Atlantic				PJM	Mid-Atlantic region, AP and Dominion control zones	Mid-Atlantic region, AP and Dominion control zones	Mid-Atlantic region, AP and Dominion control zones	
1/27/2014	PJM										
1/28/2014	PJM		PJM	PJM	PJM						
1/29/2014	PJM										
1/30/2014							PJM	Mid-Atlantic and Dominion			
2/6/2014	ComEd										
2/7/2014	PJM Western Region										
2/10/2014	PJM Western Region										
2/11/2014	PJM Western Region										
2/12/2014	PJM Western Region										
2/24/2014	ComEd										
2/25/2014	ComEd										
2/26/2014	ComEd										
2/27/2014	ComEd										
2/28/2014	PJM Mid-Atlantic and Western regions										
3/4/2014	PJM		Mid-Atlantic and Dominion	PJM				PJM	PJM	PJM	
3/13/2014	PJM Western Region										
6/17/2014		PJM									
6/18/2014		PJM									
6/19/2014		Dominion									
7/1/2014		PJM Mid-Atlantic and Southern regions									
7/2/2014		PJM Mid-Atlantic and Southern regions									
7/8/2014		PJM Mid-Atlantic and Southern regions									
9/2/2014		PJM Mid-Atlantic and Southern regions									

Energy Uplift (Operating Reserves)

Energy uplift is 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] Referred to in PJM as operating reserve credits, lost opportunity cost credits, reactive services credits, synchronous condensing credits or black start services credits, these payments are intended to be one of the incentives to generation owners to offer their energy to the PJM Energy Market for dispatch based on incremental offer curves and to operate their units at the direction of PJM dispatchers. These credits are paid by PJM market participants as operating reserve charges, reactive services charges, synchronous condensing charges or black start services charges.[2]

Overview

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges increased by $258.8 million or 40.2 percent in the first nine months of 2014 compared to the first nine months of 2013, from $644.2 million to $902.9 million. The increase of $258.8 million in the first nine months of 2014 is comprised of an increase of $12.9 million in day-ahead operating reserve charges, an increase of $444.6 million in balancing operating reserve charges, a decrease of $156.1 million in reactive services charges, a decrease of $0.3 million in synchronous condensing charges and a decrease of $42.3 million in black start services charges.
- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.139 per MWh. The balancing operating reserve reliability rates averaged $0.702, $0.023 and $0.010 per MWh for the RTO, Eastern and Western regions. The balancing operating reserve deviation rates averaged $1.491, $0.425 and $0.159 per MWh for the RTO, Eastern and Western regions. The lost opportunity cost rate averaged $1.481 per MWh and the canceled resources rate averaged $0.013 per MWh.
- **Reactive Services Rates.** The DPL, ATSI and PENELEC control zones had the three highest reactive local voltage support rates: $0.499, $0.229 and $0.210 per MWh. The reactive transfer interface support rate averaged $0.001 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 38.8 percent of all day-ahead generator credits and 56.6 percent of all balancing generator credits. Combustion turbines and diesels received 68.2 percent of the lost opportunity cost credits. Coal units received 83.8 percent of all reactive services credits.
- **Concentration of Energy Uplift Credits:** The top 10 units receiving energy uplift credits received 35.5 percent of all credits. The top 10 organizations received 81.8 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 4622, balancing operating reserves HHI was 2959, lost opportunity cost HHI was 3838 and reactive services HHI was 6964.
- **Economic and Noneconomic Generation.** In the first nine months of 2014, 87.5 percent of the day-ahead generation eligible for operating reserve credits was economic and 72.7 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability:** In the first nine months of 2014, 4.3 percent of the total day-ahead generation was scheduled as must run by PJM, of which 32.2 percent received energy uplift payments.

Geography of Charges and Credits

- In the first nine months of 2014, 90.7 percent of all charges allocated regionally (day-ahead operating reserves and balancing operating reserves) were paid by transactions at control zones or buses within a control zone, demand and generators, 2.1 percent by transactions at hubs and aggregates and 7.2 percent by transactions at interfaces.

1 Loss is defined as gross energy and ancillary services market revenues less than total energy offer, which are startup, no load and incremental offers.

2 Other types of energy uplift charges are make whole payments to emergency demand response resources and emergency transaction purchases. These categories are not covered in this section. See Section 6, "Demand Response" and Section 9 "Interchange Transactions" for an explanation on these payments.

Energy Uplift Issues

- **Lost Opportunity Cost Credits:** In the first nine months of 2014, lost opportunity cost credits increased by $62.9 million compared to the first nine months of 2013. In the first nine months of 2014, resources in the top three control zones receiving lost opportunity cost credits, AEP, Dominion and PENELEC accounted for 56.5 percent of all lost opportunity cost credits, 44.1 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 51.7 percent of all day-ahead generation not committed in real time by PJM from those unit types and 61.2 percent of all day-ahead generation not committed in real time by PJM and receiving lost opportunity cost credits from those unit types.
- **Black Start Service Units:** Certain units located in the AEP Control Zone are relied on for their black start capability on a regular basis during periods when the units are not economic. These black start units provide black start service under the ALR option, which means that the units must be running in order to provide black start services even if the units are not economic. In the first nine months of 2014, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $26.4 million.
- **Con Edison – PJM Transmission Service Agreements Support:** Certain units located near the boundary between New Jersey and New York City have been operated to support the transmission service agreements between Con Ed and PJM, formerly known as the Con Ed – PSEG Wheeling Contracts. These units are often run out of merit and received substantial balancing operating reserves credits.

Energy Uplift Recommendations

- **Impact of Quantifiable Recommendations:** The impact of implementing the recommendations related to energy uplift proposed by the MMU on the rates paid by participants would be significant. For example, in the first nine months of 2014, the average rate paid by a DEC in the Eastern Region would have been $0.324 per MWh, which is $2.632 per MWh less than the actual average rate paid.

Recommendations

- The MMU recommends that PJM clearly identify, classify all reasons for incurring operating reserves in the Day-Ahead and the Real-Time Energy Markets and the associated operating reserve charges in order for all market participants be aware of the reason of these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves. (Priority: Medium. First reported 2012.)
- The MMU recommends that PJM be transparent in the formulation of closed loop interfaces with adjustable limits and develop rules to reduce the levels of subjectivity around the creation and implementation of these interfaces. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM estimate the impact such interfaces could have on additional uplift payments inside closed loops, transmission planning, offer capping, FTR and ARR revenue, ancillary services markets and the capacity market to avoid unintended consequences. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM revise the current operating reserve confidentiality rules in order to allow the disclosure of complete information about the level of operating reserve charges by unit and the detailed reasons for the level of operating reserve payments by unit in the PJM region. (Priority: High. First reported 2013.)
- The MMU recommends the elimination of the day-ahead operating reserve category to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output. (Priority: Medium. First reported 2013.)
- The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. (Priority: Medium. First reported 2013.)
- The MMU recommends not compensating self-scheduled units for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours. (Priority: Low. First reported 2013.)

- 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. (Priority: High. First reported 2012.)
  - 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 committed in real time. (Priority: Medium. First reported 2012.)
  - 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 committed in real time. (Priority: Medium. First reported 2012.)
  - The MMU recommends using the entire offer curve and not a single point on the offer curve to calculate energy lost opportunity cost. (Priority: Medium. First reported 2012.)
- The MMU recommends that up-to congestion transactions be required to pay operating reserve charges. (Priority: High. First reported 2013.)
- The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. (Priority: High. First reported 2013.)
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements. (Priority: Medium. First reported 2013.)
- 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 the operating reserve credits calculation. (Priority: Medium. First reported 2012.)
- The MMU recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above which is currently allocated to real-time RTO load. (Priority: Low. First reported Q2, 2014.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves and the timing of commitment decisions. (Priority: High. First reported Q1, 2014.)

Conclusion

Energy uplift is 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. Referred to in PJM as day-ahead operating reserves, balancing operating reserves, energy lost opportunity cost credits, reactive services credits, synchronous condensing credits or black start services credits, 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, reactive services charges, synchronous condensing charges or black start charges.

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

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 energy uplift payments. When units receive substantial revenues through energy uplift payments, these payments are not transparent to the market because of the current confidentiality rules. As a result other market participants, including generation and transmission developers, do not have the opportunity to compete to displace them. As a result, substantial energy uplift payments to a concentrated group of units and organizations has persisted for more than ten years.

The level of energy uplift 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. Energy uplift payments 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. The balance of these costs not covered by energy revenues are collected as energy uplift rather than reflected in price as a result of the rules governing the determination of LMP.

PJM has recognized the importance of addressing the issues that result in large amounts of energy uplift charges. In 2013, PJM stakeholders created the Energy Market Uplift Senior Task Force (EMUSTF).[3] The main goals of the EMUSTF are to evaluate the causes of energy uplift payments, develop ways to minimize energy uplift payments while maintaining prices that are consistent with operational reliability needs, and explore the allocation of such payments. In December 2013, PJM stakeholders created the Market Implementation Committee – Energy/Reserve Pricing and Interchange Volatility group to address issues such as improving the incorporation of operators' actions in LMP.[4]

The MMU recommended and supports PJM in the reexamination of the allocation of uplift charges to participants to ensure that such charges are paid by all whose market actions result in the incurrence of such charges. For example, up-to congestion transactions continue to pay no energy uplift charges, which means that all others who pay these charges are paying too much. In addition, the netting of transactions against internal bilateral transactions should be eliminated.

PJM's goal should be to minimize the total level of energy uplift 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 energy uplift charges and to increase the transactions over which those charges are spread in order to reduce the impact of energy uplift charges on markets. The result would be to reduce the level of per MWh charges, to reduce the uncertainty associated with uplift charges and to reduce the impact of energy uplift charges on decisions about how and when to participate in PJM markets.

Energy Uplift

The level of energy uplift credits paid to specific units depends on the level of the resource's energy offer, the LMP, the resource's operating parameters and the decisions of PJM operators. Energy uplift credits result in part from decisions by PJM operators, who follow reliability requirements and market rules, to start resources or to keep resources operating even when hourly LMP is less than the offer price including energy, no load and startup costs.

Credits and Charges Categories

Energy uplift charges include day-ahead and balancing operating reserves, reactive services, synchronous condensing and black start services categories. Total energy uplift credits paid to PJM participants equal the total energy uplift charges paid by PJM participants. Table 4-1 and Table 4-2 show the categories of credits and charges and their relationship. These tables show how the charges are allocated.

3 See "Problem Statement – Energy Market Uplift Costs," Energy Market Uplift Senior Task Force (July 30, 2013) <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20130730/20130730-problem-statement-energy-market-uplift-costs.ashx>.

4 See "Problem Statement – Energy/Reserve Pricing and Interchange Volatility," Market Implementation Committee (December 11, 2013) <http://www.pjm.com/~/media/committees-groups/committees/mic/20131212/20131212-item-01b-energy-reserve-problem-statement-updated.ashx>.

Table 4-1 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
Economic 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 Real-Time Export Transactions	in RTO, Eastern or Western Region
			Balancing Operating Reserve for Deviations	Deviations	
			Balancing Local Constraint	Applicable Requesting Party	
Canceled Resources	Balancing Operating Reserve Startup Cancellation	→	Balancing Operating Reserve for Deviations	Deviations	in RTO Region
Lost Opportunity Cost (LOC)	Balancing Operating Reserve LOC				
Real-Time Import Transactions	Balancing Operating Reserve Transaction				
Resources Providing Quick Start Reserve	Balancing Operating Reserve Generator				
Economic Load Response Resources	Balancing Operating Reserves for Load Response	→	Balancing Operating Reserve for Load Response	Deviations	in RTO Region

Table 4-2 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	Day-Ahead Operating Reserve 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/Non-zone Peak Transmission Use and Point to Point Transmission Reservations

Energy Uplift Results

Energy Uplift Charges

Total energy uplift charges increased by 40.2 percent in the first nine months of 2014, compared to the first nine months of 2013, to a total of $902.9 million. Table 4-3 shows total energy uplift charges in the first nine months of 2013 and 2014.[5]

Table 4-3 Total energy uplift charges: January through September 2013 and 2014

	Jan - Sep 2013	Jan - Sep 2014	Change	Percentage Change
Total Energy Uplift Charges	$644,177,048	$902,934,088	$258,757,040	40.2%
Energy Uplift as a Percent of Total PJM Billing	2.6%	2.2%	(0.3%)	(13.5%)

Total energy uplift charges increased by $258.8 million or 40.2 percent in the first nine months of 2014 compared to the first nine months of 2013. Table 4-4 compares energy uplift charges by category for the first nine months of 2013 and the first nine months of 2014. The increase of $258.8 million in the first nine months of 2014 is comprised of an increase of $12.9 million in day-ahead operating reserve charges, an increase of $444.6 million in balancing operating reserve charges, a decrease of $156.1 million in reactive services charges, a decrease of $0.3 million in synchronous condensing charges and a decrease of $42.3 million in black start services charges. The increase in total energy uplift charges was a result of high demand, high natural gas costs and high LMPs in the first quarter. High natural gas prices and higher energy offers for units scheduled in the Day-Ahead Energy Market and units committed in real time for conservative operations increased the day-ahead and balancing operating reserve charges. Higher energy prices reduced the energy uplift for coal units providing black start and reactive support in the first quarter. In contrast, low demand and low natural gas prices during the second and third quarters reduced energy uplift charges.

5 Table 4-4 includes all categories of charges as defined in Table 4-1 and Table 4-2 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 energy uplift. The billing data reflected in this report were current on July 11, 2014.

Table 4-4 Energy uplift charges by category: January through September 2013 and 2014

Category	Jan - Sep 2013	Jan - Sep 2014	Change	Percentage Change
Day-Ahead Operating Reserves	$74,426,144	$87,305,917	$12,879,773	17.3%
Balancing Operating Reserves	$316,936,238	$761,500,593	$444,564,355	140.3%
Reactive Services	$183,515,064	$27,411,829	($156,103,234)	(85.1%)
Synchronous Condensing	$396,245	$103,914	($292,331)	(73.8%)
Black Start Services	$68,903,357	$26,611,834	($42,291,523)	(61.4%)
Total	$644,177,048	$902,934,088	$258,757,040	40.2%

The increase in energy uplift charges in the first nine months of 2014 was a result of increases in January. Total energy uplift charges increased $487.0 million in January 2014, compared to January 2013, while energy uplift charges decreased by $228.2 million in February through September 2014 compared to February through September 2013. Table 4-5 compares monthly energy uplift charges by category for 2013 and 2014.

Table 4-6 shows the composition of the day-ahead operating reserve charges. Day-ahead operating reserve charges consist of day-ahead operating reserve charges for credits to generators and import transactions, day-ahead operating reserve charges for economic load response resources and day-ahead operating reserve charges from unallocated congestion charges.[6,7] Day-ahead operating reserve charges increased by $12.9 million or 17.3 percent in the first nine months of 2014 compared to the first nine months of 2013. Day-ahead operating reserve charges (excluding unallocated congestion charges) increased by $33.8 million or 63.1 percent in the first nine months of 2014 compared to the first nine months of 2013. This increase was primarily the result of higher natural gas prices and higher energy offers in January. There were zero unallocated congestion charges in the first nine months of 2014 compared to $20.9 million in the first nine months of 2013.

6 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 ten times, totaling $26.9 million.

7 See Section 13, "Financial Transmission Rights and Auction Revenue Rights" at "Unallocated Congestion Charges" for an explanation of the source of these charges.

Table 4-5 Monthly energy uplift charges: 2013 and 2014

	2013						2014					
	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start	Total	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total
Jan	$11,122,613	$79,240,331	$23,604,234	$1,873	$8,453,397	$122,422,449	$35,827,200	$565,697,081	$3,773,749	$54,736	$4,037,517	$609,390,283
Feb	$5,126,444	$67,126,202	$17,624,984	$0	$6,988,632	$96,866,261	$9,492,509	$56,052,542	$1,043,326	$0	$883,414	$67,471,791
Mar	$6,688,755	$17,415,540	$14,350,138	$0	$6,768,618	$45,223,051	$5,672,791	$59,521,466	$2,682,504	$0	$2,638,249	$70,515,010
Apr	$5,712,618	$23,429,237	$13,670,581	$0	$9,242,815	$52,055,252	$4,185,010	$9,710,792	$5,272,525	$0	$2,812,795	$21,981,122
May	$11,823,204	$22,524,898	$17,214,142	$959	$8,667,665	$60,230,867	$6,385,787	$20,986,370	$5,278,711	$45,382	$1,844,100	$34,540,349
Jun	$9,805,163	$17,885,783	$22,055,239	$0	$7,954,457	$57,700,642	$5,255,216	$15,819,469	$4,156,517	$0	$2,113,151	$27,344,353
Jul	$8,310,384	$43,516,700	$19,633,771	$393,413	$5,858,221	$77,712,488	$6,732,413	$11,440,551	$2,879,977	$3,797	$4,370,704	$25,427,442
Aug	$4,159,471	$14,674,041	$27,827,070	$0	$7,584,998	$54,245,580	$5,793,886	$9,888,962	$1,043,798	$0	$4,067,771	$20,794,417
Sep	$11,677,492	$31,123,507	$27,534,905	$0	$7,384,554	$77,720,458	$7,961,105	$12,383,359	$1,280,723	$0	$3,844,132	$25,469,320
Oct	$2,473,704	$12,767,972	$41,721,299	$0	$6,708,931	$63,671,907						
Nov	$2,799,521	$17,709,922	$42,743,907	$132	$6,685,965	$69,939,448						
Dec	$5,253,661	$36,157,934	$43,464,829	$0	$4,403,308	$89,279,733						
Total (Jan - Sep)	$74,426,144	$316,936,238	$183,515,064	$396,245	$68,903,357	$644,177,048	$87,305,917	$761,500,593	$27,411,829	$103,914	$26,611,834	$902,934,088
Share (Jan - Sep)	11.6%	49.2%	28.5%	0.1%	10.7%	100.0%	9.7%	84.3%	3.0%	0.0%	2.9%	100.0%
Total	$84,953,031	$383,572,067	$311,445,099	$396,377	$86,701,561	$867,068,135	$87,305,917	$761,500,593	$27,411,829	$103,914	$26,611,834	$902,934,088
Share	9.8%	44.2%	35.9%	0.0%	10.0%	100.0%	9.7%	84.3%	3.0%	0.0%	2.9%	100.0%

Table 4-6 Day-ahead operating reserve charges: January through September 2013 and 2014

Type	Jan - Sep 2013	Jan - Sep 2014	Change	Jan - Sep 2013 Share	Jan - Sep 2014 Share
Day-Ahead Operating Reserve Charges	$53,528,214	$87,303,340	$33,775,126	71.9%	100.0%
Day-Ahead Operating Reserve Charges for Load Response	$4,376	$2,577	($1,799)	0.0%	0.0%
Unallocated Congestion Charges	$20,893,554	$0	($20,893,554)	28.1%	0.0%
Total	$74,426,144	$87,305,917	$12,879,773	100.0%	100.0%

Table 4-7 shows the composition of the balancing operating reserve charges. Balancing operating reserve charges consist of balancing operating reserve reliability charges (credits to generators), balancing operating reserve deviation charges (credits to generators and import transactions), balancing operating reserve charges for economic load response and balancing local constraint charges. Balancing operating reserve charges increased by $444.6 million in the first nine months of 2014 compared to the first nine months of 2013. This increase was primarily the result of higher natural gas prices and higher energy offers combined with significantly higher conservative operations commitment, lost opportunity cost compensation to generators scheduled in the Day-Ahead Energy Market and not committed in real time, and lost opportunity cost compensation to generators reduced in real time for reliability purposes.

Table 4-7 Balancing operating reserve charges: January through September 2013 and 2014

Type	Jan - Sep 2013	Jan - Sep 2014	Change	Jan - Sep 2013 Share	Jan - Sep 2014 Share
Balancing Operating Reserve Reliability Charges	$41,609,297	$441,956,178	$400,346,881	13.1%	58.0%
Balancing Operating Reserve Deviation Charges	$274,721,958	$318,027,927	$43,305,969	86.7%	41.8%
Balancing Operating Reserve Charges for Load Response	$468,085	$24,855	($443,230)	0.1%	0.0%
Balancing Local Constraint Charges	$136,898	$1,491,633	$1,354,735	0.0%	0.2%
Total	$316,936,238	$761,500,593	$444,564,355	100.0%	100.0%

Table 4-8 shows the composition of the balancing operating reserve deviation charges. Balancing operating reserve deviation charges equal make whole credits paid 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 nine months of 2014, 54.4 percent of balancing operating reserve deviation charges were for make whole credits paid to generators and import transactions, a decrease of 16.0 percentage points compared to the share in the first nine months of 2013.

Table 4-8 Balancing operating reserve deviation charges: January through September 2013 and 2014

Charge Attributable To	Jan - Sep 2013	Jan - Sep 2014	Change	Jan - Sep 2013 Share	Jan - Sep 2014 Share
Make Whole Payments to Generators and Imports	$193,391,245	$172,876,957	($20,514,288)	70.4%	54.4%
Energy Lost Opportunity Cost	$80,974,864	$143,861,955	$62,887,091	29.5%	45.2%
Canceled Resources	$355,849	$1,289,015	$933,166	0.1%	0.4%
Total	$274,721,958	$318,027,927	$43,305,969	100.0%	100.0%

Table 4-9 Additional energy uplift charges: January through September 2013 and 2014

Type	Jan - Sep 2013	Jan - Sep 2014	Change	Jan - Sep 2013 Share	Jan - Sep 2014 Share
Reactive Services Charges	$183,515,064	$27,411,829	($156,103,234)	72.6%	50.6%
Synchronous Condensing Charges	$396,245	$103,914	($292,331)	0.2%	0.2%
Black Start Services Charges	$68,903,357	$26,611,834	($42,291,523)	27.3%	49.2%
Total	$252,814,665	$54,127,577	($198,687,088)	100.0%	100.0%

Table 4-9 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by $156.1 million in the first nine months of 2014 compared to the first nine months of 2013. Black start services charges decreased by $42.3 million in the first nine months of 2014 compared to the first nine months of 2013. Both categories decreased primarily as a result of the fact that higher energy prices made the units more economic than in the first nine months of 2013. Reduced FMU adders decreased the amount of energy uplift paid to units providing reactive support. The removal of automatic load rejection black start units from must run black start status contributed to the reduction in the amount of energy uplift paid to units providing black start support in the first nine months of 2014.

Table 4-10 and Table 4-11 show the amount and percentages of regional balancing charges for the first nine months of 2013 and 2014. Regional balancing operating reserve charges consist of balancing operating reserve reliability and deviation charges. These charges are allocated regionally across PJM. The largest share of regional charges was paid by real-time load. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In the first nine months of 2014, regional balancing operating reserve charges increased by $443.7 million compared to the first nine months of 2013. Balancing operating reserve reliability charges increased by $400.3 million or 962.2 percent and balancing operating reserve deviation charges increased by $43.3 million or 15.8 percent.

Table 4-10 Regional balancing charges allocation: January through September 2013

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$30,792,044	9.7%	$8,615,370	2.7%	$1,240,266	0.4%	$40,647,680	12.8%
	Real-Time Exports	$705,233	0.2%	$224,896	0.1%	$31,489	0.0%	$961,618	0.3%
	Total	$31,497,277	10.0%	$8,840,266	2.8%	$1,271,755	0.4%	$41,609,297	13.2%
Deviation Charges	Demand	$98,706,646	31.2%	$64,844,624	20.5%	$2,965,723	0.9%	$166,516,993	52.6%
	Supply	$26,844,532	8.5%	$17,444,856	5.5%	$839,735	0.3%	$45,129,123	14.3%
	Generator	$40,058,985	12.7%	$21,539,621	6.8%	$1,477,237	0.5%	$63,075,843	19.9%
	Total	$165,610,163	52.4%	$103,829,100	32.8%	$5,282,695	1.7%	$274,721,958	86.8%
Total Regional Balancing Charges		$197,107,439	62.3%	$112,669,366	35.6%	$6,554,450	2.1%	$316,331,256	100%

Table 4-11 Regional balancing charges allocation: January through September 2014

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$424,714,403	55.9%	$6,413,178	0.8%	$3,174,816	0.4%	$434,302,397	57.1%
	Real-Time Exports	$7,353,995	1.0%	$204,608	0.0%	$95,178	0.0%	$7,653,781	1.0%
	Total	$432,068,398	56.9%	$6,617,787	0.9%	$3,269,994	0.4%	$441,956,178	58.2%
Deviation Charges	Demand	$159,593,264	21.0%	$11,855,188	1.6%	$4,519,107	0.6%	$175,967,559	23.2%
	Supply	$43,734,785	5.8%	$3,496,081	0.5%	$938,642	0.1%	$48,169,509	6.3%
	Generator	$86,687,540	11.4%	$4,964,628	0.7%	$2,238,692	0.3%	$93,890,860	12.4%
	Total	$290,015,589	38.2%	$20,315,898	2.7%	$7,696,440	1.0%	$318,027,927	41.8%
Total Regional Balancing Charges		$722,083,986	95.0%	$26,933,685	3.5%	$10,966,434	1.4%	$759,984,105	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 4-1 for how these charges are allocated.[8]

Figure 4-1 shows the daily day-ahead operating reserve rate for 2013 and the first nine months of 2014. The average rate in the first nine months of 2014 was $0.139 per MWh, $0.053 per MWh higher than the average in the first nine months of 2013. The highest rate occurred on January 22, when the rate reached $1.689 per MWh, $1.043 per MWh higher than the $0.646 per MWh reached in the first nine months of 2013, on July 16. Figure 4-1 also shows the daily day-ahead operating reserve rate including the congestion charges allocated to day-ahead operating reserves. There were no congestion charges allocated to day-ahead operating reserves in the first nine months of 2014. The increase in the day-ahead operating reserve rate on January 22 was in large part the result of scheduling peaking resources which were noneconomic or economic for less than 50 percent of their scheduled run time. On January 22, 116 units received day-ahead operating reserve credits, 86 were economic for 50 percent or less of their scheduled run time. That was the highest number of units scheduled noneconomic in the Day-Ahead Energy Market in the first nine months of 2014. Also, on January 22, 60 units that were made whole though day-ahead operating reserves also provided day-ahead scheduling reserves for which they received additional revenue; eight of these units received enough net revenues from day-ahead scheduling reserves to cover their total energy offer (including no load and startup cost), which would have resulted in zero day-ahead operating reserve credits if the net revenues from day-ahead scheduling reserves could be used as an offset in the day-ahead operating reserve credit calculation.[9]

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

9 Net revenues from day-ahead scheduling reserves are used as offsets in the balancing operating reserve calculation.

Figure 4-1 Daily day-ahead operating reserve rate ($/MWh): 2013 and 2014

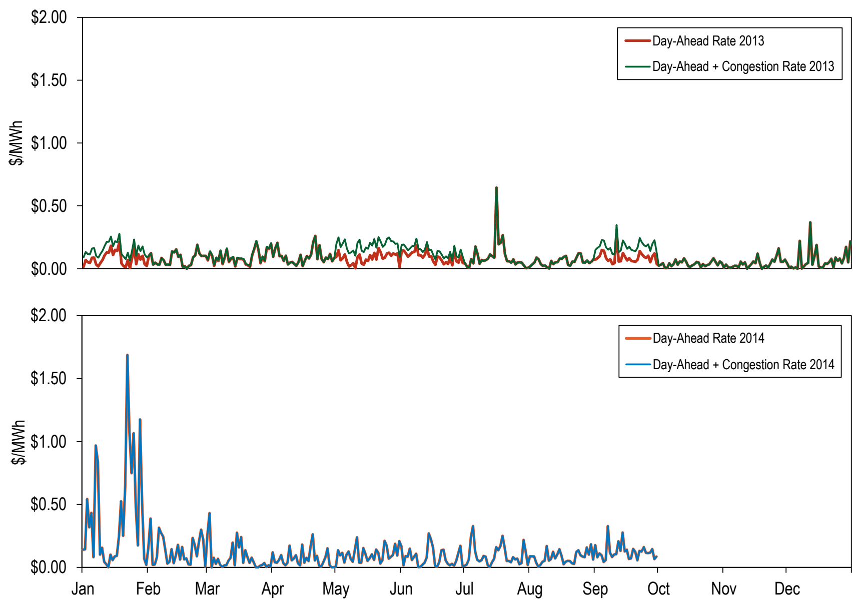


Figure 4-2 shows the RTO and the regional reliability rates for 2013 and the first nine months of 2014. The average daily RTO reliability rate was $0.702 per MWh. The highest RTO reliability rate in the first nine months of 2014 occurred on January 28, when the rate reached $24.593 per MWh, $23.791 per MWh higher than the $0.802 per MWh rate reached in the first nine months of 2013, on January 23. The increases in the RTO reliability rate on January 3, January 8 and between January 21 and 28 were the result of the commitment for conservative operations of natural gas fired generators with high offers.[10]

Figure 4-2 Daily balancing operating reserve reliability rates ($/MWh): 2013 and 2014

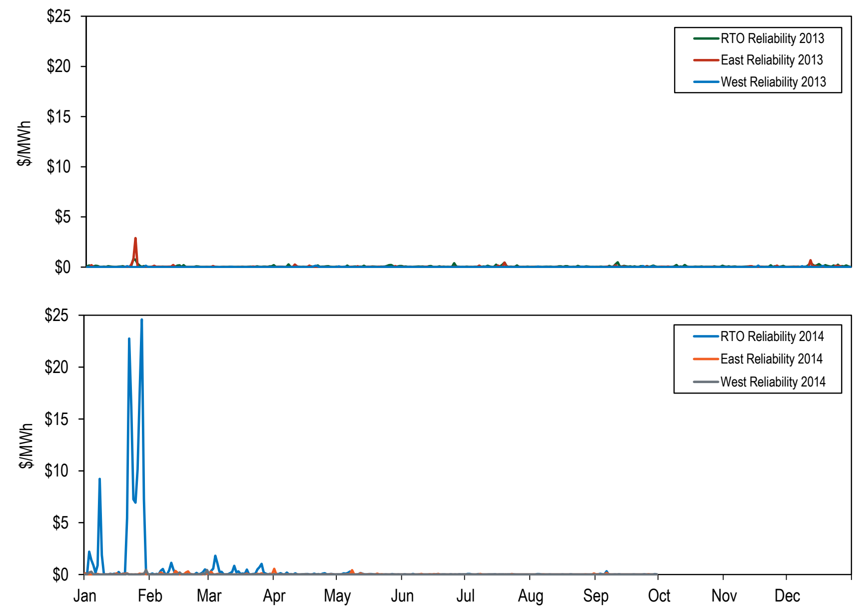


Figure 4-3 shows the RTO and regional deviation rates for 2013 and the first nine months of 2014. The average daily RTO deviation rate was $1.491 per MWh. The highest daily rate in the first nine months of 2014 occurred on January 25, when the RTO deviation rate reached $20.098 per MWh, $9.926 per MWh higher than the $10.172 per MWh rate reached in the first nine months of 2013, on January 23. In the first nine months of 2014 the RTO deviation rate increased while the Eastern Region deviation rate decreased, compared to the first nine months of 2013. In the first nine months of 2013, energy uplift was paid primarily to units committed to provide relief to local transmission constraints in the Eastern Region, while in the first nine months of 2014, energy uplift was paid primarily to units committed to meet overall load and provide reserves for peak hours.

10 See the *2014 Quarterly State of the Market Report for PJM: January through March*, Section 4, "Energy Uplift" at "Energy Uplift and Conservative Operations" for an explanation of the reasons and impact of units committed for conservative operations.

Figure 4-3 Daily balancing operating reserve deviation rates ($/MWh): 2013 and 2014

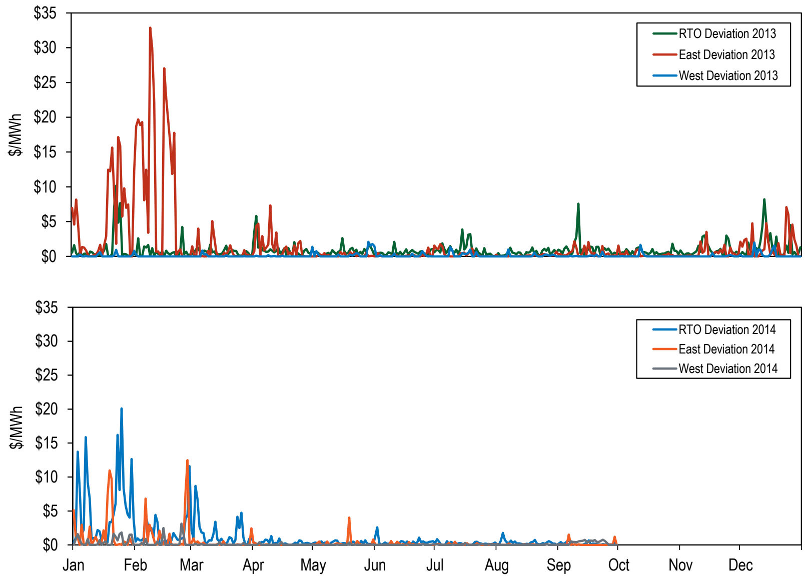


Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2013 and the first nine months of 2014. The lost opportunity cost rate averaged $1.481 per MWh. The highest lost opportunity cost rate occurred on January 24, when it reached $32.556 per MWh, $24.078 per MWh higher than the $8.478 per MWh rate reached in the first nine months of 2013, on September 11. On January 24, 2014, 63.5 percent of the lost opportunity cost rate was due to units reduced in real time for reliability purposes.

Figure 4-4 Daily lost opportunity cost and canceled resources rates ($/MWh): 2013 and 2014

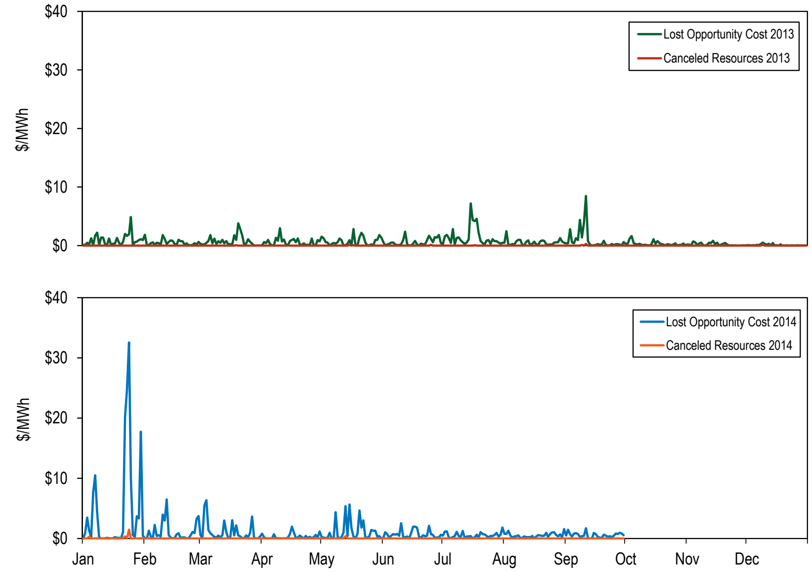


Table 4-12 shows the average rates for each region in each category for the first nine months of 2013 and the first nine months of 2014.

Table 4-12 Operating reserve rates ($/MWh): January through September 2013 and 2014

Rate	Jan - Sep 2013 ($/MWh)	Jan - Sep 2014 ($/MWh)	Difference ($/MWh)	Percentage Difference
Day-Ahead	0.086	0.139	0.053	62.1%
Day-Ahead with Unallocated Congestion	0.119	0.139	0.020	16.6%
RTO Reliability	0.053	0.702	0.650	1,235.7%
East Reliability	0.031	0.023	(0.008)	(25.9%)
West Reliability	0.004	0.010	0.006	146.6%
RTO Deviation	0.905	1.491	0.586	64.7%
East Deviation	2.208	0.425	(1.783)	(80.7%)
West Deviation	0.120	0.159	0.039	32.1%
Lost Opportunity Cost	0.870	1.481	0.611	70.2%
Canceled Resources	0.004	0.013	0.009	247.1%

Table 4-13 shows the operating reserve cost of a one MW transaction during the first nine months of 2014. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $2.956 per MWh with a maximum rate of $43.005 per MWh, a minimum rate of $0.109 per MWh and a standard deviation of $5.709 per MWh.

The rates in the table include all operating reserve charges including RTO deviation charges and unallocated congestion charges. Table 4-13 illustrates both the average level of operating reserve charges by transaction types and the uncertainty reflected in the maximum, minimum and standard deviation levels.

Table 4-13 Operating reserve rates statistics ($/MWh): January through September 2014

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	42.256	2.824	0.036	5.585
	DEC	43.005	2.956	0.109	5.709
	DA Load	1.689	0.132	0.000	0.189
	RT Load	24.630	0.592	0.000	2.711
	Deviation	42.256	2.824	0.036	5.585
West	INC	43.729	2.559	0.092	5.470
	DEC	44.478	2.691	0.109	5.596
	DA Load	1.689	0.132	0.000	0.189
	RT Load	24.652	0.579	0.000	2.712
	Deviation	43.729	2.559	0.092	5.470

Reactive Services Rates

Reactive services charges associated with local voltage support are allocated to real-time load in the control zone or zones where the service is provided. Reactive services charges associated with supporting reactive transfer interfaces above 345 kV are allocated to real-time load across the entire RTO. These charges are allocated daily based on the real-time load ratio share of each network customer.

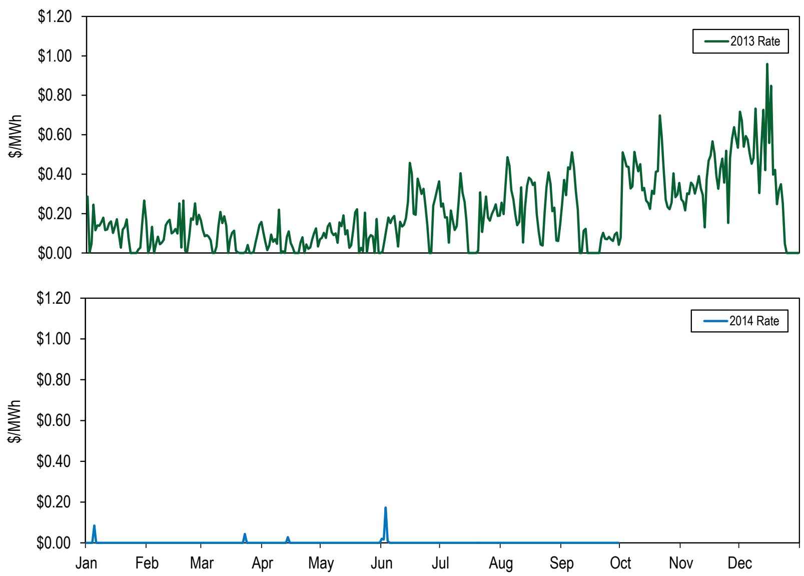
While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-14 shows the reactive services rates associated with local voltage support for the first nine months of 2013 and the first nine months of 2014. Table 4-14 shows that in the first nine months of 2014 the DPL Control Zone had the highest rate. Real-time load in the DPL Control Zone paid an average of $0.499 per MWh for reactive services associated with local voltage support, $1.366 or 73.3 percent lower than the average rate paid in the first nine months of 2013.

Table 4-14 Local voltage support rates: January through September 2013 and 2014

Control Zone	Jan - Sep 2013 ($/MWh)	Jan - Sep 2014 ($/MWh)	Difference ($/MWh)	Percentage Difference
AECO	0.269	0.012	(0.258)	(95.6%)
AEP	0.036	0.007	(0.029)	(80.3%)
AP	0.001	0.006	0.005	439.8%
ATSI	0.614	0.229	(0.386)	(62.8%)
BGE	0.187	0.001	(0.187)	(99.5%)
ComEd	0.002	0.001	(0.001)	(68.9%)
DAY	0.000	0.001	0.001	NA
DEOK	0.000	0.000	0.000	0.0%
DLCO	0.000	0.000	0.000	0.0%
Dominion	0.026	0.045	0.019	74.0%
DPL	1.865	0.499	(1.366)	(73.3%)
EKPC	0.010	0.000	(0.010)	(100.0%)
JCPL	0.010	0.000	(0.010)	(100.0%)
Met-Ed	0.426	0.003	(0.423)	(99.4%)
PECO	0.025	0.011	(0.014)	(56.9%)
PENELEC	0.021	0.210	0.189	906.9%
Pepco	1.521	0.001	(1.520)	(99.9%)
PPL	0.011	0.000	(0.011)	(99.4%)
PSEG	0.021	0.010	(0.011)	(50.7%)
RECO	0.236	0.000	(0.236)	(100.0%)

Figure 4-5 shows the daily RTO wide reactive transfer interface rate for 2013 and the first nine months of 2014. The average rate in the first nine months of 2014 was $0.001 per MWh, 99.0 percent lower than the $0.132 per MWh average rate in the first nine months of 2013. In the first nine months of 2014, energy uplift was paid to units providing support to the reactive transfer interfaces for only seven days. The significant decrease in reactive services charges allocated across the RTO was a result of the fact that units that were previously scheduled noneconomic to provide reactive services became economic based on higher energy prices and lower offers from the units providing reactive support due to reduced FMU adders, and therefore cleared the Day-Ahead Energy Market based on economics.

Figure 4-5 Daily reactive transfer interface support rates ($/MWh): 2013 and 2014



Balancing Operating Reserve Determinants

Table 4-15 shows the determinants used to allocate the regional balancing operating reserve charges for the first nine months of 2013 and the first nine months of 2014. Total real-time load and real-time exports were 16,185,475 MWh or 2.7 percent higher in the first nine months of 2014 compared to the first nine months of 2013. Total deviations summed across the demand, supply, and generator categories were 4,056,166 MWh or 4.4 percent higher in the first nine months of 2014 compared to the first nine months of 2013.

Table 4-15 Balancing operating reserve determinants (MWh): January through September 2013 and 2014

		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 - Sep 2013	RTO	583,845,687	15,243,726	599,089,413	55,392,260	14,786,604	22,914,654	93,093,518
	East	278,332,308	7,065,335	285,397,643	29,616,581	7,440,457	9,968,095	47,025,134
	West	305,513,379	8,178,391	313,691,770	24,021,589	6,934,081	12,946,559	43,902,228
Jan - Sep 2014	RTO	593,301,895	21,972,993	615,274,888	58,266,134	14,455,372	24,428,178	97,149,684
	East	279,816,694	8,406,246	288,222,940	28,505,178	8,034,714	11,231,767	47,771,659
	West	313,485,201	13,566,747	327,051,948	29,083,018	6,125,709	13,196,411	48,405,138
Difference	RTO	9,456,208	6,729,267	16,185,475	2,873,874	(331,232)	1,513,524	4,056,166
	East	1,484,386	1,340,911	2,825,297	(1,111,403)	594,256	1,263,671	746,525
	West	7,971,822	5,388,356	13,360,178	5,061,429	(808,372)	249,853	4,502,910

Deviations fall into three categories, demand, supply and generator deviations. Table 4-16 shows the different categories by the type of transactions that incurred deviations. In the first nine months of 2014, 19.6 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 80.4 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 4-16 Deviations by transaction type: January through September 2014

Deviation Category	Transaction	Deviation (MWh) RTO	East	West	Share RTO	East	West
Demand	Bilateral Sales Only	229,399	151,937	77,463	0.2%	0.3%	0.2%
	DECs Only	7,572,821	2,351,850	4,545,138	7.8%	4.9%	9.4%
	Exports Only	4,331,267	2,577,482	1,753,785	4.5%	5.4%	3.6%
	Load Only	39,435,803	19,825,844	19,609,959	40.6%	41.5%	40.5%
	Combination with DECs	4,310,342	2,707,441	1,600,797	4.4%	5.7%	3.3%
	Combination without DECs	2,386,501	890,624	1,495,877	2.5%	1.9%	3.1%
Supply	Bilateral Purchases Only	339,297	229,285	110,012	0.3%	0.5%	0.2%
	Imports Only	6,879,867	4,698,779	2,181,088	7.1%	9.8%	4.5%
	INCs Only	5,121,191	1,984,573	2,841,669	5.3%	4.2%	5.9%
	Combination with INCs	2,035,677	1,052,732	982,944	2.1%	2.2%	2.0%
	Combination without INCs	79,340	69,343	9,996	0.1%	0.1%	0.0%
Generators		24,428,178	11,231,767	13,196,411	25.1%	23.5%	27.3%
Total		97,149,684	47,771,659	48,405,138	100.0%	100.0%	100.0%

Energy Uplift Credits

Table 4-17 shows the totals for each credit category for the first nine months of 2013 and the first nine months of 2014. During the first nine months of 2014, 84.3 percent of total energy uplift credits were in the balancing operating reserve category, an increase of 33.5 percentage points from 50.8 percent in the first nine months of 2013.

Table 4-17 Energy uplift credits by category: January through September 2013 and 2014

Category	Type	Jan - Sep 2013	Jan - Sep 2014	Change	Percentage Change	Jan - Sep 2013 Share	Jan - Sep 2014 Share
Day-Ahead	Generators	$53,563,623	$87,303,336	$33,739,713	63.0%	8.6%	9.7%
	Imports	$9	$2	($7)	(75.8%)	0.0%	0.0%
	Load Response	$4,376	$2,578	($1,798)	(41.1%)	0.0%	0.0%
Balancing	Canceled Resources	$355,849	$1,289,016	$933,167	262.2%	0.1%	0.1%
	Generators	$234,961,926	$614,703,238	$379,741,311	161.6%	37.7%	68.1%
	Imports	$38,615	$122,696	$84,082	217.7%	0.0%	0.0%
	Load Response	$467,943	$24,697	($443,247)	(94.7%)	0.1%	0.0%
	Local Constraints Control	$136,898	$1,491,741	$1,354,843	989.7%	0.0%	0.2%
	Lost Opportunity Cost	$80,974,864	$143,861,958	$62,887,094	77.7%	13.0%	15.9%
Reactive Services	Day-Ahead	$166,593,049	$23,286,206	($143,306,843)	(86.0%)	26.7%	2.6%
	Local Constraints Control	$106,287	$27,067	($79,220)	(74.5%)	0.0%	0.0%
	Lost Opportunity Cost	$337,468	$216,407	($121,061)	(35.9%)	0.1%	0.0%
	Reactive Services	$16,261,292	$3,048,779	($13,212,513)	(81.3%)	2.6%	0.3%
	Synchronous Condensing	$216,968	$833,372	$616,404	284.1%	0.0%	0.1%
Synchronous Condensing		$396,245	$103,915	($292,331)	(73.8%)	0.1%	0.0%
Black Start Services	Day-Ahead	$66,621,747	$22,074,455	($44,547,292)	(66.9%)	10.7%	2.4%
	Balancing	$1,950,779	$4,290,415	$2,339,636	119.9%	0.3%	0.5%
	Testing	$295,411	$246,964	($48,448)	(16.4%)	0.0%	0.0%
Total		$623,283,351	$902,926,841	$279,643,489	44.9%	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-18 shows the distribution of total energy uplift credits by unit type for the first nine months of 2013 and the first nine months of 2014. The increase in energy uplift in the first nine months of 2014 compared to the first nine months of 2013 was due to credits paid to combined cycles, combustion turbines and steam turbines (not fired by coal). Credits to these units increased $413.4 million or 128.0 percent mainly because these units' offers were impacted by high natural gas prices in January 2014. Credits paid to remaining unit types decreased by $133.4 million.

Table 4-18 Energy uplift credits by unit type: January through September 2013 and 2014

Unit Type	Jan - Sep 2013	Jan - Sep 2014	Change	Percentage Change	Jan - Sep 2013 Share	Jan - Sep 2014 Share
Combined Cycle	$169,185,084	$391,297,533	$222,112,449	131.3%	27.2%	43.3%
Combustion Turbine	$125,151,118	$236,250,566	$111,099,448	88.8%	20.1%	26.2%
Diesel	$6,111,550	$2,820,497	($3,291,053)	(53.8%)	1.0%	0.3%
Hydro	$422,939	$1,478,402	$1,055,464	249.6%	0.1%	0.2%
Nuclear	$126,510	$166,104	$39,594	31.3%	0.0%	0.0%
Steam - Coal	$283,119,807	$154,841,133	($128,278,674)	(45.3%)	45.5%	17.2%
Steam - Other	$28,661,485	$108,876,086	$80,214,601	279.9%	4.6%	12.1%
Wind	$9,993,915	$7,046,546	($2,947,369)	(29.5%)	1.6%	0.8%
Total	$622,772,407	$902,776,866	$280,004,459	45.0%	100.0%	100.0%

Table 4-19 Energy uplift credits by unit type: January through September 2014

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Synchronous Condensing	Black Start Services
Combined Cycle	38.8%	56.6%	0.0%	0.0%	5.6%	4.7%	0.0%	0.0%
Combustion Turbine	14.0%	20.0%	0.5%	67.8%	67.4%	9.4%	99.9%	1.0%
Diesel	0.1%	0.2%	0.0%	0.0%	0.7%	0.7%	0.0%	0.0%
Hydro	0.2%	0.0%	98.5%	0.0%	0.0%	0.0%	0.1%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%
Steam - Coal	43.8%	5.9%	1.0%	29.1%	21.2%	83.8%	0.0%	99.0%
Steam - Others	3.0%	17.2%	0.0%	0.3%	0.2%	1.3%	0.0%	0.0%
Wind	0.0%	0.0%	0.0%	2.8%	4.8%	0.0%	0.0%	0.0%
Total	$87,303,336	$614,703,237	$1,289,016	$1,491,741	$143,861,957	$27,411,831	$103,915	$26,611,834

Table 4-19 shows the distribution of energy uplift credits by category and by unit type in the first nine months of 2014. Combined cycle units received 38.8 percent of the day-ahead generator credits in the first nine months of 2014, 7.8 percentage points lower than the share received in the first nine months of 2013. Combined cycle units received 56.6 percent of the balancing generator credits in the first nine months of 2014, 4.1 percentage points higher than the share received in the first nine months of 2013. Combustion turbines and diesels received 68.2 percent of the lost opportunity cost credits in the first nine months of 2014, 4.3 percentage points lower than the share received in the first nine months of 2013.

Table 4-19 also shows the distribution of reactive service credits, synchronous condensing and black start services credits by unit type. In the first nine months of 2014, coal units received 83.8 percent of all reactive services credits, 1.1 percentage points higher than the share received in the first nine months of 2013. Coal units received 99.0 percent of all black start services credits.

Concentration of Energy Uplift Credits

There continues to be a high level of concentration in the units and companies receiving energy uplift credits. This concentration results from a combination of unit operating characteristics, PJM's persistent need to commit specific units out of merit in particular locations and the fact that the lack of transparency makes it impossible for competition to affect these payments.

The concentration of energy uplift credits is first examined by analyzing the characteristics of the top 10 units receiving energy uplift credits. The focus on the top 10 units is illustrative.

The concentration of energy uplift credits in the top 10 units remains high in the first nine months of 2014. Table 4-20 shows that the top 10 units receiving total energy uplift credits, which make up less than one percent of all units in PJM's footprint, received 35.5 percent of total energy uplift credits in the first nine months of 2014, compared to 34.3 percent in the first nine months of 2013.

Table 4-20 Top 10 energy uplift credits units (By percent of total system): January through September 2013 and 2014

	Top 10 Units Credit Share	Percent of Total PJM Units
Jan - Sep 2013	34.3%	0.7%
Jan - Sep 2014	35.5%	0.7%

Table 4-21 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators.

Table 4-21 Top 10 units and organizations energy uplift credits: January through September 2014

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits	Credits Share	Credits	Credits Share
Day-Ahead	Generators	$47,948,901	54.9%	$76,967,889	88.2%
Balancing	Canceled Resources	$1,289,016	100.0%	$1,289,016	100.0%
	Generators	$301,191,968	49.0%	$540,976,934	88.0%
	Local Constraints Control	$1,204,020	80.7%	$1,482,485	99.4%
	Lost Opportunity Cost	$30,767,824	21.4%	$108,813,149	75.6%
Reactive Services		$20,912,810	76.3%	$27,117,745	98.9%
Synchronous Condensing		$94,367	90.8%	$103,915	100.0%
Black Start Services		$24,201,375	90.9%	$26,604,029	100.0%
Total		$320,622,492	35.5%	$738,339,111	81.8%

Table 4-22 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In the first nine months of 2014, 10.7 percent of all credits paid to these units were allocated to deviations while the remaining 89.3 percent were paid for reliability reasons.

Table 4-22 Identification of balancing operating reserve credits received by the top 10 units by category and region: January through September 2014

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits	$268,824,454	$0	$0	$21,160,806	$11,206,709	$0	$301,191,968
Share	89.3%	0.0%	0.0%	7.0%	3.7%	0.0%	100.0%

In the first nine months of 2014, concentration in all energy uplift credit categories was high.[11] [12] The HHI for energy uplift credits was calculated based on each organization's share of daily credits for each category. Table 4-23 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 4622, for balancing operating reserve credits to generators was 2959, for lost opportunity cost credits was 3838 and for reactive services credits was 6964.

11 See Section 3, "Energy Market" at "Market Concentration" for a complete discussion of concentration ratios and the Herfindahl-Hirshman Index (HHI).
12 Table 4-23 excludes local constraints control categories.

Table 4-23 Daily energy uplift credits HHI: January through September 2014

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	4622	1080	10000	100.0%	28.0%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	10000	10000	10000	100.0%	89.7%
Balancing	Canceled Resources	9217	6054	10000	100.0%	98.5%
	Generators	2959	841	8994	94.8%	24.6%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	10000	10000	10000	100.0%	70.6%
	Lost Opportunity Cost	3838	545	10000	100.0%	18.7%
Reactive Services		6964	2717	10000	100.0%	44.0%
Synchronous Condensing		10000	10000	10000	100.0%	51.2%
Black Start Services		6011	2906	10000	100.0%	99.0%
Total		1525	507	6725	81.7%	17.1%

Economic and Noneconomic Generation[13]

Economic generation includes units scheduled day ahead or producing energy in real time at an incremental offer less than or equal to the LMP at the unit's bus. Noneconomic generation includes units that are scheduled or producing energy at an incremental offer higher than the LMP at the unit's bus. Units are paid day-ahead operating reserve credits based on their scheduled operation for the entire day. Balancing generator operating reserve credits are paid on a segmented basis for each period defined by the greater of the day-ahead schedule and minimum run time. Table 4-24 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 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 hourly no load costs and startup costs. A unit could be noneconomic for an hour or multiple hours and not receive operating reserve credits whenever the total energy revenues covered the total offer (including no load and startup costs) for the entire day or segment. In the first nine months of 2014, 36.9 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 34.9 percent of the real-time generation was eligible for balancing operating reserve credits.[14]

Table 4-24 Day-ahead and real-time generation (GWh): January through September 2014

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percentage
Day-Ahead	631,615	233,181	36.9%
Real-Time	614,864	214,845	34.9%

Table 4-25 shows PJM's economic and noneconomic generation by hour eligible for operating reserve credits. In the first nine months of 2014, 87.5 percent of the day-ahead generation eligible for operating reserve credits was economic and 72.7 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 4-25 shows the separate amounts of economic and noneconomic generation even if the daily generation was economic.

13 The analysis of economic and noneconomic generation is based on units' incremental offers, the value used by PJM to calculate LMP. The analysis does not include no load or startup costs.

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.

Table 4-25 Day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits (GWh): January through September 2014

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percentage	Noneconomic Generation Percentage
Day-Ahead	203,928	29,253	87.5%	12.5%
Real-Time	156,087	58,758	72.7%	27.3%

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 4-26 shows the generation receiving day-ahead and balancing operating reserve credits. In the first nine months of 2014, 6.4 percent of the day-ahead generation eligible for operating reserve credits received credits and 5.0 percent of the real-time generation eligible for operating reserve credits was made whole.

Table 4-26 Day-ahead and real-time generation receiving operating reserve credits (GWh): January through September 2014

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percentage
Day-Ahead	233,181	14,966	6.4%
Real-Time	214,845	10,807	5.0%

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 requirements (from automatic load rejection units); local contingencies not modeled in the Day-Ahead Energy Market; and long lead time units not able to be scheduled in the Day-Ahead Energy Market.[15] 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 is not eligible for day-ahead operating reserve credits.[16] Units scheduled as must run by PJM may set LMP if raised above economic minimum and following the dispatch signal and are eligible for day-ahead operating reserve credits. Table 4-27 shows the total day-ahead generation and the subset of that generation scheduled as must run by PJM. In the first nine months of 2014, 4.3 percent of the total day-ahead generation was scheduled as must run by PJM, 0.4 percentage points lower than the first nine months of 2013.

Table 4-27 Day-ahead generation scheduled as must run by PJM (GWh): 2013 and 2014

	2013			2014		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	72,681	2,907	4.0%	81,479	2,627	3.2%
Feb	65,632	2,474	3.8%	70,942	3,404	4.8%
Mar	67,940	3,178	4.7%	72,681	2,894	4.0%
Apr	57,570	2,522	4.4%	60,688	2,825	4.7%
May	61,169	2,848	4.7%	61,919	2,808	4.5%
Jun	68,452	3,724	5.4%	70,230	3,421	4.9%
Jul	78,639	4,395	5.6%	75,606	3,733	4.9%
Aug	73,783	3,678	5.0%	73,003	2,778	3.8%
Sep	64,757	3,162	4.9%	65,066	2,792	4.3%
Oct	62,134	2,940	4.7%			
Nov	63,827	2,675	4.2%			
Dec	73,112	2,612	3.6%			
Total (Jan - Sep)	610,622	28,888	4.7%	631,615	27,284	4.3%
Total	809,695	37,115	4.6%	631,615	27,284	4.3%

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. It is illogical and unnecessary to pay units day-ahead operating reserves because units do not incur any costs to run and any revenue shortfalls are addressed by balancing operating reserve payments.

15 See PJM. "Item 12 - October 2012 MIC DAM Cost Allocation," PJM Presentation to the Market Implementation Committee (October 12, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mic/20121010/20121010-item-12-october-2012-mic-dam-cost-allocation.ashx>.

16 See PJM. "PJM eMkt Users Guide," Section Managing Unit Data (version April 1, 2014) p. 48, <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

Table 4-28 shows the total day-ahead generation scheduled as must run by PJM by category. In the first nine months of 2014, 32.2 percent of the day-ahead generation scheduled as must run by PJM received operating reserve credits, of which, 9.3 percent was generation from units scheduled to provide black start services, 5.5 percent was generation from units scheduled to provide reactive services and 17.4 percent was generation paid normal day-ahead operating reserve credits. The remaining 67.8 percent of the day-ahead generation scheduled as must run by PJM did not need to be made whole.

Table 4-28 Day-ahead generation scheduled as must run by PJM by category (GWh): 2014

	Black Start Services	Reactive Services	Day-Ahead Operating Reserves	Economic	Total
Jan	216	157	232	2,022	2,627
Feb	84	30	428	2,862	3,404
Mar	242	162	325	2,166	2,894
Apr	333	243	442	1,807	2,825
May	235	238	564	1,772	2,808
Jun	251	328	506	2,336	3,421
Jul	374	241	685	2,434	3,733
Aug	395	54	760	1,569	2,778
Sep	404	54	805	1,530	2,792
Oct					
Nov					
Dec					
Total	2,533	1,508	4,747	18,497	27,284
Share	9.3%	5.5%	17.4%	67.8%	100.0%

Total day-ahead operating reserve credits in the first nine months of 2014 were $87.3 million, of which $42.4 million or 48.6 percent was paid to units scheduled as must run by PJM, and not scheduled to provide black start or reactive services.

The MMU recommends that PJM clearly identify and classify all reasons for paying operating reserve credits in the Day-Ahead and the Real-Time Energy Markets and the associated operating reserve charges in order to inform all market participants of the reason for these costs and to help ensure a long term solution to the issue of how to allocate the costs of operating reserves.[17] 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.

Geography of Charges and Credits

Table 4-29 shows the geography of charges and credits in the first nine months of 2014. Table 4-29 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 1.2 percent of all operating reserve charges allocated regionally, and resources in the AECO Control Zone were paid 0.9 percent of the corresponding credits. The AECO Control Zone received less operating reserve credits than operating reserve charges paid and had a 0.8 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 4.5 percent of all operating reserve charges allocated regionally, and resources in the PSEG Control Zone were paid 14.0 percent of the corresponding credits. The PSEG Control Zone received more operating reserve credits than operating reserve charges paid and had a 22.2 percent share of the surplus. The surplus is the sum of the positive entries in the balance column. Table 4-29 also shows that 90.7 percent of all charges were allocated in control zones, 2.1 percent in hubs and aggregates and 7.2 percent in interfaces.

17 The classification could occur via defined logging codes for dispatchers. That would create data that could be analyzed by the MMU and summarized for participants.

Table 4-29 Geography of regional charges and credits: January through September 2014[18]

Location		Charges	Credits	Balance	Shares: Total Charges	Shares: Total Credits	Shares: Deficit	Shares: Surplus
Zones	AECO	$10,311,572	$7,534,342	($2,777,230)	1.2%	0.9%	0.8%	0.0%
	AEP - EKPC	$145,268,987	$39,246,546	($106,022,441)	17.1%	4.6%	29.1%	0.0%
	AP - DLCO	$60,342,035	$20,859,821	($39,482,214)	7.1%	2.5%	10.8%	0.0%
	ATSI	$59,052,889	$20,058,868	($38,994,021)	7.0%	2.4%	10.7%	0.0%
	BGE - Pepco	$66,493,009	$67,792,777	$1,299,768	7.8%	8.0%	0.0%	0.4%
	ComEd - External	$86,713,125	$33,840,006	($52,873,119)	10.2%	4.0%	14.5%	0.0%
	DAY - DEOK	$46,789,616	$3,231,318	($43,558,298)	5.5%	0.4%	12.0%	0.0%
	Dominion	$88,623,349	$126,076,408	$37,453,058	10.5%	14.9%	0.0%	10.3%
	DPL	$21,476,433	$48,933,566	$27,457,132	2.5%	5.8%	0.0%	7.5%
	JCPL	$21,292,610	$66,357,541	$45,064,931	2.5%	7.8%	0.0%	12.4%
	Met-Ed	$16,944,325	$62,939,675	$45,995,350	2.0%	7.4%	0.0%	12.6%
	PECO	$39,153,897	$90,668,156	$51,514,259	4.6%	10.7%	0.0%	14.2%
	PENELEC	$22,013,555	$24,788,998	$2,775,444	2.6%	2.9%	0.0%	0.8%
	PPL	$44,206,812	$115,881,480	$71,674,667	5.2%	13.7%	0.0%	19.7%
	PSEG	$38,295,684	$118,948,044	$80,652,361	4.5%	14.0%	0.0%	22.2%
	RECO	$1,308,514	$0	($1,308,514)	0.2%	0.0%	0.4%	0.0%
	All Zones	$768,286,412	$847,157,546	$78,871,134	90.7%	100.0%	78.3%	100.0%
Hubs and Aggregates	AEP - Dayton	$6,996,096	$0	($6,996,096)	0.8%	0.0%	1.9%	0.0%
	Dominion	$1,427,216	$0	($1,427,216)	0.2%	0.0%	0.4%	0.0%
	Eastern	$248,226	$0	($248,226)	0.0%	0.0%	0.1%	0.0%
	New Jersey	$602,076	$0	($602,076)	0.1%	0.0%	0.2%	0.0%
	Ohio	$67,568	$0	($67,568)	0.0%	0.0%	0.0%	0.0%
	Western Interface	$472,299	$0	($472,299)	0.1%	0.0%	0.1%	0.0%
	Western	$8,106,659	$0	($8,106,659)	1.0%	0.0%	2.2%	0.0%
	RTEP B0328 Source	$39	$0	($39)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$17,920,178	$0	($17,920,178)	2.1%	0.0%	4.9%	0.0%
Interfaces	CPLE Imp	$0	$0	($0)	0.0%	0.0%	0.0%	0.0%
	Hudson	$1,656,162	$0	($1,656,162)	0.2%	0.0%	0.5%	0.0%
	IMO	$6,131,342	$0	($6,131,342)	0.7%	0.0%	1.7%	0.0%
	Linden	$1,447,299	$0	($1,447,299)	0.2%	0.0%	0.4%	0.0%
	MISO	$13,248,994	$0	($13,248,994)	1.6%	0.0%	3.6%	0.0%
	Neptune	$2,921,252	$0	($2,921,252)	0.3%	0.0%	0.8%	0.0%
	NIPSCO	$8,080	$0	($8,080)	0.0%	0.0%	0.0%	0.0%
	Northwest	$90,601	$0	($90,601)	0.0%	0.0%	0.0%	0.0%
	NYIS	$10,496,917	$0	($10,496,917)	1.2%	0.0%	2.9%	0.0%
	OVEC	$3,562,980	$0	($3,562,980)	0.4%	0.0%	1.0%	0.0%
	South Exp	$4,323,469	$0	($4,323,469)	0.5%	0.0%	1.2%	0.0%
	South Imp	$17,193,758	$0	($17,193,758)	2.0%	0.0%	4.7%	0.0%
	All Interfaces	$61,080,854	$122,699	($60,958,156)	7.2%	0.0%	16.8%	0.0%
	Total	$847,287,445	$847,280,245	($7,200)	100.0%	100.0%	100.0%	100.0%

18 Zonal information in each zonal table has been aggregated to ensure that market sensitive data is not revealed. Table 4-29 does not include synchronous condensing, local constraint control, black start services and reactive services charges and credits since these are allocated zonally.

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 4-30 shows the geography of reactive services charges. In the first nine months of 2014, 96.9 percent of all reactive service charges were paid by real-time load in the single zone where the service was provided, 0.1 percent were paid by real-time load in multiple zones and 3.0 percent were paid by real-time load across the entire RTO. In the first nine months of 2014, the top three zones accounted for 80.7 percent of all the reactive services charges allocated to single zones.

Table 4-30 Geography of reactive services charges: January through September 2014[19]

Location	Charges	Share of Charges
Single Zone	$26,525,033	96.9%
Multiple Zones	$41,118	0.2%
Entire RTO	$818,614	3.0%
Total	$27,384,764	100.0%

Black start services charges are allocated to zone and non-zone peak transmission use. Resources in one zone accounted for 99.1 percent of all the black start services costs in the first nine months of 2014. 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 four control zones accounted for all synchronous condensing costs in the first nine months of 2014.

Energy Uplift Issues

Lost Opportunity Cost Credits

Balancing operating reserve lost opportunity cost (LOC) credits are paid to units under two scenarios. If a combustion turbine or a diesel is scheduled to operate in the Day-Ahead Energy Market, 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 has to pay. For purposes of this report, this LOC will be referred to as day-ahead LOC.[20] If a unit generating in real time with an offer price lower than the real-time 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 LOC based on the desired output. For purposes of this report, this LOC will be referred as real-time LOC.

In the first nine months of 2014, LOC credits increased by $62.9 million or 77.7 percent compared to the first nine months of 2013. The increase of $62.9 million is comprised of an increase of $39.4 million in day-ahead LOC and an increase of $23.5 million in real-time LOC. Table 4-31 shows the monthly composition of LOC credits in 2013 and the first nine months of 2014. The increase in LOC credits was primarily a result of higher real-time energy prices during hours for which the units had been scheduled day ahead and should have been called in real time but were not and units that were manually dispatched down in order to maintain system reliability during periods of high energy prices. The impact of high real-time energy prices was partially offset by less generation receiving LOC credits in the first nine months of 2014 compared to the first nine months of 2013. In the first nine months of 2014, 22.3 percent of the day-ahead scheduled generation from combustion turbines and diesels was not committed in real time and paid LOC credits, 9.9 percentage points lower than in the first nine months of 2013.

Table 4-31 Monthly lost opportunity cost credits: 2013 and 2014

	2013			2014		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$8,728,322	$2,753,013	$11,481,334	$47,556,189	$29,937,422	$77,493,611
Feb	$2,049,518	$2,681,099	$4,730,617	$6,049,668	$5,417,993	$11,467,661
Mar	$4,803,277	$2,324,036	$7,127,313	$8,763,427	$4,062,970	$12,826,397
Apr	$3,893,268	$1,888,605	$5,781,873	$1,624,650	$1,371,037	$2,995,687
May	$5,266,582	$3,251,673	$8,518,255	$10,480,844	$2,488,722	$12,969,566
Jun	$6,200,721	$826,758	$7,027,479	$7,231,886	$1,152,517	$8,384,403
Jul	$16,300,953	$3,191,321	$19,492,274	$6,273,056	$231,836	$6,504,892
Aug	$5,449,177	$234,782	$5,683,959	$5,232,739	$86,126	$5,318,866
Sep	$6,377,820	$4,753,940	$11,131,760	$5,278,095	$622,780	$5,900,875
Oct	$2,455,137	$630,186	$3,085,323			
Nov	$1,365,945	$778,925	$2,144,870			
Dec	$535,311	$573,134	$1,108,445			
Total (Jan - Sep)	$59,069,637	$21,905,226	$80,974,864	$98,490,554	$45,371,404	$143,861,958
Share (Jan - Sep)	72.9%	27.1%	100.0%	68.5%	31.5%	100.0%
Total	$63,426,030	$23,887,472	$87,313,502	$98,490,554	$45,371,404	$143,861,958
Share	72.6%	27.4%	100.0%	68.5%	31.5%	100.0%

19 PJM and the MMU cannot publish more detailed information about the location of the costs of reactive services, synchronous condensing or certain other ancillary services because of confidentiality requirements. See PJM. Manual 33: Administrative Services for the PJM Interconnection Agreement, Revision 11 (May 29, 2014).

20 A unit's day-ahead financial position equals the revenues from the Day-Ahead Energy Market minus 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 committed in real time incurs balancing spot energy charges since it has to cover its day-ahead scheduled energy position in real time.

Table 4-32 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. Table 4-32 shows that while day-ahead scheduled generation from CTs and diesels increased 826 GWh or 7.5 percent in the first nine months of 2014 compared to the first nine months of 2013, the generation that received LOC credits was reduced by 910 GWh or 25.6 percent.

Table 4-32 Day-ahead generation from combustion turbines and diesels (GWh): 2013 and 2014

	2013			2014		
	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	886	633	561	2,150	846	358
Feb	430	206	173	763	304	153
Mar	809	395	282	976	234	126
Apr	684	325	256	438	170	47
May	1,032	387	260	1,206	617	387
Jun	1,284	696	440	1,363	559	357
Jul	2,951	947	748	1,657	534	370
Aug	1,772	778	544	1,791	637	453
Sep	1,219	480	295	1,550	536	396
Oct	929	451	267			
Nov	578	213	120			
Dec	426	109	49			
Total (Jan - Sep)	11,068	4,846	3,558	11,894	4,437	2,648
Share (Jan - Sep)	100.0%	43.8%	32.2%	100.0%	37.3%	22.3%
Total	13,001	5,620	3,994	11,894	4,437	2,648
Share	100.0%	43.2%	30.7%	100.0%	37.3%	22.3%

In the first nine months of 2014, the top three control zones in which generation received LOC credits, AEP, Dominion and PENELEC, accounted for 56.5 percent of all LOC credits, 44.1 percent of all the day-ahead generation from combustion turbines and diesels, 51.7 percent of all day-ahead generation not committed in real time by PJM from those unit types and 61.2 percent of all day-ahead generation not committed in real time by PJM and receiving LOC credits from those unit types.

Combustion turbines and diesels receive LOC credits on an hourly basis. For example, if a combustion turbine is scheduled day ahead to run from hour 10 to hour 18 and the unit only runs from hour 12 to hour 16, the unit is eligible for LOC credits for hours 10, 11, 17 and 18. Table 4-33 shows the LOC 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 4-33 shows that in the first nine months of 2014, $53.4 million or 54.2 percent of all LOC credits were paid to combustion turbines and diesels that did not run for any hour in real time, 11.5 percentage points lower than the first nine months of 2013.

Table 4-33 Lost opportunity cost credits paid to combustion turbines and diesels by scenario: 2013 and 2014

	2013			2014		
	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	$8,081,096	$647,226	$8,728,322	$21,107,023	$26,449,165	$47,556,189
Feb	$1,860,546	$188,972	$2,049,518	$3,653,270	$2,396,398	$6,049,668
Mar	$2,985,098	$1,818,180	$4,803,277	$3,603,333	$5,160,094	$8,763,427
Apr	$2,476,452	$1,416,816	$3,893,268	$838,032	$786,618	$1,624,650
May	$3,615,804	$1,650,778	$5,266,582	$8,291,781	$2,189,063	$10,480,844
Jun	$4,758,076	$1,442,645	$6,200,721	$5,401,100	$1,830,786	$7,231,886
Jul	$7,462,411	$8,838,541	$16,300,952	$3,819,486	$2,453,570	$6,273,056
Aug	$3,378,510	$2,070,667	$5,449,177	$3,677,848	$1,554,891	$5,232,739
Sep	$4,200,542	$2,177,278	$6,377,820	$3,029,813	$2,248,281	$5,278,095
Oct	$2,167,106	$288,031	$2,455,137			
Nov	$846,109	$519,836	$1,365,945			
Dec	$195,648	$339,663	$535,311			
Total (Jan - Sep)	$38,818,535	$20,251,102	$59,069,637	$53,421,686	$45,068,867	$98,490,553
Share (Jan - Sep)	65.7%	34.3%	100.0%	54.2%	45.8%	100.0%
Total	$42,027,399	$21,398,631	$63,426,030	$53,421,686	$45,068,867	$98,490,553
Share	66.3%	33.7%	100.0%	54.2%	45.8%	100.0%

Table 4-34 Day-ahead generation (GWh) from combustion turbines and diesels receiving lost opportunity cost credits by value: 2013 and 2014[21]

	2013			2014		
	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)
Jan	544	121	664	365	359	725
Feb	171	53	224	134	159	293
Mar	269	144	413	128	105	233
Apr	225	93	318	66	114	180
May	228	129	357	374	198	572
Jun	364	272	635	336	168	504
Jul	713	202	915	334	145	480
Aug	436	275	711	336	281	617
Sep	293	166	459	332	192	524
Oct	256	175	431			
Nov	131	64	195			
Dec	35	59	94			
Total (Jan - Sep)	3,243	1,455	4,697	2,405	1,721	4,127
Share (Jan - Sep)	69.0%	31.0%	100.0%	58.3%	41.7%	100.0%
Total	3,665	1,753	5,418	2,405	1,721	4,127
Share	67.6%	32.4%	100.0%	58.3%	41.7%	100.0%

21 The total generation in Table 4-34 is lower than the day-ahead generation not requested in real time in Table 4-32 because the former only includes generation from units that received lost opportunity costs during at least one hour of the day. Table 4-34 includes all generation, including generation from units that were not committed in real time and did not receive LOC credits.

PJM may not run units in real time if the real-time value of the energy (generation multiplied by the real-time LMP) is lower than the units' total offer (including no load and startup costs). Table 4-34 shows the total day-ahead generation from combustion turbines and diesels that were not committed in real time by PJM and received LOC credits. Table 4-34 shows the scheduled generation that had a total offer (including no load and startup costs) lower than its real-time value (generation multiplied by the real-time LMP), defined here as economic scheduled generation, and the scheduled generation that had a total offer greater than its real-time value or noneconomic scheduled generation. In the first nine months of 2014, 58.3 percent of the scheduled generation not committed by PJM from units receiving LOC credits was economic and the remaining 41.7 percent was noneconomic.

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 can 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.[22]

In the first nine months of 2014, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $26.4 million, and 94.3 percent of these costs was paid by peak transmission use in the AEP Control Zone while the remaining 5.7 percent was paid by non-zone peak transmission use. The calculation of peak transmission use is based on the peak load contribution in the AEP Control Zone. Load in the AEP Control Zone paid an average of $3.99 per MW-day for black start costs related to the noneconomic operation of ALR units. Non-zone peak transmission use is based on reserved capacity for firm and non-firm transmission service. Point-to-point customers paid an average of $0.02 per MW of reserved capacity for black start costs related to the noneconomic operation of ALR units.

PJM and AEP have issued two requests for proposals (RFP) seeking additional black start capability for the AEP Control Zone. PJM awarded all viable solutions from the last RFP.[23] PJM also approved new rules concerning black start service procurement. Resources selected through the new process are expected to provide black start service as of April 1, 2015.[24,25]

Reactive / Voltage Support Units

Closed Loop Interfaces

In 2013, PJM began to develop solutions to improve the incorporation of reactive constraints into energy prices. One of PJM's solutions was to create interfaces that could be used in such a way that units needed for reactive support could set the energy price. PJM also plans to use closed loop interfaces to set the real-time LMP with emergency DR resources and PJM has done so. These closed loop interfaces would be used to model the transfer capability into a specific area. Areas or regions are defined in PJM by hubs, aggregates or control zones, all comprised of buses. Closed loop interfaces are not defined by buses, but defined by the transmission facilities that connect the buses inside of the loop with the rest of PJM. Table 4-35 shows the closed loop interfaces that PJM has defined.

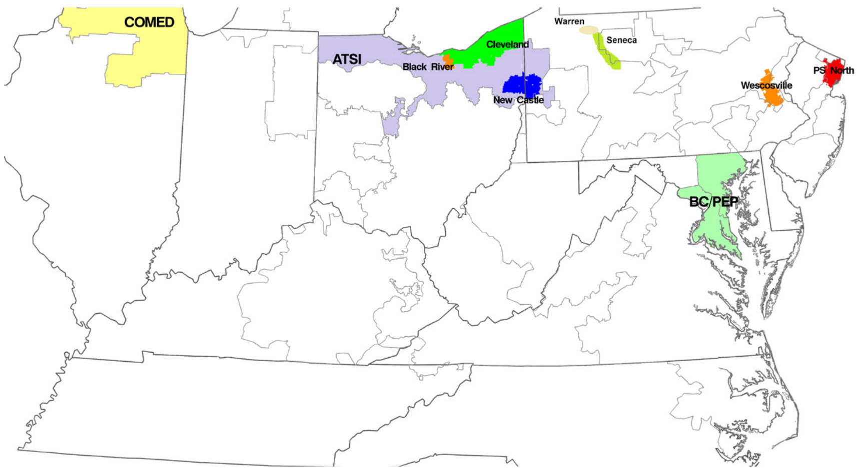
Table 4-35 PJM Closed Loop Interfaces[26,27,28]

Interface	Control Zone(s)	Objective
ATSI	ATSI	Allow emergency DR resources set real-time LMP
BC/PEPCO	BGE and Pepco	Reactive Interface (not an IROL). Used to model import capability into the BGE/PEPCO/Doubs/Northern Virginia area
Black River	ATSI	Allow emergency DR resources set real-time LMP
Cleveland	ATSI	Reactive Interface (IROL)
ComEd	ComEd	Reactive Interface (IROL)
New Castle	ATSI	Allow emergency DR resources set real-time LMP
PS North	PSEG	Objective not identified. Interface was modeled in 2014/2015 Annual FTR auction
Seneca	PENELEC	Allow unit(s) needed for reactive to set day-ahead and real-time LMP
Warren	PENELEC	Allow unit(s) needed for reactive to set day-ahead and real-time LMP
Wescosville	PPL	Allow emergency DR resources set real-time LMP

22 See PJM Interconnection, L.L.C., Docket No. ER13-481-000 (November 30, 2012).
23 See PJM. "Item 3: Black Start RFP Status," PJM Presentation to the System Restoration Strategy Task Force (June 14, 2013) <http://www.pjm.com/~/media/committees-groups/task-forces/srstf/20130614/20130614-item-03-srstf-bs-rfp-status.ashx>.
24 See the *2013 State of the Market Report for PJM, Volume II,* Section 10, "Ancillary Services" at "Black Start Service".
25 See PJM. Manual 14D: Generator Operational Requirement, Revision 28 (July 1, 2014) at "Section 10: Black Start Generation Procurement."
26 See PJM. Manual 3: Transmission Operations, Revision 45 (June 1, 2014) at "Section 3.8: Transfer Limits (Reactive/Voltage Transfer Limits)," for a description of reactive interfaces.
27 See the ATSI, Black River, New Castle, Seneca, Warren and Wescosville interfaces definitions at <http://www.pjm.com/markets-and-operations/etools/oasis/system-information.aspx>.
28 See the PS North interface definition at <http://www.pjm.com/pub/account/auction-user-info/model-annual/Annual-PJM-interface-definitions-limits.csv>.

Figure 4-6 shows the approximate geographic location of PJM's closed loop interfaces.

Figure 4-6 PJM Closed Loop Interfaces Map



Under the status quo, units scheduled for reactive support are only marginal when they are needed to supply energy above their economic minimum. Under the proposed solution these units could be made marginal even when not needed for energy, by adjusting the limit of the closed loop interface. This would create congestion in the area that can only be relieved by the units providing reactive support inside the loop. The goal is to reduce energy uplift from the noneconomic operation of units needed for reactive support by making these units marginal to the extent possible, hence reducing energy uplift costs.

The MMU has recommended and supports PJM's goal of having dispatcher decisions reflected in transparent market outcomes, preferably LMP, to the maximum extent possible and to minimize the level and rate of energy uplift charges. But part of that goal is to avoid disruption of the way in which the transmission network is modeled. The MMU recommends that PJM be transparent in the formulation of closed loop interfaces with adjustable limits and develop rules to reduce the levels of subjectivity around the creation and implementation of these interfaces. The MMU also recommends that PJM estimate the impact such interfaces could have on additional uplift payments inside closed loops, transmission planning, offer capping, FTR and ARR revenue, ancillary services markets and the capacity market before their implementation to avoid unintended consequences.

The MMU recommends that PJM not use closed loop interfaces to set zonal prices, rather than use nodal prices, to accommodate the inadequacies of the demand side resource capacity product or the inability of the LMP model to fully accommodate reactive issues. Market prices should be a function of market fundamentals and energy market prices should be a function of energy market fundamentals. The MMU recommends that the implementation of closed loop interface constraints be studied carefully sufficiently in advance to identify issues and that closed loop interfaces be implemented only after such analysis, only after significant advance notice to the markets and only if the result is consistent with energy market fundamentals.

AP South / Bedington – Black Oak Reactive Support

Beginning in 2012 and during almost all 2013, a set of units located in the BGE and Pepco control zones were scheduled and committed to provide reactive support to the AP South or the Bedington – Black Oak reactive transfer interfaces. These units were scheduled as must run in the Day-Ahead Energy Market whenever they would not clear the market based on economics and were selected by PJM to provide reactive support.

On December 24, 2013, PJM began to schedule less generation from units in the BGE and Pepco control zones in order to reduce energy uplift costs associated with the reactive support provided by these units to the 500 KV transmission lines that comprise the AP South and Bedington – Black Oak reactive transfer interfaces.[29] At the same time, PJM restarted modeling the BC/PEPCO reactive transfer interface in the Day-Ahead and Real-Time Energy

29 See PJM "Reactive Charges Update," PJM Presentation at the Market Implementation Committee (January 8, 2014) <http://www.pjm.com/committees-and-groups/committees/mic.aspx>.

Markets and reduced FMU adders to reactive units.[30] These actions eliminated energy uplift costs for the noneconomic operation of units providing reactive support to the AP South or the Bedington – Black Oak reactive transfer interfaces after December 24, 2013.

In the first nine months of 2014, the total scheduled generation from these units increased by 3,459 GWh or 31.2 percent when compared to the first nine months of 2013. Energy uplift credits in the Day-Ahead Energy Market paid to these units decreased 66.6 percent compared to the amount paid in the first nine months of 2013. These units were more economic in the first nine months of 2014 primarily as a result of higher LMPs in the first nine months of 2014.[31] The weighted average day-ahead LMP at these units' buses in the first nine months of 2014 was $87.69 per MWh, $38.98 per MWh higher than the average in the first nine months of 2013. Reduced FMU adders for these reactive units also significantly reduced the offers and energy uplift credits of these units.

Confidentiality of Energy Uplift Information

All data posted publicly by PJM or the MMU must comply with confidentiality rules. Current confidentiality rules do not appear to allow posting data for three or fewer PJM participants and cannot be aggregated in a geographic area smaller than a control zone.[32]

Energy uplift charges are out of market, non-transparent payments made to resources operating at PJM's direction. Energy uplift 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 participants to compete with the resources receiving energy uplift payments. Uplift charges are not included in the transmission planning process meaning that transmission solutions are not considered. The confidentiality rules were implemented in order to protect competition. The application of confidentiality rules in the case of energy uplift information does exactly the opposite. Energy uplift is not a market and the absence of relevant information creates a barrier to entry. The MMU recommends that PJM revise the current energy uplift confidentiality rules in order to allow the disclosure of energy uplift credits by zone, by owner and by resource.

30 In 2012, the BC/PEPCO Interface was modeled in the Day-Ahead Energy Market starting on August 22, 2012. In 2013, the interface was stopped being modeled on September 25, 2013 and was resumed on December 27, 2013. In real time the interface was only modeled twice in 2012 and once in 2013 (before December 24). After December 24, 2013, the interface was modeled every day.

31 See Section 3, "Energy Market" at "Prices" for the components of the day-ahead and real-time LMP and their contribution in the first nine months of 2014 and the first nine months of 2013.

32 See "Manual 33 Administrative Services for the PJM Interconnection Operating Agreement," Revision 11 (May 29, 2014), Market Data Posting.

Energy Uplift Recommendations

Credits Recommendations

Day-Ahead Operating Reserve Elimination

The only reason to pay energy uplift in the Day-Ahead Energy Market is that a day-ahead schedule could cause a unit to incur losses as a result of differences between the Day-Ahead and Balancing Markets. Units cannot incur losses in the Day-Ahead Energy Market. There is no reason to pay energy uplift in the Day-Ahead Energy Market. All energy uplift should be paid in real time including energy uplift that results from differences between day-ahead and real-time schedules. Paying energy uplift in the Day-Ahead Energy Market results in overpayments.

Day-ahead operating reserve credits are paid to market participants under specific conditions in order to ensure that units are not scheduled in the Day-Ahead Energy Market by PJM to operate at a loss in real time. Balancing operating reserve credits are paid to market participants under specific conditions in order to ensure that units are not operated by PJM at a loss in real time. Units are paid day-ahead operating reserve credits whenever their total offer (including no load and startup costs and based on their day-ahead scheduled output) is not covered by the day-ahead energy revenues (day-ahead LMP times day-ahead scheduled output). Units are paid balancing operating reserve credits whenever their total offer (including no load and startup costs and based on their real-time output) are not covered by their day-ahead energy revenues, balancing energy revenues and a subset of net ancillary services revenues.[33]

Units scheduled in the Day-Ahead Energy Market do not operate until committed or dispatched in real time. Therefore, it cannot be determined if a unit was operated at a loss or not until the unit actually operates. The current operating reserve rules governing the day-ahead operating reserve credits assume that units are going to operate exactly as scheduled because they are made whole based on their day-ahead scheduled output. A unit's real-time output may be greater or lower than their day-ahead scheduled output. Units dispatched in real time by PJM above their day-ahead scheduled output could be paid energy uplift in the form of balancing operating reserve credits if by increasing their output they operate at a loss because their offers are greater than the real-time LMP. Units dispatched in real time by PJM below their day-ahead scheduled output could be paid energy uplift in the form of balancing operating reserve credits if by decreasing their output the units operate at a loss or incur opportunity costs because real-time LMP is greater than the day-ahead LMP. The balancing operating reserve credits and lost opportunity costs credits ensure that units recover their total offers or keep their profits in real time.

Units scheduled in the Day-Ahead Energy Market that receive day-ahead operating reserve credits and for which real-time operation results in additional losses, are paid energy uplift in the form of balancing operating reserve or lost opportunity cost credits to ensure that they do not operate at a loss. This determination is not symmetrical because units scheduled in the Day-Ahead Energy Market that receive day-ahead operating reserve credits and for which real-time operation results in reduced losses or not loss do not have a reduction in energy uplift payments.

Units that follow PJM dispatch instructions are made whole through operating reserve credits to ensure that they do not operate at a loss. In order to determine if a unit operated at a loss, it needs to be committed or dispatched. The day-ahead scheduled output is one of PJM's dispatch instructions, but it does not determine if a unit actually operated at a loss. In order to determine if a unit operated at a loss it is necessary to take into account the unit's real-time output and both the day-ahead and balancing energy revenues and ancillary services net revenues.

In order to properly compensate units the MMU recommended enhancing the day-ahead operating reserve credits calculation in order to ensure that units receive an energy uplift payment based on their real-time output and not their day-ahead scheduled output whenever their real time operation results in a lower loss or no loss at all. The MMU also recommended including net DASR revenues as part of the offsets used in determining day-ahead operating reserve credits.[34] These recommendations are superseded by the MMU's recommendation to eliminate day-ahead operating reserve payments.[35] The elimination of the day-ahead operating reserve category also ensures that units are always made whole based on their actual operation and actual revenues. The MMU supports the PJM proposal of eliminating the day-ahead operating reserve category.

The MMU calculated the impact of this recommendation in 2013 and the first nine months of 2014. In 2013 and the first nine months of 2014, energy uplift costs associated with units scheduled in the Day-Ahead Energy Market would have had been reduced by $95.7 million or 14.0 percent ($10.3 million paid to units providing reactive support, $15.2 million paid to units providing black start support and $70.2 million paid to units as day-ahead and balancing operating reserves).

The elimination of the day-ahead operating reserve category would change the allocation of such charges under the current energy uplift rules. Under the current rules the charges categorized as day-ahead operating reserve charges would be allocated to deviations or real-time load plus real-time exports depending on the balancing operating reserve allocation rules.

33 The balancing operating reserve credit calculation includes net DASR revenues, net synchronized reserve revenues, net non-synchronized reserve revenues and reactive services revenues.

34 See *2013 State of the Market Report for PJM, Volume II* Section 4, "Energy Uplift," at "Day-Operating Reserve Credits," and at "Net DASR Revenues Offset" for an explanation of these recommendations.

35 PJM agrees with this recommendation. See "Explanation of PJM Proposals," from the Energy Market Uplift Senior Task Force (April 8, 2014). <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20140408/20140408-explanation-of-pjm-proposals.ashx>.

Net Regulation Revenues Offset

On October 1, 2008, PJM filed revisions to the Operating Agreement and Tariff with FERC related to the Regulation Market. The filing included four elements: implement the TPS test in the regulation market; increase the regulation offer adder from $7.50 per MW to $12.00 per MW; eliminate the use of net regulation revenues as an offset in the balancing operating reserve calculation; and calculate the lost opportunity cost on the lower of a unit's price-based or cost-based offer.

The elimination of the use of net regulation revenues as an offset in the balancing operating reserve calculation had a direct impact on the level of energy uplift paid to participants that regulate while operating noneconomic. The result of not using the net regulation revenues as an offset in the balancing operating reserve credit calculation is that PJM does not accurately calculate whether a unit is running at a loss. PJM procures energy, regulation, synchronized and non-synchronized reserves in a jointly optimized manner. PJM determines the mix of resources that could provide all of those services in a least-cost manner. Excluding the net regulation revenues from the balancing operating reserve credit calculation is inconsistent with the process used by PJM to procure these services.

Another issue related to this exclusion is the treatment of pool-scheduled units that elect to self-schedule a portion of their capacity for regulation. A unit can be pool-scheduled for energy, which means PJM may commit or dispatch the unit based on economics, but it can also self-schedule some of its capacity for regulation. When this happens the capacity self-scheduled for regulation is treated as a price-taker, but in the Energy Market any increase in MW to provide regulation are treated as additional costs, which can result in increased balancing operating reserve credits whenever the real-time LMP is lower than the unit's offer. For example, if a unit raises its economic minimum in order to provide regulation, the result is increased energy uplift.

The MMU recommends reincorporating the use of net regulation revenues as an offset in the calculation of balancing operating reserve credits. In 2013 and the first nine months of 2014, using net regulation revenues as an offset in the balancing operating reserve calculation would have resulted in a net decrease of balancing operating reserve charges of $22.7 million, of which $18.4 million or 81.2 percent was due to generators that elected to self-schedule for regulation while being noneconomic and receiving balancing operating reserve credits.[36]

Self Start

Participants may offer their units as pool-scheduled (economic) or self-scheduled (must run).[37] Units offered as pool-scheduled clear the Day-Ahead Energy Market based on their offers and operate in real time following PJM dispatch instructions. Units offered as self-scheduled are price takers in both the Day-Ahead and Real-Time Energy Markets unless self-scheduled units elect to submit a fixed energy amount per hour or a minimum must run amount from which the unit may be dispatched up but not down. Self-scheduled units are not eligible to receive day-ahead or balancing operating reserve credits. The current rules determine if a unit is pool-scheduled or self-scheduled for operating reserve credits purposes using the hourly commitment status flag. If the flag is set as economic the unit is assumed to be pool-scheduled, if the flag is set as must run the unit is assumed to be self-scheduled. When a unit submits different flags within a day, the day-ahead operating reserve credit calculation treats each group of hours separately. The day-ahead operating reserve credit calculation only uses the hours flagged as economic and excludes any hours flagged as must run.

In some cases, units offered as self-scheduled for some hours of the day and pool-scheduled for the remaining hours are made whole for startup cost. The MMU recommends that self-scheduled units not be paid energy uplift for their startup cost when the units are scheduled by PJM to start before the self-scheduled hours.

36 These estimates take into account the elimination of the day-ahead operating reserve category.
37 See "PJM eMkt Users Guide," Section Managing Unit Data (version April 1, 2014) p. 48. <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

Lost Opportunity Cost Calculation

The current energy LOC calculations are inaccurate and create unreasonable compensation. The MMU recommends four modifications.[38]

- **Unit Schedule Used:** Current rules require the use of the higher of a unit's price-based and cost-based schedules to calculate the LOC in the energy market. The MMU recommends that the LOC in the energy and ancillary services markets be calculated using the schedule on which the unit was scheduled to run in the energy market. This recommendation was proposed at the MIC.
- **No load and startup costs:** Current rules do not include in the calculation of LOC 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 committed 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 LOC credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. This recommendation was proposed at the MIC.
- **Day-Ahead LMP:** Current rules require the use of the day-ahead LMP as part of the LOC 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 LOC 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 if necessary. If the unit is not committed in real time, it should receive only the difference between real-time LMP and the unit's offer, which is the actual LOC. The MMU recommends eliminating the use of the day-ahead LMP to calculate LOC credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed 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 LOC in the PJM Energy Markets for units scheduled in day ahead but which are reduced, suspended or not committed 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 LOC 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 LOC 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 LOC.

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 4-36 shows the impact that each of these changes would have had on the LOC credits in the Energy Market in the first nine months of 2014, for the two categories of lost opportunity cost credits. Energy LOC credits would have been reduced by a net of $20.4 million, or 14.2 percent, if all these changes had been implemented.[39]

38 See "LOC Session MA Energy LOC Proposal," MMU Presentation to the Market Implementation Committee (October 19, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mic/20121019/20121019-loc-session-ma-energy-loc-proposal.ashx>.

39 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 4-36 Impact on energy market lost opportunity cost credits of rule changes: January through September 2014

	LOC When Output Reduced in RT	LOC When Scheduled DA Not Called RT	Total
Current Credits	$45,371,404	$98,490,553	$143,861,957
Impact 1: Committed Schedule	$1,082,561	$10,978,109	$12,060,671
Impact 2: Eliminating DA LMP	NA	($2,838,266)	($2,838,266)
Impact 3: Using Offer Curve	($1,411,862)	$6,855,396	$5,443,534
Impact 4: Including No Load Cost	NA	($26,102,603)	($26,102,603)
Impact 5: Including Startup Cost	NA	($9,013,034)	($9,013,034)
Net Impact	($329,301)	($20,120,397)	($20,449,698)
Credits After Changes	$45,042,103	$78,370,157	$123,412,259

Allocation Recommendations

Up-to Congestion Transactions

Up-to congestion transactions do not pay energy uplift charges. An up-to congestion transaction affects unit commitment and dispatch in the same way that increment offers and decrement bids affect unit commitment and dispatch in the Day-Ahead Energy Market. All such virtual transactions affect the results of the Day-Ahead Energy Market and contribute to energy uplift costs. Up-to congestion transactions are currently receiving preferential treatment, relative to increment offers and decrement bids and other transactions because they are not charged energy uplift.

The MMU calculated the impact on energy uplift rates if up-to congestion transactions had paid energy uplift charges based on deviations in the same way that increment offers and decrement bids do along with other recommendations that impact the total costs of energy uplift and its allocation.

The MMU recommends that up-to congestion transactions be required to pay energy uplift charges. Up-to congestion transactions would have paid an average rate between $0.241 and $0.993 per MWh in 2013 and between $0.566 and $0.647 per MWh in the first nine months of 2014 if the MMU's recommendations regarding energy uplift had been in place.[40,41]

Internal Bilateral Transactions

Market participants are allocated a portion of the costs of balancing 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.[42] Load, interchange transactions, internal bilateral transactions, demand resources, 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 the generators have the same electrical impact on the transmission system. Load, interchange transactions, internal bilateral transactions, demand resources, 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.[43] 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

40 The range of operating reserve rates paid by up-to congestion transactions depends on the location of the transactions' source and sink.
41 This analysis assumes that not all costs associated with units providing support to the Con Edison – PJM Transmission Service Agreements would be reallocated under the MMU's proposal. The *2013 State of the Market Report for PJM* analysis assumed that all such costs would be reallocated. This analysis also assumes that only 50 percent of all cleared up-to congestion transactions would have cleared had this recommendation been in place. The *2013 State of the Market Report for PJM* analysis showed that more than 66.7 percent of up-to congestion transactions would have remained under the MMU proposal.
42 See OATT 3.2.3 (o) for a complete description of how generators deviate.
43 Locations can be control zones, hubs, aggregates and interfaces. See the *2013 State of the Market Report for PJM, Volume II*, Section 4, "Energy Uplift" at "Energy Uplift" pp. 124-129 for a description of balancing operating reserve locations.

not set energy prices and do not impact the energy flows in either the Day-Ahead or the Real-Time Energy Market, and thus IBTs should not be considered in the allocation of balancing operating reserve charges. The use of IBTs has been extended to offset deviations from other transactions that do impact the energy market. 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.

Con Edison – PJM Transmission Service Agreements Support

It appears that certain units located near the boundary between New Jersey and New York City are frequently operated to support the transmission service agreements between Con Ed and PJM, formerly known as the Con Ed – PSEG Wheeling Contracts.[44] These units are often run out of merit and receive substantial day-ahead and 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 Services Credits and Balancing Operating Reserve Credits

Energy uplift credits to resources providing reactive services are separate from balancing operating reserve credits.[45] Under the current rules regarding energy uplift credits for reactive services, 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 services credits do not cover a unit's entire offer, the unit is made whole the balance through balancing operating reserves. The result is a misallocation of the costs of providing reactive services. Reactive services credits are paid by real-time load in the control zone or zones where the service is provided while balancing operating reserve charges are paid by deviations from day-ahead or real-time load plus exports in the RTO, Eastern or Western Region depending on the allocation process rather than by zone.

In the first nine months of 2014, units providing reactive services were paid $2.0 million in balancing operating reserve credits in order to cover their total energy offer. In 2013, this misallocation was $7.2 million, for a total of $9.2 million in the last year and six months.

The MMU recommends that reactive services credits be calculated consistent with the balancing operating reserve credit calculation. The MMU also recommends including real-time exports and real-time wheels in the allocation of the cost of providing reactive support to the 500 kV system or above. Currently only real-time RTO load pays.[46]

Allocation Proposal

The day-ahead operating reserve category elimination and other MMU recommendations require enhancements to the current energy uplift allocation methodology.

The current methodology allocates day-ahead operating reserve charges to day-ahead load, day-ahead exports and decrement bids. The elimination of the day-ahead operating reserve category shifts these costs to the balancing operating reserve category which could be paid by deviations or by real-time load plus real-time exports depending on the balancing operating reserve allocation rules. The MMU recommends creating a new category for energy uplift payments to units scheduled in the Day-Ahead Energy Market (for reasons other than reactive or black start services), which would be allocated to day-ahead load, day-ahead interchange transactions and virtual transactions. All these transaction types have an impact on the outcome of the day-ahead

44 See the *2013 State of the Market Report for PJM, Volume II*, Section 9, "Interchange Transactions" at "Con Edison and PSE&G Wheeling Contracts" for a description of the contracts.
45 OATT Attachment K - Appendix § 3.2.3B (f).
46 See the Day-Ahead Reliability and Reactive Cost Allocation Final Report (December 13, 2013) for a complete description of the issues discussed in that group. <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20131220/20131220-item-02b-darrca-final-report.ashx>.

scheduling process, so allocating these costs to all day-ahead transactions ensures that all transactions that affect the way the Day-Ahead Energy Market clears are responsible for any energy uplift credits paid to the units scheduled in the Day-Ahead Energy Market.

The MMU recommends allocating energy uplift payments to units not scheduled in the Day-Ahead Energy Market and committed in real time based on the current deviation categories with the addition of up-to congestion and wheeling transactions and the exclusion of offsets based on internal bilateral transactions. These costs should be allocated to the current deviation categories whenever the units receiving energy uplift payments are committed before the operating day.

The MMU recommends changing the allocation of lost opportunity cost and canceled resources. LOC paid to units scheduled in the Day-Ahead Energy Market and not committed in real-time should be allocated to deviations based on the proposed definition of deviations. LOC paid to units reduced for reliability in real time and payments to canceled resources should be allocated to physical deviations.

The MMU recommends allocating energy uplift payments to units committed during the operating day (CTs) to a new deviation category which would include physical transactions or resources (day-ahead minus real-time load, day-ahead minus real-time interchange transactions, generators and DR not following dispatch). This allocation would ensure that commitment changes that occur during the operating day and that result in energy uplift payments are paid by transactions or resources that result in the commitment of units during the operating day. For example, real-time load or interchange transactions that do not bid in the Day-Ahead Energy Market, generators and DR resources that do not follow dispatch would be allocated these costs. Any reliability commitment should be allocated to real-time load plus real-time exports independently of the timing of the commitment.

Table 4-37 shows the current allocation by energy uplift reason. For example, energy uplift payments to units scheduled in the Day-Ahead Energy Market are called day-ahead operating reserves, these costs are paid by day-ahead load, day-ahead exports and decrement bids. Any additional payment resulting from the real time operation of these units are called balancing operating reserves, these costs are paid by either deviations or real-time load and real-time exports depending on the amount of intervals the units are economic.

Table 4-37 Current energy uplift allocation

Reason	Energy Uplift Category	Allocation Logic	Allocation
Units scheduled in the Day-Ahead Energy Market	Day-Ahead Operating Reserve	NA	Day-Ahead Load, Day-Ahead Exports and Decrement Bids
Units scheduled in the Day-Ahead Energy Market	Balancing Operating Reserve	LMP < Offer for at least four intervals	Real-Time Load and Real-Time Exports
		LMP > Offer for at least four intervals	Deviations
Unit Not Scheduled Day Ahead and Committed in Real Time	Balancing Operating Reserve	Committed before the operating day for reliability	Real-Time Load and Real-Time Exports
		Committed before the operating day to meet forecasted load and reserves	Deviations
		Committed during the operating day and LMP < Offer for at least four intervals	Real-Time Load and Real-Time Exports
		Committed during the operating day and LMP > Offer for at least four intervals	Deviations
Units scheduled in the Day-Ahead Energy Market not committed in real time	LOC Credit	NA	Deviations
Units reduced for reliability in real time	LOC Credit	NA	Deviations
Units canceled before coming online	Cancellation Credit	NA	Deviations

Table 4-38 shows the MMU allocation proposal by energy uplift reason. The proposal eliminates the day-ahead operating reserve category and creates a new category for any energy uplift payments to units scheduled in the Day-Ahead Energy Market and committed in real time. This new category would be allocated to day-ahead load, day-ahead interchange transactions and virtual transactions. The proposal also eliminates the need to determine the number of intervals that units are economic to determine if the energy uplift charge should be allocated to deviations or to real-time load and real-time exports. In the proposal, any commitment instruction before the operating day would be allocated based on the proposed definition of deviations; any commitment instruction during the operating day would be allocated to physical deviations.

Table 4-39 shows the energy uplift cost of a 1 MW transaction if these recommendations had been implemented in 2013 and the first nine months of 2014. For example, a decrement bid in the Eastern Region (if not offset by other transactions) would have paid an average rate of $0.497 and $0.324 per MWh in the 2013 and the first nine months of 2014, $2.893 and $2.632 per MWh less than the actual average rate paid. Up-to congestion transactions sourced in the Eastern Region and sinking in the Western Region would have paid an average rate of $0.617 and $0.607 per MWh in 2013 and the first nine months of 2014. Table 4-39 shows the current and proposed averages energy uplift rates for all transactions.

Table 4-38 MMU energy uplift allocation proposal

Reason	Energy Uplift Category	Allocation Logic	Allocation
Units scheduled in the Day-Ahead Energy Market and committed in real time	Day-Ahead Segment Make Whole Credit	NA	Day-Ahead Load, Day-Ahead Interchange Transactions and Virtual Transactions
Units not scheduled in the Day-Ahead Energy Market and committed in real time	Real Time Segment Make Whole Credit	Committed before the operating day	Deviations
		Committed during the operating day	Physical Deviations
		Any commitment for reliability	Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels
Units scheduled in the Day-Ahead Energy Market not committed in real time	Day-Ahead LOC	NA	Deviations
Units reduced for reliability in real time	Real-Time LOC	NA	Physical Deviations
Units canceled before coming online	Cancellation Credit	NA	Physical Deviations

Quantifiable Recommendations Impact

The MMU calculated the rates that participants would have paid in 2013 and the first nine months of 2014 if all the MMU's recommendations on energy uplift had been in place. In order to avoid the release of confidential information, these impacts cannot be disaggregated by issue. These recommendations have been included in the analysis: day-ahead operating reserve elimination; net regulation revenues offset; implementation of the proposed changes to lost opportunity cost calculations; reallocation of operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements; elimination of internal bilateral transactions from the deviations calculation; allocation of energy uplift charges to up-to congestion transactions and the MMU energy uplift allocation proposal.

Table 4-39 Current and proposed average energy uplift rate by transaction: 2013 and January through September 2014[47]

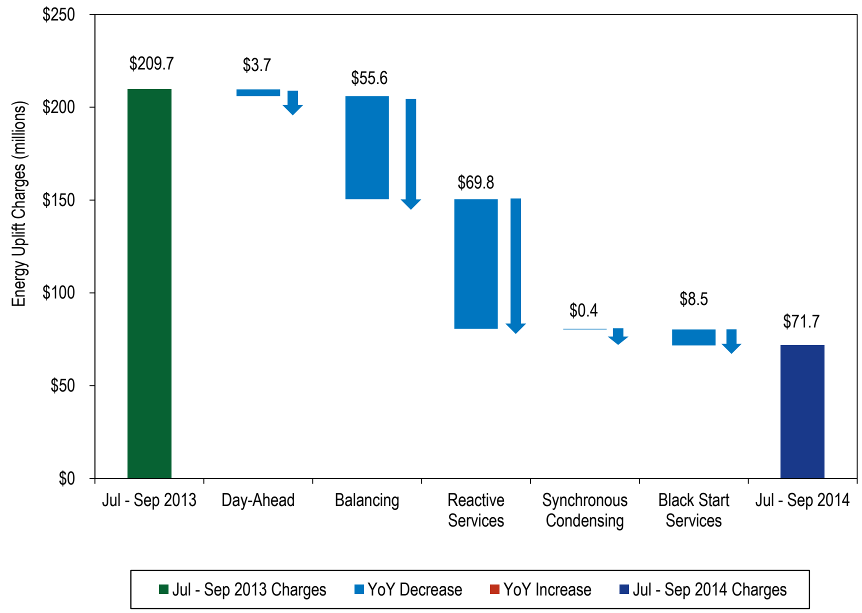
		2013		Jan - Sep 2014	
	Transaction	Current Rates ($/MWh)	Proposed Rates ($/MWh)	Current Rates ($/MWh)	Proposed Rates ($/MWh)
East	INC	3.286	0.497	2.824	0.324
	DEC	3.389	0.497	2.956	0.324
	DA Load	0.103	0.019	0.132	0.061
	RT Load	0.076	0.016	0.592	0.430
	Deviation	3.286	1.403	2.824	2.003
West	INC	1.653	0.120	2.559	0.283
	DEC	1.756	0.120	2.691	0.283
	DA Load	0.103	0.019	0.132	0.061
	RT Load	0.056	0.005	0.579	0.430
	Deviation	1.653	0.836	2.559	1.896
UTC	East to East	NA	0.993	NA	0.647
	West to West	NA	0.241	NA	0.566
	East to/from West	NA	0.617	NA	0.607

July through September 2014 Energy Uplift Charges Decrease

Energy uplift charges increased by $258.8 million (40.2 percent), from $644.2 million in the first nine months of 2013 to $902.9 million in the first nine months of 2014. This increase was highly concentrated in the first three months of 2014. Energy uplift charges increased by $482.9 million (182.5 percent), from $264.5 million in the first three months of 2013 to $747.4 million in the first three months of 2014. Energy uplift charges in the months of July through September decreased by $138.0 million (65.8 percent), from $209.7 million in 2013 to $71.7 million in 2014. This change resulted from a decrease of $69.8 million in reactive services charges, a decrease of $8.5 million in black start services charges, a decrease of $55.6 million in balancing operating reserve charges, a decrease of $3.7 million in day-ahead operating reserve charges and a decrease of $0.4 in synchronous condensing charges.

Figure 4-7 shows the net impact of each category on the change in total energy uplift charges from the July through September 2013 level to the July through September 2014 level. The outside bars show the July through September 2013 total energy uplift charges (left side) and the July through September 2014 total energy uplift charges (right side). The other bars show the change in each energy uplift category. For example, the second bar from the left shows the change in day-ahead operating reserve charges in July through September 2014 compared to July through September 2013 (a decrease of $3.7 million).

Figure 4-7 Energy uplift charges change from July through September 2013 to July through September 2014 by category



The decrease in day-ahead and balancing operating reserve charges was mainly a result of lower summer demand and lower offers from natural gas fired units in the Eastern region that had received substantial day-ahead and balancing operating reserve credits in July through September 2013. The change in the offers in 2014 was a result of lower natural gas prices in the period July through September 2014 when compared to the same period in 2013, which made these units more economic and therefore reduced the need to pay day-ahead and balancing operating reserve credits. Higher energy

47 The deviation transaction means load, interchange transactions, generators and DR deviations.

prices and reduced FMU adders reduced the energy uplift charges for reactive and black start services in July through September 2014 when compared to the same period in 2013. The removal of automatic load rejection black start units from must run black start status contributed to the reduction in the amount of energy uplift paid to units providing black start support.

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 resources and energy efficiency (EE) resources and offer them into the capacity market, or construct transmission upgrades and offer them into the capacity market.

The Market Monitoring Unit (MMU) analyzed market structure, participant conduct and market performance in the PJM Capacity Market for the first nine months of 2014, including supply, demand, concentration ratios, pivotal suppliers, volumes, prices, outage rates and reliability.[1]

Table 5-1 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, the definition of DR which permits inferior products to substitute for capacity, the replacement capacity issue, the inclusion of imports which are not substitutes for internal capacity resources and inadequate performance incentives.

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

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 *2014 Quarterly State of the Market Report for PJM: January through September*, Section 5, "Capacity Market," and include all capacity within the PJM footprint.

5 See 126 FERC ¶ 61,275 (2009) at P 86.

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.[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, although the performance incentives are inadequate. 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 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 first nine months of 2014, PJM installed capacity increased 1,304.8 MW or 0.7 percent from 183,095.2 MW on January 1 to 184,400.0 MW on September 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 September 30, 2014, 40.5 percent was coal; 30.1 percent was gas; 17.8 percent was nuclear; 5.9 percent was oil; 4.8 percent was hydroelectric; 0.4 percent was wind; 0.4 percent was solid waste; and 0.1 percent was solar.
- **Market Concentration.** In the 2015/2016 RPM Second Incremental Auction and 2016/2017 RPM First Incremental Auction, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test.[9] 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.[10,11,12]
- **Imports and Exports.** Of the 324.0 MW of imports offered in the 2015/2016 RPM Second Incremental Auction, 324.0 MW cleared. Of the cleared imports, 323.8 MW (99.9 percent) were from MISO. Of the 210.8 MW of imports in the 2016/2017 RPM First Incremental Auction, 199.8 MW cleared. Of the cleared imports, none were from MISO.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 9,493.6 MW for June 1, 2014 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2014/2015 Delivery Year (16,020.7 MW) less replacement capacity (6,527.1 MW).

Market Conduct

- **2015/2016 RPM Second Incremental Auction.** Of the 80 generation resources which submitted offers, unit-specific offer caps were calculated

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 There are 27 Locational Deliverability Areas (LDAs) identified to recognize locational constraints as defined in "Reliability Assurance Agreement Among Load Serving Entities in the PJM Region", Schedule 10.1. PJM determines, in advance of each BRA, whether the defined LDAs will be modeled in the given Delivery Year using the rules defined in OATT Attachment DD (Reliability Pricing Model) § 5.10(a)(ii).
10 See OATT Attachment DD § 6.5.
11 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.
12 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).

for 16 generation resources (20.0 percent). The MMU calculated offer caps for 25 generation resources (31.3 percent), of which nine were based on the technology specific default (proxy) ACR values.

- **2016/2017 RPM First Incremental Auction.** Of the 115 generation resources which submitted offers, unit-specific offer caps were calculated for 37 generation resources (32.2 percent). The MMU calculated offer caps for 62 generation resources (53.9 percent), of which 25 were based on the technology specific default (proxy) ACR values.

Market Performance

- The 2015/2016 RPM Second Incremental Auction and 2016/2017 RPM First Incremental Auction were conducted in the third quarter of 2014. In the 2015/2016 RPM Second Incremental Auction, the RTO clearing price for Annual Resources was $136.00 per MW-day. The weighted average capacity price for the 2015/2016 Delivery Year is $159.99 per MW-day, including all RPM Auctions for the 2015/2016 Delivery Year held through the first nine months of 2014. In the 2016/2017 RPM First Incremental Auction, the RTO clearing price for Annual Resources was $60.00 per MW-day. The weighted average capacity price for the 2016/2017 Delivery Year is $89.46, including all RPM Auctions for the 2016/2017 Delivery Year held through the first nine months of 2014.
- The Delivery Year weighted average capacity price was $116.55 per MW-day in 2013/2014 and $126.40 per MW-day in 2014/2015.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for the first nine months of 2014 was 9.7 percent, an increase from 8.2 percent for the first nine months of 2013.[13]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for the first nine months of 2014 was 83.1 percent, a decrease from 84.1 percent for the first nine months of 2013.
- **Outages Deemed Outside Management Control (OMC).** In the first nine months of 2014, 7.0 percent of forced outages were classified as OMC outages, and 5.3 percent of OMC outages were due to lack of fuel. 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.

Recommendations[14]

The MMU recommends the enforcement of a consistent definition of capacity resource. The MMU recommends that the requirement to be a physical resource be enforced and enhanced. The requirement to be a physical resource should apply at the time of auctions and should also constitute a commitment to be physical in the relevant Delivery Year. The requirement to be a physical resource should be applied to all resource types, including planned generation, demand resources and imports.[15,16] (Priority: High. First reported 2013.)

- The MMU recommends that the definition of demand side resources be modified in order to ensure that such resources be fully substitutable for other generation capacity resources. Both the Limited and the Extended Summer DR products should be eliminated in order to ensure that the DR product has the same unlimited obligation to provide capacity year round as generation capacity resources. (Priority: High. First reported 2013.)
- The MMU recommends that the use of the 2.5 percent demand adjustment (Short Term Resource Procurement Target) be terminated immediately. The 2.5 percent should be added back to the overall market demand curve. (Priority: Medium. First reported 2013.)
- The MMU recommends that the test for determining modeled Locational Deliverability Areas in RPM be redefined. A detailed reliability analysis

13 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 capacity resources in RPM. Data is for the nine months ending September 30, 2014, as downloaded from the PJM GADS database on October 27, 2014. 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.

14 The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues. These recommendations have been made in public reports. See Table 5-2.

15 See also Comments of the Independent Market Monitor for PJM. Docket No. ER14-503-000 (December 20, 2013).

16 See "Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013," <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf> (September 13, 2013).

of all at risk units should be included in the redefined model. (Priority: Medium. First reported 2013.)

- The MMU recommends that there be an explicit requirement that Capacity Resource offers in the Day-Ahead Energy Market be competitive, where competitive is defined to be the short run marginal cost of the units. (Priority: Low. First reported 2013.)
- The MMU recommends that clear, explicit operational protocols be defined for recalling the energy output of Capacity Resources when PJM is in an emergency condition. PJM has modified these protocols, but they need additional clarification and operational details. (Priority: Low. First reported 2013.)
- The MMU recommends improvements to the performance incentive requirements of RPM:
  - The MMU recommends that Generation Capacity Resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. One hundred percent of capacity market revenue should be at risk rather than only fifty percent. (Priority: High. First reported 2013.)
  - The MMU recommends that a unit which is not capable of supplying energy consistent with its day-ahead offer should reflect an appropriate outage. (Priority: Medium. First reported 2013.)
  - 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. (Priority: Medium. First reported 2013.)
  - The MMU recommends that PJM eliminate the broad exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.[17] (Priority: Medium. First reported 2013.)

17 For more on this issue and related incentive issues, see the MMU'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).

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 nine months of 2014. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive in the first nine months of 2014.[18]

The MMU has identified serious market design issues with RPM and the MMU has made specific recommendations to address those issues.[19,20,21,22,23] In 2013 and 2014, the MMU prepared a number of RPM-related reports and testimony, shown in Table 5-2.

As an example of such reports, the MMU prepared a report that addresses and quantifies the impact on market outcomes in the Base Residual Auction (BRA) for the 2017/2018 Delivery Year of the Short-Term Resource Procurement Target (2.5 percent offset) and demand side resources both separately and together. (Demand side resources include Demand Resources, DR, and Energy Efficiency resources, EE.) The report demonstrates that the limited DR product and the 2.5 percent offset significantly suppress prices.[24]

18 For more complete conclusions, see *2013 State of the Market Report for PJM*, Section 4, "Capacity Market."
19 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).
20 See "Analysis of the 2014/2015 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2012/Analysis_of_2014_2015_RPM_Base_Residual_Auction_20120409.pdf> (April 9, 2012).
21 See "Analysis of the 2015/2016 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2013/Analysis_of_2015_2016_RPM_Base_Residual_Auction_20130924.pdf> (September 24, 2013).
22 See "Analysis of the 2016/2017 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_20162017_RPM_Base_Residual_Auction_20140418.pdf> (April 18, 2014).
23 See "Analysis of the 2017/2018 RPM Base Residual Auction," <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_2017_2018_RPM_Base_Residual_Auction_20141006.pdf> (October 6, 2014).
24 See "The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses Revised," <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_20172018_RPM_BRA_Sensitivity_Analyses_Revised_20140826.pdf> (August 26, 2014).

The MMU continues to recommend that the use of the 2.5 percent demand adjustment be terminated immediately.[25] The 2.5 percent demand reduction is a barrier to entry in the capacity market. The logic of reducing demand in a market design that looks three years forward, to permit other resources to clear in Incremental Auctions, is not supportable and has no basis in economics. There are tradeoffs in using a one year forward or a three year forward design, but the design should be implemented on a consistent basis. Removing a portion of demand affects prices at the margin, which is where the critical signal to the market is determined.

The results of the report show that even when all DR is removed and the 2.5 percent offset is eliminated and holding everything else constant, prices would have risen to greater than net CONE but less than the maximum price and PJM's reliability target would have been maintained. This a measure of the impact of the removal of DR and the 2.5 percent offset and is also a measure of the price suppression effect of DR and the 2.5 percent offset.

The fact that this set of sensitivity analyses holds everything else constant is important for considering the actual impacts of the simultaneous elimination of DR and the 2.5 percent offset. The results of these sensitivity analyses are worst case, in the sense that the increases in prices and reductions in quantities cleared are the maximum levels, because they do not include any market response which would mitigate the impact on prices and cleared quantities of eliminating DR. If both these adjustments had been made prior to the 2017/2018 BRA, it is likely that additional generation resources would have entered the market, that prices would likely have been lower than the prices in these sensitivity analyses and that reliability would have been greater than in these sensitivity analyses.

25 See also the *Protest of the Independent Market Monitor for PJM*, Docket No. ER12-513 (December 22, 2011).

Table 5-2 RPM related MMU reports, 2013 through September, 2014

Date	Name
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
July 23, 2013	Analysis of Replacement Capacity for RPM Commitments http://www.monitoringanalytics.com/reports/Presentations/2013/IMM_MIC_Replacement_Capacity_Activity_Rev_20130723.pdf
August 30, 2013	RPM Unit-Specific Offer Cap Review Process http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Unit-Specific_Offer_Cap_Review_Process_20130830.pdf
September 3, 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_20130903.pdf
September 13, 2013	Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf
September 13, 2013	IMM Answer and Motion for Leave to Answer re RPM BRA Deadline Changes No. ER13-2140 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Answer_and_Motion_for_Leave_to_Answer_ER13-2140_20130913.pdf
September 24, 2013	Analysis of the 2015/2016 RPM Base Residual Auction Report http://www.monitoringanalytics.com/reports/Reports/2013/Analysis_of_2015_2016_RPM_Base_Residual_Auction_20130924.pdf
November 27, 2013	IMM Answer and Motion for Leave to Answer re Forward Capacity Market Comment Clarification No. ER11-4081-001 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Answer_and_Motion_for_Leave_to_Answer_No_ER11-4081-001_20131127.pdf
December 20, 2013	IMM Comments re RPM Import Cap No. ER14-503-000 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Comments_ER14-503-000_20131220.pdf
December 20, 2013	IMM Comments re Limited DR Cap No. ER14-504-000 http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Comments_ER14-504-000_20131220.pdf
December 20, 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_20131220.pdf
January 8, 2014	IMM Comments re Capacity Technical Conference No. AD13-7-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_AD13-7-000_20140109.pdf
January 8, 2014	IMM Answer re Limited DR Cap No. ER14-504-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_ER14-504-000_20140108.pdf
January 8, 2014	IMM Answer re RPM Import Cap No. ER14-503-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_ER14-503-000_20140108.pdf
January 27, 2014	IMM Complaint and Motion to Consolidate re DR Resources Docket No EL14-xxx-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Complaint_and_Motion_to_Consolidate_EL14-xxx_20140127.pdf
January 29, 2014	IMM Motion for Clarification and/or Reconsideration, or, in the Alternative, Rehearing re Make-Whole Waiver Docket No. ER14-1144-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Motion_for_Clarification_or_Reconsideration_or_Rehearing_ER14-1144-000_20140129.pdf
January 29, 2014	IMM Comments re Offer Cap Waiver Docket No. ER14-1145-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_ER14-1145-000_20140129.pdf
February 24, 2014	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_20140224.pdf
March 7, 2014	IMM Comments re January 28 Deficiency Letter Docket No. ER14-503-001 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_ER14-503-001_20140307.pdf
March 11, 2014	IMM Comments re Response to Deficiency Notice Docket Nos. ER14-822-001 and EL14-20-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_and_Motion_for_leave_to_Answer_EL14-20-000_20140311.pdf
March 24, 2014	IMM Comments re Response to Deficiency Notice Docket Nos. ER14-822-001 and EL14-20-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_Docket_Nos._ER14-822-001_EL14-20-000_20140324.pdf
March 26, 2014	IMM Comments re Invenergy Waiver Docket No. ER14-1475-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Brief_EL08-14-010_20140407.pdf
March 26, 2014	Informational Filing re Waiver to Permit Make-Whole Payments Docket No. ER14-1144-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Make_Whole_Waiver_Report_ER14-1144_000_20140326.pdf
April 18, 2014	Analysis of the 2016/2017 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2013/Analysis_of_20162017_RPM_Base_Residual_Auction_20140418.pdf
April 30, 2014	IMM Answer to PJM re RPM Reform Docket No. ER14-1461-000,-001 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_ER14-1461-000-001_20140430.pdf
May 9, 2014	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2015/2016, 2016/2017 and 2017/2018 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20140509.pdf
June 27, 2014	IMM Protest re CPV Maryland CfD Docket No. ER14-2106-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Protest_Docket_No_ER14-2106-000_20140627.pdf
June 27, 2014	IMM Protest re CPV New Jersey SOCA Docket No. ER14-2105-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Protest_Docket_No_ER14-2105-000_20140627.pdf
July 10, 2014	The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses http://www.monitoringanalytics.com/reports/Reports/2014/IMM_20172018_RPM_BRA_Sensitivity_Analyses_20140710.pdf
August 26, 2014	The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses Revised http://www.monitoringanalytics.com/reports/Reports/2014/IMM_20172018_RPM_BRA_Sensitivity_Analyses_Revised_20140826.pdf
August 29, 2014	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2015/2016, 2016/2017 and 2017/2018 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20140829.pdf
September 3, 2014	2017/2018 RPM BRA Sensitivity Analysis http://www.monitoringanalytics.com/reports/Presentations/2014/IMM_MIC_20172018_Sensitivity_Analyses_Revised_20140903.pdf
September 15, 2014	Capacity Performance Product Assumptions http://www.monitoringanalytics.com/reports/Market_Messages/Messages/IMM_ELC_Capacity_Performance_Product_Assumptions_20140915.pdf
September 17, 2014	IMM Comments on PJM's Capacity Performance Proposal and IMM Proposal http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_on_PJM's_Capacity_Performance_Proposal_and_IMM_Proposal_20140917.pdf
October 6, 2014	Analysis of the 2017/2018 RPM Base Residual Auction http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_2017_2018_RPM_Base_Residual_Auction_20141006.pdf

Installed Capacity

On January 1, 2014, PJM installed capacity was 183,095.2 MW (Table 5-3).[26] Over the next nine months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in PJM installed capacity of 184,400.0 MW on September 30, 2014, an increase of 1,304.8 MW or 0.7 percent over the January 1 level.[27,28] The 1,304.8 MW increase was the result of an increase in imports (2,087.3 MW), new or reactivated generation (933.3 MW), capacity modifications (334.0 MW), offset by deactivations (1,569.9 MW), derates (379.5 MW), and an increase in exports (100.4 MW).

At the beginning of the new Delivery Year on June 1, 2014, PJM installed capacity was 184,009.1 MW, an increase of 756.7 MW or 0.4 percent over the May 31 level.

Table 5-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and September 30, 2014

	1-Jan-14		31-May-14		1-Jun-14		30-Sep-14	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	75,544.6	41.3%	75,253.0	41.1%	74,785.5	40.6%	74,709.6	40.5%
Gas	53,395.0	29.2%	53,841.6	29.4%	55,041.7	29.9%	55,428.9	30.1%
Hydroelectric	8,106.7	4.4%	8,135.7	4.4%	8,463.8	4.6%	8,764.6	4.8%
Nuclear	33,076.7	18.1%	33,073.7	18.0%	32,891.0	17.9%	32,891.0	17.8%
Oil	11,314.2	6.2%	11,290.4	6.2%	11,155.7	6.1%	10,931.7	5.9%
Solar	84.2	0.0%	84.2	0.0%	94.7	0.1%	97.5	0.1%
Solid waste	701.4	0.4%	701.4	0.4%	780.0	0.4%	780.0	0.4%
Wind	872.4	0.5%	872.4	0.5%	796.7	0.4%	796.7	0.4%
Total	183,095.2	100.0%	183,252.4	100.0%	184,009.1	100.0%	184,400.0	100.0%

26 Percent values shown in Table 5-3 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

27 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.

28 Wind resources accounted for 796.7 MW of installed capacity in PJM on September 30, 2014. 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.

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.[29] In the third quarter of 2014, a Second Incremental Auction was held in July for the 2015/2016 Delivery Year, and a First Incremental Auction was held in September for the 2016/2017 Delivery Year.

Market Structure

Supply

Table 5-4 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2013/2014 Delivery Year. The 20,349.7 MW increase was the result of new Generation Capacity Resources (6,751.1 MW), reactivated Generation Capacity Resources (430.0 MW), uprates (4,620.9 MW), integration of external zones (18,109.0 MW), a net increase in capacity imports (4,363.6 MW), a net decrease in capacity exports (2,620.3 MW), offset by deactivations (13,854.4 MW) and derates (2,690.8 MW).

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

Table 5-4 Generation capacity changes: 2007/2008 through 2013/2014

	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)
2013/2014	185,567.9	264.7	20.9	397.9	0.0	2,228.9	21.6	4,027.7	421.9	(1,558.8)
2014/2015	184,009.1									
Total		6,751.1	430.0	4,620.9	18,109.0	4,363.6	(2,620.3)	13,854.4	2,690.8	20,349.7

Demand

In the 2015/2016 RPM Second Incremental Auction, 2,692.9 MW cleared of the 10,623.6 MW of participant buy bids, and 49.1 MW cleared of the 736.2 MW of PJM buy bids for the RTO. In the 2016/2017 RPM First Incremental Auction, 5,557.0 MW cleared of the 12,307.8 MW of participant buy bids, and 204.8 MW cleared of the 206.4 MW of PJM buy bids for the RTO. Participant buy bids are submitted to cover commitment and compliance shortfalls or because participants wanted to purchase additional capacity.

Market Concentration

Auction Market Structure

As shown in Table 5-5, all participants in the total PJM market as well as the LDA RPM markets failed the three pivotal supplier (TPS) test in the 2015/2016 RPM Second Incremental Auction and the 2016/2017 RPM First Incremental Auction.[30] 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.[31,32,33]

Table 5-5 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.

30 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.
31 See OATT Attachment DD § 6.5.
32 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.
33 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 5-5 RSI results: 2014/2015 through 2017/2018 RPM Auctions[34]

RPM Markets	$RSI_{1,\,1.05}$	RSI_3	Total Participants	Failed RSI_3 Participants
2014/2015 Base Residual Auction				
RTO	0.76	0.58	93	93
MAAC	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	0.00	0.00	1	1
PSEG North	0.00	0.00	1	1
2014/2015 Second Incremental Auction				
RTO	0.71	0.42	40	40
MAAC	0.40	0.01	4	4
PSEG North	0.00	0.00	1	1
2014/2015 Third Incremental Auction				
RTO	0.56	0.27	53	53
MAAC	0.29	0.17	9	9
PSEG North	0.02	0.00	3	3
2015/2016 Base Residual Auction				
RTO	0.75	0.57	99	99
MAAC	0.49	0.63	12	12
ATSI	0.01	0.00	3	3
2015/2016 First Incremental Auction				
RTO	0.70	0.61	43	43
MAAC	0.15	0.09	5	5
PSEG	0.00	0.00	1	1
ATSI	0.00	0.00	1	1
2015/2016 Second Incremental Auction				
RTO	0.40	0.21	26	26
MAAC	0.00	0.04	4	4
PSEG	0.00	0.00	0	0
ATSI	0.00	0.00	1	1
2016/2017 Base Residual Auction				
RTO	0.78	0.59	110	110
MAAC	0.56	0.38	6	6
PSEG	0.00	0.00	1	1
ATSI	0.00	0.00	1	1
2016/2017 First Incremental Auction				
RTO	0.58	0.16	29	29
MAAC	0.26	0.00	3	3
PSEG	0.00	0.00	1	1
ATSI	0.00	0.00	1	1
2017/2018 Base Residual Auction				
RTO	0.80	0.61	119	119
PSEG	0.00	0.00	1	1

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

Locational Deliverability Areas (LDAs)

Under the PJM Tariff, PJM determines, in advance of each BRA, whether defined Locational Deliverability Areas (LDAs) will be modeled in the auction. Effective with the 2012/2013 Delivery Year, an LDA will be modeled as a potentially constrained LDA for a Delivery Year if the Capacity Emergency Transfer Limit (CETL) is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), such LDA had a locational price adder in one or more of the three immediately preceding BRAs, or such LDA is determined by PJM in a preliminary analysis to be likely to have a locational price adder based on historic offer price levels. The rules also provide that starting with the 2012/2013 Delivery Year, EMAAC, SWMAAC, and MAAC LDAs will be modeled as potentially constrained LDAs regardless of the results of the above three tests.[35] 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."[36] A reliability requirement and a Variable Resource Requirement (VRR) curve are established for each modeled LDA. Effective for the 2014/2015 through 2016/2017 Delivery Years, a Minimum Annual and a Minimum Extended Summer Resource Requirement are established for each modeled LDA. Effective for the 2017/2018 and subsequent Delivery Years, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, are established for each modeled LDA.[37]

Locational Deliverability Areas are shown in Figure 5-1, Figure 5-2 and Figure 5-3.

35 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.
36 OATT Attachment DD § 5.10 (a) (ii).
37 146 FERC ¶ 61,052 (2014).

Figure 5-1 Map of PJM Locational Deliverability Areas

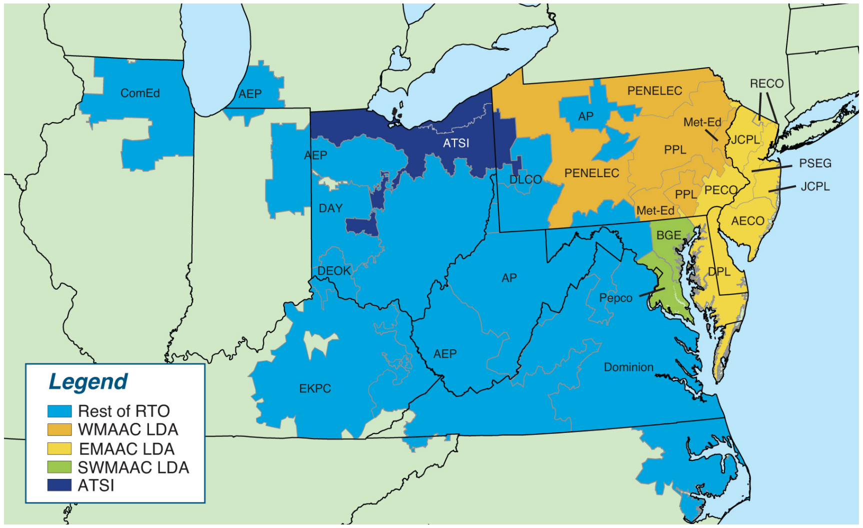


Figure 5-2 Map of PJM RPM EMAAC subzonal LDAs

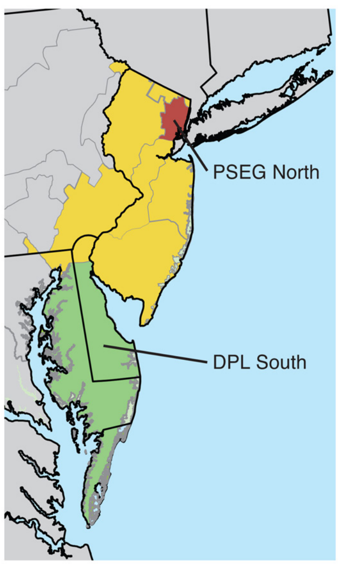
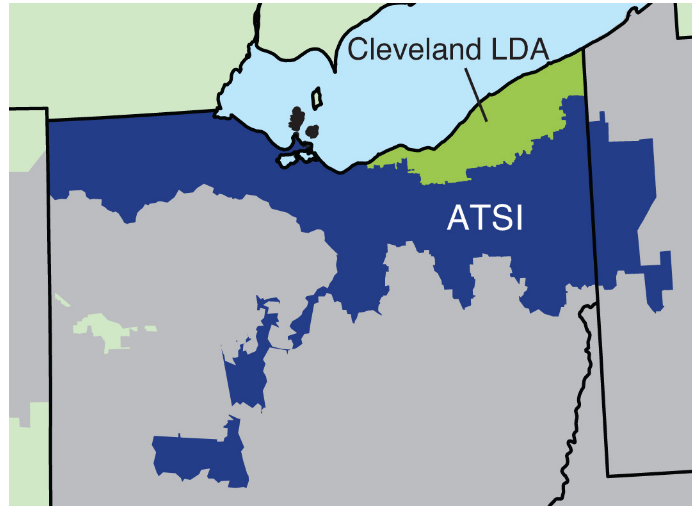


Figure 5-3 Map of PJM RPM ATSI subzonal LDA



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.[38]

The PJM market rules should not create inappropriate barriers to either the import or export of capacity. The market rules in other balancing authorities should also not create inappropriate barriers to the import or export of capacity. The PJM market rules should ensure that the definition of capacity is enforced including physical deliverability, recallability and the obligation to make competitive offers into the PJM Day-Ahead Energy Market. Physical deliverability can only be assured by requiring that all imports are required to have pseudo ties to PJM to ensure that they are full substitutes for internal capacity resources. Selling capacity into the PJM capacity market but making

38 OATT Attachment DD § 5.6.6(b).

energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the Day-Ahead Energy Market should be clarified for both internal and external resources.

As shown in Table 5-6, a total of 4,525.5 MW of imports cleared in the 2017/2018 RPM Base Residual Auction. Of these cleared imports, 2,624.3 MW (58.0 percent) were from MISO.

Table 5-6 RPM imports: 2007/2008 through 2017/2018 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
2017/2018	2,624.3	2,624.3	2,320.4	1,901.2	4,944.7	4,525.5

Demand Resources

As shown in Table 5-7 and Table 5-9, capacity in the RPM load management programs was 9,493.6 MW for June 1, 2014 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2014/2015 Delivery Year (16,020.7 MW) less replacement capacity (6,527.1 MW). Table 5-8 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 5-7 RPM load management statistics by LDA: June 1, 2013 to June 1, 2017[39,40,41]

	UCAP (MW)												
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL
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	14,943.0	7,452.4	2,976.9	2,268.4	220.9	999.5	468.4	920.0					
EE cleared	1,077.7	305.9	45.2	169.8	8.1	24.2	11.9	51.4					
DR net replacements	(6,731.8)	(3,778.7)	(1,651.1)	(1,010.7)	(156.0)	(550.4)	(231.1)	(428.9)					
EE net replacements	204.7	219.5	46.8	148.2	(6.8)	12.7	5.0	68.3					
RPM load management @ 01-Jun-14	9,493.6	4,199.1	1,417.8	1,575.7	66.2	486.0	254.2	610.8					
DR cleared	15,129.9	6,736.2	2,656.7	2,020.9	86.3	797.9	263.5	872.7	1,827.3				
EE cleared	1,015.2	246.1	46.5	159.4	0.0	14.5	4.4	55.8	81.9				
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	16,145.1	6,982.3	2,703.2	2,180.3	86.3	812.4	267.9	928.5	1,909.2				
DR cleared	12,710.5	5,354.2	2,006.5	1,603.6	105.7	630.8	226.7	664.1	1,825.1	470.8			
EE cleared	1,157.3	338.9	70.2	209.3	0.6	21.6	7.5	83.8	198.5	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	13,867.8	5,693.1	2,076.7	1,812.9	106.3	652.4	234.2	747.9	2,023.6	523.4			
DR cleared	10,975.0	4,277.3	1,535.6	1,399.6	86.3	388.4	151.5	608.4	1,020.2	290.1	1,478.1	791.2	686.4
EE cleared	1,338.9	368.5	79.3	227.9	0.8	17.6	3.4	104.2	142.0	35.7	583.3	123.7	35.6
DR net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EE net replacements	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RPM load management @ 01-Jun-17	12,313.9	4,645.8	1,614.9	1,627.5	87.1	406.0	154.9	712.6	1,162.2	325.8	2,061.4	914.9	722.0

39 Effective with 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.

40 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.

41 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 include transactions associated with RTP Controls, Inc. which was declared in collateral default on March 9, 2012.

Table 5-8 RPM load management cleared capacity and ILR: 2007/2008 through 2017/2018[42,43]

	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	14,337.6	14,943.0	1,035.4	1,077.7	0.0	0.0
2015/2016	14,525.2	15,129.9	975.5	1,015.2	0.0	0.0
2016/2017	12,217.9	12,710.5	1,113.9	1,157.3	0.0	0.0
2017/2018	10,551.0	10,975.0	1,288.0	1,338.9	0.0	0.0

Table 5-9 RPM load management statistics: June 1, 2007 to June 1, 2017[44,45]

	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	15,373.0	16,020.7	(6,458.4)	(6,731.8)	196.4	204.7	9,111.0	9,493.6
01-Jun-15	15,500.7	16,145.1	0.0	0.0	0.0	0.0	15,500.7	16,145.1
01-Jun-16	13,331.8	13,867.8	0.0	0.0	0.0	0.0	13,331.8	13,867.8
01-Jun-17	11,839.0	12,313.9	0.0	0.0	0.0	0.0	11,839.0	12,313.9

42 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.

43 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.

44 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.

45 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 included transactions 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.[46,47,48]

Table 5-10 ACR statistics: Auctions conducted in third quarter, 2014

	2015/2016 Second Incremental Auction		2016/2017 First Incremental Auction	
Offer Cap/Mitigation Type	Number of Generation Resources	Percent of Generation Resources Offered	Number of Generation Resources	Percent of Generation Resources Offered
Default ACR	9	11.3%	24	20.9%
ACR data input (APIR)	16	20.0%	32	27.8%
ACR data input (non-APIR)	0	0.0%	4	3.5%
Opportunity cost input	0	0.0%	1	0.9%
Default ACR and opportunity cost	0	0.0%	0	0.0%
Offer cap of 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned uprate and default ACR	0	0.0%	1	0.9%
Uncapped planned uprate and opportunity cost	0	0.0%	0	0.0%
Uncapped planned uprate and price taker	0	0.0%	0	0.0%
Uncapped planned uprate and 1.1 times BRA clearing price elected	NA	NA	NA	NA
Uncapped planned generation resources	3	3.8%	1	0.9%
Price takers	52	65.0%	52	45.2%
Total Generation Capacity Resources offered	80	100.0%	115	100.0%

2015/2016 RPM Second Incremental Auction

As shown in Table 5-10, 80 generation resources submitted offers in the 2015/2016 RPM Second Incremental Auction. Unit-specific offer caps were calculated for 16 generation resources (20.0 percent of all generation resources), of which 16 generation resources included an APIR component. The MMU calculated offer caps for 25 generation resources (31.3 percent), of which nine were based on the technology specific default (proxy) ACR values. Of the 80 generation resources, three Planned Generation Capacity Resources had uncapped offers (3.8 percent), while the remaining 52 generation resources were price takers (65.0 percent). Market power mitigation was applied to the sell offers for three generation resources.

2016/2017 RPM First Incremental Auction

As shown in Table 5-10, 115 generation resources submitted offers in the 2016/2017 RPM First Incremental Auction. Unit-specific offer caps were calculated for 37 generation resources (32.2 percent of all generation resources), of which 32 generation resources included an APIR component. The MMU calculated offer caps for 62 generation resources (53.9 percent), of which 25 were based on the technology specific default (proxy) ACR values. Of the 115 generation resources, one Planned Generation Capacity Resources had uncapped offers (0.9 percent), while the remaining 52 generation resources were price takers (45.2 percent). Market power mitigation was applied to the sell offers for four generation resources.

Market Performance[49]

Figure 5-4 presents cleared MW weighted average capacity market prices on a Delivery Year basis for the entire history of the PJM capacity markets. Table 5-11 shows RPM clearing prices for all RPM Auctions held through the first nine months of 2014.

Figure 5-5 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 nine months of 2014.

Table 5-12 shows RPM revenue by resource type for all RPM Auctions held through the first nine months of 2014 with $3.1 billion for new/repower/reactivated generation resources based on the unforced MW cleared and the resource clearing prices. A resource classified as “new/repower/reactivated” is

46 See OATT Attachment DD § 6.5.
47 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.
48 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).
49 The MMU provides detailed analyses of market performance in reports for each RPM Auction. See <http://www.monitoringanalytics.com/reports/Reports/2014.shtml>.

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.

Table 5-13 shows RPM revenue by calendar year for all RPM Auctions held through the first nine months of 2014.

Table 5-11 Capacity prices: 2007/2008 through 2017/2018 RPM Auctions

		RPM Clearing Price ($ per MW-day)										
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI
2007/2008 BRA		$40.80	$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	$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	$10.00	$223.85	$10.00	$10.00	$10.00	$223.85	
2009/2010 BRA		$102.04	$191.32	$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	$86.00	
2010/2011 BRA		$174.29	$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	$50.00	
2011/2012 BRA		$110.00	$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	$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	$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	$5.00
2012/2013 BRA		$16.46	$133.37	$16.46	$133.37	$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	$20.46
2012/2013 First Incremental Auction		$16.46	$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	$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	$2.51
2013/2014 BRA		$27.73	$226.15	$27.73	$226.15	$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	$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	$10.00	$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	$30.00	$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	$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	$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	$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	$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	$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	$16.56	$410.95	$16.56	$5.54
2014/2015 Second Incremental Auction	Limited	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00
2014/2015 Second Incremental Auction	Extended Summer	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00
2014/2015 Second Incremental Auction	Annual	$25.00	$56.94	$25.00	$56.94	$56.94	$56.94	$56.94	$56.94	$310.00	$56.94	$25.00
2014/2015 Third Incremental Auction	Limited	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51
2014/2015 Third Incremental Auction	Extended Summer	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51
2014/2015 Third Incremental Auction	Annual	$25.51	$132.20	$25.51	$132.20	$132.20	$132.20	$132.20	$132.20	$256.76	$132.20	$25.51
2015/2016 BRA	Limited	$118.54	$150.00	$118.54	$150.00	$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	$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	$167.46	$357.00
2015/2016 First Incremental Auction	Limited	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37

Table 5-11 Capacity prices: 2007/2008 through 2017/2018 RPM Auctions *(continued)*

		RPM Clearing Price ($ per MW-day)										
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI
2015/2016 First Incremental Auction	Extended Summer	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37
2015/2016 First Incremental Auction	Annual	$43.00	$111.00	$43.00	$111.00	$111.00	$111.00	$111.00	$122.95	$122.95	$111.00	$168.37
2015/2016 Second Incremental Auction	Limited	$123.56	$141.12	$123.56	$141.12	$141.12	$141.12	$141.12	$155.02	$155.02	$141.12	$204.10
2015/2016 Second Incremental Auction	Extended Summer	$136.00	$153.56	$136.00	$153.56	$153.56	$153.56	$153.56	$167.46	$167.46	$153.56	$216.54
2015/2016 Second Incremental Auction	Annual	$136.00	$153.56	$136.00	$153.56	$153.56	$153.56	$153.56	$167.46	$167.46	$153.56	$216.54
2016/2017 BRA	Limited	$59.37	$119.13	$59.37	$119.13	$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	$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	$119.13	$219.00	$219.00	$119.13	$114.23
2016/2017 First Incremental Auction	Limited	$53.93	$89.35	$53.93	$89.35	$89.35	$89.35	$89.35	$214.44	$214.44	$89.35	$94.45
2016/2017 First Incremental Auction	Extended Summer	$60.00	$119.13	$60.00	$119.13	$119.13	$119.13	$119.13	$244.22	$244.22	$119.13	$100.52
2016/2017 First Incremental Auction	Annual	$60.00	$119.13	$60.00	$119.13	$119.13	$119.13	$119.13	$244.22	$244.22	$119.13	$100.52
2017/2018 BRA	Limited	$106.02	$106.02	$106.02	$40.00	$106.02	$106.02	$106.02	$201.02	$201.02	$106.02	$106.02
2017/2018 BRA	Extended Summer	$120.00	$120.00	$120.00	$53.98	$120.00	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00
2017/2018 BRA	Annual	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$120.00	$215.00	$215.00	$120.00	$120.00

Table 5-12 RPM revenue by type: 2007/2008 through 2017/2018[50,51]

				Coal		Gas		Hydroelectric		Nuclear	
	Demand Resources	Energy Efficiency Resources	Imports	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated
2007/2008	$5,537,085	$0	$22,225,980	$1,022,372,301	$0	$1,474,196,391	$3,472,667	$209,490,444	$0	$996,085,233	$0
2008/2009	$35,349,116	$0	$60,918,903	$1,844,120,476	$0	$1,921,777,216	$9,751,112	$287,850,403	$0	$1,322,601,837	$0
2009/2010	$65,762,003	$0	$56,517,793	$2,417,576,805	$1,854,781	$2,290,125,059	$30,168,831	$364,742,517	$0	$1,517,723,628	$0
2010/2011	$60,235,796	$0	$106,046,871	$2,662,434,386	$3,168,069	$2,599,694,869	$58,065,964	$442,429,815	$0	$1,799,258,125	$0
2011/2012	$55,795,785	$139,812	$185,421,273	$1,595,707,479	$28,330,047	$1,615,369,731	$98,448,693	$278,529,660	$0	$1,079,386,338	$0
2012/2013	$264,387,897	$11,408,552	$13,260,822	$1,016,194,603	$7,568,127	$1,088,456,008	$76,633,409	$179,117,975	$11,397	$762,719,550	$0
2013/2014	$558,715,114	$21,598,174	$31,804,645	$1,743,995,977	$12,950,135	$1,869,087,820	$167,844,235	$308,853,673	$25,708	$1,346,223,419	$0
2014/2015	$681,315,139	$42,308,549	$135,573,409	$1,945,606,114	$57,078,818	$2,009,249,240	$205,555,569	$333,941,614	$6,649,774	$1,464,950,862	$0
2015/2016	$894,128,738	$55,975,130	$206,230,276	$2,835,489,278	$63,675,945	$2,493,249,821	$530,431,461	$387,351,989	$15,472,171	$1,849,884,449	$0
2016/2017	$444,241,430	$37,315,013	$161,388,134	$1,326,359,035	$42,543,693	$1,506,445,844	$502,578,551	$221,710,215	$10,367,343	$1,002,896,452	$0
2017/2018	$476,896,058	$59,254,100	$189,649,620	$1,839,412,938	$56,002,680	$2,083,473,655	$860,951,050	$312,755,908	$15,124,140	$1,155,829,440	$0

50 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.
51 The results for the ATSI Integration Auctions are not included in this table.

Table 5-12 RPM revenue by type: 2007/2008 through 2017/2018 *(continued)*

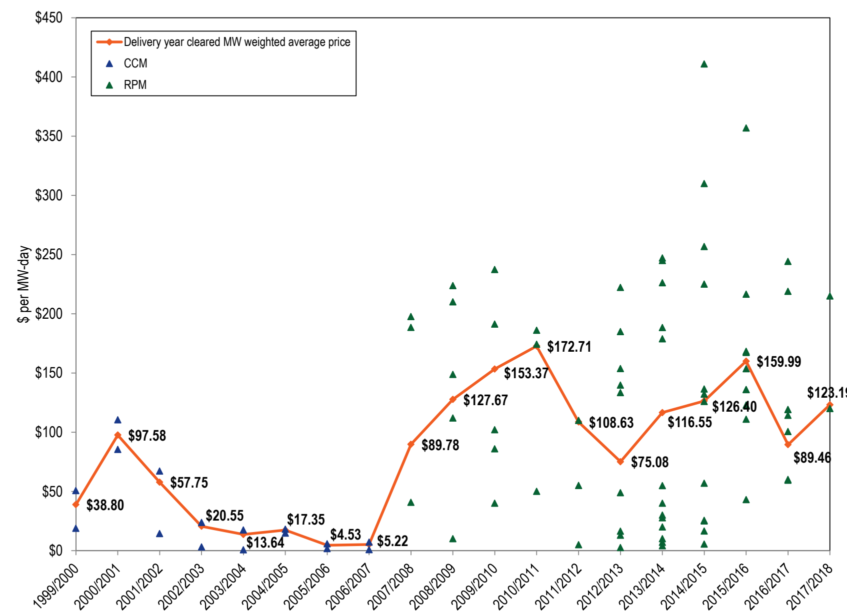
	Oil		Solar		Solid waste		Wind		
	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Existing	New/repower/ reactivated	Total revenue
2007/2008	$486,964,987	$0	$0	$0	$31,512,230	$0	$430,065	$0	$4,252,287,381
2008/2009	$560,831,808	$4,837,523	$0	$0	$35,011,991	$0	$1,180,153	$2,917,048	$6,087,147,586
2009/2010	$700,939,675	$5,676,582	$0	$0	$42,758,762	$523,739	$2,011,156	$6,836,827	$7,503,218,157
2010/2011	$655,782,363	$4,339,539	$0	$0	$40,731,606	$413,503	$1,819,413	$15,232,177	$8,449,652,496
2011/2012	$360,032,004	$967,887	$0	$66,978	$25,636,836	$261,690	$1,072,929	$9,919,881	$5,335,087,023
2012/2013	$414,915,199	$2,772,987	$0	$1,246,337	$26,840,670	$316,420	$812,644	$5,052,036	$3,871,714,635
2013/2014	$668,652,167	$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	$476,813,839	$4,106,697	$0	$3,836,582	$34,281,137	$1,709,533	$1,524,551	$32,766,219	$7,437,267,646
2015/2016	$556,911,713	$7,256,033	$0	$4,902,514	$35,605,323	$6,079,637	$1,829,269	$41,406,297	$9,985,880,044
2016/2017	$336,730,453	$5,613,584	$0	$5,308,879	$28,371,993	$4,125,154	$1,144,873	$21,665,899	$5,658,806,545
2017/2018	$380,100,780	$5,479,380	$0	$6,440,243	$30,737,198	$5,752,583	$1,292,100	$33,077,760	$7,512,229,630

Table 5-13 RPM revenue by calendar year: 2007 through 2018[52]

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	$122.32	160,668.7	365	$7,173,539,072
2015	$146.09	167,196.5	365	$8,915,526,042
2016	$118.75	171,750.5	366	$7,464,907,468
2017	$109.24	169,177.5	365	$6,745,471,039
2018	$123.19	167,068.9	151	$3,107,799,107

52 The results for the ATSI Integration Auctions are not included in this table.

Figure 5-4 History of PJM capacity prices: 1999/2000 through 2017/2018[53]



53 1999/2000-2006/2007 capacity prices are CCM combined market, weighted average prices. The 2007/2008-2017/2018 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 and subsequent Delivery Years, only the prices for Annual Resources are plotted.

Figure 5-5 Map of RPM capacity prices: 2014/2015 through 2017/2018

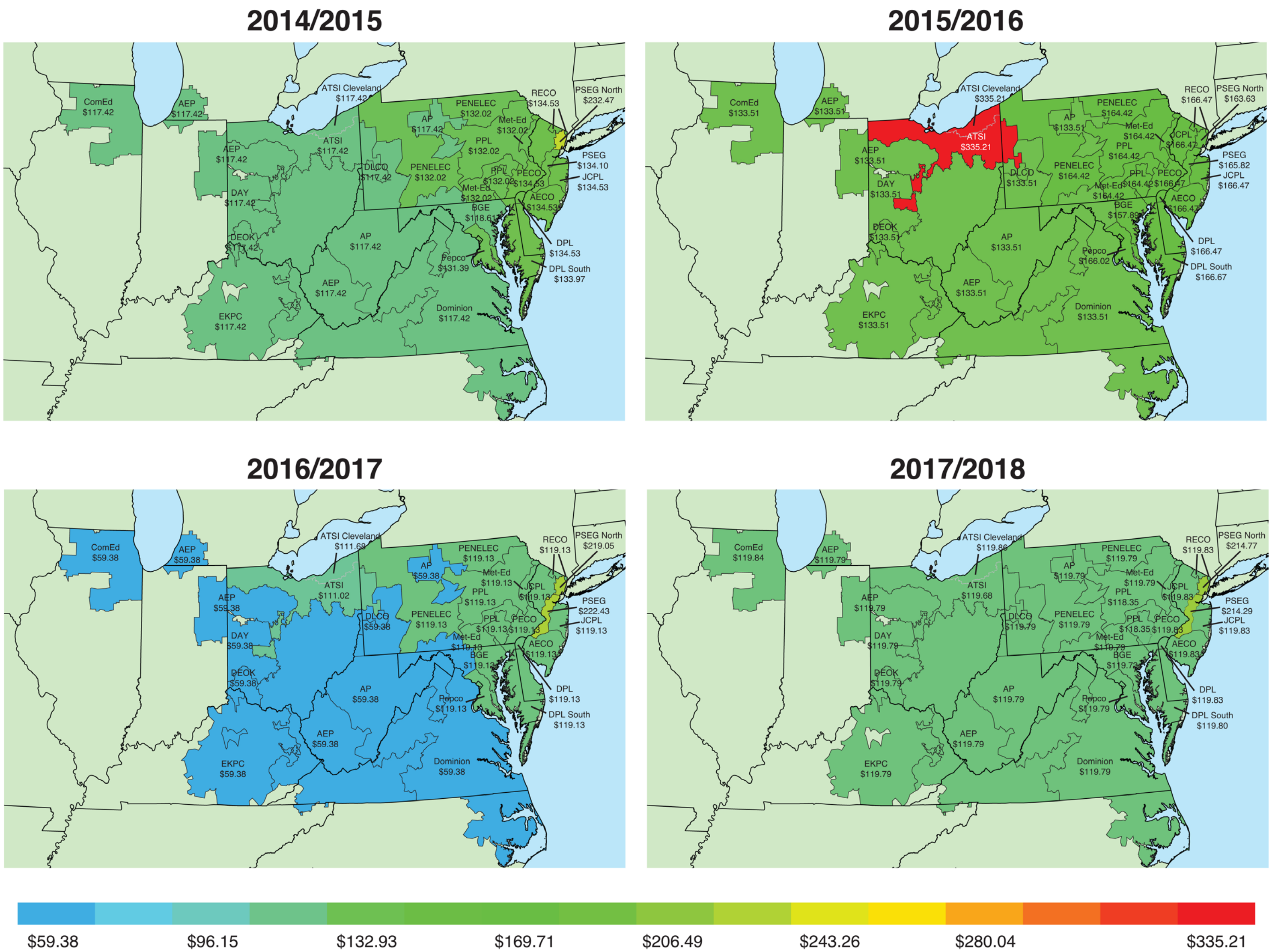


Table 5-14 RPM cost to load: 2013/2014 through 2017/2018 RPM Auctions[54,55,56]

	Net Load Price ($ per MW-day)	UCAP Obligation (MW)	Annual Charges
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	$128.38	80,953.8	$3,793,425,139
Rest of MAAC	$137.55	30,041.3	$1,508,211,854
Rest of EMAAC	$137.54	19,983.0	$1,003,188,500
DPL	$145.38	4,551.5	$241,523,752
PSEG	$171.59	11,563.7	$724,229,563
Total		147,093.3	$7,270,578,809
2015/2016			
Rest of RTO	$135.79	82,638.6	$4,107,095,920
Rest of MAAC	$166.41	55,375.9	$3,372,664,490
PSEG	$166.16	11,661.2	$709,176,272
ATSI	$296.45	14,598.2	$1,583,895,942
Total		164,273.8	$9,772,832,625
2016/2017			
Rest of RTO	$59.38	87,663.9	$1,900,087,197
Rest of MAAC	$118.73	56,662.4	$2,455,596,495
PSEG	$177.05	11,886.2	$768,108,919
ATSI	$90.82	14,850.8	$492,276,789
Total		171,063.3	$5,616,069,400
2017/2018			
Rest of RTO	$119.81	102,465.9	$4,480,913,201
Rest of MAAC	$119.92	48,299.9	$2,114,192,959
PSEG	$175.21	11,853.1	$758,017,691
PPL	$118.18	8,510.0	$367,082,164
Total		171,128.9	$7,720,206,015

54 The RPM annual charges are calculated using the rounded, net load prices as posted in the PJM RPM Auction results.
55 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.
56 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 2015/2016, 2016/2017, and 2017/2018 Net Load Prices are not finalized. The 2015/2016, 2016/2017, and 2017/2018 obligation MW are not finalized.

Table 5-14 shows the RPM annual charges to load. For the 2014/2015 Delivery Year, RPM annual charges to load total approximately $7.3 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).[57]

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 nine months of 2014, nuclear units had a capacity factor of 94.0 percent, compared to 93.7 percent in the first nine months of 2013. Combined cycle units ran more often, increasing from a capacity factor of 51.7 percent in the first nine months of 2013 to 53.4 percent in the first nine months of 2014. The capacity factor for steam units, which are primarily coal fired, increased from 50.2 percent in the first nine months of 2013 to 51.9 percent in the first nine months of 2014.

57 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.

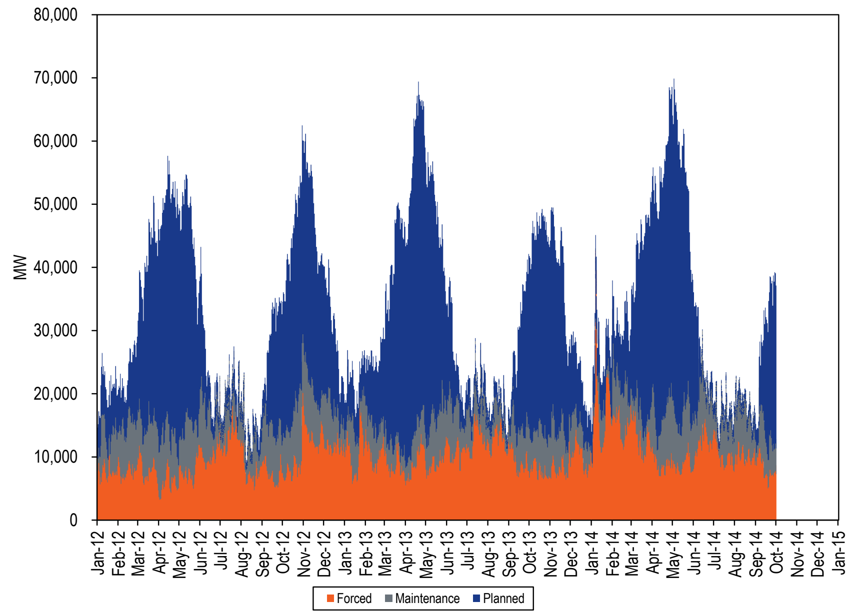
Table 5-15 PJM capacity factor (By unit type (GWh)): January through September of 2013 and 2014[58,59]

	2013 (Jan - Sep)		2014 (Jan - Sep)	
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor
Combined Cycle	90,426.0	51.7%	93,744.4	53.4%
Combustion Turbine	6,435.9	3.3%	8,130.4	4.1%
Diesel	210.4	9.4%	217.3	9.8%
Diesel (Landfill gas)	953.8	54.1%	1,036.0	61.3%
Fuel Cell	63.4	110.0%	165.7	84.3%
Nuclear	207,254.4	93.7%	207,170.7	94.0%
Pumped Storage Hydro	5,297.4	14.7%	5,754.8	15.8%
Run of River Hydro	5,793.8	36.4%	5,795.2	33.9%
Solar	288.4	17.4%	326.7	17.8%
Steam	271,021.9	50.2%	272,551.1	51.9%
Wind	10,379.3	25.3%	10,723.0	25.8%
Total	598,124.7	48.5%	605,615.3	49.5%

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 5-6, due to restrictions on planned outages during the winter and summer. The effect of the seasonal variation in outages can be seen in the monthly generator performance metrics in "Performance By Month."

Figure 5-6 PJM outages (MW): January 2012 through September 2014



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 for the first nine months of 2014 was 83.1 percent, a decrease from 84.1 percent for the first nine months of 2013. The PJM

58 The EKPC Transmission Zone was integrated on June 1, 2013 and is not included in the numbers for the first five months of 2013.
59 The capacity factor for each unit type was calculated based on units that are capacity resources and solar and wind units that are not capacity resources. As a result of not including all units, the total annual generation is slightly lower than the totals reported in the *2014 Quarterly State of the Market Report for PJM: January through June*, Section 3, "Energy Market," Energy Production by Fuel Source.

aggregate EAF, EFOF, EPOF, and EMOF are shown in Figure 5-7. Metrics by unit type are shown in Table 5-16 through Table 5-19.

Figure 5-7 PJM equivalent outage and availability factors: January through September, 2007 to 2014

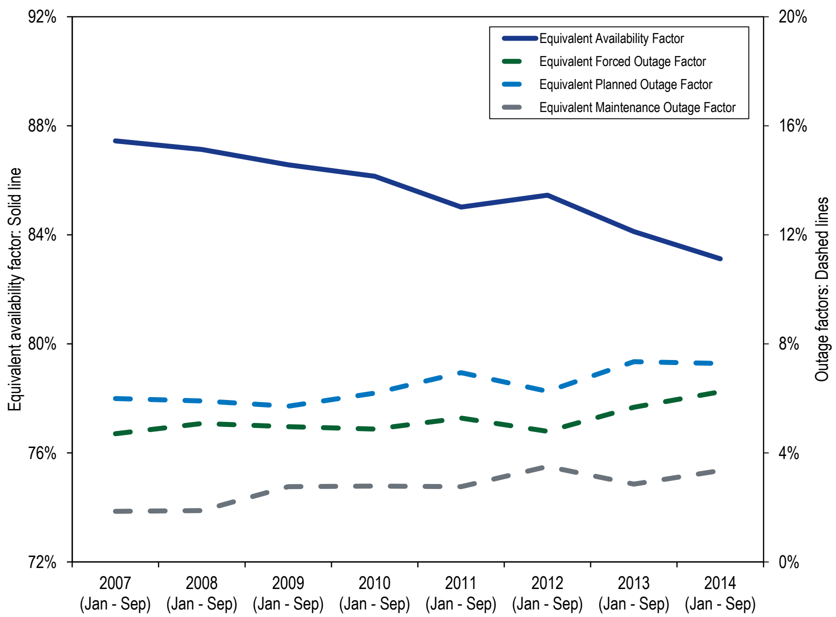


Table 5-16 EAF by unit type: January through September, 2007 through 2014

	2007 (Jan - Sep)	2008 (Jan - Sep)	2009 (Jan - Sep)	2010 (Jan - Sep)	2011 (Jan - Sep)	2012 (Jan - Sep)	2013 (Jan - Sep)	2014 (Jan - Sep)
Combined Cycle	91.2%	91.5%	88.4%	88.2%	87.9%	88.6%	86.2%	86.4%
Combustion Turbine	91.1%	91.7%	94.1%	94.4%	93.6%	94.1%	90.4%	89.0%
Diesel	86.5%	87.8%	91.8%	94.1%	94.5%	94.4%	92.9%	83.4%
Hydroelectric	91.9%	90.0%	86.4%	88.5%	86.6%	89.5%	89.4%	84.9%
Nuclear	94.7%	93.3%	90.9%	93.1%	90.5%	91.6%	92.4%	91.5%
Steam	82.2%	82.1%	82.2%	80.3%	79.5%	79.2%	77.7%	76.6%
Total	87.4%	87.1%	86.6%	86.1%	85.0%	85.5%	84.1%	83.1%

Table 5-17 EMOF by unit type: January through September, 2007 through 2014

	2007 (Jan - Sep)	2008 (Jan - Sep)	2009 (Jan - Sep)	2010 (Jan - Sep)	2011 (Jan - Sep)	2012 (Jan - Sep)	2013 (Jan - Sep)	2014 (Jan - Sep)
Combined Cycle	1.7%	1.4%	3.3%	3.1%	2.3%	2.0%	2.6%	2.0%
Combustion Turbine	2.1%	2.0%	1.9%	1.5%	1.5%	1.5%	1.6%	1.5%
Diesel	1.8%	1.2%	1.2%	0.8%	1.9%	1.7%	1.4%	2.3%
Hydroelectric	1.6%	1.8%	2.5%	2.2%	2.1%	1.9%	1.6%	3.5%
Nuclear	0.3%	0.6%	0.7%	0.5%	1.5%	0.9%	0.8%	0.9%
Steam	2.5%	2.5%	3.7%	4.0%	3.8%	5.6%	4.3%	5.4%
Total	1.9%	1.9%	2.8%	2.8%	2.8%	3.5%	2.9%	3.4%

Table 5-18 EPOF by unit type: January through September, 2007 through 2014

	2007 (Jan - Sep)	2008 (Jan - Sep)	2009 (Jan - Sep)	2010 (Jan - Sep)	2011 (Jan - Sep)	2012 (Jan - Sep)	2013 (Jan - Sep)	2014 (Jan - Sep)
Combined Cycle	5.1%	5.0%	5.1%	6.1%	7.5%	6.9%	8.4%	9.1%
Combustion Turbine	2.1%	3.5%	2.5%	2.2%	3.1%	2.3%	2.9%	3.3%
Diesel	0.7%	1.2%	0.3%	0.6%	0.0%	0.1%	0.3%	0.5%
Hydroelectric	5.3%	6.5%	8.8%	8.5%	9.5%	4.7%	6.7%	9.6%
Nuclear	3.8%	5.2%	4.2%	4.4%	5.8%	6.1%	5.6%	5.8%
Steam	8.4%	7.1%	7.2%	8.0%	8.3%	7.6%	9.4%	8.7%
Total	6.0%	5.9%	5.7%	6.2%	6.9%	6.3%	7.3%	7.3%

Table 5-19 EFOF by unit type: January through September, 2007 through 2014

	2007 (Jan - Sep)	2008 (Jan - Sep)	2009 (Jan - Sep)	2010 (Jan - Sep)	2011 (Jan - Sep)	2012 (Jan - Sep)	2013 (Jan - Sep)	2014 (Jan - Sep)
Combined Cycle	2.1%	2.1%	3.2%	2.6%	2.3%	2.4%	2.8%	2.6%
Combustion Turbine	4.6%	2.8%	1.5%	1.8%	1.8%	2.1%	5.1%	6.3%
Diesel	10.9%	9.9%	6.7%	4.4%	3.6%	3.8%	5.3%	13.7%
Hydroelectric	1.2%	1.7%	2.3%	0.8%	1.9%	3.9%	2.4%	2.0%
Nuclear	1.1%	0.9%	4.2%	1.9%	2.2%	1.4%	1.2%	1.8%
Steam	7.0%	8.3%	6.9%	7.8%	8.5%	7.6%	8.7%	9.4%
Total	4.7%	5.1%	5.0%	4.9%	5.3%	4.8%	5.7%	6.2%

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, service hours, average forced outage duration, average run time, average time between unit starts, available hours and period hours.[60] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd for the first nine months of 2014 was 9.7 percent, an increase from the 8.2 percent average PJM EFORd for the first nine months of 2013. Figure 5-8 shows the average EFORd since 2007 for all units in PJM.

Figure 5-8 Trends in the PJM equivalent demand forced outage rate (EFORd): January through September, 2007 through 2014

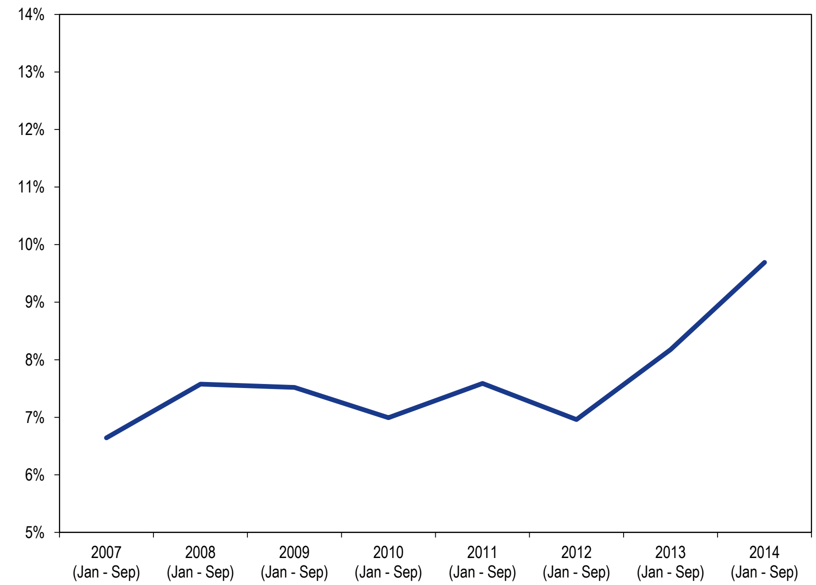


Table 5-20 shows the class average EFORd by unit type. Outage rates increased for all unit types and CT and DS units had a particularly high increase in outage rates in the first nine months of 2014.

60 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.

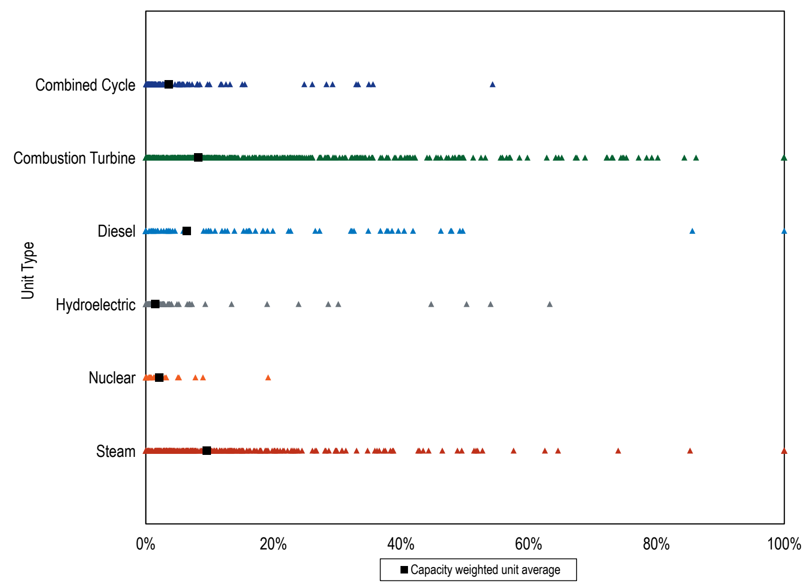
Table 5-20 PJM EFORd data for different unit types: January through September, 2007 through 2014

	2007 (Jan - Sep)	2008 (Jan - Sep)	2009 (Jan - Sep)	2010 (Jan - Sep)	2011 (Jan - Sep)	2012 (Jan - Sep)	2013 (Jan - Sep)	2014 (Jan - Sep)
Combined Cycle	3.5%	3.4%	4.5%	3.6%	3.0%	3.0%	3.5%	4.2%
Combustion Turbine	10.6%	10.7%	8.7%	8.2%	7.1%	6.5%	10.3%	16.1%
Diesel	12.5%	11.0%	8.8%	6.4%	9.6%	5.1%	5.9%	14.7%
Hydroelectric	1.9%	2.7%	2.9%	1.5%	2.5%	5.8%	3.5%	2.9%
Nuclear	1.2%	1.0%	4.3%	2.1%	2.4%	1.5%	1.3%	2.0%
Steam	8.6%	10.4%	9.4%	9.6%	11.1%	10.2%	11.8%	12.6%
Total	6.6%	7.6%	7.5%	7.0%	7.6%	7.0%	8.2%	9.7%

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 5-9. 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 in EFORd, while nuclear units had the lowest variance in EFORd values in the first nine months of 2014.

Figure 5-9 PJM distribution of EFORd data by unit type: January through September 2014



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

There are two 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's ICAP, rather than one minus EFORd.

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 in PJM's Capacity Market. Thus, the PJM capacity market rules, as currently written, create 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.

In 2006, NERC created specifications for certain types of outages deemed to be Outside Management Control (OMC).[61] 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.[62] 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 NERC.

Nothing in NERC's classification of outages requires that PJM exclude OMC outages from the forced outage rate metrics used in the Capacity Market.[63] That choice was made by PJM and can be modified without violating any NERC requirements.[64] It is possible to have an OMC outage under the NERC definition, which PJM does not define as an OMC outage 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

61 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>.

62 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>.

63 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.

64 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.

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, although PJM's actual practice appears to be improving.

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 5-21 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages accounted for 7.0 percent of all forced outages in the first nine months of 2014. The largest contributor to OMC outages, flood, was the cause of 30.5 percent of OMC outages and 2.1 percent of all forced outages.

The second-largest contributor to OMC outages, hurricane, affected several units that have been on outage since the 2012 hurricane.

Table 5-21 OMC Outages: January through September 2014

OMC Cause Code	Percent of OMC Forced Outages	Percent of all Forced Outages
Flood	30.5%	2.1%
Hurricane	24.2%	1.7%
Other switchyard equipment	13.2%	0.9%
Storms	10.4%	0.7%
Lightning	5.7%	0.4%
Lack of fuel	5.3%	0.4%
Transmission system problems other than catastrophes	3.2%	0.2%
Transmission equipment beyond the 1st substation	1.6%	0.1%
Switchyard transformers and associated cooling systems	1.4%	0.1%
Switchyard circuit breakers	1.2%	0.1%
High sulfur content	1.0%	0.1%
Other miscellaneous external problems	0.8%	0.1%
Transmission line	0.7%	0.1%
Lack of water	0.5%	0.0%
Switchyard system protection devices	0.2%	0.0%
Other fuel quality problems	0.1%	0.0%
Transmission equipment at the first substation	0.0%	0.0%
Miscellaneous regulatory	0.0%	0.0%
Tornado	0.0%	0.0%
Total	100.0%	7.0%

An outage is an outage, regardless of the cause. It is inappropriate that units on outage do not have to reflect that outage in their outage statistics, which affect their performance incentives and the level of unforced capacity and therefore capacity sold. No outages should be treated as OMC because when a unit is not available it is not available, regardless of the reason, and the data and payments to units should reflect that fact.

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, including contracts with intermediaries, 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 for one of the OMC reasons, that is a real feature of the units that should be reflected in overall PJM system planning as well as in the economic fundamentals of the capacity market and the capacity market outcomes. Permitting OMC outages to be excluded from the forced outage metric skews the results of the capacity market towards less reliable units and away from more reliable units. This is exactly the wrong incentive. Paying for capacity from units using the EFORd, not the XEFORd, metric would provide a market incentive for unit owners to address all their outage issues in an efficient manner. Pretending that some outages simply do not exist distorts market outcomes. That is exactly the result of using OMC outages to reduce EFORd.[65]

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.

Performance Incentives

There are a number of performance incentives in the capacity market, but they fall short of the incentives that a unit would face if it earned all its revenue in an energy market.[66] The most basic incentive is that associated with the reduction of payments for a failure to perform. In any market, sellers are not paid when they do not provide a product. That is only partly true in the PJM Capacity Market. In addition to the exclusion of OMC outages, which reduces forced outage rates resulting in payments to capacity resources not consistent with actual forced outage rates, other performance incentives are not designed to ensure that capacity resources are paid when they perform and not paid when they do not perform.

In concept, units do not receive RPM revenues to the extent that they do not perform during defined peak hours, but there are significant limitations on this incentive in the current rules.

The maximum level of RPM revenues at risk are based on the difference between a unit's actual Peak Period Capacity Available (PCAP) and the unit's

65 For more on this issue, see the MMU'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).

66 This section focuses on capacity resources that are not in FRR plans. The FRR incentives differ from the incentives discussed here.

expected Target Unforced Capacity (TCAP). PCAP is based on EFORp while TCAP is based on XEFORd-5. PCAP is the resource position, while TCAP is the resource commitment. In other words, if the forced outage rate during the peak hours (EFORp) is greater than the forced outage rate calculated over a five year period (XEFORd-5), the unit owner may have a capacity shortfall of up to 50 percent of the unit's capacity commitment in the first year.

(PCAP) Peak Period Capacity = ICAP * (1 - EFORp)

(TCAP) Target Unforced Capacity = ICAP * (1 – XEFORd-5)

Peak Period Capacity Shortfall = TCAP – PCAP

The Peak-Hour Period Availability Charge is equal to the seller's weighted average resource clearing price for the delivery year for the LDA.[67]

The peak hour availability charge understates the appropriate revenues at risk for underperformance because it is based on EFORp and because it is compared to a five year XEFORd. Both outage measures exclude OMC outages. The use of a five year average XEFORd measure is questionable as the measure of expected performance during the delivery year because it covers a period which is so long that it is unlikely to be representative of the current outage performance of the unit. The UCAP sold during a delivery year is a function of ICAP and the final Effective EFORd,[68] which is defined to be the XEFORd calculated for the 12 months ending in September in the year prior to the Delivery Year.

This maximum level of RPM revenues at risk is reduced by several additional factors including the ability to net any shortfalls against over performance across all units owned by the same participant within an LDA and the ability to use performance by resources that were offered into RPM but did not clear as an offset.[69]

67 PJM. OATT Attachment DD § 10 (j).
68 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), p. 159
69 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), Section 8.4.5.

Excess Available Capacity (EAC) may also be used to offset Peak Hour Availability shortfalls. EAC is capacity which was offered into RPM Auctions, did not clear but was offered into all PJM markets consistent with the obligations of a capacity resource. EAC must be part of a participant's total portfolio, but does not have to be in the same LDA as the shortfall being offset, unlike the netting provision.[70]

There is a separate exception to the performance related incentives related to lack of gas during the winter period. Single-fuel, natural gas-fired units do not face the Peak-Hour Period Availability Charge during the winter if the capacity shortfall was due to nonavailability of gas to supply the unit.[71] The result is an exception, analogous to the lack of fuel exception, except much broader, which appears to have no logical basis.

There is a separate exception to the performance related incentives related to a unit that runs less than 50 hours during the RPM peak period. If a unit runs for less than 50 peak period service hours, then the EFORp used in the calculation of the peak hour availability charges is based on PCAP calculated using the lower of the delivery year XEFORd or the EFORp.[72]

There is a separate exception for wind and solar capacity resources which are exempt from this performance incentive.[73]

The peak hour availability charge does not apply if the unit unavailability resulted in another performance related charge or penalty.[74]

Under the peak hour availability charge, the maximum exposure to loss of capacity market revenues is 50 percent in the first year of higher than 50 percent EFORp. That percent increases to 75 percent in year two of sub 50 percent performance and to 100 percent in year three, but returns to a maximum of 50 percent after three years of better performance.

70 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), Section 8.4.5.1.
71 PJM. OATT Attachment DD § 7.10 (e).
72 PJM. OATT Attachment DD § 7.10 (e).
73 PJM. OATT Attachment DD § 7.10 (e).
74 PJM. OATT Attachment DD § 7.10 (e).

This limitation on maximum exposure is in addition to limitations that result from the way in which PJM applies the OMC rules in the calculation of EFORp and XEFORd, is in addition to the exclusion for gas availability in the winter, which is over and above the OMC exclusion, and is in addition to the case where a unit has less than 50 service hours in a delivery year and can use the lower of the delivery year XEFORd or EFORp.

Not all unit types are subject to RPM performance incentives. In addition to the exceptions which apply to conventional generation as a result of EFORp and XEFORd calculations, wind, solar and hydro generation capacity resources are exempt from key performance incentives. Wind and solar generation capacity resources are not subject to peak hour availability incentives, to summer or winter capability testing or to peak season maintenance compliance rules. Hydro generation capacity resources are not subject to peak season maintenance compliance rules.[75]

Given that all generation is counted on for comparable contributions to system reliability, the MMU recommends that all generation types face the same performance incentives. The MMU recommends that the performance incentives in the RPM Capacity Market design be strengthened.

The MMU recommends that generation capacity resources be paid on the basis of whether they produce energy when called upon during any of the hours defined as critical. All revenues should be at risk under the peak hour availability charge.

Given that all generation is counted on for comparable contributions to system reliability, the MMU recommends that all generation types face the same performance incentives.

The MMU recommends elimination of the exception related to lack of gas during the winter period for single-fuel, natural gas-fired units.

The MMU recommends elimination of the exception related to a unit that runs less than 50 hours during the RPM peak period.

75 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012) p. 98.

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.[76] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor.[77]

PJM EFOF was 6.2 percent in the first nine months of 2014. This means there was 6.2 percent lost availability because of forced outages. Table 5-22 shows that forced outages for boiler tube leaks, at 20.5 percent of the systemwide EFOF, were the largest single contributor to EFOF.

Table 5-22 Contribution to EFOF by unit type by cause: January through September 2014

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	3.3%	0.0%	0.0%	0.0%	0.0%	28.9%	20.5%
Economic	11.5%	36.6%	1.7%	2.4%	0.0%	4.7%	10.2%
Electrical	2.1%	7.9%	7.0%	24.5%	18.9%	5.6%	6.8%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	7.8%	5.5%
Catastrophe	0.5%	26.5%	3.5%	26.5%	0.0%	0.0%	5.0%
Boiler Piping System	4.3%	0.0%	0.0%	0.0%	0.0%	5.4%	4.0%
Boiler Fuel Supply from Bunkers to Boiler	0.2%	0.0%	0.0%	0.0%	0.0%	4.5%	3.2%
Reserve Shutdown	1.8%	3.9%	8.1%	11.1%	2.8%	2.1%	2.6%
Precipitators	0.0%	0.0%	0.0%	0.0%	0.0%	3.5%	2.5%
Feedwater System	1.3%	0.0%	0.0%	0.0%	7.9%	2.8%	2.4%
Controls	6.4%	0.2%	0.2%	0.4%	6.8%	1.9%	2.1%
Miscellaneous (Boiler)	0.0%	0.0%	0.0%	0.0%	0.0%	2.7%	1.9%
Fuel Quality	0.0%	0.1%	2.3%	0.0%	0.0%	2.5%	1.8%
Generator	7.1%	0.1%	3.4%	1.2%	1.7%	1.7%	1.7%
Miscellaneous (Generator)	12.4%	1.6%	48.3%	0.0%	0.0%	0.7%	1.7%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	30.0%	0.0%	1.6%
Exciter	0.5%	0.4%	0.3%	6.9%	0.0%	1.8%	1.5%
Boiler Internals and Structures	0.6%	0.0%	0.0%	0.0%	0.0%	2.0%	1.4%
Slag and Ash Removal	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%	1.4%
All Other Causes	48.1%	22.6%	25.1%	27.0%	32.0%	19.4%	22.3%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

76 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.

77 EFOF incorporates all outages regardless of their designation as OMC.

Table 5-23 shows the categories which are included in the economic category.[78] Lack of fuel that is considered outside management control accounted for 3.6 percent of all economic reasons.

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."[79] 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 5-23 Contributions to Economic Outages: January through September 2014

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	3.3%	0.0%	0.0%	0.0%	0.0%	28.9%	20.5%
Economic	11.5%	36.6%	1.7%	2.4%	0.0%	4.7%	10.2%
Electrical	2.1%	7.9%	7.0%	24.5%	18.9%	5.6%	6.8%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	7.8%	5.5%
Catastrophe	0.5%	26.5%	3.5%	26.5%	0.0%	0.0%	5.0%
Boiler Piping System	4.3%	0.0%	0.0%	0.0%	0.0%	5.4%	4.0%
Boiler Fuel Supply from Bunkers to Boiler	0.2%	0.0%	0.0%	0.0%	0.0%	4.5%	3.2%
Reserve Shutdown	1.8%	3.9%	8.1%	11.1%	2.8%	2.1%	2.6%
Precipitators	0.0%	0.0%	0.0%	0.0%	0.0%	3.5%	2.5%
Feedwater System	1.3%	0.0%	0.0%	0.0%	7.9%	2.8%	2.4%
Controls	6.4%	0.2%	0.2%	0.4%	6.8%	1.9%	2.1%
Miscellaneous (Boiler)	0.0%	0.0%	0.0%	0.0%	0.0%	2.7%	1.9%
Fuel Quality	0.0%	0.1%	2.3%	0.0%	0.0%	2.5%	1.8%
Generator	7.1%	0.1%	3.4%	1.2%	1.7%	1.7%	1.7%
Miscellaneous (Generator)	12.4%	1.6%	48.3%	0.0%	0.0%	0.7%	1.7%
Reactor Coolant System	0.0%	0.0%	0.0%	0.0%	30.0%	0.0%	1.6%
Exciter	0.5%	0.4%	0.3%	6.9%	0.0%	1.8%	1.5%
Boiler Internals and Structures	0.6%	0.0%	0.0%	0.0%	0.0%	2.0%	1.4%
Slag and Ash Removal	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%	1.4%
All Other Causes	48.1%	22.6%	25.1%	27.0%	32.0%	19.4%	22.3%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

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.[80] It is reasonable to expect that units have some degree of control over when to take a forced outage, depending on the underlying cause of the forced outage. If units had no control over the timing of forced outages, outages during peak hours of the peak months would be expected to occur at roughly the same rate as outages during periods of demand throughout the rest of the year. With the exception of combustion turbines and nuclear units, EFORp is lower than XEFORd, suggesting that units elect to take non-OMC 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 but it does not directly address the question of the incentive effect of omitting OMC outages from the EFORP metric.

Table 5-24 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 combustion turbine units.

78 The definitions of these outages are defined by NERC GADS.
79 The definitions of these outages are defined by NERC GADS.
80 See PJM. "Manual 22: Generator Resource Performance Indices," Revision 16 (November 16, 2011), Definitions.

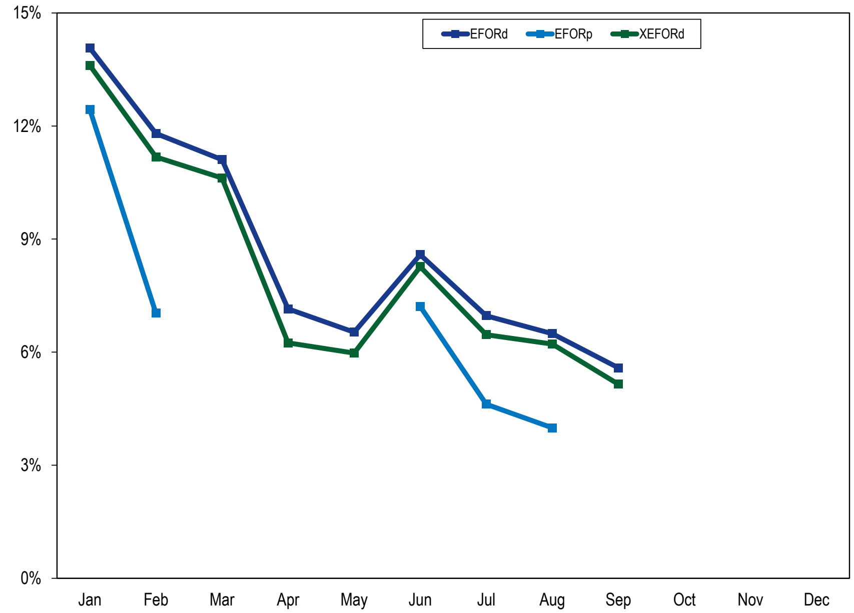
Table 5-24 PJM EFORd, XEFORd and EFORp data by unit type: January through September 2014[81]

	Contribution to Economic Reasons
Lack of fuel (Non-OMC)	87.3%
Other economic problems	6.5%
Lack of fuel (OMC)	3.6%
Fuel conservation	1.8%
Problems with primary fuel for units with secondary fuel operation	0.4%
Lack of water	0.3%
Ground water or other water supply problems	0.1%
Total	100.0%

Performance By Month

On a monthly basis, EFORp values were significantly less than EFORd and XEFORd values as shown in Figure 5-10, demonstrating that units had fewer non-OMC outages during peak hours than would have been expected based on EFORd.

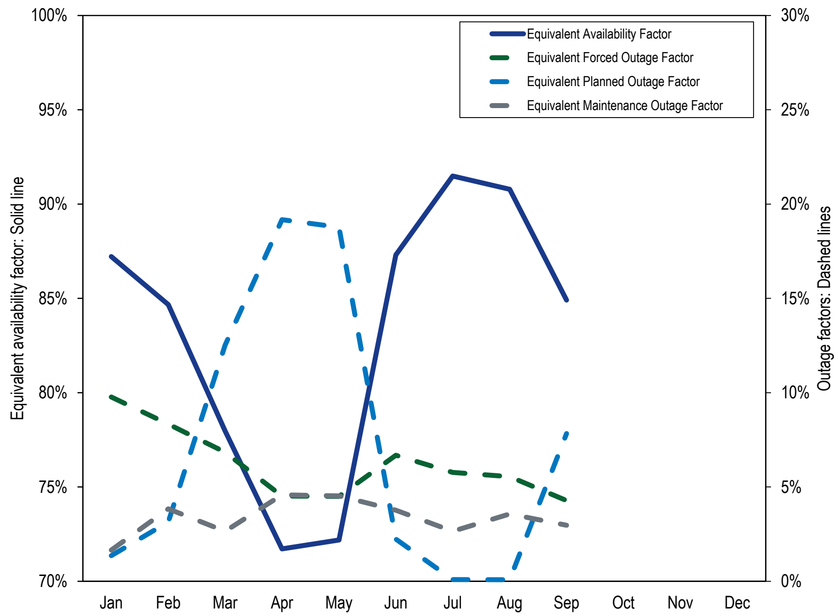
Figure 5-10 PJM EFORd, XEFORd and EFORp: January through September 2014



On a monthly basis, unit availability as measured by the equivalent availability factor is shown in Figure 5-11.

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

Figure 5-11 PJM monthly generator performance factors: January through September 2014



Demand Response

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 as a proxy for full participation.

Overview

- **Demand Response Jurisdiction.** In a panel decision issued May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit vacated in its entirety Order No. 745, which provided for payment of demand-side resources at full LMP.[1] The decision calls into question the jurisdictional foundation for all demand response programs currently subject to FERC oversight, and, in particular, for those programs that involve FERC regulated payments to demand resources. A motion for stay was granted until at least December 16, 2014, by the United States Court of Appeals. The FERC is now deciding whether to petition the Supreme Court for review. If a petition is filed, the stay will remain in effect until the Supreme Court's final disposition. FirstEnergy filed an amended complaint on September 22, 2014, that seeks to the extend EPSA v. FERC to the PJM capacity markets, and would, if granted, eliminate tariff provisions that provide for the compensation of Demand Resources as a form of supply effective May 23, 2014, and require a rerun of the 2017/2018 Base Residual Auction.[2]

- **Demand Response Activity.** Demand response is split into two main categories; economic and emergency. The emergency program revenue consists of both capacity and energy revenue. The capacity market is still the primary source of revenue to participants in PJM demand response programs. In the first nine months of 2014, capacity market revenue increased by $162.7 million, or 54.7 percent, from $297.4 million in the first nine months of 2013 to $460.1 million in the first nine months of 2014.[3] Emergency energy revenue increased by $6.2 million, from $36.7 million in the first nine months of 2013 to $43.0 million compared to the first nine months of 2013. The economic program only consists of energy revenue. Economic program credits increased by $7.9 million, from $7.4 million in the first nine months of 2013 to $16.3 million in the first nine months of 2014, a 121 percent increase.[4] Due to the cold winter, economic DR credits increased 1,075 percent in the first three months of 2014. In contrast, economic DR credits in the third quarter of 2014 decreased by 57.5 percent, from $4.8 million in the third quarter of 2013 to $2.0 million in the third quarter of 2014. Not all DR activities in the third quarter of 2014 have been reported to PJM at the time of this report.

  All demand response energy payments are uplift. LMP does not cover demand response energy payments. Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the real-time market. Economic demand response energy costs are assigned to real-time exports from the PJM Region and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than the price determined under the net benefits test for that month.[5]

- **Demand Response Market Concentration.** Economic demand response had high market concentration in the first nine months of 2013 and 2014. The HHI for economic demand response reductions decreased 472 points, from 8260 in the first nine months of 2013 to 7788 in the first nine months of 2014. Emergency demand response had moderate market concentration in the first nine months of 2014. The HHI for emergency demand response registrations increased 231 points, from 1529 in the first nine months of 2013 to 1760 in the first nine months of 2014. In the first nine months of 2014, the four largest companies contributed 65.3 percent of all registered emergency demand response resources.

- **Locational Dispatch of Demand Resources.** PJM dispatches demand resources on a zonal or subzonal basis, but subzonal dispatches are only on a voluntary basis during the 2013/2014 Delivery Year. Beginning

1 Electric Power Supply Association v. FERC, No. 11-1486, *petition for en banc review denied; see Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, FERC Stats. & Regs. ¶ 31,322 (2011); *order on reh'g*, Order No. 745-A, 137 FERC ¶ 61,215 (2011); *order on reh'g*, Order No. 745-B, 138 FERC 61,148 (2012).

2 See FirstEnergy Service Company complaint, FERC Docket No. EL14-55-000, amending the complaint filed May 23, 2014.

3 The total credits and MWh numbers for demand resources were calculated as of October 15, 2014 and may change as a result of continued PJM billing updates.

4 Economic credits are synonymous with revenue received for reductions under the economic load response program.

5 PJM: "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), p 70.

with the 2014/2015 Delivery Year, demand resources are dispatchable for mandatory reduction on a subzonal basis, defined by zip codes. More locational dispatch of demand resources in a nodal market improves market efficiency. The goal should be nodal dispatch of demand resources.

- **Emergency Event Day Analysis.** PJM's calculations overstate participants' compliance during emergency load management events. In PJM's calculations, load increases are not netted against load decreases for dispatched demand resources across hours or across registrations within hours for compliance purposes, but are treated as zero. This skews the compliance results towards showing apparent higher compliance since poorly performing demand resources are not used in the compliance calculation. Considering all reported positive and negative values, the observed average load reduction of the eight events in the first nine months of 2014 should have been 2,198.6 MW, rather than the 2,840.9 MW calculated using PJM's method. The observed compliance is 29.2 percent rather than PJM's calculated 37.7 percent. This does not include locations that did not report their load during the emergency event days. All locations should be required to report their load.

Recommendations

- The MMU recommends that there be only one demand response product, with an obligation to respond when called for all hours of the year, and that the demand response be on the demand side of the capacity market. (Priority: High. First reported 2013.)
- The MMU recommends that the emergency load response program be classified as an economic program, responding to economic price signals and not an emergency program responding only after an emergency is called. (Priority: High. First reported 2012.)
- The MMU recommends that a daily must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[6] (Priority: High. First reported 2013.)
- The MMU recommends that demand response programs adopt an offer cap equal to the offer cap applicable to energy offers from generation capacity resources, currently $1,000 per MWh.[7] (Priority: High. First reported 2013.)
- The MMU recommends that the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. This recommendation has been adopted. (Priority: Medium. First reported 2013.)
- The MMU recommends that demand resources be required to provide their nodal location on the electricity grid. (Priority: High. First reported 2013.)
- The MMU recommends that measurement and verification methods for demand resources be further modified to more accurately reflect compliance. (Priority: Medium. First reported 2012.)
- The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations. (Priority: Medium. First reported 2012.)
- The MMU recommends that PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for reliability and that market payments to demand resources be calculated based on interval meter data at the site of the demand reductions.[8] (Priority: Medium. First reported 2013.)
- The MMU recommends that demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance. (Priority: Medium. First reported 2013.)
- The MMU recommends that demand resources whose load drop method is designated as "Other" explicitly record the method of load drop. (Priority: Low. First reported 2013.)

6 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 27, 2014) at 1.

7 *Id* at 1.

8 See ISO-NE Tariff, Section III, Market Rule 1, Appendix E1 and Appendix E2, "Demand Response," <http://www.iso-ne.com/regulatory/tariff/sect_3/mr1_append-e.pdf>. (Accessed November 11, 2013) ISO-NE requires that DR have an interval meter with five minute data reported to the ISO and each behind the meter generator is required to have a separate interval meter. After June 1, 2017, demand response resources in ISO-NE must also be registered at a single node.

- The MMU recommends that load management testing be initiated by PJM with limited warning to CSPs in order to more accurately resemble the conditions of an emergency event. (Priority: Low. First reported 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.

With exception of large wholesale customers in some areas, most customers in PJM are not on retail rates that directly expose them to the wholesale price of energy or capacity. As a result, most customers in PJM do not have the direct ability to see, respond to or benefit from a response to price signals in PJM's markets. PJM's demand side programs are generally designed to allow customers (or their intermediaries in the form of load serving entities (LSEs) or curtailment service providers (CSPs)) to either directly, or through intermediaries, be paid as if they were directly paying the wholesale price of energy and capacity and avoiding those prices when reducing load. PJM's demand side programs are designed to provide direct incentives for load resources to respond, via load reductions, to wholesale market price signals and/or system emergency events.

If retail markets reflected hourly wholesale locational prices and customers or their intermediaries 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, as long as there are demand side programs, 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.

If demand resources are to continue competing directly with generation capacity resources in the PJM Capacity Market, the product must be defined such that it can actually serve as a substitute for generation. That is a prerequisite to a functional market design.

In order to be a substitute for generation, demand resources should be defined in PJM rules as an economic resource, as generation is defined. Demand resources should be required to offer in the day ahead market and should be called when the resources are required and prior to the declaration of an emergency. Demand resources should be available for every hour of the year and not be limited to a small number of hours.

In order to be a substitute for generation, demand resources should provide a nodal location and should be dispatched nodally to enhance the effectiveness of demand resources and to permit the efficient functioning of the energy market.

In order to be a substitute for generation, compliance by demand resources to PJM dispatch instructions should include both increases and decreases in load. The current method applied by PJM simply ignores increases in load and thus artificially overstates compliance.

As a preferred alternative, demand response would be on the demand side of the capacity market rather than on the supply side. Customers would avoid paying for capacity by interrupting designated load when PJM indicates that it is a critical hour. Customers would pay for actual load on the system during PJM-defined critical hours, e.g. maximum generation alerts, rather than relying on flawed measurement and verification methods. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these critical hours.

PJM Demand Response Programs

All demand response programs in PJM can be grouped into economic and emergency programs. Table 6-1 provides an overview of the key features of PJM demand response programs. Demand response program is used here to refer to both emergency and economic programs. Demand resource is used here to refer to both resources participating in the capacity market and resources participating in the energy market.

In a panel decision issued May 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit vacated in its entirely Order No. 745, which provided for payment of demand-side resources at full LMP.[9] The court found Order No. 745 arbitrary and capricious on its merits.[10] More importantly, the court found that the FERC lacked jurisdiction to issue Order No. 745 because the "rule entails direct regulation of the retail market–a matter exclusively within state control."[11] The decision calls into question the jurisdictional foundation for all demand response programs currently subject to FERC oversight, and, in particular, for those programs that involve FERC regulated payments to demand resources. An appeal to the court for en banc review is pending. A motion for stay was granted until at least December 16, 2014, by the United States Court of Appeals. The FERC is now deciding whether to petition the Supreme Court for review. If a petition is filed, the stay will remain in effect until the Supreme Court's final disposition.

FirstEnergy filed an amended complaint on September 22, 2014, that seeks to the extend the finding in *EPSA v. FERC* to the PJM capacity market, and would, if granted, eliminate tariff provisions that provide for the compensation of Demand Resources as a form of capacity supply effective May 23, 2014.[12] The complaint also seeks to void the results of the 2017/2018 Base Residual Auction conducted in May 2014 and to rerun the auction excluding Demand Resources. The Market Monitor issued a report on July 10, 2014, analyzing the worst case effects in the event that such relief were granted.[13] The report concludes that "should a legal or policy decision be made to eliminate Demand Resources from its current participation as supply in the PJM capacity market, PJM markets could adapt."[14] The proceeding is pending before the Commission.

Participation in Demand Response Programs

On April 1, 2012, FERC Order No. 745 was implemented in the PJM economic program, requiring payment of full LMP for dispatched demand resources when a net benefit test (NBT) is met rather than payment of LMP offset by the payment for wholesale power already included in customers' tariff rates. In the first nine months of 2014, credits in the economic program were higher than in the same period for each of the last five years. There were fewer settlements submitted and more active participants in the first nine months of 2014 compared to the first nine months of 2013, and credits increased.

Table 6-1 Overview of demand response programs

	Emergency Load Response Program			Economic Load Response Program
	Load Management (LM)			
Market	Capacity Only	Capacity and Energy	Energy Only	Energy Only
Capacity Market	DR cleared in RPM	DR cleared in RPM	Not included in RPM	Not included in RPM
Dispatch Requirement	Mandatory Curtailment	Mandatory Curtailment	Voluntary Curtailment	Dispatched Curtailment
Penalties	RPM event or test compliance penalties	RPM event or test compliance penalties	NA	NA
Capacity Payments	Capacity payments based on RPM clearing price	Capacity payments based on RPM price	NA	NA
Energy Payments	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.

9 Electric Power Supply Association v. FERC, No. 11-1486.
10 *Id.*, slip. op. at 14.
11 *Id.*
12 See FirstEnergy Service Company complaint, FERC Docket No. EL14-55-000, amending the complaint filed May 23, 2014.
13 See IMM, The 2017/2018 RPM Base Residual Auction: Sensitivity Analyses, which can be accessed at: <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_20172018_RPM_BRA_Sensitivity_Analyses_20140710.pdf>.
14 *Id.* at 10.

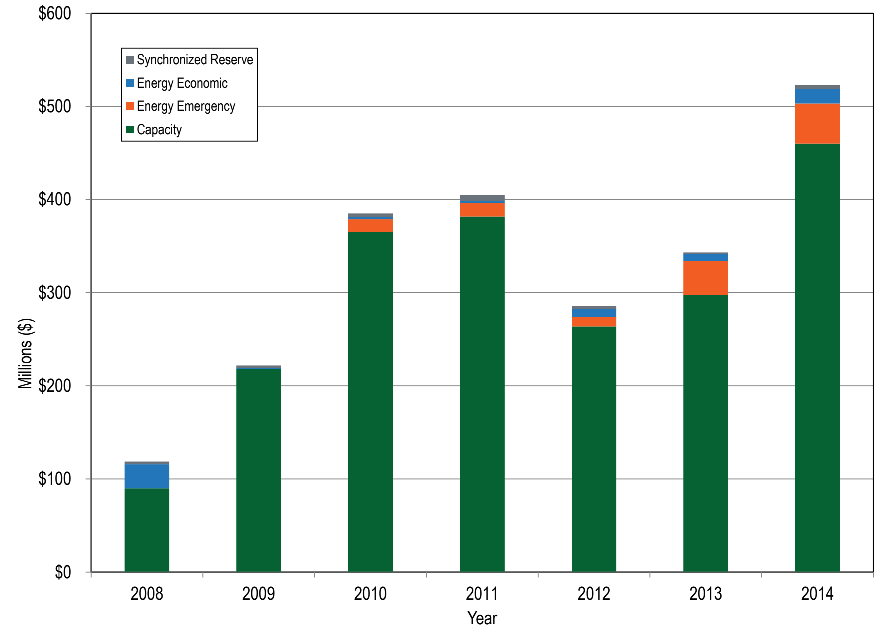
Figure 6-1 shows all revenue from PJM demand response programs by market for the period 2002 through the first nine months of 2014. Since the implementation of the RPM capacity market on June 1, 2007, demand response that participated through the capacity market, which includes emergency energy revenue, has been the primary source of revenue to demand response participants.[15]

Total emergency revenue increased by $169.0 million, or 50.6 percent, from $334.1 million in the first nine months of 2013 to $503.1 in the first nine months of 2014. Of the total emergency revenue, capacity market revenue increased by $162.7 million, or 54.7 percent, from $297.4 million in the first nine months of 2013 to $460.1 million in the first nine months of 2014, primarily due to higher clearing prices in the capacity market for the 2013/2014 and 2014/2015 delivery years. Of the total emergency revenue, emergency energy revenue to demand response that sold capacity increased by $6.2 million from $36.7 million in the first nine months of 2013, to $43.0 million in the first nine months of 2014.

Total credits under the economic program increased by $8,960,269 from $7,387,658 in the first nine months of 2013 to $16,347,928 in the first nine months of 2014, a 121 percent increase.

In the first nine months of 2014, emergency revenue, which includes capacity and emergency energy revenue, accounted for 96.2 percent of all revenue received by demand response providers, credits from the economic program were 2.9 percent and revenue from synchronized reserve was 0.8 percent.

Figure 6-1 Demand response revenue by market: January through September, 2008 through 2014



Economic Program

Table 6-2 shows registered sites and MW for the last day of each month for the period January 2010 through September 2014. Registration is a prerequisite for CSPs to participate in the economic program. The average number of registrations decreased and the average registered MW increased in the first nine months of 2014. The average number of registrations decreased by 46 from 1,113 in the first nine months of 2013 to 1,067 in the first nine months of 2014. The average monthly registered MW for the first nine months of 2014 increased by 318 MW, or 13.5 percent, from 2,364 MW in the first nine months of 2013 to 2,750 MW in the first nine months of 2014.

15 This includes both capacity market revenue and emergency energy revenue for capacity resources.

The economic program registered MW did not increase after FERC Order No. 745. The average registered MW in the first nine months of 2011, before FERC Order No. 745, was 2,382 MW, and the average registered MW in the first nine months of 2013, right after the implementation of FERC Order No. 745, was 2,364 MW, a decrease of 18 MW, or 0.76 percent.

Economic demand response had high market concentration in the first nine months of 2013 and 2014. The HHI for demand response reductions decreased 472 points, from 8260 in the first nine months of 2013 to 7788 in the first nine months of 2014.[16]

There is some overlap between economic registrations and emergency capacity registrations. There were 307 registrations and 1,885 MW of nominated MW in the emergency program that were also in the economic program at the end of the first nine months of 2014.

The registered MW in the economic load response program are not a good measure of the amount of MW available for dispatch in the energy market. Economic resources can dispatch more, less or the amount of MW registered in the program.

Table 6-3 shows the sum of maximum economic MW dispatched by registration each month for January 2011 through September 2014. The monthly maximum is the sum of each registration's monthly noncoincident peak dispatched MW. The annual maximum is the sum of each registration's annual noncoincident peak dispatched MW. This annual aggregated maximum dispatched MW for all economic demand response registered resources in the first nine months of 2014 increased by 12 MW, from 1,458 MW in the first nine months of 2013 to 1,470 MW in the first nine months of 2014.[17] The dispatch reflected the demand conditions in 2014 compared to prior years. For example, January through March of 2014 had significantly more dispatched MW than January through March in each of the last four years.

All demand response energy payments are uplift rather than market payments. Economic demand response energy costs are assigned to real-time exports from the PJM Region and real-time loads in each zone for which the load-weighted average real-time LMP for the hour during which the reduction occurred is greater than the price determined under the net benefits test for that month.[18]

Table 6-2 Economic program registrations on the last day of the month: January, 2010 through September, 2014

	2011		2012		2013		2014	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	1,609	2,432	1,993	2,385	841	2,314	1,180	2,343
Feb	1,612	2,435	1,995	2,384	843	2,327	1,174	2,349
Mar	1,612	2,5 19	1,996	2,356	788	2,284	1,185	2,710
Apr	1,611	2,534	189	1,318	970	2,346	1,194	2,845
May	1,687	3,166	371	1,669	1,375	2,414	745	2,529
Jun	1,143	1,912	803	2,347	1,302	2,144	928	2,961
Jul	1,228	2,062	942	2,323	1,315	2,443	1,036	3,024
Aug	1,987	2,194	1,013	2,373	1,299	2,527	1,080	3,052
Sep	1,962	2,183	1,052	2,421	1,280	2,475	1,077	2,937
Oct	1,954	2,179	828	2,269	1,210	2,335		
Nov	1,988	2,255	824	2,267	1,192	2,307		
Dec	1,992	2,259	846	2,283	1,192	2,311		
Avg.	1,699	2,344	1,071	2,200	1,134	2,352	1,067	2,750

16 For more information, see Table 6-8.

17 As a result of the 60 day data lag from event date to settlement, not all settlements for June 2014 are incorporated in this report.
18 PJM: "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), p 70.

Table 6-3 Maximum economic MW dispatched by registration per month: January, 2010 through September, 2014

	Maximum Dispatched MW by Registration				
Month	2010	2011	2012	2013	2014
Jan	233	243	104	193	446
Feb	121	190	101	119	307
Mar	115	153	72	127	369
Apr	111	80	108	133	146
May	172	98	143	192	151
Jun	209	561	944	433	483
Jul	999	561	1,641	1,088	665
Aug	794	161	980	497	284
Sep	276	84	451	530	611
Oct	118	81	242	168	
Nov	111	86	165	155	
Dec	41	88	99	168	
Total	1,209	841	1,956	1,486	1,470

Table 6-4 shows total credits paid to participants in the economic program. The average credits per MWh increased by $71.47 per MWh, or 101.9 percent, from $70.16 per MWh in the first nine months of 2013 to $141.63 per MWh dispatched in the first nine months of 2014. The average real time PJM LMP increased by $20.42 per MWh, from $37.30 per MWh during the first nine months of 2013 to $57.72 per MWh during the first nine months of 2014. Curtailed energy for the economic program was 115,427 MWh in the first nine months of 2014 and the total payments were $16,347,928. Credits, for the first nine months of 2014, increased by $8,960,269, or 121 percent, compared to the first nine months of 2013.

Table 6-4 Credits paid to the PJM economic program participants: January through September, 2010 through 2014

Year (Jan-Sep)	Total MWh	Total Credits	$/MWh
2010	58,280	$2,677,937	$45.95
2011	15,376	$1,943,507	$126.40
2012	122,080	$8,179,884	$67.00
2013	105,299	$7,387,658	$70.16
2014	115,427	$16,347,928	$141.63

Economic demand response resources that are dispatched in both the economic and emergency programs at the same time are settled under emergency rules. For example, assume a demand resource has an economic strike price of $100 per MWh and an emergency strike price of $1,800 per MWh. If this resource was scheduled to reduce in the Day-Ahead Energy Market, the demand resource would receive $100 per MWh, but if an emergency event were called during the economic dispatch, the demand resource would receive its emergency strike price of $1,800 per MWh instead of the economic strike price of $100 per MWh. The rationale for this rule is not clear. All other resources that clear in the day-ahead market are financially firm at that clearing price.

Figure 6-2 shows monthly economic demand response credits and MWh, for 2010 through the first nine months of 2014. Higher energy prices and FERC Order No. 745 increased incentives to participate starting in April 2012. The high LMPs in the first nine months of 2014, driven by an extremely cold winter in PJM, resulted in more participation in the economic program. The January economic credits were more than twice the previous monthly maximum from July 2012 and the highest in the last five years.

Figure 6-2 Economic program credits and MWh by month: January, 2010 through September, 2014

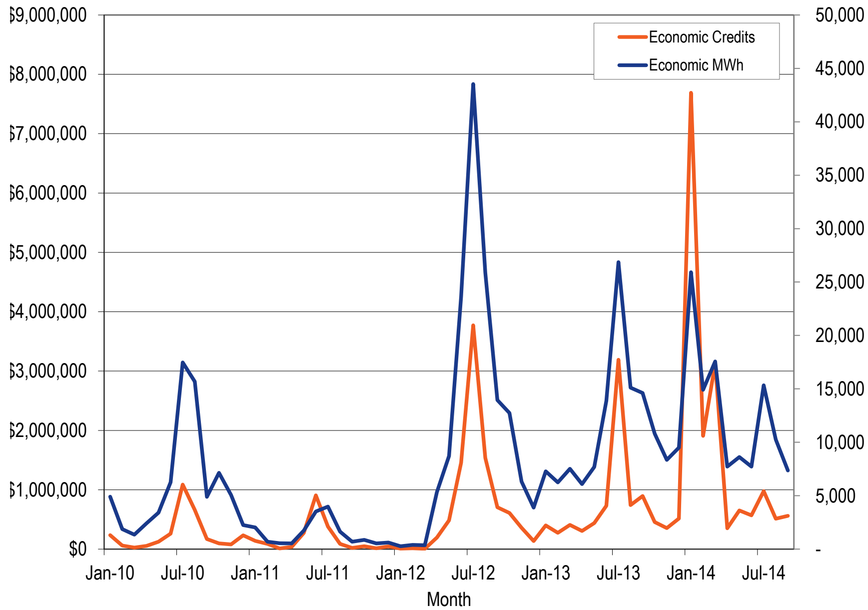


Table 6-5 PJM economic program participation by zone: January through September, 2013 and 2014[19]

	Credits			MWh Reductions		
Zones	2013	2014	Percentage Change	2013	2014	Percentage Change
AECO, JCPL, PECO, Pepco, RECO	$510,155	$3,192,586	526%	3,785	15,760	316%
AEP, APS	$192,243	$315,236	64%	2,833	3,187	13%
ATSI, ComEd, DAY, DEOK, DLCO, EKPC	$714,647	$932,929	31%	13,875	7,803	(44%)
BGE, DPL, Met-Ed, PENELEC	$948,990	$10,064,421	961%	8,437	80,349	852%
Dominion	$4,322,168	$195,717	(95%)	68,407	617	(99%)
PPL	$280,695	$44,343	(84%)	3,310	435	(87%)
PSEG	$418,760	$1,602,696	283%	4,653	7,276	56%
Total	$7,387,658	$16,347,928	121%	105,299	115,427	10%

19 PJM and the MMU cannot publish more detailed information about the Economic Program Zonal Settlements as a result of confidentiality requirements.

Table 6-5 shows 2013 and 2014 performance in the economic program by control zone and participation type. Total economic program reductions increased ten percent from 105,299 MW in the first nine months of 2013 to 115,427 MW in the first nine months of 2014. The economic credits increased by 121 percent from $7,387,658 in the first nine months of 2013, to $16,347,928 in the first nine months of 2014.

Table 6-6 shows total settlements submitted by year for the first nine months of 2009 through the first nine months of 2014. A settlement is counted for every day on which a registration is dispatched in the economic program. Settlements increased after FERC Order No. 745 in 2012, but decreased in 2013. There were 1,821 economic settlements in the first nine months of 2014 compared to 1,952 settlements in the first nine months of 2013.

Table 6-6 Settlements submitted by year in the economic program: January through September, 2009 through 2014

Jan – Sep	2009	2010	2011	2012	2013	2014
Number of Settlements	1,642	3,367	703	4,195	1,952	1,821

Table 6-7 shows the number of curtailment service providers (CSPs) and participants actively submitting settlements by year for the first nine months of 2009 through the first nine months of 2014. The number of active participants during the first nine months of 2014 was lower by 119 participants than in the first nine months of 2013.

Economic demand response had high market concentration in the first nine months of 2013 and 2014, as shown in Table 6-8. Table 6-8 shows the monthly HHI index, the overall HHI index in the first nine months of 2014. The table also lists the percentage of reductions provided by, and the percentage of credits claimed by, the four DR companies that provided the highest amount of economic DR reduction. The HHI for demand response reductions decreased 472 points, from 8260 in the first nine months of 2013 to 7788 in the first nine months of 2014. In the first nine months of 2014, the four most dispatched CSPs contributed 81.3 percent of all Economic DR reduction, and they claimed 78.2 percent of Economic DR revenue.

Table 6-7 Participants and CSPs submitting settlements in the economic program by year: January through September, 2009 through 2014

	2009		2010		2011		2012		2013		2014	
	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants	Active CSPs	Active Participants
Total Distinct Active	15	206	16	257	15	203	22	428	20	273	16	154

Table 6-8 HHI and market concentration in the economic program: January through September, 2013 and 2014

	HHI			Top Four Companies Share of Reduction			Top Four Companies Share of Credit		
Month	2013	2014	Percentage Change	2013	2014	Change Percent	2013	2014	Change Percent
Jan	7981	3347	(58.1%)	98.0%	86.7%	(11.2%)	94.1%	84.2%	(9.9%)
Feb	8478	2559	(69.8%)	100.0%	84.1%	(15.9%)	99.0%	77.5%	(21.5%)
Mar	8237	4435	(46.2%)	99.9%	87.4%	(12.4%)	99.9%	88.5%	(11.3%)
Apr	8573	5951	(30.6%)	100.0%	100.0%	0.0%	100.0%	100.0%	0.0%
May	5468	6092	11.4%	99.5%	98.8%	(0.7%)	99.8%	99.1%	(0.7%)
Jun	3682	2404	(34.7%)	88.2%	90.8%	2.6%	86.0%	87.1%	1.1%
Jul	1943	3358	72.8%	75.4%	87.9%	12.5%	71.0%	85.2%	14.2%
Aug	2862	5506	92.4%	98.2%	100.0%	1.8%	98.5%	100.0%	1.5%
Sep	3702	3880	4.8%	92.8%	99.0%	6.2%	87.4%	98.4%	11.0%
Total	3793	3617	(4.6%)	88.2%	81.3%	(6.9%)	76.1%	78.2%	2.1%

Table 6-9 shows average MWh reductions and credits by hour for the first nine months of 2013 and the first nine months of 2014. The majority of reductions occurred between the hour ending 0700 and hour ending 2100 in the first nine months of 2013 and 2014. In the first nine months of 2013, 98 percent of reductions and 99 percent of credits occurred from 0700 to 2100, and in the first nine months of 2014, 88 percent of reductions and 85 percent of credits occurred from 0700 to 2100. The credits earned increased for all hours except hours ending 1500, 1600 and 1700 in the first nine months of 2014 compared to the first nine months of 2013.

Table 6-9 Hourly frequency distribution of economic program MWh reductions and credits: January through September, 2013 and 2014

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2013	2014	Percentage Change	2013	2014	Percentage Change
1	152	771	406%	$5,101	$127,448	2,398%
2	140	719	415%	$3,303	$112,127	3,295%
3	140	875	524%	$2,520	$149,110	5,817%
4	139	1,473	960%	$1,683	$290,489	17,157%
5	145	1,304	802%	$1,687	$201,531	11,844%
6	152	1,801	1,085%	$3,592	$316,148	8,701%
7	3,616	4,646	28%	$192,380	$872,658	354%
8	4,356	5,847	34%	$266,581	$1,079,702	305%
9	4,457	6,242	40%	$213,867	$837,467	292%
10	4,418	6,440	46%	$195,747	$962,270	392%
11	3,809	4,754	25%	$182,047	$841,202	362%
12	3,610	3,948	9%	$166,844	$753,218	351%
13	5,514	4,441	(19%)	$308,768	$638,323	107%
14	8,912	7,069	(21%)	$798,680	$822,022	3%
15	12,353	9,860	(20%)	$956,763	$908,335	(5%)
16	12,806	10,349	(19%)	$1,101,327	$963,144	(13%)
17	12,668	10,458	(17%)	$1,113,826	$998,988	(10%)
18	12,085	10,536	(13%)	$930,150	$1,202,584	29%
19	8,881	6,880	(23%)	$554,598	$1,022,290	84%
20	4,036	5,755	43%	$225,716	$1,061,535	370%
21	1,551	4,680	202%	$97,641	$922,105	844%
22	742	3,087	316%	$40,233	$596,910	1,384%
23	363	1,909	426%	$14,788	$379,388	2,466%
24	256	1,583	520%	$9,814	$288,934	2,844%
Total	105,299	115,427	10%	$7,387,658	$16,347,928	121%

Table 6-10 shows the distribution of economic program MWh reductions and credits by ranges of real-time zonal, load-weighted, average LMP in the first nine months of 2013 and 2014. Reductions occurred at all price levels. In the hours when the applicable zonal LMP was higher than $400 per MWh, 7.5 percent of MWh reductions and 28.3 percent of program credits occurred in the first nine months of 2014. When LMP was above $1,000 per MWh, 0.45 percent of MWh reductions and 3.13 percent of program credits occurred. MWh reductions in the first nine months of 2014 increased 10 percent compared to the first nine months of 2013.

Table 6-10 Frequency distribution of economic program zonal, load-weighted, average LMP (By hours): January through September, 2013 and 2014

	MWh Reductions			Program Credits		
LMP	2013	2014	Percentage Change	2013	2014	Percentage Change
$0 to $25	433	259	(40%)	$5,702	$2,751	(52%)
$25 to $50	59,212	37,091	(37%)	$2,472,053	$1,697,382	(31%)
$50 to $75	22,378	23,848	7%	$1,479,817	$1,608,096	9%
$75 to $100	6,612	11,568	75%	$641,211	$1,157,598	81%
$100 to $125	6,221	6,700	8%	$855,156	$844,644	(1%)
$125 to $150	4,089	5,062	24%	$639,673	$779,456	22%
$150 to $175	1,318	4,109	212%	$203,376	$758,596	273%
$175 to $200	990	3,447	248%	$172,700	$748,172	333%
$200 to $225	830	2,951	256%	$143,437	$672,056	369%
$225 to $250	1,068	2,816	164%	$182,700	$702,572	285%
$250 to $275	143	2,303	1,515%	$34,753	$636,510	1,732%
$275 to $300	640	1,844	188%	$169,186	$545,908	223%
$300 to $325	374	1,529	309%	$99,169	$447,031	351%
$325 to $350	205	1,059	417%	$19,008	$359,764	1,793%
$350 to $375	216	1,259	483%	$50,647	$435,346	760%
$375 to $400	47	916	1,851%	$12,574	$333,491	2,552%
> $400	523	8,660	1,554%	$206,495	$4,618,554	2,137%
Total	105,299	115,420	10%	$7,387,658	$16,347,928	121%

Following the implementation of FERC Order No. 745 on April 1, 2012, demand resources were paid full LMP for any load reductions during the hours they were dispatched, provided that LMP was greater than the net benefits test threshold. The Economic DR program revenue was $16,347,928 in the first nine months of 2014. Without FERC Order 745, the estimated total revenue would have been $9,526,185, or 41.7 percent lower.[20]

Following Order 745, the NBT is calculated for each month to define a price point above which the net benefits of DR are deemed to exceed the cost to load. Demand response reduction has two effects on the per MWh energy payment by loads and exports. DR reduces LMP by reducing demand in the energy market. At the same time, DR payment causes an additional uplift charge. NBT is designed as a threshold above which the payment reduction effect overweighs the payment inflation effect. NBT is a monthly estimate calculated from the supply curve of PJM, and it does not incorporate the real-time or day-ahead prices. When the LMP is above the NBT threshold, the demand response resource receives credit for the full LMP. Demand resources are not paid for any load reductions during hours where the LMP is below the net benefits test price. About two percent of DR dispatch occurred during hours with LMP lower than NBT.

Table 6-11 shows the net benefit test threshold from April 2012, when FERC Order 745 was implemented in PJM, through the first nine months of 2014.

Table 6-11 Result from net benefit tests: April, 2012 through September, 2014

	Net Benefit Test Threshold ($/MWh)		
Month	2012	2013	2014
Jan		$25.72	$29.51
Feb		$26.27	$30.44
Mar		$25.60	$34.93
Apr	$25.89	$26.96	$32.59
May	$23.46	$27.73	$32.08
Jun	$23.86	$28.44	$31.62
Jul	$22.99	$29.42	$31.62
Aug	$24.47	$28.58	$29.85
Sep	$24.93	$28.80	$29.83
Oct	$25.96	$29.13	
Nov	$25.63	$31.63	
Dec	$25.97	$28.82	
Average	$24.80	$28.09	$31.39

Table 6-12 shows the number of hours that at least one zone in PJM has day-ahead LMP or real-time LMP higher than NBT. In the first nine months of 2014, the highest zonal LMP in PJM was higher than NBT in 5,789 hours out of the entire 6,551 hours, or 88.4 percent of all hours. Reductions occurred in 5,125 hours, or 88.5 percent, out of the 5,789 hours in the first nine months of 2014.

Table 6-12 Hours with price higher than NBT and DR occurrences in those hours: January through September, 2013 and 2014

	Number of Hours	Number of Hours with LMP Higher than NBT			Percentage of NBT Hours with DR		
Month	2013/2014	2013	2014	Percentage Change	2013	2014	Change Percent
Jan	744	716	742	3.6%	78.9%	93.8%	14.9%
Feb	672	672	672	0.0%	89.3%	92.9%	3.6%
Mar	743	743	732	(1.5%)	80.8%	81.8%	1.1%
Apr	720	717	661	(7.8%)	86.6%	86.5%	(0.1%)
May	744	669	694	3.7%	88.3%	85.3%	(3.0%)
Jun	720	597	557	(6.7%)	94.0%	87.8%	(6.2%)
Jul	744	609	540	(11.3%)	94.7%	97.8%	3.0%
Aug	744	550	586	6.5%	89.8%	88.6%	(1.3%)
Sep	720	582	605	4.0%	88.8%	83.6%	(5.2%)
Total	6,551	5,855	5,789	(1.1%)	87.5%	88.5%	1.0%

Following the implementation of FERC Order No. 745, DR in PJM is paid by real-time loads and real-time scheduled exports. Table 6-13 shows the sum of real-time DR charges and day-ahead DR charges for each zone and for exports. The demand response charges in January 2014 were 47.0 percent of the total economic DR charges in the first nine months of 2014. Real-time loads in AEP, Dominion, and ComEd paid the highest DR charges in the first nine months of 2014.

20 We use the average day-ahead LMP as an approximation of the generation potion of retail rate. Per unit DR payment for a zone is estimated as (day-ahead hourly LMP – average LMP).

Table 6-14 shows the monthly day-ahead and real-time DR charges and the per MWh DR charges in the first nine months of 2013 and 2014. The day-ahead DR charges increased $2,959,092, or 78.0 percent, from $3,792,296 in the first nine months of 2013 to $6,751,388 in the first nine months of 2014. The real-time DR charge increased $6,001,082, or 167 percent, from $3,595,362 in the first nine months of 2013 to $9,596,444 in the first nine months of 2014. The per MW load charge from DR increased $0.0243/MWh, or 89.8 percent, from $0.027/MWh in the first nine months of 2013 to $0.0514/MWh in the first nine months of 2014.

Table 6-13 Zonal DR charge: January through September 2014

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$88,787	$21,811	$36,352	$4,216	$6,575	$7,867	$16,679	$6,786	$8,203	$197,277
AEP	$1,287,055	$312,328	$490,612	$55,153	$105,762	$86,463	$130,093	$79,304	$82,060	$2,628,831
APS	$499,040	$121,446	$194,455	$20,964	$38,630	$32,054	$54,049	$29,254	$31,587	$1,021,479
ATSI	$610,023	$155,457	$248,281	$30,829	$57,728	$48,066	$71,721	$42,787	$46,213	$1,311,105
BGE	$336,929	$79,554	$130,350	$14,007	$28,830	$24,750	$48,599	$23,288	$26,010	$712,318
ComEd	$751,170	$204,212	$329,208	$35,592	$77,758	$70,601	$83,644	$66,001	$60,560	$1,678,746
DAY	$163,297	$40,896	$62,819	$7,580	$14,810	$12,270	$17,406	$11,432	$12,192	$342,705
DEOK	$248,017	$62,898	$93,801	$10,662	$23,030	$19,939	$27,326	$17,958	$18,590	$522,222
DLCO	$125,595	$24,946	$49,291	$5,212	$12,433	$10,406	$15,241	$8,968	$9,219	$261,312
Dominion	$1,021,400	$236,410	$393,303	$40,645	$91,199	$72,760	$133,387	$64,534	$76,837	$2,130,474
DPL	$199,098	$46,459	$75,679	$7,990	$12,526	$13,135	$27,171	$11,720	$12,952	$406,729
EKPC	$156,880	$34,851	$52,705	$4,838	$9,578	$8,339	$12,025	$7,747	$7,720	$294,683
JCPL	$200,870	$50,017	$81,694	$8,870	$15,532	$17,879	$38,668	$15,056	$17,810	$446,395
Met-Ed	$147,504	$36,986	$60,434	$6,656	$9,572	$9,503	$19,167	$7,837	$9,296	$306,954
PECO	$375,055	$92,690	$150,894	$17,175	$26,901	$27,270	$56,417	$22,286	$27,223	$795,912
PENELEC	$164,067	$42,050	$68,023	$8,248	$14,718	$10,794	$18,958	$10,089	$10,518	$347,464
Pepco	$313,611	$73,684	$119,799	$13,360	$28,608	$23,994	$45,233	$22,606	$25,615	$666,510
PPL	$420,890	$104,335	$167,056	$18,205	$26,241	$24,189	$48,016	$20,558	$24,073	$853,563
PSEG	$368,239	$92,173	$150,738	$18,849	$30,794	$31,715	$66,823	$26,544	$31,852	$817,727
RECO	$12,180	$3,050	$5,037	$658	$1,098	$1,239	$2,527	$1,064	$1,243	$28,096
Export	$199,606	$72,391	$168,380	$21,206	$18,342	$16,302	$44,458	$16,505	$20,140	$577,330
Total	$7,689,314	$1,908,644	$3,128,912	$350,913	$650,665	$569,536	$977,608	$512,326	$559,914	$16,347,832

Table 6-14 Monthly day-ahead and real-time DR charge: January through September, 2013 and 2014

	Day-ahead DR Charge			Real-time DR Charge			Per MW Charge ($/MWh)		
Month	2013	2014	Percentage Change	2013	2014	Percentage Change	2013	2014	Percentage Change
Jan	$251,494	$3,580,411	1,324%	$147,937	$4,108,903	2,677%	$0.016	$0.131	725%
Feb	$241,179	$1,148,053	376%	$34,565	$760,591	2,100%	$0.011	$0.038	246%
Mar	$344,210	$762,224	121%	$64,371	$2,366,688	3,577%	$0.015	$0.075	(76%)
Apr	$267,301	$67,996	(75%)	$39,944	$282,918	608%	$0.013	$0.012	(4%)
May	$276,352	$151,962	(45%)	$161,883	$498,703	208%	$0.018	$0.024	38%
Jun	$323,881	$309,885	(4%)	$406,716	$259,651	(36%)	$0.022	$0.018	(20%)
Jul	$1,467,622	$506,523	(65%)	$1,722,650	$471,085	(73%)	$0.068	$0.031	(55%)
Aug	$182,941	$141,828	(22%)	$560,348	$370,497	(34%)	$0.020	$0.018	(11%)
Sep	$437,316	$82,507	(81%)	$456,949	$477,407	4%	$0.031	$0.028	(8%)
Total	$3,792,296	$6,751,388	78%	$3,595,362	$9,596,444	167%	$0.027	$0.051	90%

Emergency Program

The emergency load response program consists of the limited demand response product in the capacity market during the 2013/2014 Delivery Year and the limited, extended summer and annual demand response product in the capacity market during the 2014/2015 Delivery Year. To participate as a limited demand resource, the provider must clear MW in an RPM auction. Emergency resources receive capacity revenue from the capacity market and also receive revenue from the energy market for reductions during a PJM initiated emergency event. The rules applied to demand resources in the current market design do not treat demand resources in a manner comparable to generation capacity resources, even though demand resources are sold in the same capacity market, are treated as a substitute for other capacity resources and displace other capacity resources in RPM auctions. The MMU recommends that if demand resources remain on the supply side of the capacity market, a daily must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources. This will help to ensure comparability and consistency for demand resources. The MMU also recommends that demand resources have an offer cap equal to the offer cap applicable to energy offers from generation capacity resources, currently $1,000 per MWh.[21]

Emergency demand response had moderate market concentration in the first nine months of 2014. The HHI for emergency demand response registrations increased 231 points, from 1529 in the first nine months of 2013 to 1760 in the first nine months of 2014. In the first nine months of 2014, the four largest companies contributed 65.3 percent of all registered emergency demand response resources.

Table 6-15 shows zonal monthly capacity market revenue to demand resources for the first nine months of 2014. Capacity market revenue increased in the first nine months of 2014 by $162.7 million, or 54.7 percent, compared to the first nine months of 2013, from $297.4 million to $460.1 million, as a result of higher RPM prices and more cleared DR in RPM for the 2013/2014 and 2014/2015 delivery years.

Table 6-15 Zonal monthly capacity revenue: January through September, 2014

Zone	January	February	March	April	May	June	July	August	September	Total
AECO	$1,035,717	$935,486	$1,035,717	$1,002,307	$1,035,717	$805,435	$832,282	$832,282	$805,435	$8,320,379
AEP, EKPC	$776,197	$701,081	$776,197	$751,158	$776,197	$6,203,447	$6,410,228	$6,410,228	$6,203,447	$29,008,179
AP	$493,260	$445,525	$493,260	$477,348	$493,260	$3,380,132	$3,492,803	$3,492,803	$3,380,132	$16,148,523
ATSI	$377,750	$341,193	$377,750	$365,564	$377,750	$3,717,155	$3,841,060	$3,841,060	$3,717,155	$16,956,434
BGE	$7,736,807	$6,988,083	$7,736,807	$7,487,232	$7,736,807	$5,140,527	$5,311,878	$5,311,878	$5,140,527	$58,590,547
ComEd	$808,185	$729,973	$808,185	$782,114	$808,185	$5,846,358	$6,041,237	$6,041,237	$5,846,358	$27,711,833
DAY	$44,278	$39,993	$44,278	$42,849	$44,278	$872,987	$902,087	$902,087	$872,987	$3,765,824
DEOK	$16,653	$15,041	$16,653	$16,115	$16,653	$330,654	$341,676	$341,676	$330,654	$1,425,774
DLCO	$148,045	$133,718	$148,045	$143,269	$148,045	$840,774	$5,338,145	$5,338,145	$5,165,946	$17,404,131
Dominion	$605,391	$546,805	$605,391	$585,862	$605,391	$5,165,946	$1,593,999	$1,593,999	$1,542,580	$12,845,366
DPL	$1,979,013	$1,787,496	$1,979,013	$1,915,174	$1,979,013	$1,542,580	$868,800	$868,800	$840,774	$13,760,662
JCPL	$2,288,883	$2,067,378	$2,288,883	$2,215,048	$2,288,883	$1,709,946	$1,766,944	$1,766,944	$1,709,946	$18,102,852
Met-Ed	$2,246,581	$2,029,170	$2,246,581	$2,174,111	$2,246,581	$1,558,377	$1,610,323	$1,610,323	$1,558,377	$17,280,426
PECO	$5,314,219	$4,799,939	$5,314,219	$5,142,792	$5,314,219	$3,249,878	$3,358,207	$3,358,207	$3,249,878	$39,101,559
PENELEC	$2,980,723	$2,692,266	$2,980,723	$2,884,571	$2,980,723	$1,675,004	$1,730,838	$1,730,838	$1,675,004	$21,330,692
Pepco	$4,229,396	$3,820,100	$4,229,396	$4,092,964	$4,229,396	$3,467,834	$3,583,429	$3,583,429	$3,467,834	$34,703,778
PPL	$7,253,736	$6,551,762	$7,253,736	$7,019,745	$7,253,736	$5,215,729	$5,389,586	$5,389,586	$5,215,729	$56,543,345
PSEG	$8,859,978	$8,002,561	$8,859,978	$8,574,172	$8,859,978	$5,460,187	$5,642,193	$5,642,193	$5,460,187	$65,361,427
RECO	$257,721	$232,781	$257,721	$249,408	$257,721	$118,962	$122,927	$122,927	$118,962	$1,739,131
Total	$47,452,531	$42,860,351	$47,452,531	$45,921,805	$47,452,531	$56,301,913	$58,178,643	$58,178,643	$56,301,913	$460,100,861

21 See "Complaint and Motion to Consolidate of the Independent Market Monitor," Docket No. EL14-20-000 (January 28, 2014).

Table 6-16 shows the amount of energy efficiency (EE) resources in PJM for 2012/2013 through 2014/2015 delivery years. Energy efficiency resources are offered in the PJM Capacity Market. The total MW of energy efficiency resources increased by 24 percent from 1,029.2 MW in the 2013/2014 delivery year to 1,282.4 MW in 2014/2015 Delivery Year.

Table 6-16 Energy efficiency resources by MW: 2012/2013 through 2014/2015 Delivery Year

	EE ICAP (MW)			EE UCAP (MW)		
	2012/2013	2013/2014	2014/2015	2012/2013	2013/2014	2014/2015
Total	609.8	990.9	1,231.8	631.2	1,029.2	1,282.4

Table 6-17 shows the number of customers and the nominated MW by product type and lead time for the 2014/2015 Delivery Year. The annual and extended summer products are new for the 2014/2015 Delivery Year. The quick lead time, which is obligated to respond within 30 minutes, is also new for the 2014/2015 Delivery Year. The quick lead time has 7.5 percent of all nominated MW with 704.0 MW and only 22 locations responding.

The quick, 30 minute, lead time was defined after the auctions cleared. FERC accepted PJM's proposed 30 minute lead time as a phased in approach on May 9, 2014.[22] PJM submitted a filing on October 20, 2014, to allow DR that is unable to respond within 30 minutes to exit the market without penalty before the mandatory 30 minute lead time with the 2015/2016 Delivery Year.[23]

Table 6-17 Lead time by product type: 2014/2015 Delivery Year

Lead Type	Product Type	Locations	Nominated MW
Long Lead (120 Minutes)	Annual and Extended Summer	2,079	1,130.9
	Limited	13,781	7,039.8
Short Lead (60 Minutes)	Annual, Extended Summer and Limited	55	485.7
Quick Lead (30 Minutes)	Annual and Limited	22	704.0
Total		15,937	9,360.3

Table 6-18 shows the MW registered by measurement and verification method and by load drop method for the 2013/2014 Delivery Year. Of the DR MW committed, 4.9 percent use the guaranteed load drop (GLD) measurement and verification method, 86.8 percent use the firm service level (FSL) method and 8.4 percent use direct load control (DLC).

The program type is submitted as "Other" for 1.5 percent of committed MW, which does not explain the basis for the reduction. The choice of other is no longer a valid option for new registrations as of the 2014/2015 Delivery Year.

Table 6-18 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	1,810.8	1,414.7	241.7	737.0	3,382.1	77.8	121.0	7,785.0	87.0%
Guaranteed Load Drop	69.9	169.2	4.1	23.6	33.7	0.8	12.0	313.2	3.5%
Non hourly metered sites (DLC)	0.0	812.6	0.0	0.0	0.0	40.0	0.0	852.6	9.5%
Total	1,880.7	2,396.6	245.7	760.6	3,415.7	118.6	133.0	8,950.8	100.0%
Percentage by method	21.0%	26.8%	2.7%	8.5%	38.2%	1.3%	1.5%	100.0%	

22 See "Order Rejecting, in part, and Accepting, in part, Proposed Tariff Changes, Subject to Conditions," Docket No. ER14-822-001 (May 9, 2014).
23 See "PJM Interconnection, L.L.C.," Docket No. ER14-135-000 (October 20, 2014).

Table 6-19 Reduction MW by each demand response method: 2014/2015 Delivery Year

Program Type	On-site Generation MW	HVAC MW	Refrigeration MW	Lighting MW	Manufacturing MW	Water Heating or Other MW	Total	Percentage by type
Firm Service Level	2,119.6	1,970.8	207.4	740.6	3,428.5	69.9	8,536.8	91.2%
Guaranteed Load Drop	25.2	152.9	1.8	12.2	33.9	0.5	226.6	2.4%
Non hourly metered sites (DLC)	0.0	551.1	0.0	0.0	0.0	41.0	592.1	6.3%
Total	2,144.7	2,674.8	209.2	752.8	3,462.4	111.4	9,355.4	100.0%
Percentage by method	22.9%	28.6%	2.2%	8.0%	37.0%	1.2%	100.0%	

Table 6-19 shows the MW registered by measurement and verification method and by load drop method for the 2014/2015 Delivery Year. Of the DR MW committed, 2.4 percent use the guaranteed load drop (GLD) measurement and verification method, 91.2 percent use the firm service level (FSL) method and 6.3 percent use direct load control (DLC). FSL registrations increased by 751.8 MW while GLD registrations decreased by 86.7 MW and DLC registrations decreased by 260.6 MW from the 2013/2014 delivery year to the 2014/2015 delivery year.

Table 6-20 shows the fuel type used by the on-site generators identified in Table 6-18 for the 2013/2014 Delivery Year. Of the 17.5 percent of emergency demand response identified as using on-site generation, 76.2 percent of MW are diesel, 5.3 percent are natural gas and 0.9 percent is coal, oil, other and 17.6 percent are no fuel source, meaning that the participant responded inaccurately.[24]

Table 6-20 On-site generation fuel type by MW: 2013/2014 Delivery Year

Fuel Type	MW	Percentage
Coal, Oil, Other	16.3	0.9%
Diesel	1,432.8	76.2%
Natural Gas	100.2	5.3%
None	331.3	17.6%
Total	1,880.7	100.00%

Table 6-21 shows the fuel type used in the on-site generators identified in Table 6-19 for the 2014/2015 Delivery Year. Of the 17.5 percent of emergency demand response identified as using on-site generation, 81.6 percent of MW are diesel, 11.7 percent are natural gas and 2.8 percent is coal, gasoline, kerosene, oil, propane, waste products and 4.0 percent are no fuel source, meaning the participant responded inaccurately.

Table 6-21 On-site generation fuel type by MW: 2014/2015 Delivery Year

Fuel Type	MW	Percentage
Coal, Gasoline, Kerosene, Oil, Propane, Waste Products	59.6	2.8%
Diesel	1,749.1	81.6%
Natural Gas	251.0	11.7%
None	85.0	4.0%
Total	2,144.7	100.00%

Emergency Event Reported Compliance

PJM declared eight emergency events in the first nine months of 2014, two on January 7, one on January 8, one on January 22, two on January 23, one on January 24 and one on March 4. There were 13 events during the 2013/2014 Delivery Year, two events during the 2012/2013 Delivery Year and one event in the 2011/2012 Delivery Year. Since all of the 2014 events occurred outside of the summer compliance period, none were considered in PJM's compliance assessment.[25] Table 6-22 shows the demand response cleared UCAP MW for PJM by Delivery Year. Total demand response cleared in PJM increased from 1.4 percent in the 2011/2012 Delivery Year to 9.3 percent of capacity resources in the 2014/2015 Delivery Year.

24 Since 1.5 percent of committed MW are registered under the other option, the 17.5 percent of emergency load response resources registered with on-site generation could be conservatively low.

25 Annual and extended summer demand response products were not active in PJM's demand response program until June 1, 2014.

Table 6-22 Demand response cleared MW UCAP for PJM: 2011/2012 through 2014/2015 Delivery Year

	2011/2012 Delivery Year		2012/2013 Delivery Year		2013/2014 Delivery Year		2014/2015 Delivery Year	
	DR Cleared MW UCAP	DR Percentage of Capacity MW UCAP	DR Cleared MW UCAP	DR Percentage of Capacity MW UCAP	DR Cleared MW UCAP	DR Percentage of Capacity MW UCAP	DR Cleared MW UCAP	DR Percentage of Capacity MW UCAP
Total	1,826.6	1.4%	8,740.9	6.2%	10,779.6	6.7%	14,943.0	9.3%

Table 6-23 lists PJM emergency load management events declared by PJM in the first nine months of 2014 and the affected zones. The SWMAAC LDA was the only LDA called for all eight events. All demand response events called in the first nine months of 2014 were voluntary, so no penalties are assessed for under compliance.

Participants in the emergency demand response program are paid based on the average performance by registration for the duration of a demand response event. Demand response should measure compliance based on each hour to accurately report reductions during demand response events. This would be consistent with the rules that apply to generation resources. The MMU recommends demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance.

PJM deployed both long lead time resources, which require more than one hour but less than two hours notification, and short lead time resources, which require less than an hour notification during the 2013/2014 Delivery Year. Any resource is eligible to be either a short lead time or long lead time resource, and there are no differences in payment for these resources. Approximately 99.5 percent of registrations, accounting for 91.6 percent of registered MW, are designated as long lead time resources. The MMU recommends that the lead times for demand resources be shortened to 30 minute lead time with an hour minimum dispatch for all resources. This will enable quicker response and greater flexibility.

Table 6-23 PJM declared load management events: January through September, 2014

Event Date	Event Times	Compliance Hours	Minutes not Measured for Compliance	Lead Time	Geographical Area
7-Jan-14	5:30-11:00	None	330	Short Lead	RTO
	6:30-11:00	None	270	Long Lead	RTO
	16:00-18:15	None	135	Short Lead	RTO
	17:00-18:15	None	75	Long Lead	RTO
8-Jan-14	6:00-7:00	None	60	Short Lead	RTO
	7:00-7:00	None	0	Long Lead	RTO
22-Jan-14	15:00-21:00	None	360	Short Lead	SWMAAC
	16:00-21:00	None	300	Long Lead	SWMAAC
23-Jan-14	5:30-8:30	None	180	Short Lead	MAAC, APS, Dominion
	6:30-8:30	None	120	Long Lead	MAAC, APS, Dominion
	15:00-19:00	None	240	Short Lead	MAAC, APS, Dominion
	16:00-19:00	None	180	Long Lead	MAAC, APS, Dominion
24-Jan-14	5:30-8:45	None	195	Short Lead	MAAC, APS, Dominion
	6:30-8:45	None	135	Long Lead	MAAC, APS, Dominion
4-Mar-14	5:30-8:30	None	180	Short Lead	RTO
	6:30-8:30	None	120	Long Lead	RTO

There were eight events in 2014, on January 7, 2014, January 8, 2014, January 22, 2014, January 23, 2014, January 24, 2014, and March 4, 2014, for which PJM requested voluntary dispatch of emergency demand side resources. All of these events occurred outside of the limited demand response product's window of mandatory response from June through September and from 12:00 to 20:00.[26] Compliance penalties are not applicable to the events in the first nine months of 2014 for that reason, but resources that did curtail received emergency energy payments, which are paid by PJM market participants in proportion to their net purchases in the real-time market.

26 Annual and extended summer demand response products were not active in PJM's demand response program until June 1, 2014.

Subzonal dispatch by zip code was voluntary for the 2013/2014 Delivery Year, but is mandatory beginning on June 1, 2014 with the 2014/2015 Delivery Year. PJM proposed to allow compliance to be measured across zones within a compliance aggregation area (CAA). This would change the way CSPs dispatch resources when multiple electrically contiguous areas with the same RPM clearing prices are dispatched. The compliance rules determine how CSPs are paid and thus create incentives that CSPs will incorporate in their decisions about how to respond to PJM dispatch.[27] More locational deployment of load management resources would improve efficiency. The MMU recommends that demand resources be required to provide their nodal location. Nodal dispatch of demand resources would be consistent with the nodal dispatch of generation.

Load increases are not netted against load decreases for dispatched demand resources across hours or across registrations within hours for compliance purposes, but are treated as zero. This skews the compliance results towards higher compliance since poorly performing demand resources are not used in the compliance calculation. When load is above the peak load contribution during a demand response event, the load reduction is negative; it is a load increase rather than a decrease. PJM ignores such negative reduction values and instead replaces the negative values with a zero MW reduction value. The PJM Tariff and PJM Manuals do not limit the compliance calculation value to a zero MW reduction value.[28] The compliance values PJM reports for demand response events are different than the actual compliance values accounting for both increases and decreases in load from demand resources that are called on and paid under the program.

The MMU recommends that compliance rules be revised to include submittal of all necessary hourly load data, and that negative values be included when calculating event compliance across hours and registrations.

Emergency demand response customers that registered for economic demand response had an adjusted baseline for the emergency event days. The change of baseline resulted in a greater calculated load reduction for the PJM system emergency event days. The changes in reported load reductions reflect emergency resources registering as economic resources to have modified baselines for measurement during the emergency voluntary event days.

Table 6-24 shows the performance for the first January 7, 2014, event. The first column shows the nominated value, which is the reduction capability indicated for each registration. The nominated MW are used to fulfill the committed MW capacity obligation and may exceed the committed MW. The second column shows load management committed MW, which are used to assess RPM compliance. The third column shows the reported load reduction in MW during the hours of an event. The reported load reduction is reported by PJM and does not include load increases. The fourth column shows the observed load reduction in MWh, which includes all reported reduction values, including load increases. The observed load reduction is calculated by the MMU. The observed load reduction is a conservative estimate of what occurred during the demand response events as load increases are not required to be reported. Compliance is calculated by comparing the load reduction during an event to the committed MW value.

The APS, ComEd, Day, DEOK and EKPC zones did not submit any data for this event. Since the event was voluntary, none of these customers responded or received payments for this event. The reported compliance for the DPL Control Zone was 104.7 percent. Overall, the reported compliance for the first event on January 7, 2014, was 39.9 percent, or 3,007.2 MW out of 7,535.7 MW committed. The observed compliance was 30.7 percent, or 2,314.6 MW, a difference of 692.6 MW compared to the reported load reduction.

27 See "Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM," Docket No. ER14-822-002 (July 25, 2014), at 2.
28 OATT Attachment K § PJM Emergency Load Response Program at Reporting and Compliance.

Table 6-24 Demand response event performance: January 7, 2014 (Event 1)

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	124.9	102.5	25.0	20.6	4.4	24.4%	20.1%
AEP	1,635.7	1,253.6	792.3	683.5	108.8	63.2%	54.5%
APS	674.0	499.4	0.0	0.0	0.0	0.0%	0.0%
ATSI	796.1	683.1	452.9	349.3	103.6	66.3%	51.1%
BGE	826.6	627.2	217.9	191.7	26.2	34.7%	30.6%
ComEd	1,129.8	820.3	0.0	0.0	0.0	0.0%	0.0%
DAY	96.7	68.6	0.0	0.0	0.0	0.0%	0.0%
DEOK	436.2	155.4	0.0	0.0	0.0	0.0%	0.0%
DLCO	113.1	69.2	33.3	4.2	29.1	48.1%	6.1%
Dominion	872.4	757.0	516.4	445.9	70.4	68.2%	58.9%
DPL	301.7	65.9	69.1	51.5	17.5	104.7%	78.1%
EKPC	110.3	79.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	209.1	156.7	81.4	61.6	19.8	51.9%	39.3%
Met-Ed	233.9	173.9	80.8	56.9	24.0	46.5%	32.7%
PECO	587.5	410.3	200.0	147.5	52.5	48.7%	35.9%
PENELEC	330.1	265.1	67.4	0.1	67.3	25.4%	0.0%
Pepco	795.8	372.0	108.1	81.3	26.8	29.1%	21.8%
PPL	800.0	621.1	249.7	144.4	105.2	40.2%	23.3%
PSEG, RECO	488.7	354.6	113.0	76.2	36.9	31.9%	21.5%
Total	10,562.6	7,535.7	3,007.2	2,314.6	692.6	39.9%	30.7%

The second event on January 7, 2014, called both long and short lead resources for the RTO at 1600 and ended the event at 1815 EPT. Long lead resources were only dispatched for one hour during this event, even though minimum dispatch is two hours for demand resources. Since PJM canceled the demand response event before the minimum run time requirement was met, demand resources still received energy settlements for two hours after the event started. As a result, the effective dispatch period for long lead resources was actually from 1700 to 1900 EPT. Short lead resources were dispatched for more than two hours.

Table 6-25 shows the performance for the second January 7, 2014, event. The APS, ComEd, Day, DEOK and EKPC zones did not submit any data for this event. The reported compliance for the DPL Control Zone was 105.9 percent, or 69.8 MW out of 65.9 MW committed. The observed compliance for the DPL Control Zone was 85.6 percent, or 56.4 MW out of 65.9 MW committed. Overall, the reported compliance for the second event on January 7, 2014, was 42.5 percent, or 3,203.0 MW out of 7,535.7 MW committed. The observed compliance was 34.6 percent, or 2,604.4 MW, a difference of 598.6 MW compared to the reported load reduction.

Table 6-25 Demand response event performance: January 7, 2014 (Event 2)

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	124.9	102.5	23.4	20.9	2.6	22.9%	20.4%
AEP	1,635.7	1,253.6	872.4	740.6	131.8	69.6%	59.1%
APS	674.0	499.4	0.0	0.0	0.0	0.0%	0.0%
ATSI	796.1	683.1	534.9	452.3	82.6	78.3%	66.2%
BGE	826.6	627.2	230.9	210.2	20.7	36.8%	33.5%
ComEd	1,129.8	820.3	0.0	0.0	0.0	0.0%	0.0%
DAY	96.7	68.6	0.0	0.0	0.0	0.0%	0.0%
DEOK	436.2	155.4	0.0	0.0	0.0	0.0%	0.0%
DLCO	113.1	69.2	32.6	(16.3)	48.9	47.1%	(23.6%)
Dominion	872.4	757.0	513.5	465.2	48.3	67.8%	61.5%
DPL	301.7	65.9	69.8	56.4	13.4	105.9%	85.6%
EKPC	110.3	79.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	209.1	156.7	78.6	58.0	20.6	50.2%	37.0%
Met-Ed	233.9	173.9	85.4	71.7	13.6	49.1%	41.2%
PECO	587.5	410.3	190.8	150.3	40.5	46.5%	36.6%
PENELEC	330.1	265.1	97.7	60.3	37.4	36.8%	22.8%
Pepco	795.8	372.0	111.3	92.1	19.2	29.9%	24.8%
PPL	800.0	621.1	252.4	174.3	78.1	40.6%	28.1%
PSEG, RECO	488.7	354.6	109.3	68.4	41.0	30.8%	19.3%
Total	10,562.6	7,535.7	3,203.0	2,604.4	598.6	42.5%	34.6%

There was one event on January 8, 2014. The event was called for both long and short lead resources for the RTO at 500 and ended the event at 700 EPT. Since PJM canceled the demand response event before the minimum run time requirement was met, demand resources still received energy settlements for two hours after the event started. Short lead resources were active for one hour and long lead resources were not active during this call.

Table 6-26 shows the performance for the January 8, 2014, event. The APS, ComEd, Day, DEOK and EKPC zones did not submit any data for this event. The reported compliance for the DPL Control Zone was 64.4 percent, or 42.4 MW out of 65.9 MW committed. The observed compliance for the DPL Control Zone was 56.9 percent, or 37.5 MW out of 65.9 MW committed. Overall, the reported compliance for the event on January 8, 2014, was 30.4 percent, or 2,289.7 MW out of 7,537.7 MW committed. The observed compliance was 22.3 percent, or 1,683.0 MW, a difference of 606.8 MW compared to the reported load reduction.

Table 6-26 Demand response event performance: January 8, 2014

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	124.9	102.5	18.1	16.1	1.9	17.6%	15.8%
AEP	1,635.7	1,253.6	752.9	628.1	124.8	60.1%	50.1%
APS	674.0	499.4	0.0	0.0	0.0	0.0%	0.0%
ATSI	796.1	683.1	364.6	274.0	90.7	53.4%	40.1%
BGE	826.6	627.2	132.2	110.1	22.1	21.1%	17.6%
ComEd	1,129.8	820.3	0.0	0.0	0.0	0.0%	0.0%
DAY	96.7	68.6	0.0	0.0	0.0	0.0%	0.0%
DEOK	436.2	155.4	0.0	0.0	0.0	0.0%	0.0%
DLCO	113.1	69.2	17.1	9.2	7.9	24.7%	13.3%
Dominion	872.4	757.0	359.4	279.2	80.2	47.5%	36.9%
DPL	301.7	65.9	42.4	37.5	4.9	64.4%	56.9%
EKPC	110.3	79.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	209.1	156.7	59.0	42.4	16.5	37.6%	27.1%
Met-Ed	233.9	173.9	54.3	14.3	40.0	31.2%	8.2%
PECO	587.5	410.3	129.7	91.0	38.7	31.6%	22.2%
PENELEC	330.1	265.1	46.5	(6.0)	52.5	17.5%	(2.3%)
Pepco	795.8	372.0	61.1	42.0	19.1	16.4%	11.3%
PPL	800.0	621.1	166.1	87.9	78.2	26.7%	14.2%
PSEG, RECO	488.7	354.6	86.2	57.1	29.2	24.3%	16.1%
Total	10,562.6	7,535.7	2,289.7	1,683.0	606.8	30.4%	22.3%

Table 6-27 Demand response event performance: January 22, 2014

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
BGE	826.6	627.2	239.6	218.5	21.1	38.2%	34.8%
Pepco	795.8	372.0	166.1	148.8	17.3	44.7%	40.0%
Total	1,622.5	999.2	405.7	367.3	38.4	40.6%	36.8%

There was one event on January 22, 2014. The event was called for both long and short lead resources for the SWMAAC LDA at 1400 and ended the event at 2100 EPT.

Table 6-27 shows the performance for the January 22, 2014, event. The reported compliance for the BGE Control Zone was 38.2 percent, or 239.6 MW out of 627.2 MW committed. The observed compliance for the BGE Control Zone was 34.8 percent, or 218.5 MW out of 627.2 MW committed. Overall, the reported compliance for the event on January 22, 2014, was 40.6 percent, or 405.7 MW out of 999.2 MW committed. The observed compliance was 36.8 percent, or 367.3 MW, a difference of 38.4 MW compared to the reported load reduction.

There were two events on January 23, 2014. The first event was called for both long and short lead resources for the MAAC LDA, APS and Dominion zones at 430 and ended the event at 830 EPT.

Table 6-28 shows the performance for the first January 23, 2014, event. The APS Control Zone did not submit any data for this event. The reported compliance for the RECO Control Zone was 154.2 percent, or 6.2 MW out of 4.0 MW committed. The observed compliance for the RECO Control Zone was 149.2 percent, or 6.0 MW out of 4.0 MW committed. Overall, the reported compliance for the first event on January 23, 2014, was 40.8 percent, or 1,799.5 MW out of 4,405.6 MW committed. The observed compliance was 30.6 percent, or 1,349.0 MW, a difference of 450.5 MW compared to the reported load reduction.

The second event on January 23, 2014, was called for both long and short lead resources for the MAAC LDA, APS and Dominion zones at 1400 and ended the event at 1900 EPT.

Table 6-29 shows the performance for the second January 23, 2014, event. The APS Control Zone did not submit any data for this event. The reported compliance for the RECO Control Zone was 69.6 percent, or 2.8 MW out of

Table 6-28 Demand response event performance: January 23, 2014 (Event 1)

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	124.9	102.5	20.3	18.5	1.8	19.8%	18.0%
APS	674.0	499.4	0.0	0.0	0.0	0.0%	0.0%
BGE	826.6	627.2	226.8	192.9	33.9	36.2%	30.8%
Dominion	872.4	757.0	516.3	457.8	58.5	68.2%	60.5%
DPL	301.7	65.9	53.4	39.8	13.6	80.9%	60.3%
JCPL	209.1	156.7	82.3	55.7	26.6	52.5%	35.5%
Met-Ed	233.9	173.9	90.3	66.3	23.9	51.9%	38.2%
PECO	587.5	410.3	199.7	145.5	54.2	48.7%	35.5%
PENELEC	330.1	265.1	50.7	(5.7)	56.4	19.1%	(2.1%)
Pepco	795.8	372.0	165.5	138.5	27.0	44.5%	37.2%
PPL	800.0	621.1	264.4	143.7	120.6	42.6%	23.1%
PSEG	482.3	350.6	123.7	90.0	33.7	35.3%	25.7%
RECO	6.4	4.0	6.2	6.0	0.2	154.2%	149.2%
Total	6,244.7	4,405.6	1,799.5	1,349.0	450.5	40.8%	30.6%

Table 6-29 Demand response event performance: January 23, 2014 (Event 2)

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	124.9	102.5	19.4	17.9	1.5	18.9%	17.4%
APS	674.0	499.4	0.0	0.0	0.0	0.0%	0.0%
BGE	826.6	627.2	225.4	199.2	26.2	35.9%	31.8%
Dominion	872.4	757.0	547.1	508.3	38.8	72.3%	67.1%
DPL	301.7	65.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	209.1	156.7	81.5	54.7	26.8	52.0%	34.9%
Met-Ed	233.9	173.9	98.4	85.1	13.3	56.6%	49.0%
PECO	587.5	410.3	195.6	148.2	47.4	47.7%	36.1%
PENELEC	330.1	265.1	61.0	25.4	35.6	23.0%	9.6%
Pepco	795.8	372.0	167.8	150.2	17.6	45.1%	40.4%
PPL	800.0	621.1	263.4	181.0	82.4	42.4%	29.2%
PSEG	482.3	350.6	110.8	80.1	30.7	31.6%	22.8%
RECO	6.4	4.0	2.8	2.7	0.1	69.6%	67.6%
Total	6,244.7	4,405.6	1,773.2	1,452.8	320.4	40.2%	33.0%

4.0 MW committed. The observed compliance for the RECO Control Zone was 67.6 percent, or 2.7 MW out of 4.0 MW committed. Overall, the reported compliance for the second event on January 23, 2014, was 40.2 percent, or 1,773.2 MW out of 4,405.6 MW committed. The observed compliance was 33.0 percent, or 1,452.8 MW, a difference of 320.4 MW compared to the reported load reduction.

There was one event on January 24, 2014. The event was called for both long and short lead resources for the MAAC LDA, APS and Dominion zones at 430 and ended the event at 845 EPT.

Table 6-30 shows the performance for the January 24, 2014, event. The APS Control Zone did not submit any data for this event. The reported compliance for the DPL Control Zone was 60.1 percent, or 39.6 MW out of 65.9 MW committed. The observed compliance for the DPL Control Zone was 50.0 percent, or 33.0 MW out of 65.9 MW committed. Overall, the reported compliance for the event on January 24, 2014, was 33.1 percent, or 1,459.1 MW out of 4,405.6 MW committed. The observed compliance was 24.9 percent, or 1,095.2 MW, a difference of 363.9 MW compared to the reported load reduction.

There was one event on March 4, 2014. The event was called for both long and short lead resources for the RTO at 430 and ended the event at 830 EPT.

Table 6-31 shows the performance for the March 4, 2014, event. The APS, ComEd, DAY, DEOK and EKPC Control Zones did not submit any data for this event. The reported compliance for the DPL Control Zone was 75.9 percent, or 50.0 MW out of 65.9 MW committed. The observed compliance for the DPL Control Zone was 69.7 percent, or 45.9 MW out of 65.9 MW committed. Overall, the reported compliance for the event on March 4, 2014, was 36.2 percent, or 2,730.3 MW out of 7,535.7 MW committed. The observed compliance was 27.0 percent, or 2,031.9 MW, a difference of 698.4 MW compared to the reported load reduction.

Table 6-30 Demand response event performance: January 24, 2014

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	124.9	102.5	18.3	16.6	1.7	17.9%	16.2%
APS	674.0	499.4	0.0	0.0	0.0	0.0%	0.0%
BGE	826.6	627.2	156.3	133.2	23.2	24.9%	21.2%
Dominion	872.4	757.0	446.2	385.7	60.4	58.9%	51.0%
DPL	301.7	65.9	39.6	33.0	6.6	60.1%	50.0%
JCPL	209.1	156.7	64.3	39.4	24.9	41.1%	25.2%
Met-Ed	233.9	173.9	83.0	60.8	22.3	47.8%	35.0%
PECO	587.5	410.3	161.7	116.1	45.7	39.4%	28.3%
PENELEC	330.1	265.1	50.7	9.4	41.3	19.1%	3.6%
Pepco	795.8	372.0	123.0	98.9	24.1	33.1%	26.6%
PPL	800.0	621.1	209.8	127.5	82.4	33.8%	20.5%
PSEG, RECO	488.7	354.6	106.0	74.6	31.4	29.9%	21.0%
Total	6,244.7	4,405.6	1,459.1	1,095.2	363.9	33.1%	24.9%

Table 6-31 Demand response event performance: March 4, 2014

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	124.9	102.5	17.1	14.3	2.8	16.7%	13.9%
AEP	1,635.7	1,253.6	764.2	530.9	233.3	61.0%	42.3%
APS	674.0	499.4	0.0	0.0	0.0	0.0%	0.0%
ATSI	796.1	683.1	484.5	401.3	83.2	70.9%	58.7%
BGE	826.6	627.2	183.1	160.9	22.2	29.2%	25.7%
ComEd	1,129.8	820.3	0.0	0.0	0.0	0.0%	0.0%
DAY	96.7	68.6	0.0	0.0	0.0	0.0%	0.0%
DEOK	436.2	155.4	0.0	0.0	0.0	0.0%	0.0%
DLCO	113.1	69.2	20.3	10.2	10.1	29.3%	14.7%
Dominion	872.4	757.0	430.4	370.7	59.7	56.9%	49.0%
DPL	301.7	65.9	50.0	45.9	4.1	75.9%	69.7%
EKPC	110.3	79.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	209.1	156.7	62.5	41.1	21.4	39.9%	26.3%
Met-Ed	233.9	173.9	65.1	34.0	31.1	37.5%	19.6%
PECO	587.5	410.3	176.8	138.7	38.1	43.1%	33.8%
PENELEC	330.1	265.1	52.4	(1.6)	53.9	19.7%	(0.6%)
Pepco	795.8	372.0	107.3	87.4	20.0	28.9%	23.5%
PPL	800.0	621.1	217.1	119.7	97.3	34.9%	19.3%
PSEG, RECO	488.7	354.6	99.5	78.4	21.1	28.1%	22.1%
Total	10,562.6	7,535.7	2,730.3	2,031.9	698.4	36.2%	27.0%

Table 6-32 shows aggregated load management event performance for the eight demand response emergency events for 2014. The reported compliance for all PJM control zones was 37.7 percent in the first nine months of 2014 for resources called during emergency events, while observed compliance was 29.2 percent. The reported compliance for the DPL Control Zone was 64.8 percent, or 42.7 MW out of 65.9 MW committed. The observed compliance for the DPL Control Zone was 51.1 percent, or 33.7 MW out of 65.9 MW committed. The reported and observed compliance for the DPL Control Zone were the highest in PJM. The reported and observed compliance for the APS, ComEd, Day, DEOK and EKPC control zones reported were 0.0 percent, the lowest in PJM.

The average observed compliance for the BGE Control Zone, which responded to all eight emergency events in 2014, was 36.7 percent, or 229.9 MW out of 627.2 MW committed. The average observed compliance for the Pepco Control Zone, which also responded to all eight emergency events in 2014, was 37.5 percent, or 139.4 MW out of 621.1 MW committed.

Table 6-32 Aggregated load management event performance: January through September, 2014

Zone	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
AECO	124.9	102.5	20.2	17.8	2.4	19.7%	17.4%
AEP	1,635.7	1,253.6	698.4	557.2	141.1	55.7%	44.4%
APS	674.0	499.4	0.0	0.0	0.0	0.0%	0.0%
ATSI	796.1	683.1	401.1	328.2	72.9	58.7%	48.1%
BGE	826.6	627.2	229.9	198.2	31.7	36.7%	31.6%
ComEd	1,129.8	820.3	0.0	0.0	0.0	0.0%	0.0%
DAY	96.7	68.6	0.0	0.0	0.0	0.0%	0.0%
DEOK	436.2	155.4	0.0	0.0	0.0	0.0%	0.0%
DLCO	113.1	69.2	36.3	10.1	26.2	52.4%	14.6%
Dominion	872.4	757.0	430.3	381.6	48.7	56.9%	50.4%
DPL	301.7	65.9	42.7	33.7	9.0	64.8%	51.1%
EKPC	110.3	79.9	0.0	0.0	0.0	0.0%	0.0%
JCPL	209.1	156.7	72.1	46.4	25.7	46.0%	29.6%
Met-Ed	233.9	173.9	90.4	66.6	23.8	52.0%	38.3%
PECO	587.5	410.3	167.3	120.0	47.3	40.8%	29.3%
PENELEC	330.1	265.1	63.0	18.6	44.4	23.8%	7.0%
Pepco	795.8	372.0	139.4	110.6	28.8	37.5%	29.7%
PPL	800.0	621.1	217.3	132.3	85.0	35.0%	21.3%
PSEG, RECO	488.7	354.6	99.1	70.9	28.2	27.9%	20.0%
Weighted Total	10,562.6	7,535.7	2,840.9	2,198.6	428.9	37.7%	29.2%

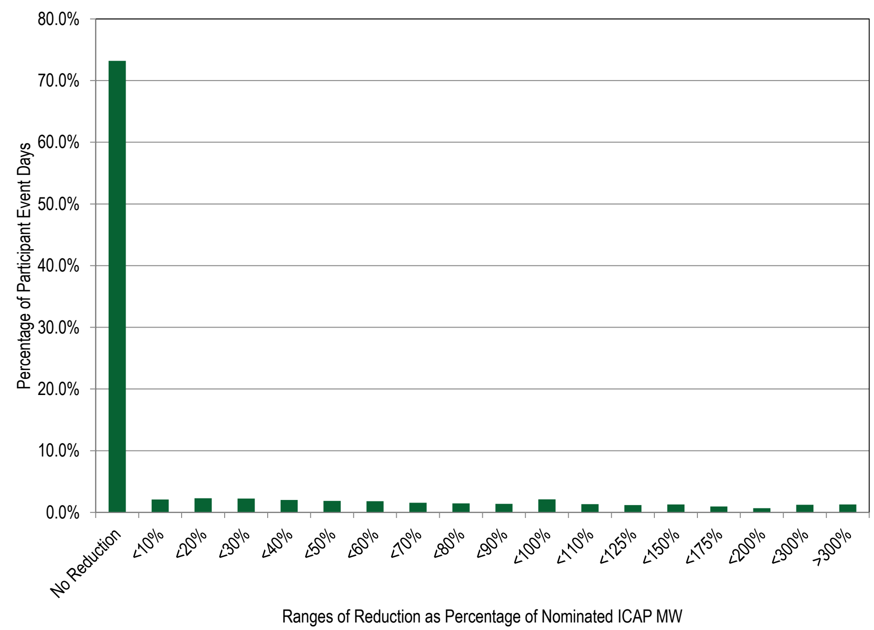
Performance for specific customers varied significantly. Table 6-33 shows the distribution of participant event days by performance levels for the eight events in the 2013/2014 compliance period. Table 6-33 includes the participation for all resources dispatched for the emergency events. For these events, 73.2 percent of participant event days showed no reduction, load increased or participants did not report data. For these events 83.7 percent of participant event days provided less than half of their nominated MW, while 81.0 percent of the nominated MW provided less than half of their nominated MW. The majority of participants, 92.0 percent, provided less than 100 percent reduction compared to their nominated MW, while 91.2 percent of the nominated MW provided less than 100 percent reduction.

Table 6-33 Distribution of participant event days and nominated MW across ranges of performance levels across the events: January through September, 2014

Ranges of performance as a percentage of nominated ICAP MW	Number of participant event days	Proportion of participant event days	Nominated MW	Proportion of Nominated MW
0%, load increase, or no reporting	67,953	73.2%	42,977	68.6%
0% - 10%	1,951	2.1%	1,746	2.8%
10% - 20%	2,121	2.3%	1,684	2.7%
20% - 30%	2,088	2.2%	1,736	2.8%
30% - 40%	1,874	2.0%	1,367	2.2%
40% - 50%	1,730	1.9%	1,186	1.9%
50% - 60%	1,672	1.8%	1,257	2.0%
60% - 70%	1,439	1.6%	1,118	1.8%
70% - 80%	1,363	1.5%	1,099	1.8%
80% - 90%	1,293	1.4%	915	1.5%
90% - 100%	1,953	2.1%	2,002	3.2%
100% - 110%	1,239	1.3%	2,289	3.7%
110% - 125%	1,099	1.2%	818	1.3%
125% - 150%	1,193	1.3%	752	1.2%
150% - 175%	884	1.0%	420	0.7%
175% - 200%	625	0.7%	336	0.5%
200% - 300%	1,151	1.2%	524	0.8%
> 300%	1,198	1.3%	381	0.6%
Total	92,826	100.0%	62,607	100.0%

Figure 6-3 shows the data in Table 6-33.[29]

Figure 6-3 Distribution of participant event days across ranges of performance levels across the events: January through September, 2014



29 Participant event days, shown in Figure 6-3, and Table 6-22, are defined as distinct event performances by registration. If a registration was deployed for multiple events, each event constitutes a single participant event day. The load reduction values associated do not reflect actual MWh curtailments, but average curtailments in each event, summed for all events in the period.

Definition of Compliance

Currently, the calculation methods of event and test compliance do not provide reliable results. PJM's interpretation of load management event rules allows over compliance to be reported when there is no actual over compliance. Settlement locations with a negative load reduction value (load increase) are not netted by PJM within registrations or within demand response portfolios. A resource that has load above their baseline during a demand response event has a calculated negative performance value. PJM limits compliance shortfall values at the nominated MW value for underperformance. This is not explicitly stated in the Tariff or supporting Manuals. According to the Tariff, the compliance formulas for FSL and GLD customers allow for negative compliance values.[30] For example, if a registration had two locations, one with a 50 MWh load increase when called, and another with a 75 MWh load reduction when called, compliance for that registration is calculated as a 75 MWh load reduction for that event hour. Settlement MWh are not netted across hours or across registrations for compliance purposes. A location with a load increase is set to a zero MW reduction. For example, in a two hour event, if a registration showed a 15 MWh load increase in hour one, but a 30 MWh reduction in hour two, the registration would show a 0 MWh reduction in hour one and a 30 MWh reduction in hour two and an average hourly 15 MWh load reduction for that two hour event. Reported compliance is less than actual compliance, as locations with load increases, negative reductions, are treated as zero for compliance purposes. Overall, 73 percent of event hours demonstrated negative reductions or no reduction in load, as shown in Table 6-33.[31]

Settlements that are not submitted to PJM are treated as zero compliance for the event. Overall, 63.0 percent of locations were not submitted to PJM for compliance purposes. While the performance of these resources is not known, it is reasonable to assume, given the incentives to report reductions, that these locations had negative compliance (load increases relative to baseline), further skewing reported compliance values and performance penalties. Registrations with negative compliance are treated as zero for the purposes of imposing penalties and reporting.

Changing a demand resource compliance calculation from a negative value to 0 MW inaccurately values event performance and capacity performance. Inflated compliance numbers for an event overstates the true value and capacity of demand resources. A demand response capacity resource that performs negatively is also displacing another capacity resource that could supply capacity during a delivery year. By setting the negative compliance value to 0 MW, PJM is inaccurately calculating the value of demand resources.

Table 6-34 shows the number of locations that did not report during the first three months of 2014 event days. In total, 63.0 percent of locations did not report during event days in 2013 and were assigned zero load response. This accounted for 60.1 percent of all nominated MW for those events. It is likely that these locations were not responding to the emergency event and had loads greater than their committed MW for those locations, and the corresponding registrations.

Table 6-34 Non-reporting locations and nominated ICAP: January through September, 2014 event days

	Locations Not Reporting	Percent Non Reporting	Nominated ICAP Not Reporting	Percent N on Reporting
Total	58,443	63.0%	37,627	60.1%

Emergency Energy Payments

For any PJM declared load management event in the first nine months of 2014, participants registered under the full option of the emergency load response program, which contains 99.6 percent of registrations, that were dispatched and demonstrated a load reduction were eligible to receive emergency energy payments. The emergency energy payments are equal to the higher of hourly zonal LMP or a strike price energy offer made by the participant, including a dollar per MWh minimum dispatch price and an associated shutdown cost. The new scarcity pricing rules increased the maximum DR energy price offer for the 2013/2014 Delivery Year to $1,800 per MWh. The maximum offer decreased to $1,599 per MWh for the 2014/2015 Delivery Year and will

30 OATT PJM Emergency Load Response Program.

31 The demand response events that occurred in the first nine months of 2014 were all voluntary since they were outside the mandatory curtailment window of June 1, through September 30 from 1200 to 2000.

increase to $1,849 per MWh for the 2015/2016 Delivery Year. The maximum generator offer will remain at $1,000 per MWh.[32] [33]

Participants may elect to be paid their emergency offer, regardless of the zonal LMP. Table 6-35 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2013/2014 Delivery Year. The majority of participants, 69.7 percent, have a minimum dispatch price of $1,000 per MWh, and 18.4 percent of participants have a dispatch price of $1,800 per MWh, which is the maximum price allowed for the 2013/2014 Delivery Year. Energy offers are further increased by submitted shutdown costs, which, in the 2013/2014 Delivery Year, range from $0 to more than $10,000. Depending on the size of the registration, the shutdown costs can significantly increase the effective energy offer. The shutdown cost of resources with $500 to $800 strike prices had the highest average at $3,262.88 per location.

Shutdown costs for demand response resources are not adequately defined in Manual 15. PJM's Cost Development Subcommittee (CDS) recently approved changes to Manual 15 to eliminate shutdown costs for demand response resources participating in the Synchronized Reserve Market, but not the emergency or economic demand response program.[34]

Table 6-35 Distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices: 2013/2014 Delivery Year[35]

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location
$0-$1	538	3.6%	861.0	9.6%	$0.00
$1-$200	905	6.0%	379.9	4.2%	$8.73
$200-$500	216	1.4%	186.9	2.1%	$141.90
$500-$800	66	0.4%	82.8	0.9%	$3,262.88
$800-$999	67	0.4%	50.8	0.6%	$520.37
$1,000	10,499	69.7%	5,926.0	66.1%	$26.05
$1,800	2,776	18.4%	1,479.5	16.5%	$0.00
Total	15,067	100.0%	8,966.9	100.0%	$37.32

Table 6-36 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2014/2015 Delivery Year. The majority of participants, 94.7 percent, have a minimum dispatch price between $1,000 and $1,100 per MWh, and 0.1 percent of participants have a dispatch price between $1,276 and $1,549 per MWh, which is the maximum price allowed for the 2014/2015 Delivery Year. Energy offers are further increased by submitted shutdown costs, which, in the 2014/2015 Delivery Year, range from $0 to more than $10,000. Depending on the size of the registration, the shutdown costs can significantly increase the effective energy offer. The shutdown cost of resources with $1,101 to $1,275 per MWh strike prices had the highest average at $160.05 per location.

Table 6-36 Distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices: 2014/2015 Delivery Year[36]

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location
$0-$1	570	3.6%	630.0	6.7%	$0.00
$1-$999	218	1.4%	160.9	1.7%	$28.54
$1,000-$1,100	15,101	94.7%	7,497.1	80.1%	$72.88
$1,101-$1,275	29	0.2%	368.7	3.9%	$160.05
$1,276-$1,549	21	0.1%	703.6	7.5%	$66.67
Total	15,939	100.0%	9,360.3	100.0%	$69.81

32 139 FERC ¶ 61,057 (2012).
33 FERC accepted proposed changes to have the maximum strike price for 30 minute demand response to be $1,000/MWh + 1*Shortage penalty - $1.00 from ER14-822-000.
34 PJM. "Manual 15: Cost Development Guidelines," Revision 23 (August 1, 2013), p. 51.
35 In this analysis nominated MW does not include capacity only resources, which do not receive energy market credits.
36 In this analysis nominated MW does not include capacity only resources, which do not receive energy market credits.

Table 6-37 includes the energy reduction MWh and average real time LMP during the eight demand response event days. The first column shows the hour beginning for each event day. The second column has the emergency demand response MWh reductions, which are calculated by comparing each resource's CBL to their actual load during the demand response event.[37] If a resource is registered for both the economic and emergency program, the economic CBL is used for the emergency CBL. If a resource is only registered under the emergency option, the CBL is the hour before the reductions occur.[38] On January 7, 2014, all demand response resources in the RTO were called at 430 to reduce at 530 and 630 EPT for short and long lead resources. If a resource could reduce before their designated lead time, that resource was eligible for energy settlements. The average LMP columns consist of the average LMP for each hour of an event day based on what zones were called. The January 22, 2014, event day included only SWMAAC, so the average LMP is the average of the BGE and Pepco zones. The LMP was only greater than $1,000 per MWh for the dispatched areas for three events, both of the January 7 events and the January 22 event.

Table 6-38 shows emergency revenue for each event day in 2014. Energy payments in the emergency program differ significantly from energy payments in the economic program and from capacity payments through the emergency load response program in that they are not based on or tied to any market price signal. Once an emergency demand response event is called for a zone or sub zone, payments are guaranteed if a resource is determined to have responded. Emergency demand response energy costs are paid by PJM market participants in proportion to their net purchases in the Real-Time Energy Market.[39] Emergency demand response energy costs are not covered by LMP. All demand response energy payments and shutdown costs are out of market payments. These payments are a form of uplift.

The events on January 7, 2014, were the first voluntary events of 2014, and all resources in the RTO were called for both events. January 7 had the most MWh reductions and highest average LMP which resulted in the total emergency revenue of $22,691,122. The total emergency revenue for the voluntary emergency event days in the first nine months of 2014 were $42,971,731.

37 This table assumes that PJM's CBL calculation is correct.

38 PJM has stated in the demand response subcommittee meeting, that when two events occurred in a single calendar day, that the hour before the first event is the CBL used for both events. If a resource does not submit for an energy settlement for the first event, the CBL would be the hour before the second event.

39 PJM. "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), p 69.

Table 6-37 Energy reduction MWh and average real-time LMP during demand response event days: January through September, 2014

	January 7, 2014		January 8, 2014		January 22, 2014		January 23, 2014		January 24, 2014		March 4, 2014	
Hour Beginning	MWh Reduction	Average LMP ($/MWh)	MWh Reduction	Average LMP ($/MWh)	MWh Reduction	Average LMP ($/MWh)	MWh Reduction	Average LMP ($/MWh)	MWh Reduction	Average LMP ($/MWh)	MWh Reduction	Average LMP ($/MWh)
0		321.5		159.3		60.7		285.2		382.0		147.3
1		416.4		179.8		160.4		245.6		445.6		164.1
2		422.7		170.3		185.7		283.3		520.1		190.5
3		277.8		110.3		153.2		272.4		468.0		225.6
4	464.3	473.1		119.7		102.0	127.8	283.3	144.8	487.4	307.7	231.3
5	834.0	487.0	447.1	198.5		404.7	233.9	203.9	217.6	618.6	575.3	847.6
6	1,359.8	1,030.5	902.7	328.6		312.1	448.4	278.5	484.2	678.1	1,319.1	191.2
7	1,740.2	1,726.3	1,095.6	290.8		557.7	620.2	348.3	578.0	833.6	1,763.9	199.4
8	1,981.7	1,832.7	911.1	184.3		515.6	544.3	225.8	575.2	540.2	1,634.0	180.1
9	1,955.2	1,784.2		213.5		460.0		123.7		426.1		239.9
10	1,799.9	1,772.1		200.0		503.0		272.0		361.1		250.2
11		1,434.3		216.0		513.8		502.1		278.2		309.0
12		406.3		101.1		462.9		395.9		294.7		228.6
13		495.8		121.0		274.8		488.7		313.4		242.0
14		327.6		42.2	10.9	274.3	423.7	587.8		250.9		234.3
15	1,247.9	244.1		96.4	37.6	1,206.8	588.0	565.7		144.5		186.4
16	1,802.5	291.6		131.4	93.7	466.8	905.6	353.6		207.0		145.7
17	2,346.9	1,018.2		182.0	108.0	1,818.6	930.7	476.7		398.0		210.4
18	2,227.9	437.8		117.4	133.0	1,816.6	957.1	553.3		283.3		261.8
19		438.0		127.8	154.0	1,825.1		623.1		276.0		192.8
20		354.8		156.1	159.3	1,749.3		707.9		396.0		227.8
21		258.8		100.7		592.7		647.4		371.2		273.7
22		215.3		65.4		469.6		627.8		144.9		126.3
23		211.2		39.8		358.7		492.8		230.4		128.8
Total	17,760.0	694.9	3,356.4	152.2	696.6	635.2	5,779.7	410.2	1,999.7	389.6	5,600.0	234.8

Table 6-38 Emergency revenue by event: January through September, 2014

Event Date	Total
January 7, 2014	$22,691,122
January 8, 2014	$3,536,061
January 22, 2014	$1,210,678
January 23, 2014	$7,076,824
January 24, 2014	$2,637,138
March 4, 2014	$5,819,908
Total	$42,971,731

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 1200 (EPT) to 2000 (EPT) and be capable of maintaining an interruption for a minimum of two hours to a maximum of six 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 committed MW, a penalty is charged. 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.

No penalties were assessed based on events that occurred during the first nine months of 2014, because all emergency events in 2014 were voluntary curtailment. The penalties are assessed daily and have increased by $15,817,614.31 from $2,037,700.10 in the 2012/2013 Delivery Year compared to $17,855,314.41 of the 2013/2014 Delivery Year. Table 6-39 shows penalty charges by zone for the 2012/2013 and 2013/2014 Delivery Year. The PECO Control Zone had the highest penalty amount, due to the clearing prices in EMAAC and a reported performance at 93.2 percent of the committed MW.[40] The penalty charges represent 3.3 percent of the capacity revenue for the 2013/2014 Delivery Year and 0.8 percent of the capacity revenue for the 2012/2013 Delivery Year.

There were no penalties for the 2014/2015 Delivery Year since there were no emergency events called and testing compliance was not completed at the date of report publication.

Table 6-39 Penalty charges per zone: 2012/2013 and 2013/2014 Delivery Years

	2012/2013 Penalty Charge	2013/2014 Penalty Charge
AECO	$91.25	$125,889.92
AEP	$143,499.75	$590,009.95
AP	$0.00	$0.00
ATSI	$0.00	$1,104,441.56
BGE, Met-Ed, Pepco	$634,753.25	$2,468,448.72
ComEd	$0.00	$0.00
DAY	$0.00	$0.00
DEOK	$0.00	$0.00
Dominion	$59,020.50	$310,907.51
DPL	$740,756.55	$766,832.39
DLCO	$0.00	$74,600.56
EKPC	$0.00	$0.00
JCPL	$5,332.65	$604,141.64
PECO	$399,404.90	$5,768,980.77
PENELEC	$44,066.45	$434,076.46
PPL	$594.95	$3,601,276.68
PSEG, RECO	$10,179.85	$2,005,708.25
Total	$2,037,700.10	$17,855,314.41

40 Refer to Section 5: Capacity, Table 5-11 for complete listing of capacity prices.

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), diesel (DS), nuclear (NU), solar, and wind generating units.

Overview

Net Revenue

- The net revenues reported are theoretical energy and ancillary net revenues and do not include capacity market revenues.
- Energy net revenues are affected by fuel prices and energy prices. Natural gas prices and energy prices were significantly higher in the first three months of 2014 than in the first three months of 2013, resulting in large increases in net revenues in the first three months of 2014. Eastern natural gas prices were 160.3 percent higher and Western natural gas prices were 81.1 percent higher in the first quarter of 2014 compared to the first quarter of 2013. Energy prices were 131.6 percent higher in the first quarter of 2014 compared to the first quarter of 2013. Eastern natural gas prices were 13.9 percent lower and Western natural gas prices were 1.6 percent higher for the second and third quarters of 2014 compared to the same period of 2013. Energy prices were 2.6 percent lower for the second and third quarters of 2014 compared to the same period of 2013.[1]
- Increases in average net revenues for the first nine months of 2014 were primarily the result of substantial increases in net revenues for the first three months of 2014 as a result of significantly higher energy prices which offset higher fuel costs.
- For the first three months of 2014, energy net revenues increased by 1,444 percent for a new CT, 377 percent for a new CC, 637 percent for a new CP, 9,293 percent for a new DS, 188 percent for a new nuclear plant, 54 percent for a new wind installation, and 33 percent for a new solar installation.
- Average net revenues increased for the second and third quarters of 2014 compared to the same period of 2013 by 7.3 percent for a new CT, increased by 15.9 percent for a new CC, decreased by 1.8 percent for a new CP, decreased by 72.1 percent for a new DS, decreased by 3.9 percent for a new nuclear plant, increased by 6.1 percent for a new wind installation, and increased by 2.2 percent for a new solar installation.
- Average net revenues increased for the first nine months of 2014 by 275 percent for a new CT, 114 percent for a new CC, 202 percent for a new CP, 1,173 percent for a new DS, 58 percent for a new nuclear plant, 28 percent for a new wind installation, and 10 percent for a new solar installation.

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.

1 Percentage increase is the percentage increase of the average zonal LMP.

The net revenue results illustrate some fundamentals of the PJM wholesale power market. High loads that result in high prices tend to increase energy market net revenues for all unit types. Even a relatively small number of high price hours can significantly increase net revenues. This illustrates the potential role of scarcity pricing as a source of net revenues and also makes it more important to address the appropriate net revenue offset mechanism in the capacity market.

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.

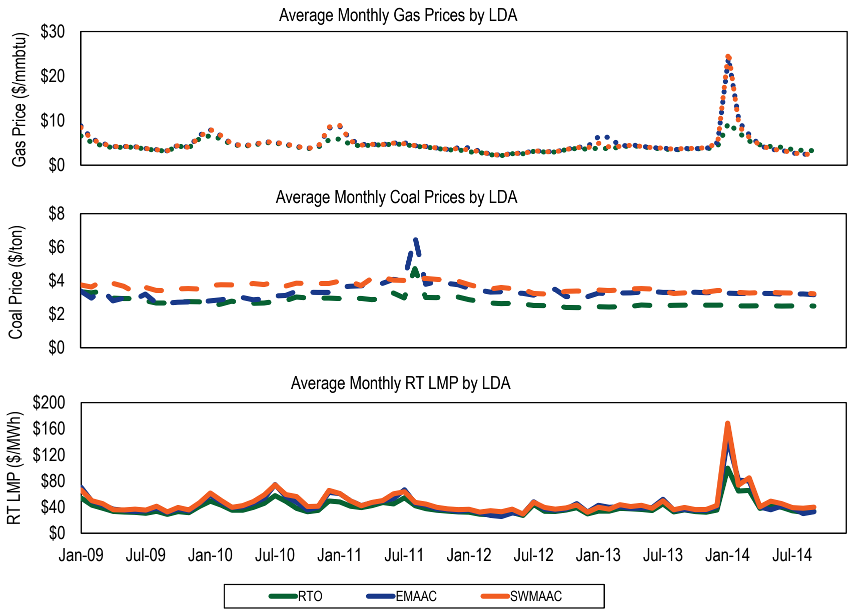
In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all annualized fixed costs for the marginal unit, including a competitive return on investment. The PJM market design includes other markets intended to contribute 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 (uplift) payments are included when the analysis is based on the peak-hour, economic dispatch model and when the analysis uses actual net revenues.[2]

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The real-time load-weighted average LMP was 47.4 percent higher in the first nine months of 2014 than in the first nine months of 2013, \$58.60 per MWh versus \$39.75 per MWh. Comparing fuel prices in the first nine months of 2014 to the first nine months of 2013, the price of Northern Appalachian coal was 0.5 percent higher; the price of Central Appalachian coal was 2.9 percent lower; the price of Powder River Basin coal was 10.1 percent higher; the price of eastern natural gas was 54.9 percent higher; and the price of western natural gas was 27.0 percent higher.

2 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.

Figure 7-1 Energy Market net revenue factor trends: 2009 through September 2014



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 has an installed capacity of 410.2 MW and 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 has an installed capacity of 655.7 MW and 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.[3]
- The CP has an installed capacity of 600.0 MW and 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 DS plant has an installed capacity of 2.0 MW and consists of one oil fired CAT 2 MW unit.
- The nuclear plant has an installed capacity of 2,200 MW and 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.

Net revenue calculations for the CT, CC and CP include the hourly effect of actual local ambient air temperature on plant heat rates and generator output for each of the three plant configurations.[4,5] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

3 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.
4 Hourly ambient conditions supplied by Schneider Electric.
5 Heat rates provided by Pasteris Energy, Inc. No-load costs are included in 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.

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.[6]

A forced outage rate for each class of plant was calculated from PJM data and incorporated into all revenue calculations.[7] Each CT, CC, CP, and DS 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 four plant types were set to zero. Ancillary service revenues for the provision of regulation service were calculated for the CP only. 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. No black start service capability is assumed for any of the unit types.

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.

Zonal net revenues reflect zonal fuel costs based on locational fuel indices, actual unit consumption patterns, and zone specific delivery charges.[8] The delivered fuel cost for natural gas reflects the zonal, daily delivered price of natural gas and is from published commodity daily cash prices, with a basis adjustment for transportation costs.[9] The delivered cost of coal reflects the zone specific, delivered price of coal and was developed from the published prompt-month price, adjusted for rail transportation cost.[10]

Operating costs are the short run marginal cost of operations and include fuel costs, emissions costs, and VOM costs.[11,12] Average zonal operating costs in the first nine months of 2014 are shown in Table 7-1.

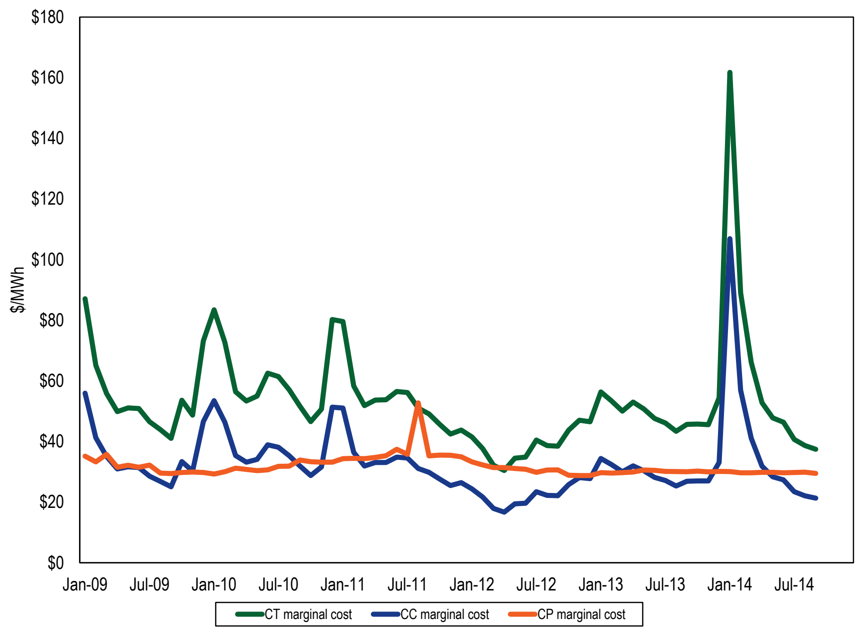
Table 7-1 Average zonal operating costs: January through September, 2014

Unit Type	Operating Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$64.45	10,241	$8.59
CC	$39.89	7,127	$1.50
CP	$29.78	9,250	$3.32
DS	$216.67	9,660	$12.50
Nuclear	$8.50	NA	$3.00
Wind	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

A significant increase in gas prices on cold days in January resulted in a corresponding increase in the average zonal operating cost of CTs and CCs in the first nine months of 2014 (Figure 7-2).

6 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.
7 Outage figures obtained from the PJM eGADS database.
8 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.
9 Gas daily cash prices obtained from Platts.
10 Coal prompt prices obtained from Platts.
11 Fuel costs are calculated using the daily spot price and may not equal what participants actually paid.
12 VOM rates provided by Pasteris Energy, Inc.

Figure 7-2 Average zonal operating costs: 2009 through September 2014



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

New Entrant Combustion Turbine

Energy market net revenue was calculated for a CT plant dispatched by PJM. 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.

New entrant CT plant energy market net revenues were higher in the first nine months of 2014 as a result of higher energy market prices which more than offset the higher fuel prices. The net revenue increase was the result of an increase in profitable run hours and a number of very high price hours. The impact of very high energy prices varied by zone. The increase in run hours occurred across all zones (Table 7-2).

Table 7-2 Run hours: January through September, 2013 and 2014

Zone	2013 (Jan-Sep)	2014 (Jan-Sep)	Change in 2014 from 2013
AECO	1,335	2,674	100%
AEP	914	1,470	61%
AP	1,093	1,696	55%
ATSI	1,013	1,703	68%
BGE	1,587	3,395	114%
ComEd	620	884	43%
DAY	898	1,507	68%
DEOK	883	2,718	208%
DLCO	785	1,309	67%
Dominion	1,317	1,646	25%
DPL	1,451	2,915	101%
EKPC	NA	2,654	NA
JCPL	1,491	2,540	70%
Met-Ed	1,238	2,330	88%
PECO	1,183	2,405	103%
PENELEC	1,550	3,481	125%
Pepco	1,532	3,079	101%
PPL	1,171	2,358	101%
PSEG	1,337	2,643	98%
RECO	1,413	2,551	81%

Table 7-3 Energy Market net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year): January through September, 2013 and 2014[13]

Zone	2013 (Jan-Sep)	2014 (Jan-Sep)	Change in 2014 from 2013
AECO	$18,686	$65,291	249%
AEP	$11,603	$53,310	359%
AP	$14,996	$73,123	388%
ATSI	$13,803	$61,854	348%
BGE	$25,497	$92,791	264%
ComEd	$10,072	$34,072	238%
DAY	$11,537	$53,814	366%
DEOK	$10,906	$58,684	438%
DLCO	$12,586	$48,058	282%
Dominion	$18,527	$54,896	196%
DPL	$21,532	$79,746	270%
EKPC	NA	$60,573	NA
JCPL	$23,193	$67,204	190%
Met-Ed	$18,252	$61,592	237%
PECO	$17,783	$63,823	259%
PENELEC	$18,100	$97,180	437%
Pepco	$23,929	$85,225	256%
PPL	$17,943	$61,550	243%
PSEG	$17,833	$59,171	232%
RECO	$20,190	$57,927	187%
PJM	$17,209	$64,494	275%

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.[14] 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.

New entrant CC plant energy market net revenues were higher in the first nine months of 2014 because of higher energy market prices which more than offset the higher natural gas prices. The number of run hours for the new entrant CC for the first nine months of 2014 was not significantly different than the run hours for the first nine months of 2013 but profit margins were higher in the first nine months of 2014.

13 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.
14 All starts associated with combined cycle units are assumed to be hot starts.

Table 7-4 PJM Energy Market net revenue for a new entrant gas-fired CC under economic dispatch (Dollars per installed MW-year): January through September, 2013 and 2014

Zone	2013 (Jan-Sep)	2014 (Jan-Sep)	Change in 2014 from 2013
AECO	$67,902	$151,523	123%
AEP	$53,408	$106,530	99%
AP	$62,620	$134,896	115%
ATSI	$61,237	$121,291	98%
BGE	$81,869	$186,170	127%
ComEd	$36,599	$61,380	68%
DAY	$55,638	$109,053	96%
DEOK	$52,640	$135,719	158%
DLCO	$50,183	$90,588	81%
Dominion	$67,963	$117,614	73%
DPL	$73,935	$166,883	126%
EKPC	NA	$138,031	NA
JCPL	$74,591	$154,888	108%
Met-Ed	$65,164	$140,813	116%
PECO	$63,313	$144,435	128%
PENELEC	$77,855	$192,957	148%
Pepco	$77,997	$178,865	129%
PPL	$63,118	$141,757	125%
PSEG	$67,283	$142,819	112%
RECO	$71,138	$138,674	95%
PJM	$64,445	$137,744	114%

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.

New entrant CP plant energy market net revenues were higher in the first nine months of 2014 because of higher energy market prices. The number of profitable hours in the first nine months of 2014 was significantly greater than the number of profitable hours in the first nine months of 2013.

Table 7-5 PJM Energy Market net revenue for a new entrant CP (Dollars per installed MW-year): January through September, 2013 and 2014

Zone	2013 (Jan-Sep)	2014 (Jan-Sep)	Change in 2014 from 2013
AECO	$33,333	$156,476	369%
AEP	$63,464	$135,003	113%
AP	$71,702	$158,894	122%
ATSI	$70,204	$147,947	111%
BGE	$40,323	$187,606	365%
ComEd	$48,494	$107,804	122%
DAY	$73,127	$137,111	87%
DEOK	$64,970	$126,284	94%
DLCO	$17,243	$71,137	313%
Dominion	$86,199	$199,209	131%
DPL	$33,867	$190,074	461%
EKPC	NA	$111,751	NA
JCPL	$38,650	$162,409	320%
Met-Ed	$31,734	$151,305	377%
PECO	$30,480	$154,381	407%
PENELEC	$81,468	$168,945	107%
Pepco	$37,535	$176,294	370%
PPL	$30,409	$151,798	399%
PSEG	$51,343	$183,010	256%
RECO	$56,616	$176,195	211%
PJM	$50,587	$152,682	202%

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.

New entrant DS plant energy market net revenues were higher in the first nine months of 2014 because of higher energy market prices which more than offset the higher fuel prices. The number of profitable hours in the first nine months of 2014 was significantly higher than in the first nine months of 2013 for a new entrant DS plant.

Table 7-6 PJM Energy Market net revenue for a new entrant DS (Dollars per installed MW-year): January through September, 2013 and 2014

Zone	2013 (Jan-Sep)	2014 (Jan-Sep)	Change in 2014 from 2013
AECO	$1,122	$38,223	3,305%
AEP	$503	$16,786	3,235%
AP	$771	$21,440	2,681%
ATSI	$23,776	$16,495	(31%)
BGE	$2,644	$58,273	2,104%
ComEd	$399	$13,242	3,223%
DAY	$535	$16,611	3,007%
DEOK	$477	$15,688	3,189%
DLCO	$1,198	$15,197	1,168%
Dominion	$1,562	$49,358	3,060%
DPL	$1,125	$44,715	3,874%
EKPC	NA	$16,789	NA
JCPL	$2,079	$38,384	1,746%
Met-Ed	$1,292	$37,217	2,782%
PECO	$1,024	$37,592	3,572%
PENELEC	$1,141	$18,883	1,555%
Pepco	$2,207	$59,878	2,613%
PPL	$1,088	$38,287	3,418%
PSEG	$1,302	$37,889	2,811%
RECO	$2,469	$35,009	1,318%
PJM	$2,459	$31,298	1,173%

New Entrant Nuclear Plant

Energy market net revenue for a nuclear plant was calculated by assuming the unit was dispatched day ahead by PJM. The unit runs for all hours of the year.

New entrant nuclear energy market net revenues were higher in the first nine months of 2014 because of higher energy market prices and correspondingly higher margins.

Table 7-7 PJM Energy Market net revenue for a new entrant nuclear plant (Dollars per installed MW-year): January through September, 2013 and 2014

Zone	2013 (Jan-Sep)	2014 (Jan-Sep)	Change in 2014 from 2013
AECO	$201,009	$338,646	68%
AEP	$176,738	$257,847	46%
AP	$185,986	$284,798	53%
ATSI	$184,807	$271,947	47%
BGE	$218,045	$381,897	75%
ComEd	$159,147	$226,449	42%
DAY	$179,154	$261,071	46%
DEOK	$169,935	$248,818	46%
DLCO	$172,976	$239,409	38%
Dominion	$202,566	$330,659	63%
DPL	$209,085	$364,267	74%
EKPC	NA	$244,774	NA
JCPL	$207,587	$342,907	65%
Met-Ed	$197,535	$326,222	65%
PECO	$196,192	$330,703	69%
PENELEC	$195,363	$297,750	52%
Pepco	$214,271	$368,649	72%
PPL	$195,457	$327,259	67%
PSEG	$222,893	$365,127	64%
RECO	$228,625	$358,855	57%
PJM	$195,651	$308,403	58%

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 in that hour.

New entrant wind energy market net revenues were higher in the first nine months of 2014 because of higher energy market prices and correspondingly higher margins. Wind net revenues did not increase as much as other technology types because wind is not dispatchable in response to higher prices.

Table 7-8 Energy Market net revenue for a wind installation (Dollars per installed MW-year): January through September, 2013 and 2014

Zone	2013 (Jan-Sep)	2014 (Jan-Sep)	Change in 2014 from 2013
ComEd	$103,483	$128,975	25%
PENELEC	$110,020	$145,550	32%

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 in that hour.

New entrant solar energy market net revenues were higher in the first nine months of 2014 because of higher energy market prices and correspondingly higher margins. Like wind, solar net revenues did not increase as much as other technology types because solar is not dispatchable in response to higher prices.

Table 7-9 PSEG Energy Market net revenue for a solar installation (Dollars per installed MW-year): January through September, 2013 and 2014

Zone	2013 (Jan-Sep)	2014 (Jan-Sep)	Change in 2014 from 2013
PSEG	$428,020	$470,617	10%

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 fuel fired power plants in the PJM footprint in order to reduce heavy metal emissions. The EPA has promulgated intrastate and interstate air quality standards and associated emissions limits for states. The most recent interstate emissions rule, the Cross-State Air Pollution Rule (CSAPR), will, when implemented, also require investments for some fossil fuel 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 some 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 significant impacts on PJM wholesale markets.[1]

Overview

Federal Environmental Regulation

- **EPA Mercury and Air Toxics Standards Rule.** 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.[2] 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 (PM). On March 28, 2013, the EPA issued a rule that raised the new source limits for new coal- and oil-fired power plants based on new information and analysis.[3]

- **Air Quality Standards (NO_X and SO_2 Emissions).** The CAA requires each state to attain and maintain compliance with fine PM and ozone national ambient air quality standards (NAAQS). Much recent regulatory activity concerning emissions has concerned the development and implementation of a transport rule to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[4]

  On April 29, 2014, the U.S. Supreme Court upheld EPA's Cross-State Air Pollution Rule (CSAPR) and on October 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit lifted the stay imposed on CSAPR, clearing the way for the EPA to implement this rule and to replace the Clean Air Interstate Rule (CAIR) now in effect.[5,6]

- **National Emission Standards for Reciprocating Internal Combustion Engines.** On January 14, 2013, the EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[7] RICE includes certain types of electrical generation facilities like diesel engines typically used for backup,

1 For quantification of the economics of new entrant wind and solar installations, see the *2013 State of the Market Report for PJM*, Volume II, Section 7, "Net Revenue."

2 *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).

3 *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).

4 CAA § 110(a)(2)(D)(i)(I).

5 See EPA et al. v. EME Homer City Generation, L.P. et al., No. 12-1182.

6 Order, No. 11-1302.

7 *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).

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.

Pending initiatives in Pennsylvania and the District of Columbia would reverse the EPA's exception in those jurisdictions and apply comparable regulatory standards to generation with similar operational characteristics.[8]

In PJM's filing to improve its ability to dispatch DR prior to emergency system conditions, PJM proposed to retain the PJM Emergency Load Response Program which would allow RICE to continue to use the EPA's exception.[9] The MMU protested retention of the emergency program, particularly for the purpose of according discriminatory preference to resources that are not good for reliability, the markets or the environment.[10] An order from the Commission in this matter is now pending.

- **Greenhouse Gas Emissions Rule.** On September 20, 2013, the EPA proposed standards placing national limits on the amount of CO_2 that new power plants would be allowed to emit.[11] Once GHG NSPS standards for CO_2 are in place, the CAA permits the EPA to take the much more significant step of regulating CO_2 emissions from existing sources.[12] In anticipation of timely issuance of a final GHG NSPS, the EPA issued a proposed rule for regulating CO_2 from certain existing power generation facilities on June 2, 2014, the Existing Stationary Sources Notice of Proposed Rulemaking ("ESS NOPR").[13] The ESS NOPR established interim and final emissions goals for each state that must be met, respectively, by 2020 and 2030. States have flexibility to meet these goals, including through participation in multistate CO_2 credit trading programs.
- **Cooling Water Intakes.** Section 316(b) of the Clean Water Act (CWA) requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. A final rule implementing this requirement was issued May 19, 2014.[14]

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.[15] 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.[16]
- **Illinois Air Quality Standards (NO_X, SO_2 and Hg).** The State of Illinois has promulgated its own standards for NO_X, SO_2 and Hg (mercury) known as Multi-Pollutant Standards ("MPS") and Combined Pollutants Standards ("CPS").[17] MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as EPA's MATS.

  The Illinois Pollution Control Board has granted variances with conditions for compliance with MPS/CPS for Illinois units included in or potentially included in PJM markets that may have impacted PJM markets.[18] In order to obtain variances, companies in PJM, such as Midwest Generation LLC, agreed to terms with the Illinois Pollution Control Board that may have resulted in investments in the installation of environmental pollution

8 See Pennsylvania House of Representatives, House Bill No. 1699; Council of the District of Columbia Bill 20-569.
9 PJM Tariff filing, FERC Docket No. ER14-822 (December 24, 2013).
10 Comments, Complaint and Motion to Consolidate of the Independent Market Monitor for PJM, FERC Docket No. ER14-822 (January 14, 2014) at 3–6.
11 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units, Propose Rule*, EPA-HQ-OAR-2013-0495 ("GHG NSPS").
12 See CAA § 111(b)&(d).
13 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, 79 Fed. Reg. 34830 (June 18, 2014).
14 See EPA, *National Pollutant Discharge Elimination System—Final Regulations to Establish Requirements for Cooling Water Intake Structures at Existing Facilities and Amend Requirements at Phase I Facilities*, EPA-HQ-OW-2008-0667.
15 N.J.A.C. § 7:27–19.
16 CTs must have either water injection or selective catalytic reduction (SCR) controls; steam units must have either an SCR or selective non-catalytic reduction (SNCR).
17 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).
18 See, e.g., Midwest Generation, LLC, Opinion and Order of the Board, Docket No. PCB 13-24 (Variance-Air) (April 4, 2013); Midwest Generation, LLC, Opinion and Order of the Board, Docket No. PCB 12-121 (Variance-Air) (August 23, 2012).

control equipment at units and deactivation of Illinois units that differ from what would have occurred had only Federal regulations applied.[19]

- **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 2014 for the 2012-2014 compliance period were $5.02 per ton, above the price floor for 2014. The clearing price is equivalent to a price of $5.53 per metric tonne, the unit used in other carbon markets.

Emissions Controls in PJM Markets

Environmental regulations affect decisions about emission control investments in existing units, investment in new units and decisions to retire units lacking emission controls. As a result of environmental regulations and agreements to limit emissions, many PJM units burning fossil fuels have installed emission control technology. On June 30, 2014, 71.1 percent of coal steam MW had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions, while 98.7 percent of coal steam MW had some type of particulate control, and 92.2 percent of fossil fuel fired capacity in PJM had NO_x emission control technology.

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, 2014, 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 not enacted renewable portfolio standards. West Virginia has enacted a renewable portfolio standard, but it will not be in effect until 2015.

19 See *Id.*

Renewable energy credits (RECs) and federal production tax credits provide out of market payments to qualifying resources, primarily wind and solar, which create an incentive to generate MWh until the LMP is equal to the marginal cost of producing power minus the credit received for each MWh. The credits provide an incentive to make negative energy offers when the net of marginal cost and credits is negative. These subsidies affect the offer behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources. During the first nine months of 2014, there were 6,065 intervals with negative LMPs as a result of negative offers from wind units.

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. Attempts to extend the definition of renewable energy to include nuclear power in order to provide subsidies to nuclear power could increase this impact if successful. Renewable energy credit markets are markets related to the production and purchase of wholesale power, but are not subject to FERC regulation unless bundled with a wholesale sale of electric energy.[20] REC markets are not transparent. Data on RECs prices and markets are not publicly available. 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. Costs for environmental controls are part of bids for capacity resource in the PJM capacity market. The costs of environmental permits are included in energy offers. PJM markets also provide a flexible mechanism that incorporates renewable resources and renewable energy credit markets, and ensure that renewable resources have access to a broad market. PJM markets

20 See 139 FERC ¶ 61,061 at PP 18, 22 (2012) ("[W]e conclude that unbundled REC transactions fall outside of the Commission's jurisdiction under sections 201, 205 and 206 of the FPA. We further conclude that bundled REC transactions fall within the Commission's jurisdiction under sections 201, 205 and 206 of the FPA,… [A]lthough a transaction may not directly involve the transmission or sale of electric energy, the transaction could still fall under the Commission's jurisdiction because it is "in connection with" or "affects" jurisdictional rates or charges.").

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. The EPA issues technology based standards for major sources and certain area sources of emissions.[21,22] The EPA actions have and will 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 Clean Water Act (CWA) affects generating plants that rely on water drawn from jurisdictional water bodies.[23]

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.

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.[24] 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 (PM). On March 28, 2013, the EPA issued a rule that raised the new source limits for new coal and oil fired power plants based on new information and analysis.[25]

Air Quality Standards: Control of NO_x, SO_2 and O_3 Emissions Allowances

The CAA requires each state to attain and maintain compliance with fine particulate matter and ozone national ambient air quality standards (NAAQS). Under NAAQS, the EPA establishes emission standards for six air pollutants, including NO_x, SO_2, O_3 at ground level, PM, CO, and Pb, and approves state plans to implement these standards, known as State Implementation Plans (SIPs).[26] Standards for each pollutant are set and periodically revised, most recently for SO_2 in 2010, and SIPS are filed, approved and periodically revised accordingly.

Much recent regulatory activity concerning emissions has concerned the development and implementation of a transport rule to address the CAA's requirement that each state prohibit emissions that significantly interfere with the ability of another state to meet NAAQS.[27]

On April 29, 2014, the U.S. Supreme Court upheld the EPA's Cross-State Air Pollution Rule (CSAPR), clearing the way for the EPA to implement this rule and to replace the Clean Air Interstate Rule (CAIR) now in effect.[28]

21 42 U.S.C. § 7401 et seq. (2000).
22 The 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.
23 The CWA applies to "navigable waters," which are, in turn, defined to include the "waters of the United States, including territorial seas." 33 U.S.C. § 1362(7). An interpretation of this rule has created some uncertainty on the scope of the waters subject to EPA jurisdiction, (see *Rapanos v. U.S., et al.*, 547 U.S. 715 (2006)), which the EPA continues to attempt to resolve.
24 *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); *aff'd*, White Stallion Energy Center, LLC v EPA, No. 12-1100 (D.C. Cir. April 15, 2014).
25 *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).
26 Nitric Oxides (NO_x), Sulfur Dioxide (SO_2), Ozone (O_3), Particulate Matter (PM), Carbon Monoxide (CO) and Lead (Pb).
27 CAA § 110(a)(2)(D)(i)(I).
28 See EPA et al. v. EME Homer City Generation, L.P. et al., No. 12-1182. Some issues, involving what the EPA characterizes as EPA "technical and scientific judgments" continue to require resolution by the courts. See Respondents' Motion To Lift The Stay Entered On December 30, 2011, USCA for the Dist. of Columbia Circuit No. 11-1302, et al. (June 26, 2014) at 9–10 ("EPA Motion to Lift Stay). On October 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit granted EPA's motion.

The EPA finalized the CSAPR on July 6, 2011. CSAPR requires specific states in the eastern and central United States to reduce power plant emissions of SO_2 and NO_X that cross state lines and contribute to ozone and fine particle pollution in other states, to levels consistent with the 1997 ozone and fine particle and 2006 fine particle NAAQS.[29] The CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[30]

CSAPR establishes two groups of states with separate requirements standards. Group 1 includes a core region comprised of 21 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[31] Group 2 does not include any states in the PJM region.[32] Group 1 states must reduce both annual SO_2 and NO_X emissions to help downwind areas attain the 24-Hour and/or Annual Fine Particulate Matter[33] NAAQS and to reduce ozone season NO_X emissions to help downwind areas attain the 1997 8-Hour Ozone NAAQS.

Under the original timetable for implementation, Phase 1 emission reductions were expected to become effective starting January 1, 2012, for SO_2 and annual NO_X reductions and May 1, 2012, for ozone season NO_X reductions. CSAPR requires reductions of emissions for each state below certain assurance levels, established separately for each emission type. Assurance levels are the state budget for each type of emission, determined by the sum of unit-level allowances assigned to each unit located in such state, plus a variability limit, which is meant to account for the inherent variability in the state's yearly baseline emissions. Because allowances are allocated only up to the state emissions budget, any level of emissions in a state above its budget must be covered by allowances obtained through trading for unused allowances allocated to units located in other states included in the same group.

29 *Federal Implementation Plans: Interstate Transport of Fine Particulate Matter and Ozone and Correction of SIP Approvals*, Final Rule, Docket No. EPA-HQ-OAR-2009-0491, 76 Fed. Reg. 48208 (August 8, 2011) (CSAPR); *Revisions to Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone*, Final Rule, Docket No. EPA-HQ-2009-0491, 77 Fed. Reg. 10342 (February 21, 2012) (CSAPR II).

30 *Id.*

31 Group 1 states include: New York, Pennsylvania, New Jersey, Maryland, Virginia, West Virginia, North Carolina, Tennessee, Kentucky, Ohio, Indiana, Illinois, Missouri, Iowa, Wisconsin, and Michigan.

32 Group 2 states include: Minnesota, Nebraska, Kansas, Texas, Alabama, Georgia and South Carolina.

33 EPA defines Particulate Matter (PM) as "[a] complex mixture of extremely small particles and liquid droplets. It is made up of a number of components, including acids (such as nitrates and sulfates), organic chemicals, metals, and soil or dust particles." Fine PM ($PM_{2.5}$) measures less than 2.5 microns across.

Under the original implementation timetable, significant additional Phase 2 SO_2 emission reductions would have taken effect in 2014 from certain states, including all of the PJM states except Delaware, and also excluding the District of Columbia.

The rule provides for implementation of a trading program for states in the CSAPR region. Sources in each state may achieve those limits as they prefer, including unlimited trading of emissions allowances among power plants within the same state and limited trading of emission allowances among power plants in different states in the same group. Thus, units in PJM states may only trade and use allowances originating in Group 1 states.

If state emissions exceed the applicable assurance level, including the variability limit, a penalty would be assessed that is allocated to resources within the state in proportion to their responsibility for the excess. The penalty would be a requirement to surrender two additional allowances for each allowance needed to the cover the excess.

On October 23, 2014, the U.S. Court of Appeals for the District of Columbia Circuit granted EPA's motion to lift the stay imposed on CSAPR.[34] EPA requested that the court move the original compliance deadlines back three years to account for the delays from litigation.[35]

The court did not address EPA's proposed revised schedule, and its status is unclear. In the meantime, EPA advises that CAIR remains in effect and "no immediate action from States or affected sources is expected."[36]

Emission Standards for Reciprocating Internal Combustion Engines

On January 14, 2013, the EPA signed a final rule regulating emissions from a wide variety of stationary reciprocating internal combustion engines (RICE).[37] RICE include certain types of electrical generation facilities like diesel engines

34 Order, No. 11-1302.

35 See EPA Motion to Lift Stay at 14–17.

36 See EPA, "Cross-State Air Pollution Rule (CSAPR),"which can be accessed at <http://www.epa.gov/airtransport/CSAPR/>.

37 *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").

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) of Performance for Stationary Spark Ignition Internal Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively "RICE Rules").[38]

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 whether the engine is an "area source" or "major source)," and the starter mechanism for the engine (compression ignition or spark ignition).[39]

On May 22, 2012, the EPA proposed amendments to the RICE NESHAP Rule.[40] 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 MMU 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 resources in the PJM markets, nor for reliability.[41] The final rule approves the proposed 100 hours per year exception, provided that RICE uses ultra low sulfur diesel fuel (ULSD).[42] Otherwise a 15-hour exception applies.[43] The exempted emergency demand response programs include demand resources in RPM.[44]

38 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.

39 CAA § 112(a) defines "major source" to mean "any stationary source or group of stationary sources located within a contiguous area and under common control that emits or has the potential to emit considering controls, in the aggregate, 10 tons per year or more of any hazardous air pollutant or 25 tons per year or more of any combination of hazardous air pollutants," and "area source" to mean, "any stationary source of hazardous air pollutants that is not a major source."

40 *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.

41 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).

42 Final NESHAP RICE Rule at 31-24.

43 *Id.* at 31.

44 If FERC approves PJM's proposal on this issue in Docket No. ER14-822-000, demand resources that utilize behind the meter generators will maintain emergency status and not have to curtail during pre-emergency events, unlike other demand resources.

Pending initiatives in Pennsylvania and the District of Columbia would reverse the EPA's exception in those jurisdictions and apply comparable regulatory standards to generation with similar operational characteristics in those jurisdictions.[45] The MMU and PJM have stated that these state measures would not, if enacted, have any harmful impact on system reliability.[46] The MMU has also explained that such measures would improve markets.[47]

On December 24, 2013, PJM filed revisions to the rules providing for a PJM Pre-Emergency Load Response Program that allows PJM to dispatch resources participating in the program with no prerequisite for system emergency conditions.[48] PJM retained the PJM Emergency Load Response Program (ELRP), but proposed to restrict participation in the ELRP to DR based on "generation that is behind the meter and has strict environmental restrictions on when it can operate."[49] Such restrictions refer to the EPA's amended RICE NESHAP Rule. The EPA created an exception to and weakened its NESHAP RICE Rule based on arguments that markets such as PJM needed RICE for reliability. PJM created an exception to its rule, which would allow RICE to continue to use the EPA's exception. The MMU protested retention of the emergency program, particularly for the purpose of according discriminatory preference to resources that are not good for reliability, the markets or the environment.[50] By order issued May 9, 2014, the Commission ordered that PJM "either: (i) justify the need for, and scope of, its proposed exemption, including any necessary revisions to its Tariff to ensure that the exemption is properly tailored to the environmental restrictions imposed on these units, or (ii) remove the exemption for behind-the-meter demand response resources from its tariff."[51] In its compliance filing, PJM attempted to justify

45 See Pennsylvania House of Representatives, House Bill No. 1699; Council of the District of Columbia bill 20-569.

46 See Comments of the Independent Market Monitor for PJM, EPA Docket No. EPA-HQ-OAR-0708 (August 9, 2012); Comments of the Independent Market Monitor for PJM, EPA Docket No. EPA-HQ-OGC-2011-1030 (February 16, 2012); Market Monitor, Comments of the Independent Market Monitor for PJM, Supporting Testimony before the Pennsylvania House of Representatives Environmental and Energy Committee re House Bill 1699, An Act Providing for the Regulation of Certain Reciprocal Internal Combustion Engines (November 20, 2013), which can be accessed at: <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Comments_to_PA_CERE_1699_20131120.pdf>; Letter from Terry Boston, President & CEO, PJM to Hon. Chris Ross re Pennsylvania House Bill 1999 (November 11, 2013) ("With regards to your inquiry of potential impacts to grid reliability, PJM does not anticipate the emergence of system reliability issues, should HB 1699 become law."); Letter from Terry Boston, President & CEO, PJM to Hon. Mary M. Cheh re District of Columbia Bill 20-569 (December 19, 2013).

47 *Id.*

48 PJM Tariff filing, FERC Docket No. ER14-822 (December 24, 2014).

49 *Id.* at 8-9.

50 Comments, Complaint and Motion to Consolidate of the Independent Market Monitor for PJM, FERC Docket No. ER14-822 (January 14, 2014) at 3-6.

51 See 147 FERC ¶ 61,103 at P 41.

the exception.[52] An order from the Commission on PJM's compliance filing is now pending.

Regulation of Greenhouse Gas Emissions

The EPA has proposed to regulate CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS and encourage coordination between the EPA and the states.[53,54]

The EPA's first step is the development of regulations applicable to new resources, New Source Performance Standards (NSPS). On September 20, 2013, the EPA proposed national limits on the amount of CO_2 that new power plants would be allowed to emit.[55,56] The standards would require advanced technologies like efficient natural gas units and efficient coal units implementing partial carbon capture and storage (CCS). The proposed rule includes two limits for fossil fuel fired utility boilers and IGCC units based on the compliance period selected: 1,100 lb CO_2/MWh gross over a 12 operating month period, or 1,000–1,050 lb CO_2/MWh gross over an 84 operating month (seven year) period. The proposed rule also includes two standards for natural gas fired stationary combustion units based on the size (MW): 1,000 lb CO_2/MWh gross for larger units (> 850 mmBtu/hr), or 1,100 lb CO_2/MWh gross for smaller units (≤ 850 mmBtu/hr).

Once NSPS standards for CO_2 are in place, the CAA permits the EPA to take the much more significant step of regulating CO_2 emissions from existing sources.[57] In anticipation of timely issuance of a final NSPS for CO_2, the EPA issued a proposed rule for regulating CO_2 from certain existing power generation facilities ("ESS NOPR") on June 2, 2014.[58] The President requested that the EPA issue a final rule by June 1, 2015.[59]

The ESS NOPR sets state by state CO_2 emissions targets, which are expressed as interim and final rate based goals.[60] States would be required to develop and obtain EPA approval of plans to achieve the interim goals effective 2020 and the final goals effective 2030.[61] The ESS NOPR would allow states to translate the rate based goals into mass based goals (a cap on the tons of CO_2 emissions) when they submit their plans.[62] Mass based goals would facilitate multistate approaches to emissions reductions. The EPA anticipates that meeting these goals would reduce CO_2 emissions from Electric Generating Units (EGUs) by 2030 to a level 30 percent below the level of emissions in 2005.[63]

The EPA has calculated goals based on EGU emissions rates for each state. The EPA uses four building blocks to calculate state goals.[64] The EPA calculates emissions as of 2005 from EGUs in each state, and then assumes reduced emissions based on implementation of the building blocks.[65]

To calculate state interim and final goals, EPA assumes the following building blocks: (i) heat rate improvement of six percent at affected EGUs; (ii) displacement in the system dispatch of the most carbon intensive EGUs with generation from less carbon intensive EGUs (including NGCC units under construction); (iii) displacement in the system dispatch of affected EGUs with low or zero carbon generation (renewables and nuclear, including planned nuclear); and (iv) reduced emissions from affected EGUs from the use of demand side energy efficiency.[66]

The interim and final targets for CO_2 emissions goals for PJM states, in order of highest to lowest, are included in Table 8-1.

52 See PJM compliance filing, ER14-822-002 (June 2, 2014) at 4–8.
53 See CAA § 111.
54 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 the EPA to determine whether greenhouse gases endanger public health and welfare. Massachusetts v. EPA, 549 U.S. 497. 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. 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). 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. Coalition for Responsible Regulation, Inc., et al. v. EPA, No 09-1322.
55 *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units*, Proposed Rule, EPA-HQ-OAR-2013-0495, 79 Fed. Reg. 1430 (January 8, 2014); The President's Climate Action Plan, Executive Office of the President (June 2013) (Climate Action Plan); Presidential Memorandum–Power Sector Carbon Pollution Standards, Environmental Protection Agency (June 25, 2013); Presidential Memorandum–Power Section Carbon Pollution Standards (June 25, 2013) ("June 25th Presidential Memorandum"). The Climate Action Plan can be accessed at: <http://www.whitehouse.gov/sites/default/files/image/president27sclimateactionplan.pdf>.
56 79 Fed. Reg. 1352 (January 8, 2014).
57 See CAA § 111(b)&(d).
58 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, 79 Fed. Reg. 34830 (June 18, 2014).
59 See June 25th Presidential Memorandum.
60 *Id.* at 34894.
61 ESS NOPR at 34837.
62 *Id.* at 34894.
63 *Id.* at 34839.
64 *Id.* at 34836.
65 *Id.* at 34856–34858.
66 *Id.* at 34861.

Table 8-1 Interim and final targets for CO_2 emissions goals for PJM states (lbs/MWh)[67,68]

PJM State	2020 Interim Rate-Based Goal (lb/MWh)	2030 Final Rate-Based Goal (lb/MWh)
Kentucky	1,844	1,763
West Virginia	1,748	1,620
Indiana	1,607	1,531
Ohio	1,452	1,338
Illinois	1,366	1,271
Maryland	1,347	1,187
Tennessee	1,254	1,163
Michigan	1,227	1,161
Pennsylvania	1,179	1,052
North Carolina	1,077	992
Delaware	913	841
Virginia	884	810
New Jersey	647	531
District of Columbia	NA	NA

Each state would be required to develop an EPA approved plan to meet its interim and final goals.[69] The ESS NOPR would not require states to implement the building blocks in their plan; it would require states to meet the goals through an approach included in an EPA-approved plan.[70] The EPA would impose its own plan if a state does not timely propose a plan that EPA finds satisfactory.[71]

States could implement portfolio approaches that would "require EGUs and other entities to be legally responsible for actions required under the plan that will, in aggregate, achieve the emission performance level."[72] States could choose from market based trading programs, emissions performance standards, renewable portfolio standards (RPS), energy efficiency resource standards (EERS), and other demand-side energy efficiency programs.[73]

67 The District of Columbia has no affected EGUs and is not subject to the ESS NOPR. *Id.* at 34867.
68 CO_2 targets reported in adjusted output-weighted average pounds per net MWh.
69 *Id.* at 34830.
70 *Id.* at 34897 ("[A] core flexibility provided under CAA section 111(d) is that while states are required to establish standards of performance that reflect the degree of emission limitation from application of the control measures that the EPA identifies as the BSER, they need not mandate the particular control measures the EPA identifies as the basis for its BSER determination.").
71 *Id.* at 34844.
72 *Id.* at 34901.
73 *Id.* at 34835.

The ESS NOPR recognizes that many states have already implemented programs to reduce CO_2 emissions from fossil fuel fired EGUs and specifically highlights the Regional Greenhouse Gas Initiative (RGGI), California's Global Warming Solutions Act of 2006, and Colorado's Clean Air, Clean Jobs Act.[74] Each of these programs would require significant changes in order to comply with the approach in the ESS NOPR. The trading rules could remain, but new regional goals and compliance deadlines that equal or exceed the state goals and compliance deadlines set in the ESS NOPR would be needed. The rules would also take into account that the ESS NOPR relies on reduced emissions from EGUs to reach state goals and does not count non EGU offsets towards meeting those goals.[75]

The ESS NOPR permits states to partner and submit multistate plans to reduce CO_2 emissions from EGUs.[76]

Federal Regulation of Environmental Impacts on Water

On May 19, 2014, 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 CWA.[77]

The final rule requires an existing facility to use BTA to reduce impingement of aquatic organisms (pinned against intake structures) if the facility withdraws 25 percent or more of its cooling water from waters of the United States and has a design intake flow of greater than two million gallons per day (mgd).[78] Existing facilities withdrawing 125 mgd must conduct studies that may result

74 *Id.* at 34848–34849.
75 *Id.* at 34910.
76 *Id.* at 34834.
77 See 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 ("316(b) Rule"). "BTA" is the term adopted by the EPA for the 316(b) Rule (at mimeo at 11) ("the term BTA means "best technology available for minimizing adverse environmental impact.").
78 *Id. mimeo* at 22–25; see 40 CFR §§ 125.91, 125.94(c) and (d). Existing facilities must comply with one of the following seven alternatives identified in the national BTA standards for impingement mortality: "(1) operate a closed-cycle recirculating system …; (2) operate a cooling water intake structure that has a maximum through-screen design intake velocity of 0.5 fps; (3) operate a cooling water intake structure that has a maximum through-screen intake velocity of 0.5 fps; (4) operate an offshore velocity cap as defined at § 125.92 that is installed before [the rule became effective]; (5) operate a modified traveling screen [accepted by the Director]; (6) operate any other combination of technologies, management practices and operational measures that the Director determines is the [BTA] for impingement reduction; or (7) achieve the specified impingement mortality performance standard." 40 CFR § 125.94(c).

in a requirement to install site-specific controls for reducing entrainment of aquatic organisms (drawn into intake structures).[79] If a new generating unit is added to an existing facility, the rule requires addition of BTA that either (i) reduces actual intake flow at the new unit to a level at least commensurate with what can be attained using a closed-cycle recirculating system or (ii) reduces entrainment mortality of all stages of aquatic organisms that pass through a sieve with a maximum opening dimension of 0.56 inches to a prescribed level.[80]

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 reason 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.[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]

Table 8-2 shows the HEDD emissions limits applicable to each unit type. NO_x emissions limits for coal units became effective December 15, 2012.[83] NO_x emissions limits for other unit types will become effective May 1, 2015.[84]

Table 8-2 HEDD maximum NO_x emission rates[85]

Fuel and Unit Type	NO_x 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

Illinois Air Quality Standards (NO_X, SO_2 and Hg)

The State of Illinois has promulgated its own standards for NO_X, SO_2 and Hg (mercury) known as Multi-Pollutant Standards ("MPS") and Combined Pollutants Standards ("CPS").[86] MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as EPA's MATS.

The Illinois Pollution Control Board has granted variances with conditions for compliance with MPS/CPS for Illinois units included in or potentially included in PJM markets that may have impacted PJM markets.[87] In order to obtain variances, companies in PJM, such as Midwest Generation LLC, agreed to terms with the Illinois Pollution Control Board that may have resulted in investments in the installation of environmental pollution control equipment at units and deactivation of Illinois units that differ from what would have occurred had only Federal regulations applied.[88]

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

79 *Id. mimeo* at 39–41; see 40 CFR §§ 122.21(r)(1)(ii)(B), 125.91, 125.94(c) and (d).
80 *Id. mimeo* at 93–95; see 40 CFR § 125.94(e).
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).
83 N.J.A.C. § 7:27-19.4.
84 N.J.A.C. § 7:27-19.5.
85 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.
86 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_x and SO_2 (CPS)).
87 See, e.g., Midwest Generation, LLC, Opinion and Order of the Board, Docket No. PCB 13-24 (Variance-Air) (April 4, 2013); Midwest Generation, LLC, Opinion and Order of the Board, Docket No. PCB 12-121 (Variance-Air) (August 23, 2012).
88 See *Id.*

facilities.[89,90] RGGI generates revenues for the participating states. The states have spent approximately 65 percent of revenues to date on energy efficiency, six percent on clean and renewable energy, six percent on greenhouse gas abatements and 17 percent on direct bill assistance.[91]

Table 8-3 shows the RGGI CO_2 auction clearing prices and quantities for the 14 2009-2011 compliance period auctions and additional auctions for the 2012-2014 compliance period held as of September 30, 2014, in short tons and metric tonnes. Prices for auctions held June 4, 2014 for the 2012-2014 compliance period were at the highest clearing price to date, $5.02 per allowance (equal to one ton of CO_2), above the current price floor of $2.00 for RGGI auctions.[92] The price increased from the previous high of $4.00 in March 2014 as the result of a 45 percent reduction in the quantity of allowances offered in this auction.[93] The 23,491,350 allowances sold include the original allowances offered for sale in the market of 18,491,350 as well as 5,000,000 additional cost containment reserves (CCR). This auction included the additional CCRs for the first time, due to the demand for allowances above the CCR trigger price of $4.00 per ton. There are no additional CCRs available for sale in 2014. Prices increased in the June 4, 2014, auction to $5.02 per allowance. In the September 3, 2014, auction, prices decreased by $0.14 per allowance to $4.88 per allowance.

Table 8-3 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 2009-2011 and 2012-2014 Compliance Periods[94]

	Short Tons			Metric Tonnes		
Auction Date	Clearing Price	Quantity Offered	Quantity Sold	Clearing Price	Quantity Offered	Quantity Sold
September 25, 2008	$3.07	12,565,387	12,565,387	$3.38	11,399,131	11,399,131
December 17, 2008	$3.38	31,505,898	31,505,898	$3.73	28,581,678	28,581,678
March 18, 2009	$3.51	31,513,765	31,513,765	$3.87	28,588,815	28,588,815
June 17, 2009	$3.23	30,887,620	30,887,620	$3.56	28,020,786	28,020,786
September 9, 2009	$2.19	28,408,945	28,408,945	$2.41	25,772,169	25,772,169
December 2, 2009	$2.05	28,591,698	28,591,698	$2.26	25,937,960	25,937,960
March 10, 2010	$2.07	40,612,408	40,612,408	$2.28	36,842,967	36,842,967
June 9, 2010	$1.88	40,685,585	40,685,585	$2.07	36,909,352	36,909,352
September 10, 2010	$1.86	45,595,968	34,407,000	$2.05	41,363,978	31,213,514
December 1, 2010	$1.86	43,173,648	24,755,000	$2.05	39,166,486	22,457,365
March 9, 2011	$1.89	41,995,813	41,995,813	$2.08	38,097,972	38,097,972
June 8, 2011	$1.89	42,034,184	12,537,000	$2.08	38,132,781	11,373,378
September 7, 2011	$1.89	42,189,685	7,847,000	$2.08	38,273,849	7,118,681
December 7, 2011	$1.89	42,983,482	27,293,000	$2.08	38,993,970	24,759,800
March 14, 2012	$1.93	34,843,858	21,559,000	$2.13	31,609,825	19,558,001
June 6, 2012	$1.93	36,426,008	20,941,000	$2.13	33,045,128	18,997,361
September 5, 2012	$1.93	37,949,558	24,589,000	$2.13	34,427,270	22,306,772
December 5, 2012	$1.93	37,563,083	19,774,000	$2.13	34,076,665	17,938,676
March 13, 2013	$2.80	37,835,405	37,835,405	$3.09	34,323,712	34,323,712
June 5, 2013	$3.21	38,782,076	38,782,076	$3.54	35,182,518	35,182,518
September 4, 2013	$2.67	38,409,043	38,409,043	$2.94	34,844,108	34,844,108
December 4, 2013	$3.00	38,329,378	38,329,378	$3.31	34,771,837	34,771,837
March 5, 2014	$4.00	23,491,350	23,491,350	$4.41	21,311,000	21,311,000
June 4, 2014	$5.02	18,062,384	18,062,384	$5.53	16,385,924	16,385,924
September 3, 2014	$4.88	17,998,687	17,998,687	$5.38	16,328,139	16,328,139

Figure 8-1 shows average, daily settled prices for NO_x, CO_2 and SO_2 emissions.[95] In the first nine months of 2014, annual NO_x prices were 33.1 percent higher than in the first nine months of 2013. The increase in NO_x prices was at least in part due to the recent Supreme Court ruling which upheld the EPA's CSAPR program which limits the amount of NO_x emissions by power plant.[96] SO_2 prices were 7.2 percent higher in the first nine months of 2014 compared to the first nine months of 2013. Figure 8-1 also shows the average, daily settled

89 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>.

90 For more details see the *2013 State of the Market Report for PJM*, Volume 2: Section 8, "Environmental and Renewables."

91 *Regional Investment of RGGI CO_2 Allowance Proceeds, 2012*, The Regional Greenhouse Gas Initiative, February 2014 <http://www.rggi.org/docs/Documents/2012-Investment-Report_ES.pdf> (Accessed November 3, 2014).

92 RGGI measures carbon in short tons (short ton equals 2,000 pounds) while world carbon markets measure carbon in metric tonnes (metric tonne equals 1,000 kilograms or 2,204.6 pounds).

93 *RGGI States Make Major Cuts to Greenhouse Gas Emissions from Power Plants*, Regional Greenhouse Gas Initiative, <http://www.rggi.org/docs/PressReleases/PR011314_AuctionNotice23.pdf> (Accessed October 27, 2014).

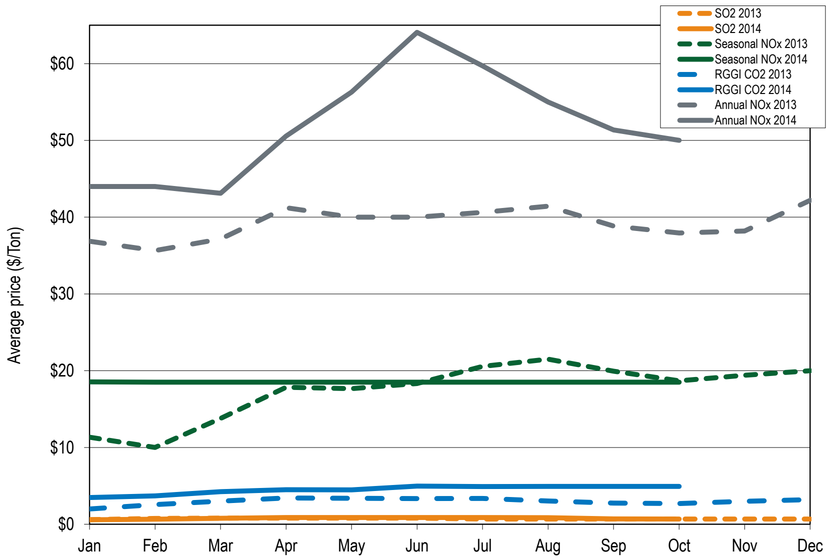
94 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results> (Accessed October 13, 2014).

95 The NO_x prices result from the Clean Air Interstate Rule (CAIR) established by the EPA covering 28 states. The SO_2 prices result from the Acid Rain cap and trade program established by the EPA. The CO_2 prices are from RGGI.

96 See EPA et al. v. EME Homer City Generation, L.P. et al., No. 12-1182.

price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances. RGGI allowances are required for generating units in participating RGGI states. This includes the PJM states of Delaware and Maryland.

Figure 8-1 Spot monthly average emission price comparison: 2013 and January through September of 2014[97]



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, 2014, 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.

97 See *Evolution Markets*, <http://www.evomarkets.com> (Accessed October 13, 2014).

Under the proposed standards, a substantial amount of load in PJM is required to be served by renewable resources by 2024. As shown in Table 8-4, New Jersey will require 24.1 percent of load to be served by renewable resources in 2024, the most stringent standard of all PJM jurisdictions. Renewable resources earn renewable energy credits (RECs) (also known as alternative energy credits) when they generate electricity. These RECs are bought by utilities and load serving entities to fulfill the requirements for generation from renewable resources. 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 for 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.

Table 8-4 Renewable standards of PJM jurisdictions to 2024[98,99]

Jurisdiction	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Delaware	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.00%	21.00%	22.00%	23.00%
Illinois	8.00%	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.50%	22.00%
Indiana	4.00%	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Kentucky	No Standard										
Maryland	12.80%	13.00%	15.20%	15.60%	18.30%	17.40%	18.00%	18.70%	20.00%	20.00%	20.00%
Michigan	6.75%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
New Jersey	12.53%	13.76%	14.90%	15.99%	18.03%	19.97%	21.91%	23.85%	23.94%	24.03%	24.12%
North Carolina	3.00%	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%	12.50%	12.50%	12.50%	12.50%
Ohio	2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%	10.50%	11.50%	12.50%
Pennsylvania	10.72%	11.22%	13.72%	14.22%	14.72%	15.22%	15.72%	18.02%	18.02%	18.02%	18.02%
Tennessee	No Standard										
Virginia	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	12.00%	12.00%	12.00%
Washington, D.C.	10.50%	12.00%	13.50%	15.00%	16.50%	18.00%	20.00%	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%	15.00%

Table 8-5 Pennsylvania weighted average AEC price and AEC price for 2010 to 2013 Delivery Years[100]

	2010/2011 Delivery Year		2011/2012 Delivery Year		2012/2013 Delivery Year		2013/2014 Delivery Year	
Pennsylvania	Weighted Average Price	Price Range	Weighted Average Price	Price Range	Weighted Average Price	Price Range	Weighted Average Price	Price Range
Solar AEC	$325.00	$235.00-$415.00	$247.82	$25.00-$653.00	$180.39	$10.00-$675.00	$109.23	$5.50-$600.00
Tier I	$4.77	$0.50-$24.15	$3.94	$0.14-$50.00	$5.23	$0.20-$23.00	$8.31	$0.13-$100.00
Tier II	$0.32	$0.01-$1.75	$0.22	$0.01-$20.00	$0.17	$0.01-$5.00	$0.22	$0.01-$20.00

REC prices are required to be disclosed in Maryland, Pennsylvania and the District of Columbia, but in the other states REC prices are not publicly available and are difficult to determine. Table 8-5 has the Pennsylvania weighted average price and price range for 2010 through 2014 delivery years. The weighted average price of solar credits in Pennsylvania decreased from $325.00 in the 2010/2011 Delivery Year to $109.23 in the 2013/2014 Delivery Year. Tier I credits increased from $4.77 in the 2010/2011 Delivery year to $8.31 in the 2013/2014 Delivery Year, while Tier II resources dropped $0.10 from $0.32 in the 2010/2011 Delivery Year to $0.22 in the 2013/2014 Delivery Year.[101]

Some PJM jurisdictions have also added specific requirements for the purchase of solar resources. These solar requirements are included in the standards shown in Table 8-4 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.[102] Indiana, Kentucky, Michigan, Tennessee, Virginia, and West Virginia have no specific solar standards. In 2014, New Jersey had the most stringent standard in PJM, requiring that 2.05 percent of load be served by solar resources. As Table 8-6 shows, by 2024, New Jersey will continue to have the most stringent standard, requiring that at least 3.74 percent of load be served by solar resources.

98 This shows the total standard of renewable resources in all PJM jurisdictions, including Tier I, Tier II and Tier III resources.
99 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.
100 See PAPUC. Pennsylvania AEPS Alternative Energy Credit Program, "Pricing," <http://paaeps.com/credit/pricing.do> (Accessed October 13, 2014).
101 Tier I resources are solar photovoltaic and thermal energy, wind power, low-impact hydropower, geothermal energy, biologically derived methane gas, biomass and coal mine methane. Tier II resources are waste coal, distributed generation, demand-side management, large-scale hydropower, municipal solid waste and integrated combined coal gasification technology.
102 Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill the solar requirement.

Table 8-6 Solar renewable standards of PJM jurisdictions 2014 to 2024

Jurisdiction	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Delaware	0.80%	1.00%	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%	2.75%	3.00%	3.25%
Illinois	0.12%	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%	1.23%	1.32%
Indiana	No Solar Standard										
Kentucky	No Standard										
Maryland	0.35%	0.50%	0.70%	0.95%	1.40%	1.75%	2.00%	2.00%	2.00%	2.00%	2.00%
Michigan	No Solar Standard										
New Jersey	2.05%	2.45%	2.75%	3.00%	3.20%	3.29%	3.38%	3.47%	3.56%	3.65%	3.74%
North Carolina	0.07%	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio	0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%	0.42%	0.46%	0.50%
Pennsylvania	0.08%	0.14%	0.25%	0.29%	0.34%	0.39%	0.44%	0.50%	0.50%	0.50%	0.50%
Tennessee	No Standard										
Virginia	No Solar Standard										
Washington, D.C.	0.60%	0.70%	0.83%	0.98%	1.15%	1.35%	1.58%	1.85%	2.18%	2.50%	2.50%
West Virginia	No Solar Standard										

Table 8-7 Additional renewable standards of PJM jurisdictions 2014 to 2024

Jurisdiction		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Illinois	Wind Requirement	6.00%	6.75%	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%	14.25%	15.38%	16.50%
Illinois	Distributed Generation	0.04%	0.68%	0.10%	0.12%	0.13%	0.15%	0.16%	0.18%	0.19%	0.21%	0.22%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	2.50%	2.50%	0.00%	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)	772	965	1,150	1,357	1,591	1,858	2,164	2,518	2,928	3,433	3,989
North Carolina	Swine Waste	0.07%	0.14%	0.14%	0.14%	0.20%	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%	8.20%	8.20%	8.20%	8.20%	8.20%	10.00%	10.00%	10.00%	10.00%
Washington, D.C.	Tier II Standard	2.50%	2.50%	2.00%	1.50%	1.00%	0.50%	0.00%	0.00%	0.00%	0.00%	0.00%

Some PJM jurisdictions have also added other specific requirements to their renewable portfolio standards for other technologies. The standards shown in Table 8-7 are also included in the base standards. Illinois requires that a percentage of utility load be served by wind resources, increasing from 6.00 percent of load served in 2014 to 16.50 percent in 2024. Maryland, New Jersey, Pennsylvania and Washington D.C. all have "Tier II" or "Class 2" standards, which allow specific technology types, such as waste coal units in Pennsylvania, to qualify for renewable energy credits.[103] North Carolina also requires that 0.2 percent of power be generated using swine waste and poultry waste to fulfill their renewable portfolio standards by 2018 (Table 8-7).

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 $339.00 per MWh.[104] 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 state's renewable portfolio standard be met through alternative compliance payments. Standard alternative compliance payments can replace solar, wind energy, organic biomass and hydro power. Table 8-8 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.

103 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.

104 See Database of State Incentives for Renewables & Efficiency (DSIRE), New Jersey Incentives/Policies for Renewables & Efficiency, "Renewables Portfolio Standard," <http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=NJ05R&re=0&ee=0> (Accessed October 13, 2013).

Table 8-8 Renewable alternative compliance payments in PJM jurisdictions: As of September 30, 2014[105]

Jurisdiction	Standard Alternative Compliance ($/MWh)	Tier II Alternative Compliance ($/MWh)	Solar Alternative Compliance ($/MWh)
Delaware	$25.00		$400.00
Illinois	$1.89		
Indiana	Voluntary standard		
Kentucky	No standard		
Maryland	$40.00	$15.00	$400.00
Michigan	No specific penalties		
New Jersey	$50.00		$339.00
North Carolina	No specific penalties		
Ohio	$47.56		$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 8-9 Renewable resource generation by jurisdiction and renewable resource type (GWh): January through September 2014

Jurisdiction	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	36.4	0.0	0.0	0.0	0.0	0.0	0.0	36.4	72.7
Illinois	125.5	0.0	0.0	12.7	0.0	0.0	4,742.7	4,880.8	4,880.8
Indiana	0.0	0.0	34.7	0.0	0.0	0.0	1,792.4	1,827.1	1,827.1
Kentucky	0.0	0.0	53.8	0.0	0.0	0.0	0.0	53.8	53.8
Maryland	75.9	0.0	1,363.8	55.9	737.4	0.0	215.1	1,710.7	2,448.1
Michigan	17.1	0.0	49.5	0.0	0.0	0.0	0.0	66.6	66.6
New Jersey	250.5	446.8	30.7	227.8	1,474.7	0.0	7.0	515.9	2,437.4
North Carolina	0.0	0.0	515.0	0.0	0.0	0.0	0.0	515.0	515.0
Ohio	259.9	0.0	362.3	2.3	0.0	0.0	778.3	1,402.8	1,402.8
Pennsylvania	632.0	2,026.9	3,266.5	19.7	1,297.8	8,070.4	2,513.9	6,432.0	17,827.0
Tennessee	0.0	0.0	0.0	0.0	249.8	0.0	0.0	0.0	249.8
Virginia	363.0	3,503.4	504.9	0.0	1,562.1	2,434.3	0.0	867.9	8,367.7
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	7.4	0.0	888.8	0.0	0.0	791.7	1,073.4	1,969.5	2,761.2
Total	1,767.6	5,977.0	7,069.8	318.3	5,321.8	11,296.3	11,122.7	20,278.5	42,873.6

Table 8-9 shows renewable resource generation by jurisdiction and resource type in the first nine months of 2014. 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 11,112.7 GWh of 20,278.5 Tier I GWh, or 54.8 percent, in the PJM footprint. As shown in Table 8-9, 42,873.6 GWh were generated by resources that were renewable, including both Tier II and Tier I renewable credits, of which, Tier I type resources accounted for 47.3 percent. Landfill gas, solid waste and waste coal were 18,385.7 GWh of renewable resource generation or 42.9 percent of the total Tier I and Tier II.

Table 8-10 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary or alternative fuel types.[106] This capacity includes coal and natural gas units that have a renewable fuel as a secondary fuel, and thus are able to earn renewable energy credits based on the fuel used to generate energy. Coal and natural gas units are considered to generate renewable energy only when generating using a renewable fuel, like waste coal in West Virginia. West Virginia has the largest amount of renewable capacity in PJM, 10,255.4 MW, or 21.7 percent of the total renewable capacity. West Virginia allows coal technology, coal bed methane, waste coal and fuel produced by a coal gasification facility to be counted as alternative energy resources. New Jersey has the largest amount of solar capacity in PJM, 223.5 MW, or 76.9 percent of the total solar capacity. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 3,439.8 MW, or 56.6 percent of the total wind capacity.

105 See PJM – EIS (Environmental Management System). "Program Information," <http://www.pjm-eis/program-information.aspx> (Accessed October 1, 2014).

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

Table 8-10 PJM renewable capacity by jurisdiction (MW), on September 30, 2014

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	1,797.0	13.0	0.0	0.0	0.0	0.0	0.0	0.0	1,818.1
Illinois	0.0	79.5	0.0	0.0	0.0	0.0	9.0	0.0	0.0	2,187.4	2,275.9
Indiana	0.0	0.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	1,252.4	1,260.6
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0	185.0
Kentucky	0.0	0.0	0.0	0.0	0.0	61.0	0.0	0.0	0.0	0.0	61.0
Maryland	0.0	25.1	0.0	69.0	0.0	494.0	48.8	0.0	0.0	120.0	757.0
Michigan	0.0	8.0	0.0	0.0	0.0	13.9	0.0	0.0	0.0	0.0	21.9
New Jersey	0.0	84.5	0.0	0.0	453.0	11.5	223.5	0.0	0.0	4.5	777.0
North Carolina	0.0	0.0	0.0	0.0	0.0	325.0	0.0	0.0	0.0	0.0	325.0
Ohio	13,864.0	64.7	580.0	156.0	0.0	47.4	1.1	0.0	0.0	403.0	15,116.2
Pennsylvania	0.0	222.0	2,346.0	0.0	1,269.0	888.3	8.0	84.0	1,611.0	1,337.7	7,766.0
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.0	0.0	0.0	50.0
Virginia	0.0	130.1	0.0	17.0	5,166.2	350.5	0.0	321.9	585.0	0.0	6,570.7
West Virginia	8,772.0	2.2	519.0	0.0	0.0	213.9	0.0	0.0	165.0	583.3	10,255.4
PJM Total	22,636.0	624.2	5,242.0	255.0	6,888.2	2,413.7	290.5	455.9	2,361.0	6,073.2	47,239.6

Table 8-11 shows renewable capacity registered in the PJM generation attribute tracking system (GATS), a system operated by PJM EIS. This includes solar capacity of 1,668.2 MW of which 1,106.1 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 8-11 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 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 8-11 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW), on September 30, 2014[107]

Jurisdiction	Coal	Hydroelectric	Landfill Gas	Natural Gas	Other Gas	Other Source	Solar	Solid Waste	Wind	Total
Alabama	0.0	0.0	0.0	0.0	0.0	0.0	0.0	87.5	0.0	87.5
Delaware	0.0	0.0	0.0	0.0	0.0	0.0	59.2	0.0	2.1	61.3
Georgia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	258.9	0.0	258.9
Illinois	0.0	6.6	92.4	0.0	0.3	0.0	25.2	0.0	502.5	627.0
Indiana	0.0	0.0	44.0	0.0	6.0	94.6	2.1	0.0	180.0	326.7
Iowa	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	185.0	185.0
Kentucky	600.0	2.2	16.0	0.0	0.0	0.0	1.2	93.0	0.0	712.4
Maryland	65.0	0.4	13.7	129.0	0.0	0.0	154.1	0.0	0.3	362.4
Michigan	55.0	1.3	3.2	0.0	0.0	0.0	1.4	0.0	0.0	60.9
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	58.0	0.0	8.3	23.3	1,106.1	0.0	5.0	1,200.7
New York	0.0	153.2	0.0	0.0	0.0	0.0	0.4	0.0	0.0	153.6
North Carolina	0.0	0.0	0.0	0.0	0.0	0.0	8.6	30.0	0.0	38.6
Ohio	0.0	1.0	30.4	119.6	12.5	0.0	100.4	109.3	23.1	396.2
Pennsylvania	109.7	37.0	44.2	91.0	11.5	1.0	187.9	7.6	3.3	493.0
Tennessee	0.0	0.0	0.0	0.0	0.0	0.3	0.0	0.0	0.0	0.3
Virginia	0.0	17.4	17.5	0.0	0.0	0.0	7.4	287.6	0.0	329.9
West Virginia	0.0	42.0	0.0	0.0	0.0	0.0	2.1	0.0	0.0	44.1
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	11.9	0.0	0.0	11.9
Total	829.7	270.0	319.4	339.6	38.5	119.2	1,668.2	831.0	1,047.3	5,462.9

107 See PJM – EIS (Environmental Information Services), "Renewable Generators Registered in GATS," <https://gats.pjm-eis.com/reports-and-news/public-reports.aspx> (Accessed October 1, 2014).

Emissions Controlled Capacity and Renewables in PJM Markets

Emission Controlled Capacity in the PJM Region

Environmental regulations 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 SO_2 emission rates. Of the current 70,067.8 MW of coal capacity in PJM, 49,788.0 MW of capacity, 71.1 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions. Table 8-12 shows SO_2 emission controls by fossil fuel fired units in PJM.[108,109]

Table 8-12 SO_2 emission controls (FGD) by fuel type (MW), as of September 30, 2014

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	49,788.0	20,279.8	70,067.8	71.1%
Diesel Oil	0.0	6,093.8	6,093.8	0.0%
Natural Gas	0.0	51,394.7	51,394.7	0.0%
Other	325.0	7,411.8	7,736.8	4.2%
Total	50,113.0	85,180.1	135,293.1	37.0%

NO_x emission control technology is used by all fossil fuel fired unit types. Coal steam, combined cycle, combustion turbine, and non-coal steam units in PJM have NO_x controls. Of current fossil fuel fired units in PJM, 124,702.1 MW, 92.2 percent, of 135,293.1 MW of capacity in PJM, have emission controls for NO_x. Table 8-13 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 likely need to be upgraded in order to meet each state's emission compliance standards. Future NO_x compliance standards will require SCRs or SCNRs for coal steam units, as well as SCRs or water injection technology for HEDD combustion turbine units.[110]

Table 8-13 NO_x emission controls by fuel type (MW), as of September 30, 2014

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal	68,653.2	1,414.6	70,067.8	98.0%
Diesel Oil	1,432.8	4,661.0	6,093.8	23.5%
Natural Gas	49,835.3	1,559.4	51,394.7	97.0%
Other	4,780.8	2,956.0	7,736.8	61.8%
Total	124,702.1	10,591.0	135,293.1	92.2%

Most coal units in PJM have particulate controls. Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[111] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric causing particulates in the gas to be filtered out. In PJM, 69,133.8 MW, 98.7 percent, of all coal steam unit MW, have some type of particulate emissions control technology. Table 8-14 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 each state's emission compliance standards. Future particulate compliance standards will require baghouse technology or ESPs, or a combination of an FGD and SCR to meet EPA regulations.[112] Currently 52 of the 228 coal steam units have baghouse technology installed, representing 49,540.0 MW out of the 70,067.8 MW total coal capacity, or 70.7 percent.

Table 8-14 Particulate emission controls by fuel type (MW), as of September 30, 2014

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	69,133.8	934.0	70,067.8	98.7%
Diesel Oil	0.0	6,093.8	6,093.8	0.0%
Natural Gas	260.0	51,134.7	51,394.7	0.5%
Other	3,159.0	4,577.8	7,736.8	40.8%
Total	72,552.8	62,740.3	135,293.1	53.6%

108 See EPA. "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed October 13, 2014).
109 The total MW for each fuel type are less than the 141,758.9 MW reported in Section 5: Capacity, because EPA data on controls could not be matched to some PJM units. "Air Markets Program Data," <http://ampd.epa.gov/ampd/QueryToolie.html> (Accessed October 1, 2014).
110 See EPA. "Mercury and Air Toxics Standards," <http://www.epa.gov/mats/index.html> (Accessed October 13, 2014).
111 See EPA, "Air Pollution Control Technology Fact Sheet," <http://www.epa.gov/ttnchie1/mkb/documents/ff-pulse.pdf> (Accessed October 13, 2014).
112 See EPA. "Mercury and Air Toxics Standards," <http://www.epa.gov/mats/index.html> (Accessed October 13, 2014).

Fossil fuel fired units in PJM emit multiple pollutants, including CO_2, SO_2, and NO_x. Table 8-15 shows the emissions from units in PJM in the first nine months of 2014. It is estimated that over 468 million metric tons of CO_2, 888 thousand metric tons of SO_2, and 789 thousand tons of NO_x were emitted in the first nine months of 2014 by PJM units.

Table 8-15 CO_2, SO_2 and NO_x emissions by month (short and metric tons), by PJM units, January through September, 2014[113]

	Short Tons			Metric Tonnes		
	CO_2	SO_2	NO_x	CO_2	SO_2	NO_x
January	70,013,821.7	146,056.7	122,392.8	63,515,488.8	132,500.5	111,032.9
February	62,480,382.4	132,356.0	108,610.4	56,681,265.7	120,071.4	98,529.7
March	62,060,748.6	128,875.8	106,257.7	56,300,580.3	116,914.2	96,395.4
April	46,670,742.6	93,749.5	78,436.9	42,338,997.6	85,048.2	71,156.7
May	46,884,473.8	79,220.7	73,838.4	42,532,891.4	71,867.9	66,985.1
June	57,739,239.7	107,104.6	96,199.2	52,380,172.2	97,163.7	87,270.4
July	61,261,083.5	109,373.2	103,910.6	55,575,136.0	99,221.8	94,266.1
August	58,288,114.4	104,514.3	97,875.4	52,878,103.0	94,813.8	88,791.1
September	50,724,798.9	77,214.2	81,811.5	46,016,776.7	70,047.6	74,218.2
Total	516,123,405.6	978,465.2	869,332.8	468,219,411.7	887,648.9	788,645.7

Wind Units

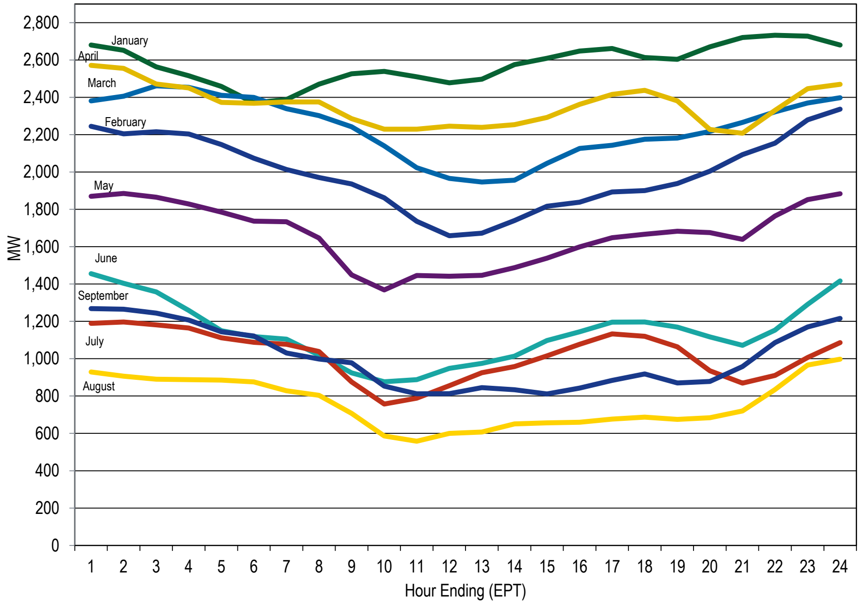
Table 8-16 shows the capacity factor of wind units in PJM. In the first nine months of 2014, the capacity factor of wind units in PJM was 25.8 percent. Wind units that were capacity resources had a capacity factor of 26.6 percent and an installed capacity of 5,798 MW. Wind units that were classified as energy only had a capacity factor of 16.9 percent and an installed capacity of 544 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.[114]

Table 8-16 Capacity factor of wind units in PJM: January through September 2014[115]

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	16.9%	544
Capacity Resource	26.6%	5,798
All Units	25.8%	6,342

Figure 8-2 shows the average hourly real time generation of wind units in PJM, by month. The highest average hour, 2,732.2 MW, occurred in January, and the lowest average hour, 558.2 MW, occurred in June. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

Figure 8-2 Average hourly real-time generation of wind units in PJM: January through September, 2014



113 The emissions are calculated by multiplying the amount of generated MWh at a power plant times the heat rate of the plant times the emissions rate by fuel source, accounting for the controls a generator has installed to date.
114 Wind resources are derated to 13 percent unless demonstrating higher availability during peak periods.
115 Capacity factor is calculated based on online date of the resource.

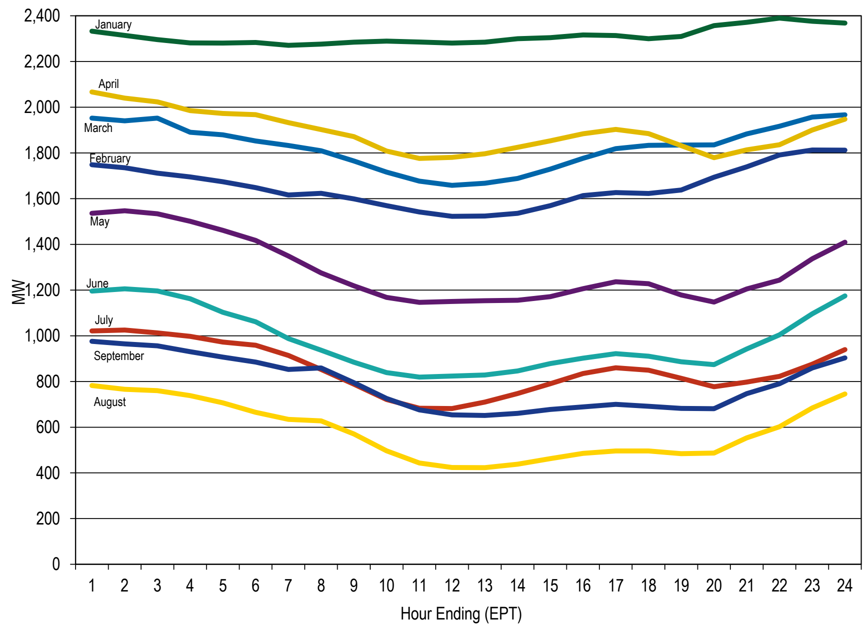
Table 8-17 shows the generation and capacity factor of wind units in each month of the first nine months of 2013 and the first nine months of 2014.

Table 8-17 Capacity factor of wind units in PJM by month, 2013 and January through September, 2014

	2013		2014	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	1,784,359.3	40.3%	1,918,441.4	40.7%
February	1,397,468.3	35.4%	1,342,055.5	31.5%
March	1,606,248.3	36.5%	1,661,382.1	35.3%
April	1,639,590.9	37.8%	1,697,703.3	37.2%
May	1,271,272.4	28.5%	1,238,061.3	26.2%
June	862,532.2	19.8%	820,312.2	18.0%
July	588,174.8	13.4%	757,166.8	16.0%
August	510,448.5	12.0%	566,425.3	12.0%
September	719,196.4	16.7%	721,411.2	15.8%
October	1,070,829.4	23.5%		
November	1,833,051.6	41.2%		
December	1,543,685.2	34.2%		
Annual	14,826,857.3	28.3%	10,722,958.9	25.8%

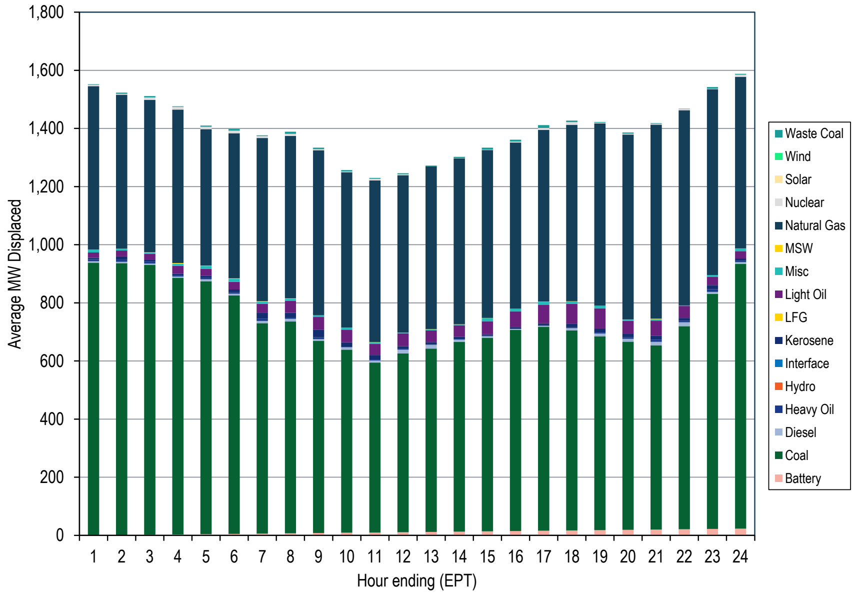
Wind units that are capacity resources are required, like all capacity resources except demand resources, to offer the energy associated with their cleared capacity in the Day-Ahead Energy Market and in the Real-Time Energy Market. Wind units may offer non-capacity related wind energy at their discretion. Figure 8-3 shows the average hourly day-ahead generation offers of wind units in PJM, by month. The hourly day-ahead generation offers of wind units in PJM may vary.

Figure 8-3 Average hourly day-ahead generation of wind units in PJM: January through September, 2014



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 8-4 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 nine months of 2014. Figure 8-4 shows potentially displaced marginal unit MW by fuel type in the first nine months of 2014. 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.

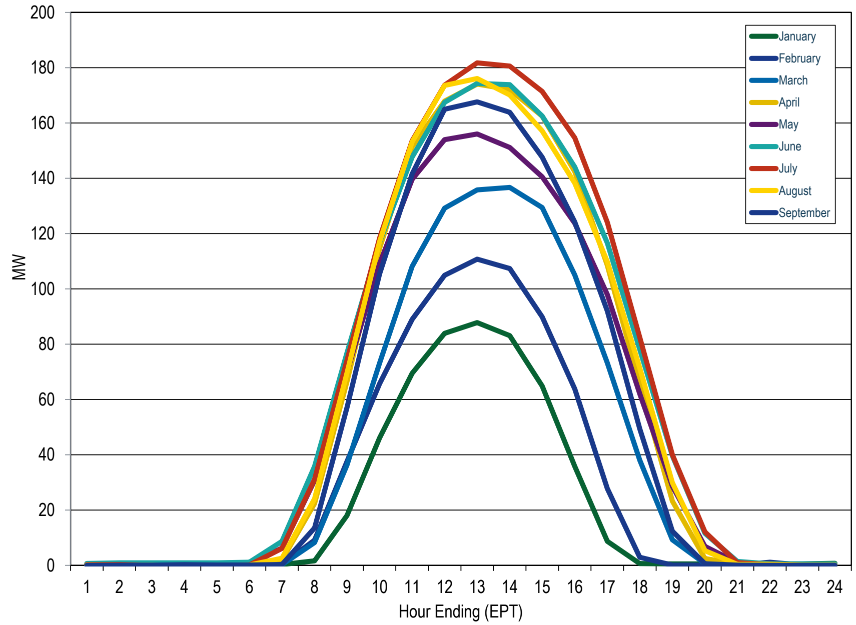
Figure 8-4 Marginal fuel at time of wind generation in PJM: January through September, 2014



Solar Units

Solar output differs from month to month, based on seasonal variation and daylight hours during the month. Figure 8-5 shows the average hourly real time generation of solar units in PJM, by month. Solar generation was highest in July, the month with the highest average hour, 181.8 MW, compared to 283.5 MW of solar installed capacity in PJM. Solar generation in PJM is highest during the hours of 11:00 through 13:00 EPT.

Figure 8-5 Average hourly real-time generation of solar units in PJM: January through September, 2014



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

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first nine months of 2014, PJM was a net importer of energy in the Real-Time Energy Market in January, May, June and August, and a net exporter of energy in the remaining five months.[1] During the first nine months of 2014, the real-time net interchange of -982.1 GWh was lower than net interchange of 4,706.7 GWh in the first nine months of 2013.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first nine months of 2014, PJM was a net exporter of energy in the Day-Ahead Energy Market in all months. During the first nine months of 2014, the total day-ahead net interchange of -12,142.4 GWh was lower than net interchange of -12,727.7 GWh during the first nine months of 2013.
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first nine months of 2014, gross imports in the Day-Ahead Energy Market were 113.9 percent of gross imports in the Real-Time Energy Market (150.8 percent during the first nine months of 2013), gross exports in the Day-Ahead Energy Market were 141.5 percent of the gross exports in the Real-Time Energy Market (218.5 percent during the first nine months of 2013).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first nine months of 2014, there were net scheduled exports at 12 of PJM's 20 interfaces.

1 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, for the first nine months of 2014, there were net scheduled exports at 12 of PJM's 18 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 nine months of 2014, there were net scheduled exports at 12 of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, for the first nine months of 2014, there were net scheduled exports at 11 of PJM's 19 interface pricing points eligible for day-ahead transactions.
- **Up-to Congestion Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Market, for the first nine months of 2014, up-to congestion transactions were net exports at six of PJM's 19 interface pricing points eligible for day-ahead transactions.
- **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 nine months of 2014, net scheduled interchange was -1,081 GWh and net actual interchange was -331 GWh, a difference of 750 GWh. For the first nine months of 2013, net scheduled interchange was 3,316 GWh and net actual interchange was 3,474 GWh, a difference of 158 GWh. This difference is inadvertent interchange.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first nine months of 2014, the direction of the average hourly flow was consistent with the real-time

2 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. The direction of flow was consistent with price differentials in 53.0 percent of the hours in the first nine months of 2014.

- **PJM and New York ISO Interface Prices.** In the first nine months of 2014, 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 56.0 percent of the hours in the first nine months of 2014.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first nine months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus.[3] The direction of flow was consistent with price differentials in 58.9 percent of the hours in the first nine month of 2014.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first nine months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO Linden Bus.[4] The direction of flow was consistent with price differentials in 56.2 percent of the hours in the first nine months of 2014.
- **Hudson DC Line.** In the first nine months of 2014, the average hourly flow (PJM to NYISO) was inconsistent with the real-time average hourly price difference between the PJM Hudson Interface and the NYISO Hudson Bus.[5] The direction of flow was consistent with price differentials in 59.3 percent of the hours in the first nine months of 2014.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued five TLRs of level 3a or higher during the first nine months of 2014, compared to 45 such TLRs issued during the first nine months of 2013.
- **Up-To Congestion.** The average number of up-to congestion bids submitted in the Day-Ahead Energy Market increased by 80.1 percent, from 105,472 bids per day in the first nine months of 2013 to 189,997 bids per day in the first nine months of 2014. The average cleared volume of up-to congestion bids increased by 22.6 percent, from 1,221,114 MWh per day in the first nine months of 2013 to 1,496,675 MWh per day in the first nine months of 2014. But the increases all occurred prior to September 8, 2014, after which the number and volume of bids declined sharply.

  On August 29, 2014, FERC issued an Order which, among other things, created an obligation for UTCs to pay any uplift determined to be appropriate in the Commission review, effective September 8, 2014.[6] The average number of up-to congestion bids submitted in the Day-Ahead Energy Market decreased by 79.5 percent, from 192,097 bids per day in the three week period prior to the September 8, 2014 refund effective date to 39,429 bids per day in the three week period following the September 8, 2014 refund effective date. The average cleared volume of up-to congestion bids decreased by 79.9 percent, from 1,633,746 MWh per day in the three week period prior to the September 8, 2014 refund effective date to 328,041 MWh per day in the three week period following the September 8, 2014 refund effective date (Figure 9-13).
- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule to become compliant with Order No. 764.[7,8] PJM and the MMU issued a statement indicating that both remain concerned about market participants' scheduling behavior, and

3 In the first nine months of 2014, there were 590 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 $58.04 while the NYISO LMP at the Neptune Bus during non-zero flows was $66.75, a difference of $8.71.

4 In the first nine months of 2014, there were 1,510 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 $63.82 while the NYISO LMP at the Neptune Bus during non-zero flows was $66.24, a difference of $2.42.

5 In the first nine months of 2014, there were 4,840 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $111.11 while the NYISO LMP at the Hudson Bus during non-zero flows was $114.83, a difference of $3.72.

6 *Order Instituting Section 206 Proceeding and Establishing Procedures*, 148 FERC ¶ 61,144 (2014).

7 *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).

8 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).

will continue to monitor and address any scheduling behavior that raises operational or market manipulation concerns.[9]

Recommendations

- The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually. (Priority: Low. New recommendation.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1200 day-prior to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be utilized to meet load in the most economic manner. (Priority: Medium. New recommendation.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized joint dispatch approach that treats seams between balancing authorizes as a constraint, similar to any other constraint within an LMP market. (Priority: Medium. New recommendation.)
- The MMU recommends 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. (Priority: Medium. First reported 2012.)
- The MMU recommends that PJM implement a validation method for submitted transactions that would prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction. (Priority: Medium. First reported 2013.)
- The MMU recommends that the validation also require market participants to submit transactions on market paths that reflect the expected actual flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM implement rules to prevent sham scheduling. The MMU's proposed validation rules would address sham scheduling. (Priority: High. First reported 2012.)
- The MMU recommends that PJM eliminate the NIPSCO and Southeast interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM immediately provide the required 12-month notice to PEC to unilaterally terminate the Joint Operating Agreement. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM and MISO work together to align interface pricing definitions, using the same number of external buses and selecting buses in close proximity on either side of the border with comparable bus weights. (Priority: Medium. First reported 2012.)

Conclusion

Transactions between PJM and multiple balancing authorities in the Eastern Interconnection are part of a single energy market. While some of these balancing authorities are termed market areas and some are termed non-market areas, all electricity transactions are part of a single energy market.

9 See joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, which can be accessed at: <http://www.pjm.com/~/media/documents/reports/20140729-pjm-imm-joint-statement-on-interchange-scheduling.ashx>.

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 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's recommendations related to transactions with external balancing authorities all share the goal of improving the economic efficiency of interchange transactions. The standard of comparison is an LMP market. In an LMP market, redispatch based on LMP and generator offers results in an efficient dispatch and efficient prices.

Interchange Transaction Activity

Aggregate Imports and Exports

During the first nine months of 2014, PJM was a monthly net importer of energy in the Real-Time Energy Market in January, May, June and August, and a net exporter of energy in the remaining five months (Figure 9-1).[10] For the first nine months of 2014, the total real-time net interchange of -982.1 GWh was lower than the net interchange of 4,706.7 GWh during the first nine months of 2013. In the first nine months of 2014, the peak month for net importing interchange was January, 1,608.8 GWh; in the first nine months of 2013 it was July, 1,464.4 GWh. Gross monthly export volumes during the first nine months of 2014 averaged 4,439.3 GWh compared to 3,257.1 GWh for the first nine months of 2013, while gross monthly imports in the first nine months of 2014 averaged 4,330.2 GWh compared to 3,780.1 GWh for the first nine months of 2013.

During the first nine months of 2014, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in all months (Figure 9-1). In the first nine months of 2014, the total day-ahead net interchange of -12,142.4 GWh was lower than the net interchange of -12,727.7 GWh for the first nine months of 2013. In the first nine months of 2014, the peak month for net exporting interchange was April, -1,992.1 GWh; in the first nine months of 2013 it was January, -2,602.8 GWh. Gross monthly export volumes in the first nine months of 2014 averaged 6,282.3 GWh compared to 7,115.8 GWh for the first nine months of 2013, while gross monthly imports in the first nine months of 2014 averaged 4,933.1 GWh compared to 5,701.6 GWh for the first nine months of 2013.

Figure 9-1 shows the impact of net import and export up-to congestion transactions on the overall net day-ahead energy 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 9-1 represents the net interchange for fixed and dispatchable day-ahead transactions only.

In the first nine months of 2014, gross imports in the Day-Ahead Energy Market were 113.9 percent of gross imports in the Real-Time Energy Market (150.8 percent for the first nine months of 2013), gross exports in the Day-Ahead Energy Market were 141.5 percent of gross exports in the Real-Time Energy Market (218.5 percent for the first nine months of 2013). In the first nine months of 2014, net interchange was -12,142.4 GWh in the Day-Ahead Energy Market and -982.1 GWh in the Real-Time Energy Market compared to -12,727.7 GWh in the Day-Ahead Energy Market and 4,706.7 GWh in the Real-Time Energy Market for the first nine months of 2013.

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.[11] In the first nine months of 2014, 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.

10 Calculated values shown in Section 9, "Interchange Transactions," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

11 Up-to congestion transactions create financial obligations to deliver in real time, but do not pay operating reserve charges.

Figure 9-1 PJM real-time and day-ahead scheduled imports and exports: January through September, 2014

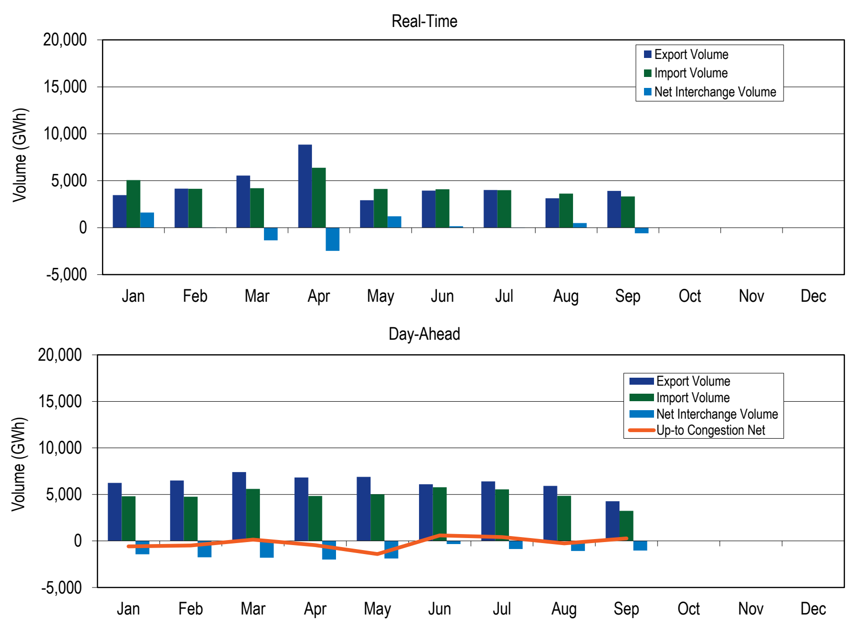
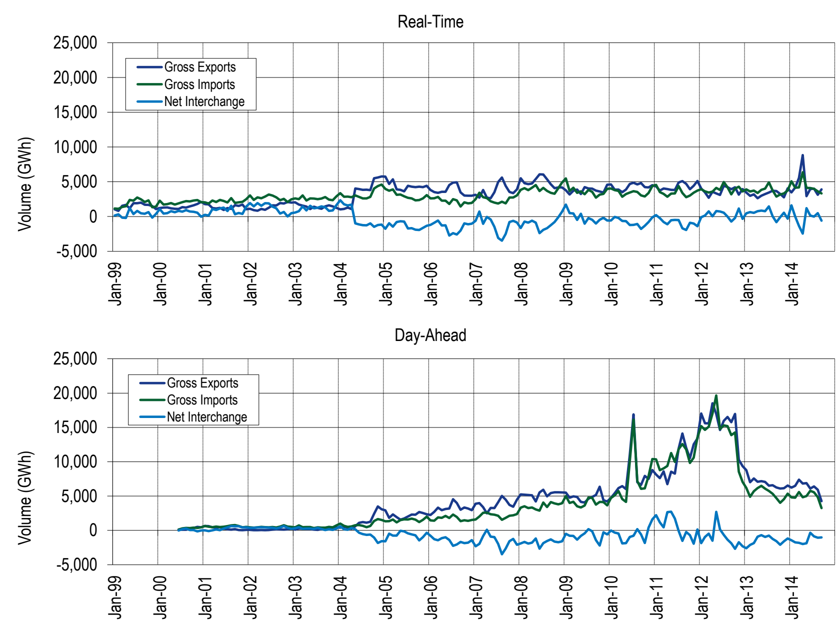


Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through June 2014. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Energy Markets, coincident with the expansion of the PJM footprint caused by the integrations of Commonwealth Edison, American Electric Power and Dayton Power and Light into PJM's operation. In January 2012, the direction of real-time power flows began 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 Energy 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. While the gross import and export volumes in the Day-Ahead Energy Market have decreased, the net direction of power flows has remained predominantly in the export direction.

Figure 9-2 PJM real-time and day-ahead scheduled import and export transaction volume history: 1999 through September, 2014



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 9-16 for a list of active interfaces during the first nine months of 2014. Figure 9-3 shows the approximate geographic location of the interfaces. In the first nine months of 2014, PJM had 20 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. Table 9-1 through Table 9-3 show the Real-Time Energy 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 nine months of 2014 in Table 9-1, while gross imports and exports are shown in Table 9-2 and Table 9-3.

In the Real-Time Energy Market, in the first nine months of 2014, there were net scheduled exports at 12 of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 58.8 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 22.7 percent, PJM/Eastern Alliant Energy Corporation (ALTE) with 18.4 percent and PJM/Neptune (NEPT) with 17.8 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 37.0 percent of the total net PJM exports in the Real-Time Energy Market. Seven PJM interfaces had net scheduled imports, with three importing interfaces accounting for 81.6 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 40.6 percent, PJM/Ameren-Illinois (AMIL) with 28.6 percent and PJM/Tennessee Valley Authority (TVA) with 12.4 percent of the net import volume.[12]

Eleven shareholders own the generation located in the OVEC footprint and share OVEC's generation output. Approximately 80 percent of OVEC is owned by load serving entities or their affiliates located in the PJM footprint. The Inter-Company Power Agreement (ICPA), signed by OVEC's shareholders, requires delivery of approximately 80 percent of the generation output into the PJM footprint.[13]

12 In the Real-Time Energy Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).
13 See "Ohio Valley Electric Corporation: Company Background," <http://www.ovec.com/OVECHistory.pdf> (October 15, 2014).

Table 9-1 Real-time scheduled net interchange volume by interface (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(33.5)	(11.2)	(12.8)	(43.8)	(31.3)	37.3	(24.2)	(17.7)	(32.1)	(169.4)
CPLW	0.0	0.6	5.2	0.0	0.0	0.0	0.0	0.0	0.0	5.8
DUK	294.7	395.5	541.7	214.6	183.8	(37.1)	(135.1)	(114.3)	(41.3)	1,302.6
LGEE	262.4	230.3	159.5	99.7	129.6	233.3	182.1	207.7	182.3	1,687.1
MEC	(421.8)	(387.0)	(239.8)	(829.9)	(512.5)	(611.3)	(606.6)	(607.8)	(658.8)	(4,875.3)
MISO	1,193.0	(460.9)	(1,620.2)	(1,670.7)	453.8	(90.4)	188.9	684.8	(523.7)	(1,845.4)
ALTE	(140.8)	(241.9)	(770.7)	(1,032.8)	(361.5)	(412.4)	(290.0)	(199.4)	(501.5)	(3,950.8)
ALTW	(49.5)	(85.5)	(98.5)	(219.6)	(8.1)	(8.7)	(4.0)	(0.5)	(39.5)	(513.9)
AMIL	917.6	478.4	317.9	792.1	566.6	576.5	791.0	764.2	667.5	5,871.9
CIN	318.9	(341.6)	(350.1)	(527.8)	(32.6)	15.2	9.5	16.8	(132.5)	(1,024.1)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	87.3	(65.3)	(2.3)	27.0	7.1	(222.1)	(75.2)	6.7	(58.7)	(295.4)
MECS	158.2	(25.4)	(564.6)	(774.2)	140.3	(41.1)	(31.4)	134.1	(363.7)	(1,368.0)
NIPS	15.2	(51.6)	(3.7)	224.5	266.0	179.3	(4.1)	53.3	93.8	772.7
WEC	(113.8)	(128.0)	(148.3)	(159.9)	(124.0)	(177.2)	(207.1)	(90.4)	(189.2)	(1,337.8)
NYISO	(1,091.2)	(1,328.3)	(1,701.2)	(1,783.0)	(15.6)	(410.0)	(635.3)	(547.5)	(434.5)	(7,946.6)
HUDS	(79.2)	(210.2)	(98.9)	(0.2)	(2.6)	(5.9)	(9.6)	(3.9)	(33.7)	(444.2)
LIND	(72.8)	(134.8)	(117.6)	(96.2)	69.9	7.3	5.0	(14.3)	(27.9)	(381.5)
NEPT	(303.6)	(424.0)	(390.7)	(870.7)	(256.7)	(369.9)	(426.6)	(462.1)	(310.5)	(3,814.7)
NYIS	(635.5)	(559.4)	(1,094.0)	(816.0)	173.9	(41.5)	(204.1)	(67.2)	(62.4)	(3,306.2)
OVEC	1,055.5	990.6	972.3	1,169.3	631.7	875.9	911.9	841.7	866.2	8,315.1
TVA	349.8	552.2	545.5	380.7	368.7	153.0	102.7	42.3	49.1	2,544.0
Total	1,608.8	(18.3)	(1,349.8)	(2,463.0)	1,208.3	150.7	(15.5)	489.3	(592.7)	(982.1)

Table 9-2 Real-time scheduled gross import volume by interface (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	0.7	5.1	2.4	7.8	0.8	76.0	4.6	1.3	0.0	98.5
CPLW	0.0	0.6	5.2	0.0	0.0	0.0	0.0	0.0	0.0	5.8
DUK	355.0	427.5	563.5	401.3	310.3	196.6	166.9	148.7	157.0	2,726.8
LGEE	263.5	230.3	162.7	140.9	130.9	233.9	182.5	208.1	185.8	1,738.6
MEC	16.5	0.2	226.2	1.9	0.0	0.0	2.9	0.0	0.0	247.7
MISO	1,922.9	1,066.3	918.6	2,597.1	1,668.9	1,523.0	1,568.0	1,362.4	1,177.5	13,804.8
ALTE	55.0	9.3	0.3	1.5	1.4	0.3	75.2	1.0	1.5	145.5
ALTW	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
AMIL	967.4	627.9	486.4	1,068.4	619.9	615.6	829.8	807.1	694.2	6,716.7
CIN	517.5	160.6	176.7	550.9	327.3	303.7	254.5	124.9	97.5	2,513.5
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	141.4	44.7	166.9	278.8	165.0	121.1	128.4	87.5	66.5	1,200.2
MECS	215.2	219.9	85.1	430.1	287.3	301.4	278.0	288.6	224.0	2,329.5
NIPS	25.9	3.9	0.9	267.2	267.8	180.9	2.1	53.3	93.8	895.8
WEC	0.0	0.0	2.4	0.2	0.2	0.0	0.2	0.1	0.1	3.1
NYISO	1,022.4	838.9	773.7	1,623.0	984.6	993.4	1,005.4	936.3	830.5	9,008.2
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LIND	23.2	5.2	5.8	3.3	82.5	25.8	46.7	18.0	18.1	228.6
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	999.1	833.6	767.9	1,619.8	902.2	967.5	958.7	918.3	812.5	8,779.6
OVEC	1,082.6	1,016.0	995.4	1,204.8	649.7	892.8	929.3	859.3	883.0	8,512.8
TVA	413.4	559.8	549.5	401.2	385.8	182.7	140.2	107.6	88.0	2,828.1
Total	5,076.9	4,144.7	4,197.2	6,378.0	4,131.0	4,098.3	3,999.8	3,623.7	3,321.9	38,971.5

Table 9-3 Real-time scheduled gross export volume by interface (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	34.2	16.3	15.2	51.6	32.0	38.7	28.8	19.0	32.1	267.9
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	60.3	32.0	21.8	186.6	126.5	233.8	302.0	263.0	198.3	1,424.3
LGEE	1.1	0.0	3.2	41.1	1.3	0.5	0.4	0.4	3.6	51.5
MEC	438.3	387.1	466.0	831.8	512.5	611.3	609.5	607.8	658.8	5,123.0
MISO	729.9	1,527.2	2,538.8	4,267.8	1,215.1	1,613.4	1,379.2	677.6	1,701.2	15,650.2
ALTE	195.9	251.2	771.0	1,034.3	362.9	412.7	365.1	200.3	502.9	4,096.2
ALTW	50.1	85.5	98.5	219.6	8.1	8.7	4.0	0.5	39.5	514.4
AMIL	49.8	149.6	168.5	276.3	53.3	39.1	38.8	42.9	26.7	844.8
CIN	198.6	502.1	526.7	1,078.7	359.9	288.4	245.0	108.2	230.0	3,537.6
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	54.1	110.0	169.2	251.8	157.8	343.2	203.6	80.8	125.2	1,495.6
MECS	57.1	245.3	649.7	1,204.4	147.0	342.5	309.4	154.5	587.6	3,697.5
NIPS	10.7	55.5	4.6	42.7	1.8	1.6	6.2	0.0	0.0	123.1
WEC	113.8	128.0	150.7	160.1	124.2	177.2	207.2	90.4	189.3	1,341.0
NYISO	2,113.6	2,167.2	2,475.0	3,406.1	1,000.2	1,403.3	1,640.7	1,483.8	1,265.0	16,954.8
HUDS	79.2	210.2	98.9	0.2	2.6	5.9	9.6	3.9	33.7	444.2
LIND	96.1	140.0	123.4	99.4	12.6	18.5	41.8	32.3	46.0	610.1
NEPT	303.6	424.0	390.7	870.7	256.7	369.9	426.6	462.1	310.5	3,814.7
NYIS	1,634.7	1,393.0	1,862.0	2,435.8	728.3	1,009.1	1,162.7	985.5	874.9	12,085.9
OVEC	27.1	25.5	23.0	35.5	18.1	16.9	17.4	17.5	16.7	197.8
TVA	63.6	7.6	4.0	20.5	17.0	29.6	37.5	65.4	38.9	284.1
Total	3,468.0	4,163.0	5,546.9	8,841.0	2,922.7	3,947.6	4,015.3	3,134.4	3,914.6	39,953.6

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.[14] 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

14 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.[15]

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.[16] 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.[17] 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 9-17 presents the interface pricing points used in the first nine months of 2014.

15 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.

16 See "Interface Pricing Point Assignment Methodology," (August 28, 2014) <http://www.pjm.com/~/media/etools/exschedule/interface-pricing-point-assignment-methodology.ashx> (Accessed October 16, 2014). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

17 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>.

The interface pricing methodology implies that the weighting factors reflect the actual system flows in a dynamic manner. In fact, the weightings are static, and are modified by PJM only occasionally. The MMU recommends that PJM monitor, and adjust as necessary, the weights applied to the components of the interfaces to ensure that the interface prices reflect ongoing changes in system conditions and that loop flows are accounted for on a dynamic basis. The MMU also recommends that PJM review the mappings of external balancing authorities to individual interface pricing points to reflect changes to the impact of the external power source on PJM tie lines as a result of system topology changes. The MMU recommends that this review occur at least annually.

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.[18]

In the Real-Time Energy Market, in the first nine months of 2014, there were net scheduled exports at 12 of PJM's 18 interface pricing points eligible for

18 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.

real-time transactions.[19] The top three net exporting interface pricing points in the Real-Time Energy Market accounted for 87.4 percent of the total net exports: PJM/MISO with 64.6 percent, PJM/Neptune (NEPT) with 13.1 percent and PJM/NYIS with 9.7 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 25.7 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 81.0 percent of the total net imports: PJM/SouthIMP with 51.4 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 29.6 percent of the net import volume.

Table 9-4 Real-time scheduled net interchange volume by interface pricing point (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS	(79.2)	(210.2)	(98.9)	(0.2)	(2.6)	(5.9)	(9.6)	(3.9)	(33.7)	(444.2)
IMO	390.9	171.2	227.6	955.3	525.8	476.6	531.5	403.6	300.5	3,983.1
LINDENVFT	(72.8)	(134.8)	(117.6)	(96.2)	69.9	7.3	5.0	(14.3)	(27.9)	(381.5)
MISO	(817.2)	(1,772.6)	(2,939.2)	(4,872.8)	(1,493.6)	(1,979.0)	(1,736.5)	(1,021.0)	(2,120.9)	(18,752.8)
NEPTUNE	(303.6)	(424.0)	(390.7)	(870.7)	(256.7)	(369.9)	(426.6)	(462.1)	(310.5)	(3,814.7)
NORTHWEST	(0.4)	(0.7)	(2.7)	(116.8)	(103.3)	(140.1)	(134.9)	(133.2)	(132.6)	(764.6)
NYIS	(548.6)	(414.6)	(997.0)	(771.4)	152.6	(19.0)	(173.0)	(18.3)	(25.3)	(2,814.7)
OVEC	1,055.5	990.6	972.3	1,169.3	631.7	875.9	911.9	841.7	866.2	8,315.1
SOUTHIMP	2,145.9	1,840.7	2,040.8	2,440.9	1,862.3	1,607.7	1,386.5	1,259.1	1,165.0	15,748.8
CPLEIMP	0.4	0.0	0.1	7.8	0.3	71.3	0.0	0.0	0.0	79.8
DUKIMP	101.2	216.8	106.6	90.1	32.6	42.1	32.6	33.8	30.1	685.9
NCMPAIMP	96.3	113.1	113.1	73.7	50.5	14.6	39.8	42.3	34.8	578.2
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	1,948.0	1,510.7	1,820.9	2,269.3	1,779.0	1,479.7	1,314.1	1,183.0	1,100.1	14,404.9
SOUTHEXP	(161.5)	(63.9)	(44.4)	(300.5)	(177.7)	(302.8)	(369.8)	(362.5)	(273.6)	(2,056.7)
CPLEEXP	(31.0)	(16.2)	(14.6)	(50.8)	(31.7)	(28.7)	(22.8)	(13.5)	(32.1)	(241.5)
DUKEXP	(32.3)	(22.3)	(14.9)	(141.5)	(97.7)	(163.1)	(112.5)	(48.9)	(80.2)	(713.5)
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(0.0)	(0.0)
SOUTHEAST	(2.7)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(2.7)
SOUTHWEST	(2.4)	(7.1)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(9.4)
SOUTHEXP	(93.2)	(18.4)	(14.9)	(108.2)	(48.2)	(110.9)	(234.5)	(300.1)	(161.2)	(1,089.5)
Total	1,608.8	(18.3)	(1,349.8)	(2,463.0)	1,208.3	150.7	(15.5)	489.3	(592.7)	(982.1)

Table 9-5 Real-time scheduled gross import volume by interface pricing point (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IMO	447.2	222.9	260.3	965.1	525.9	477.8	534.3	405.3	311.2	4,150.0
LINDENVFT	23.2	5.2	5.8	3.3	82.5	25.8	46.7	18.0	18.1	228.6
MISO	341.1	123.6	57.0	109.3	129.8	104.0	113.4	115.6	95.7	1,189.5
NEPTUNE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NORTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	1,036.9	935.0	834.9	1,654.6	880.8	988.9	987.0	966.4	849.0	9,133.5
OVEC	1,082.6	1,016.0	995.4	1,204.8	649.7	892.8	929.3	859.3	883.0	8,512.8
SOUTHIMP	2,145.9	1,841.9	2,043.8	2,440.9	1,862.3	1,609.1	1,389.1	1,259.1	1,165.0	15,757.1
CPLEIMP	0.4	0.0	0.1	7.8	0.3	71.3	0.0	0.0	0.0	79.8
DUKIMP	101.2	216.8	106.6	90.1	32.6	42.1	32.6	33.8	30.1	685.9
NCMPAIMP	96.3	113.1	113.1	73.7	50.5	14.6	39.8	42.3	34.8	578.2
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	1,948.0	1,511.9	1,824.0	2,269.3	1,779.0	1,481.1	1,316.7	1,183.0	1,100.1	14,413.1
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	5,076.9	4,144.7	4,197.2	6,378.0	4,131.0	4,098.3	3,999.8	3,623.7	3,321.9	38,971.5

19 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).

Table 9-6 Real-time scheduled gross export volume by interface pricing point (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS	79.2	210.2	98.9	0.2	2.6	5.9	9.6	3.9	33.7	444.2
IMO	56.3	51.7	32.6	9.8	0.1	1.2	2.8	1.7	10.7	166.9
LINDENVFT	96.1	140.0	123.4	99.4	12.6	18.5	41.8	32.3	46.0	610.1
MISO	1,158.3	1,896.2	2,996.2	4,982.2	1,623.4	2,083.0	1,849.9	1,136.6	2,216.6	19,942.3
NEPTUNE	303.6	424.0	390.7	870.7	256.7	369.9	426.6	462.1	310.5	3,814.7
NORTHWEST	0.4	0.7	2.7	116.8	103.3	140.1	134.9	133.2	132.6	764.6
NYIS	1,585.5	1,349.7	1,832.0	2,426.0	728.3	1,007.9	1,160.0	984.7	874.2	11,948.2
OVEC	27.1	25.5	23.0	35.5	18.1	16.9	17.4	17.5	16.7	197.8
SOUTHIMP	0.0	1.2	3.0	0.0	0.0	1.4	2.6	0.0	0.0	8.2
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	1.2	3.0	0.0	0.0	1.4	2.6	0.0	0.0	8.2
SOUTHEXP	161.5	63.9	44.4	300.5	177.7	302.8	369.8	362.5	273.6	2,056.7
CPLEEXP	31.0	16.2	14.6	50.8	31.7	28.7	22.8	13.5	32.1	241.5
DUKEXP	32.3	22.3	14.9	141.5	97.7	163.1	112.5	48.9	80.2	713.5
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	2.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.7
SOUTHWEST	2.4	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.4
SOUTHEXP	93.2	18.4	14.9	108.2	48.2	110.9	234.5	300.1	161.2	1,089.5
Total	3,468.0	4,163.0	5,546.9	8,841.0	2,922.7	3,947.6	4,015.3	3,134.4	3,914.6	39,953.6

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 in 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.[20] 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.[21]

In the Day-Ahead Energy Market, transaction sources and sinks are determined solely by the market participants. In Table 9-7, Table 9-8 and Table 9-9, 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 Energy 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 9-7 through Table 9-9 show the day-ahead interchange totals at the individual interfaces. Net interchange in the Day-Ahead Energy Market is shown by interface for the first nine months of 2014 in Table 9-7, while gross imports and exports are shown in Table 9-8 and Table 9-9.

In the Day-Ahead Energy Market, in the first nine months of 2014, there were net scheduled exports at 12 of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 68.7 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 25.5 percent, PJM/New York Independent System Operator, Inc. (NYIS) with 23.1 percent and PJM/Neptune (NEPT) with 20.1 percent of the net export

20 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.

21 See the *2010 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," for details.

volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 45.2 percent of the total net PJM exports in the Day-Ahead Energy Market. The nine separate interfaces that connect PJM to MISO together represented 27.9 percent of the total net PJM exports in the Day-Ahead Energy Market. Six PJM interfaces had net scheduled imports, with two importing interfaces accounting for 96.4 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 82.3 percent, and PJM/DUK with 14.1 percent of the net import volume.[22]

Table 9-7 Day-Ahead scheduled net interchange volume by interface (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	(30.1)	(15.5)	(13.9)	(20.2)	(25.2)	15.7	(22.4)	(12.5)	(24.9)	(149.0)
CPLW	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
DUK	151.9	128.5	270.6	116.8	152.3	73.5	42.0	8.6	9.0	953.1
LGEE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	(433.6)	(375.5)	(438.5)	(230.5)	(505.0)	(587.7)	(608.6)	(605.8)	(595.6)	(4,380.8)
MISO	(137.8)	(528.3)	(1,069.7)	(898.3)	(277.0)	(477.1)	(512.8)	(135.5)	(748.9)	(4,785.4)
ALTE	(96.1)	(148.5)	(516.3)	(439.3)	(263.1)	(315.0)	(311.1)	(167.5)	(396.2)	(2,653.1)
ALTW	(7.3)	(18.8)	(13.8)	(9.9)	0.0	0.0	(3.5)	0.0	(36.2)	(89.4)
AMIL	25.4	81.2	27.2	(17.0)	(7.5)	(20.0)	(16.7)	(1.3)	5.1	76.4
CIN	(31.5)	(209.0)	(221.1)	(179.5)	37.7	84.4	(23.5)	(5.7)	(46.4)	(594.6)
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	87.1	0.0	(28.3)	(21.2)	(7.2)	(1.2)	(4.9)	24.3
MECS	75.0	(113.1)	(360.3)	(180.8)	86.1	(51.9)	40.9	126.8	(82.5)	(459.8)
NIPS	0.0	(45.2)	0.0	(6.9)	0.0	0.0	(4.4)	0.0	0.0	(56.4)
WEC	(103.4)	(74.9)	(72.5)	(64.8)	(101.9)	(153.4)	(187.4)	(86.6)	(187.9)	(1,032.7)
NYISO	(1,140.8)	(1,230.9)	(1,482.8)	(988.0)	(285.5)	(594.6)	(834.2)	(667.4)	(534.3)	(7,758.4)
HUDS	(45.7)	(141.5)	(77.2)	0.0	(0.6)	(0.8)	(1.0)	0.0	(20.0)	(286.7)
LIND	(10.2)	(22.3)	(15.8)	(11.7)	5.4	5.5	(4.1)	(1.5)	(3.8)	(58.6)
NEPT	(280.3)	(437.6)	(430.2)	(445.9)	(260.4)	(378.2)	(434.5)	(467.5)	(317.9)	(3,452.5)
NYIS	(804.6)	(629.4)	(959.6)	(530.4)	(29.9)	(221.1)	(394.6)	(198.4)	(192.6)	(3,960.6)
OVEC	727.2	728.3	733.3	439.0	451.0	634.3	642.8	616.9	597.2	5,569.9
TVA	8.8	29.3	55.2	35.1	13.6	4.5	6.9	(16.7)	6.3	143.0
Total without Up-To Congestion	(854.4)	(1,263.4)	(1,945.9)	(1,546.1)	(475.7)	(931.4)	(1,286.3)	(812.4)	(1,291.4)	(10,407.0)
Up-To Congestion	(578.5)	(482.9)	143.1	(446.1)	(1,399.6)	598.5	423.1	(260.6)	267.6	(1,735.4)
Total	(1,433.0)	(1,746.3)	(1,802.8)	(1,992.1)	(1,875.3)	(332.9)	(863.2)	(1,073.0)	(1,023.8)	(12,142.4)

22 In the Day-Ahead Energy Market, two PJM interfaces had a net interchange of zero (PJM/City Water Light & Power (CWLP) and PJM/LG&E Energy Transmission Services (LGEE)).

Table 9-8 Day-Ahead scheduled gross import volume by interface (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	0.0	0.0	0.0	3.2	0.0	40.9	0.0	0.0	0.0	44.1
CPLW	0.0	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6
DUK	157.5	128.5	270.6	125.7	153.2	95.6	85.7	63.6	49.5	1,129.9
LGEE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.8	2.8
MISO	152.3	127.1	150.7	219.8	283.2	247.9	146.2	203.2	286.7	1,817.1
ALTE	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	31.9	32.9
ALTW	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
AMIL	25.4	88.7	45.4	0.0	0.0	0.0	0.0	0.1	5.5	165.1
CIN	26.1	0.0	0.0	114.4	151.8	122.8	41.8	15.3	6.4	478.7
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	87.1	0.0	0.0	0.0	0.0	0.0	0.0	87.1
MECS	99.4	38.4	15.9	105.4	131.4	125.1	104.4	187.8	242.9	1,050.7
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WEC	0.0	0.0	2.3	0.0	0.0	0.0	0.0	0.0	0.0	2.3
NYISO	679.5	611.9	610.9	629.3	684.3	771.1	761.1	753.4	644.5	6,146.1
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LIND	3.6	2.6	3.5	1.1	11.0	15.7	8.3	5.1	6.5	57.4
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	675.9	609.4	607.4	628.2	673.3	755.4	752.8	748.3	638.0	6,088.6
OVEC	727.3	728.3	733.3	439.0	467.2	651.2	660.2	632.5	635.0	5,673.9
TVA	29.7	29.3	55.2	35.1	20.5	12.8	10.4	2.0	21.0	215.9
Total without Up-To Congestion	1,746.2	1,625.7	1,820.7	1,452.1	1,608.4	1,819.6	1,663.6	1,654.7	1,639.4	15,030.4
Up-To Congestion	3,054.9	3,127.2	3,778.6	3,384.6	3,397.8	3,948.4	3,877.9	3,194.9	1,603.4	29,367.6
Total	4,801.1	4,752.9	5,599.2	4,836.7	5,006.1	5,768.0	5,541.5	4,849.6	3,242.8	44,398.0

Table 9-9 Day-Ahead scheduled gross export volume by interface (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
CPLE	30.1	15.5	13.9	23.4	25.2	25.2	22.4	12.5	24.9	193.1
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	5.6	0.0	0.0	8.8	0.9	22.1	43.8	55.0	40.5	176.7
LGEE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MEC	433.6	375.5	438.5	230.5	505.0	587.7	608.6	605.8	598.4	4,383.6
MISO	290.1	655.3	1,220.4	1,118.1	560.1	725.0	659.0	338.8	1,035.6	6,602.5
ALTE	97.2	148.5	516.3	439.3	263.1	315.0	311.1	167.5	428.1	2,686.1
ALTW	7.6	18.8	13.8	9.9	0.0	0.0	3.5	0.0	36.2	89.7
AMIL	0.0	7.5	18.3	17.0	7.5	20.0	16.7	1.4	0.3	88.6
CIN	57.6	209.0	221.1	293.9	114.1	38.4	65.3	21.0	52.8	1,073.3
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	28.3	21.2	7.2	1.2	4.9	62.8
MECS	24.4	151.5	376.2	286.2	45.3	177.0	63.6	61.0	325.4	1,510.6
NIPS	0.0	45.2	0.0	6.9	0.0	0.0	4.4	0.0	0.0	56.4
WEC	103.4	74.9	74.8	64.8	101.9	153.4	187.4	86.6	187.9	1,035.0
NYISO	1,820.3	1,842.8	2,093.7	1,617.3	969.7	1,365.7	1,595.3	1,420.8	1,178.8	13,904.4
HUDS	45.7	141.5	77.2	0.0	0.6	0.8	1.0	0.0	20.0	286.7
LIND	13.8	24.9	19.3	12.9	5.6	10.2	12.5	6.6	10.3	116.0
NEPT	280.3	437.6	430.2	445.9	260.4	378.2	434.5	467.5	317.9	3,452.5
NYIS	1,480.5	1,238.8	1,567.0	1,158.6	703.2	976.6	1,147.3	946.7	830.6	10,049.2
OVEC	0.1	0.0	0.0	0.0	16.2	16.9	17.4	15.6	37.9	104.0
TVA	20.9	0.0	0.0	0.0	6.9	8.4	3.5	18.6	14.7	73.0
Total without Up-To Congestion	2,600.6	2,889.1	3,766.6	2,998.2	2,084.1	2,751.1	2,949.9	2,467.1	2,930.8	25,437.4
Up-To Congestion	3,633.4	3,610.2	3,635.5	3,830.6	4,797.4	3,349.9	3,454.7	3,455.5	1,335.8	31,103.0
Total	6,234.0	6,499.3	7,402.0	6,828.8	6,881.5	6,101.0	6,404.7	5,922.6	4,266.6	56,540.4

Day-Ahead Interface Pricing Point Imports and Exports

Table 9-10 through Table 9-15 show the Day-Ahead Energy Market interchange totals at the individual interface pricing points. In the first nine months of 2014, up-to congestion transactions accounted for 66.1 percent of all scheduled import MW transactions, 55.0 percent of all scheduled export MW transactions and 14.3 percent of the net interchange volume in the Day-Ahead Energy Market. Net interchange in the Day-Ahead Energy Market, including up-to congestion transactions, is shown by interface pricing point in the first nine months of 2014 in Table 9-10. Up-to congestion transactions by interface pricing point in the first nine months of 2014 are shown in Table 9-11. Gross imports and exports, including up-to congestion transactions, for the Day-Ahead Energy Market are shown in Table 9-12 and Table 9-14, while gross import up-to congestion transactions are show in Table 9-13 and gross export up-to congestion transactions are shown in Table 9-15.

There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO). The NIPSCO interface pricing point was created when the individual balancing authorities that integrated to form MISO operated independently. Transactions sourcing or sinking in the NIPSCO balancing authority were eligible to receive the real-time NIPSCO interface pricing point. After the formation of the MISO RTO, all real-time transactions sourcing or sinking in NIPSCO are represented on the NERC tag as sourcing or sinking in MISO, and thus receive the MISO interface pricing point in the Real-Time Energy Market. For this reason, it was no longer possible to receive the NIPSCO interface pricing point in the Real-Time Energy Market after the integration of NIPSCO into MISO. The NIPSCO interface pricing point remains an eligible interface pricing point in the PJM Day-Ahead Energy Market to facilitate the long term day-ahead positions created at the NIPSCO Interface prior to the integration.

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. After the consolidation, several units were eligible to continue to receive the real-time Southeast and Southwest interface pricing points through grandfathered agreements. The Southeast pricing point also remains eligible to receive the real-time interface price only through the reserve sharing agreement with VACAR. The grandfathered agreements for the Southeast interface pricing point have expired. The Southeast interface pricing point remains an eligible interface pricing point in the PJM Day-

Ahead Energy Market to facilitate the long term day-ahead positions created prior to the consolidation of the Southeast and Southwest interface pricing points.

The MMU recommends that PJM eliminate the NIPSCO and Southeast interface pricing points from the Day-Ahead and Real-Time Energy Markets and, with VACAR, assign the transactions created under the reserve sharing agreement to the SouthIMP/EXP pricing point.

In the Day-Ahead Energy Market, in the first nine months of 2014, there were net scheduled exports at 11 of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points in the Day-Ahead Energy Market accounted for 53.7 percent of the total net exports: PJM/SouthEXP with 23.8 percent, PJM/MISO with 16.1 percent and PJM/Southwest with 13.8 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 24.6 percent of the total net PJM exports in the Day-Ahead Energy Market. Eight PJM interface pricing points had net imports, with three importing interface pricing points accounting for 80.6 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 36.4 percent, PJM/Southeast with 22.4 percent and PJM/SouthIMP with 21.7 percent of the net import volume.

In the Day-Ahead Energy Market, in the first nine months of 2014, up-to congestion transactions had net exports at six of PJM's 19 interface pricing points eligible for day-ahead transactions. The top three net exporting interface pricing points for up-to congestion transactions accounted for 91.5 percent of the total net up-to congestion exports: PJM/SouthEXP with 44.0 percent, PJM/Southwest with 26.5 percent and PJM/NIPSCO with 21.0 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 2.1 percent of the net up-to congestion PJM exports in the Day-Ahead Energy Market (PJM/Linden with 1.2 percent and PJM/NEPTUNE with 0.9 percent). The PJM/NYIS, and PJM/HUDS interface pricing points had net imports in the Day-Ahead Energy Market. Seven PJM interface pricing points had net up-to congestion imports, with three importing interface pricing points accounting for 57.8 percent of the total net up-to congestion imports: PJM/Southeast with 24.0 percent, PJM/MISO with 18.6 percent and PJM/Northwest with 15.1 percent of the net import volume.[23]

Table 9-10 Day-ahead scheduled net interchange volume by interface pricing point (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS	(19.6)	(8.6)	68.1	107.5	174.9	178.8	285.0	336.6	(8.6)	1,114.1
IMO	319.5	296.7	271.0	169.4	68.5	148.6	196.9	305.2	193.9	1,969.7
LINDENVFT	(72.0)	(69.4)	(0.6)	(77.5)	(31.6)	(54.4)	58.7	13.9	8.4	(224.4)
MISO	(442.9)	(648.2)	(977.1)	(823.7)	(384.9)	(57.5)	(157.1)	50.3	(763.5)	(4,204.6)
NEPTUNE	(353.8)	(396.7)	(433.3)	(437.3)	(353.3)	(422.7)	(429.6)	(427.3)	(318.2)	(3,572.2)
NIPSCO	(763.3)	(19.3)	(274.5)	(630.7)	(616.1)	(33.9)	(242.9)	(172.1)	(119.2)	(2,872.0)
NORTHWEST	24.1	134.8	(36.0)	140.9	(376.9)	(704.4)	(561.0)	(536.6)	(482.4)	(2,397.5)
NYIS	(755.3)	(510.8)	(912.7)	(460.5)	131.1	31.3	(39.2)	(48.7)	(82.2)	(2,647.0)
OVEC	1,225.6	54.0	599.1	140.3	227.2	976.7	652.2	200.2	628.7	4,703.9
SOUTHIMP	641.1	834.2	1,639.1	1,129.2	1,247.2	1,184.5	889.3	828.0	637.3	9,029.9
CPLEIMP	0.0	0.6	0.0	3.2	0.0	40.9	0.0	0.0	0.0	44.7
DUKIMP	29.3	64.1	17.8	8.2	6.2	27.2	1.5	0.5	0.7	155.5
NCMPAIMP	67.9	31.7	51.3	25.6	46.3	10.8	36.3	40.8	27.9	338.7
SOUTHEAST	216.3	238.1	718.8	394.6	610.7	473.8	314.5	433.1	417.9	3,817.8
SOUTHWEST	161.0	156.2	164.8	384.5	193.9	201.0	301.4	218.2	85.9	1,866.9
SOUTHIMP	166.5	343.6	686.3	313.1	390.0	430.8	235.6	135.4	105.0	2,806.3
SOUTHEXP	(1,236.4)	(1,412.9)	(1,745.9)	(1,249.8)	(1,961.4)	(1,580.0)	(1,515.6)	(1,622.4)	(718.1)	(13,042.4)
CPLEEXP	(28.4)	(14.5)	(13.1)	(22.0)	(24.0)	(23.5)	(21.9)	(12.1)	(24.6)	(184.1)
DUKEXP	0.0	0.0	0.0	(8.8)	(0.9)	(16.0)	0.0	(24.6)	(0.5)	(50.9)
NCMPAEXP	(1.7)	(0.9)	(0.8)	(1.4)	(1.3)	(0.4)	(0.4)	(170.2)	(0.3)	(177.5)
SOUTHEAST	(59.9)	(83.4)	(26.0)	(151.0)	(232.1)	(110.3)	(89.4)	(123.3)	(48.2)	(923.5)
SOUTHWEST	(507.8)	(648.2)	(831.2)	(611.3)	(662.4)	(571.3)	(613.5)	(687.9)	(357.2)	(5,490.8)
SOUTHEXP	(638.6)	(665.8)	(874.8)	(455.2)	(1,040.7)	(858.5)	(790.4)	(604.3)	(287.2)	(6,215.6)
Total	(1,433.0)	(1,746.3)	(1,802.8)	(1,992.1)	(1,875.3)	(332.9)	(863.2)	(1,073.0)	(1,023.8)	(12,142.4)

23 In the Day-Ahead Energy Market, six PJM interface pricing points (PJM/CPLEIMP, PJM/DUKIMP, PJM/NCMPAIMP, PJM/CPLEEXP, PJM/DUKEXP and PJM/NCMPAEXP) had a net interchange of zero.

Table 9-11 Up-to congestion scheduled net interchange volume by interface pricing point (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS	26.1	123.2	145.2	107.5	175.5	179.5	286.0	336.6	11.4	1,391.2
IMO	218.6	259.9	255.7	64.0	(65.1)	24.7	92.7	117.4	56.1	1,023.7
LINDENVFT	(61.7)	(47.1)	15.3	(65.7)	(37.1)	(59.9)	62.8	15.4	7.9	(170.0)
MISO	(195.6)	5.7	243.1	296.4	170.4	665.0	501.9	385.0	145.1	2,217.0
NEPTUNE	(73.5)	41.0	(3.1)	8.5	(92.9)	(44.5)	4.9	40.2	1.5	(118.0)
NIPSCO	(763.3)	(19.3)	(274.5)	(630.7)	(616.1)	(33.9)	(242.9)	(172.1)	(113.9)	(2,866.7)
NORTHWEST	457.7	510.3	402.6	371.4	128.0	(116.6)	47.6	(100.6)	103.7	1,804.0
NYIS	49.3	128.0	42.5	65.6	163.3	252.7	355.4	149.7	86.8	1,293.2
OVEC	498.4	(674.3)	(130.4)	(298.6)	(223.8)	342.4	9.4	(416.7)	28.0	(865.6)
SOUTHIMP	445.3	587.1	1,178.8	853.1	926.5	913.4	751.2	751.2	546.3	6,952.9
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	216.3	238.1	718.8	346.0	610.6	473.8	314.5	433.1	417.9	3,769.2
SOUTHWEST	161.0	156.2	164.8	384.5	193.9	201.0	301.4	218.2	79.9	1,861.0
SOUTHIMP	68.0	192.9	295.2	122.5	121.9	238.6	135.3	99.8	48.5	1,322.7
SOUTHEXP	(1,179.8)	(1,397.4)	(1,732.0)	(1,217.5)	(1,928.3)	(1,524.3)	(1,445.9)	(1,366.5)	(605.3)	(12,397.1)
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	(59.9)	(83.4)	(26.0)	(151.0)	(232.1)	(110.3)	(86.8)	(123.3)	(31.5)	(904.2)
SOUTHWEST	(507.8)	(648.2)	(831.2)	(611.3)	(662.4)	(571.3)	(613.5)	(687.9)	(346.1)	(5,479.7)
SOUTHEXP	(612.2)	(665.8)	(874.8)	(455.2)	(1,033.8)	(842.7)	(745.6)	(555.3)	(227.7)	(6,013.2)
Total Interfaces	(578.5)	(482.9)	143.1	(446.1)	(1,399.6)	598.5	423.1	(260.6)	267.6	(1,735.4)
INTERNAL	35,413.4	36,715.9	41,839.2	46,018.1	47,071.4	42,767.0	42,702.3	42,796.1	15,430.5	350,754.0
Total	34,834.9	36,109.8	41,837.1	45,464.5	45,496.3	43,186.0	42,839.5	42,198.9	15,686.6	347,627.3

Table 9-12 Day-ahead scheduled gross import volume by interface pricing point (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS	187.4	317.0	257.6	162.1	221.6	246.9	365.8	409.1	82.2	2,249.6
IMO	358.4	375.9	340.3	298.4	336.3	312.4	386.3	383.4	238.1	3,029.6
LINDENVFT	84.4	70.4	100.5	59.2	56.8	74.9	144.8	85.4	36.6	713.0
MISO	334.1	318.3	445.6	544.0	397.3	734.7	620.7	462.1	247.9	4,104.6
NEPTUNE	38.4	133.4	156.1	78.9	36.7	26.0	93.5	81.9	17.3	662.2
NIPSCO	85.5	172.9	80.0	72.6	69.0	114.6	69.2	86.1	32.0	781.9
NORTHWEST	614.8	605.4	503.2	505.7	270.2	168.8	252.1	165.8	184.5	3,270.5
NYIS	810.5	787.0	726.5	806.2	902.4	1,058.5	1,146.4	925.9	778.8	7,942.1
OVEC	1,646.5	1,138.6	1,350.5	1,180.3	1,468.7	1,846.8	1,573.3	1,421.9	988.2	12,614.7
SOUTHIMP	641.1	834.2	1,639.1	1,129.2	1,247.2	1,184.5	889.3	828.0	637.3	9,029.9
CPLEIMP	0.0	0.6	0.0	3.2	0.0	40.9	0.0	0.0	0.0	44.7
DUKIMP	29.3	64.1	17.8	8.2	6.2	27.2	1.5	0.5	0.7	155.5
NCMPAIMP	67.9	31.7	51.3	25.6	46.3	10.8	36.3	40.8	27.9	338.7
SOUTHEAST	216.3	238.1	718.8	394.6	610.7	473.8	314.5	433.1	417.9	3,817.8
SOUTHWEST	161.0	156.2	164.8	384.5	193.9	201.0	301.4	218.2	85.9	1,866.9
SOUTHIMP	166.5	343.6	686.3	313.1	390.0	430.8	235.6	135.4	105.0	2,806.3
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	4,801.1	4,752.9	5,599.2	4,836.7	5,006.1	5,768.0	5,541.5	4,849.6	3,242.8	44,398.0

Table 9-13 Up-to congestion scheduled gross import volume by interface pricing point (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS	187.4	317.0	257.6	162.1	221.6	246.9	365.8	409.1	82.2	2,249.6
IMO	257.5	337.5	324.4	193.0	202.6	188.5	282.1	195.6	73.0	2,054.2
LINDENVFT	80.8	67.8	97.0	58.1	45.8	59.2	136.4	80.3	25.2	650.7
MISO	291.2	318.3	445.3	541.7	392.5	732.3	620.7	458.0	195.5	3,995.4
NEPTUNE	38.4	133.4	156.1	78.9	36.7	26.0	93.5	81.9	17.3	662.2
NIPSCO	85.5	172.9	80.0	72.6	69.0	114.6	69.2	86.1	27.3	777.2
NORTHWEST	614.8	605.4	503.2	505.7	270.2	168.8	252.1	165.8	176.6	3,262.6
NYIS	134.6	177.6	115.2	178.0	231.4	303.3	393.7	177.5	117.1	1,828.5
OVEC	919.3	410.3	621.0	741.4	1,001.4	1,195.5	913.1	789.4	342.9	6,934.4
SOUTHIMP	445.3	587.1	1,178.8	853.1	926.5	913.4	751.2	751.2	546.3	6,952.9
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	216.3	238.1	718.8	346.0	610.6	473.8	314.5	433.1	417.9	3,769.2
SOUTHWEST	161.0	156.2	164.8	384.5	193.9	201.0	301.4	218.2	79.9	1,861.0
SOUTHIMP	68.0	192.9	295.2	122.5	121.9	238.6	135.3	99.8	48.5	1,322.7
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	3,054.9	3,127.2	3,778.6	3,384.6	3,397.8	3,948.4	3,877.9	3,194.9	1,603.4	29,367.6

Table 9-14 Day-ahead scheduled gross export volume by interface pricing point (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS	206.9	325.6	189.5	54.7	46.6	68.1	80.8	72.5	90.7	1,135.5
IMO	39.0	79.2	69.2	129.0	267.8	163.8	189.4	78.2	44.2	1,059.9
LINDENVFT	156.4	139.8	101.1	136.7	88.5	129.3	86.1	71.5	28.1	937.3
MISO	776.9	966.5	1,422.6	1,367.7	782.2	792.3	777.8	411.8	1,011.4	8,309.1
NEPTUNE	392.2	530.0	589.5	516.2	390.0	448.7	523.1	509.2	335.4	4,234.4
NIPSCO	848.8	192.2	354.4	703.3	685.1	148.5	312.1	258.3	151.2	3,653.9
NORTHWEST	590.7	470.6	539.1	364.9	647.1	873.2	813.1	702.4	666.9	5,668.0
NYIS	1,565.8	1,297.8	1,639.2	1,266.7	771.4	1,027.2	1,185.6	974.6	860.9	10,589.1
OVEC	421.0	1,084.6	751.4	1,040.0	1,241.5	870.1	921.1	1,221.7	359.5	7,910.8
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	1,236.4	1,412.9	1,745.9	1,249.8	1,961.4	1,580.0	1,515.6	1,622.4	718.1	13,042.4
CPLEEXP	28.4	14.5	13.1	22.0	24.0	23.5	21.9	12.1	24.6	184.1
DUKEXP	0.0	0.0	0.0	8.8	0.9	16.0	0.0	24.6	0.5	50.9
NCMPAEXP	1.7	0.9	0.8	1.4	1.3	0.4	0.4	170.2	0.3	177.5
SOUTHEAST	59.9	83.4	26.0	151.0	232.1	110.3	89.4	123.3	48.2	923.5
SOUTHWEST	507.8	648.2	831.2	611.3	662.4	571.3	613.5	687.9	357.2	5,490.8
SOUTHEXP	638.6	665.8	874.8	455.2	1,040.7	858.5	790.4	604.3	287.2	6,215.6
Total	6,234.0	6,499.3	7,402.0	6,828.8	6,881.5	6,101.0	6,404.7	5,922.6	4,266.6	56,540.4

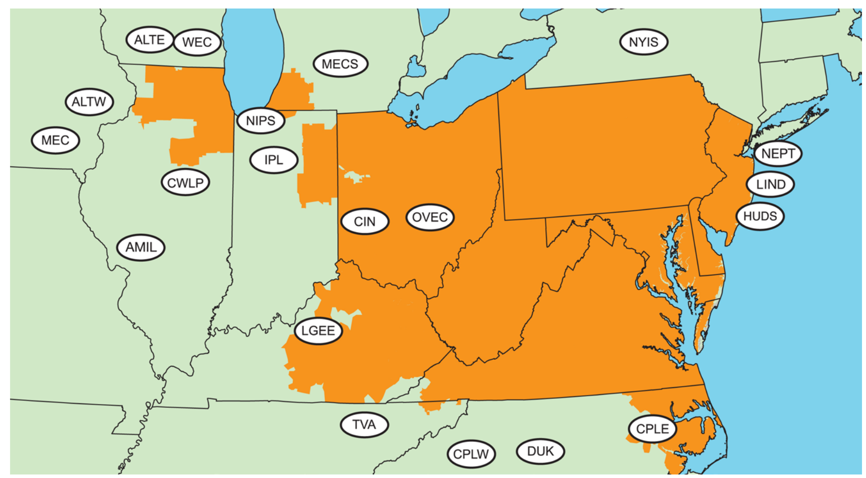
Table 9-15 Up-to congestion scheduled gross export volume by interface pricing point (GWh): January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Total
HUDS	161.2	193.7	112.4	54.7	46.0	67.3	79.8	72.5	70.7	858.4
IMO	39.0	77.6	68.7	129.0	267.8	163.8	189.4	78.2	17.0	1,030.4
LINDENVFT	142.6	114.9	81.7	123.8	82.9	119.1	73.6	64.9	17.3	820.8
MISO	486.8	312.6	202.2	245.2	222.1	67.3	118.7	73.0	50.4	1,778.4
NEPTUNE	111.9	92.4	159.3	70.4	129.7	70.4	88.6	41.7	15.7	780.1
NIPSCO	848.8	192.2	354.4	703.3	685.1	148.5	312.1	258.3	141.2	3,644.0
NORTHWEST	157.1	95.1	100.6	134.4	142.2	285.4	204.5	266.4	72.9	1,458.6
NYIS	85.3	49.6	72.8	112.4	68.2	50.6	38.3	27.8	30.4	535.3
OVEC	420.9	1,084.6	751.4	1,040.0	1,225.2	853.1	903.7	1,206.1	314.9	7,800.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	1,179.8	1,397.4	1,732.0	1,217.5	1,928.3	1,524.3	1,445.9	1,366.5	605.3	12,397.1
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	59.9	83.4	26.0	151.0	232.1	110.3	86.8	123.3	31.5	904.2
SOUTHWEST	507.8	648.2	831.2	611.3	662.4	571.3	613.5	687.9	346.1	5,479.7
SOUTHEXP	612.2	665.8	874.8	455.2	1,033.8	842.7	745.6	555.3	227.7	6,013.2
Total	3,633.4	3,610.2	3,635.5	3,830.6	4,797.4	3,349.9	3,454.7	3,455.5	1,335.8	31,103.0

Table 9-16 Active interfaces: January through September, 2014[24]

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
ALTE	Active	Active	Active	Active	Active	Active	Active	Active	Active
ALTW	Active	Active	Active	Active	Active	Active	Active	Active	Active
AMIL	Active	Active	Active	Active	Active	Active	Active	Active	Active
CIN	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLE	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLW	Active	Active	Active	Active	Active	Active	Active	Active	Active
CWLP	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUK	Active	Active	Active	Active	Active	Active	Active	Active	Active
HUDS	Active	Active	Active	Active	Active	Active	Active	Active	Active
IPL	Active	Active	Active	Active	Active	Active	Active	Active	Active
LGEE	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active
MEC	Active	Active	Active	Active	Active	Active	Active	Active	Active
MECS	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPS	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active
TVA	Active	Active	Active	Active	Active	Active	Active	Active	Active
WEC	Active	Active	Active	Active	Active	Active	Active	Active	Active

Figure 9-3 PJM's footprint and its external interfaces



24 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of June 30, 2014, DUK, CPLE and CPLW have continued to operate as separate balancing authorities, and are still considered distinct interfaces within the PJM Energy Market.

Table 9-17 Active pricing points: January through September, 2014

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
CPLEEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
CPLEIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
DUKIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
HUDS	Active	Active	Active	Active	Active	Active	Active	Active	Active
LIND	Active	Active	Active	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
NCMPAIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
NEPT	Active	Active	Active	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southeast	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active	Active	Active	Active	Active
SOUTHIMP	Active	Active	Active	Active	Active	Active	Active	Active	Active
Southwest	Active	Active	Active	Active	Active	Active	Active	Active	Active

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.[25]

Loop flows result, in part, from a mismatch between incentives to use a particular scheduled transmission path and the market based price differentials that result from the actual physical flows on the transmission system. PJM's approach to interface pricing attempts to match prices with physical power flows and their impacts on the transmission system. For example, if market participants want to import energy from the Southwest Power Pool (SPP) to PJM, they are likely to choose a scheduled path with the fewest transmission providers along the path and therefore the lowest transmission costs for the transaction, regardless of whether the resultant path is related to the physical flow of power. The lowest cost transmission path runs from SPP, through MISO, and into PJM, requiring only three transmission reservations, two of which are available at no cost (MISO transmission would be free based on the regional through and out rates, and the PJM transmission would be free, if using spot import transmission). Any other transmission path entering PJM, where the generating control area is to the south would require the market participant to acquire transmission through non-market balancing authorities, and thus incur additional transmission costs. PJM's interface pricing method recognizes that transactions sourcing in SPP and sinking in PJM will create flows across the southern border and prices those transactions at the SouthIMP Interface price. As a result, the transaction is priced appropriately, but a difference between scheduled and actual flows is created at both PJM's border with MISO (higher scheduled than actual flows) and PJM's southern border (higher actual than scheduled flows). In the first nine months of 2014, there were net scheduled flows of 7,349 GWh through MISO that received an interface pricing point associated with the southern border. Conversely, in the first nine months of 2014, there were no net scheduled flows across the southern border that received the MISO interface pricing point.

In the first nine months of 2014, net scheduled interchange was -1,081 GWh and net actual interchange was -331 GWh, a difference of 750 GWh. In the first nine months of 2013, net scheduled interchange was 3,316 GWh and net actual interchange was 3,474 GWh, a difference of 158 GWh.[26] This difference is system inadvertent. PJM attempts to minimize the amount of accumulated

25 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

26 The "Net Scheduled" values shown in Table 9-18 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. Table 9-1 through Table 9-6 represent block scheduled transactions, submitted through the Enhanced Energy Scheduling (EES) application and tagged through the NERC e-tag process only. As a result, the net interchange in Table 9-18 does not match the interchange values shown in Table 9-1 through Table 9-6.

inadvertent interchange by continually monitoring and correcting for inadvertent interchange.[27]

Table 9-18 Net scheduled and actual PJM flows by interface (GWh): January through September, 2014

	Actual	Net Scheduled	Difference (GWh)
CPLE	5,429	(114)	5,543
CPLW	(1,350)	6	(1,356)
DUK	(340)	1,195	(1,536)
LGEE	2,426	1,637	789
MEC	(1,851)	(4,455)	2,604
MISO	(11,740)	(1,223)	(10,517)
ALTE	(5,641)	(3,434)	(2,207)
ALTW	(1,577)	(404)	(1,173)
AMIL	7,674	5,476	2,198
CIN	(4,019)	(867)	(3,152)
CWLP	(529)	0	(529)
IPL	850	(415)	1,265
MECS	(8,739)	(981)	(7,758)
NIPS	(3,657)	660	(4,317)
WEC	3,898	(1,258)	5,156
NYISO	(7,002)	(7,222)	220
HUDS	(444)	(444)	0
LIND	(333)	(333)	0
NEPT	(3,379)	(3,379)	0
NYIS	(2,845)	(3,066)	220
OVEC	10,104	7,730	2,374
TVA	3,993	1,364	2,629
Total	(331)	(1,081)	750

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.[28] 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.

27 See PJM. "Manual 12: Balancing Operations," Revision 30 (December 1, 2013).

28 The terms balancing authority and control area are used interchangeably in this section. The NERC tag applications maintained the terminology of generation control area (GCA) and load control area (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.)

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 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 9-19 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 (10,158 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 11,666 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 9-19 Net scheduled and actual PJM flows by interface pricing point (GWh): January through September, 2014

	Actual	Net Scheduled	Difference (GWh)
HUDSONTP	(444)	(444)	0
IMO	0	3,505	(3,505)
LINDENVFT	(333)	(333)	0
MISO	(11,740)	(16,529)	4,789
NEPTUNE	(3,379)	(3,379)	0
NORTHWEST	(1,851)	(700)	(1,150)
NYIS	(2,845)	(2,596)	(249)
OVEC	10,104	7,730	2,374
SOUTHIMP	10,158	13,573	(3,415)
CPLEIMP	0	76	(76)
DUKIMP	0	641	(641)
NCMPAIMP	0	541	(541)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	10,158	12,315	(2,156)
SOUTHEXP	0	(1,906)	1,906
CPLEEXP	0	(216)	216
DUKEXP	0	(643)	643
NCMPAEXP	0	0	0
SOUTHEAST	0	(3)	3
SOUTHWEST	0	(9)	9
SOUTHEXP	0	(1,035)	1,035
Total	(331)	(1,081)	750

Table 9-20 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.

Table 9-20 Net scheduled and actual PJM flows by interface pricing point (GWh) (Adjusted for IMO Scheduled Interfaces): January through September, 2014

	Actual	Net Scheduled	Difference (GWh)
HUDSONTP	(444)	(444)	0
LINDENVFT	(333)	(333)	0
MISO	(11,740)	(12,932)	1,192
NEPTUNE	(3,379)	(3,379)	0
NORTHWEST	(1,851)	(700)	(1,150)
NYIS	(2,845)	(2,689)	(157)
OVEC	10,104	7,730	2,374
SOUTHIMP	10,158	13,573	(3,415)
CPLEIMP	0	76	(76)
DUKIMP	0	641	(641)
NCMPAIMP	0	541	(541)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	10,158	12,315	(2,156)
SOUTHEXP	0	(1,906)	1,906
CPLEEXP	0	(216)	216
DUKEXP	0	(643)	643
NCMPAEXP	0	0	0
SOUTHEAST	0	(3)	3
SOUTHWEST	0	(9)	9
SOUTHEXP	0	(1,035)	1,035
Total	(331)	(1,081)	750

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.

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 prohibit market participants from breaking transactions into smaller segments to defeat the interface pricing rule and receive higher prices (for imports) or lower prices (for exports) from PJM resulting from the inability to identify the true source or sink of the transaction. If all of the Northeast ISOs and RTOs implemented validation to prohibit the breaking of transactions into smaller segments, the level of Lake Erie loops flows would be reduced.

The MMU recommends that the validation also require market participants to submit transactions on market paths that reflect the expected actual flow in order to reduce unscheduled loop flows.

Table 9-21 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 9-21 shows that in the first nine months of 2014, 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 mapped to the IMO interface, and thus actual flows were assigned the IMO interface pricing point (874 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 (2,914 GWh).

Table 9-21 Net scheduled and actual PJM flows by interface and interface pricing point (GWh): January through September, 2014

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)	Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(5,641)	(3,434)	(2,207)	IPL		850	(415)	1,265
	MISO	(5,641)	(3,521)	(2,120)		IMO	0	901	(901)
	SOUTHIMP	0	87	(87)		MISO	850	(1,407)	2,258
ALTW		(1,577)	(404)	(1,173)		NORTHWEST	0	(1)	1
	MISO	(1,577)	(404)	(1,173)		SOUTHEXP	0	(1)	1
AMIL		7,674	5,476	2,198		SOUTHIMP	0	92	(92)
	MISO	7,674	31	7,643	LGEE		2,426	1,637	789
	SOUTHIMP	0	5,454	(5,454)		SOUTHEXP	0	(31)	31
	SOUTHWEST	0	(9)	9		SOUTHIMP	2,426	1,668	758
CIN		(4,019)	(867)	(3,152)	LIND		(333)	(333)	0
	IMO	0	874	(874)		LINDENVFT	(333)	(333)	0
	MISO	(4,019)	(2,914)	(1,105)	MEC		(1,851)	(4,455)	2,604
	NORTHWEST	0	(9)	9		IMO	0	2	(2)
	NYIS	0	377	(377)		MISO	0	(3,994)	3,994
	SOUTHEXP	0	(2)	2		NORTHWEST	(1,851)	(690)	(1,161)
	SOUTHIMP	0	807	(807)		SOUTHIMP	0	228	(228)
CPLE		5,429	(114)	5,543	MECS		(8,739)	(981)	(7,758)
	CPLEEXP	0	(216)	216		IMO	0	1,821	(1,821)
	CPLEIMP	0	76	(76)		MISO	(8,739)	(3,049)	(5,690)
	DUKEXP	0	(7)	7		NORTHWEST	0	(1)	1
	DUKIMP	0	7	(7)		SOUTHEXP	0	(15)	15
	SOUTHEXP	0	(16)	16		SOUTHIMP	0	263	(263)
	SOUTHIMP	5,429	46	5,384	NEPT		(3,379)	(3,379)	0
	SOUTHEAST	0	(3)	3		NEPTUNE	(3,379)	(3,379)	0
CPLW		(1,350)	6	(1,356)	NIPS		(3,657)	660	(4,317)
	SOUTHIMP	(1,350)	6	(1,356)		MISO	(3,657)	(11)	(3,645)
CWLP		(529)	0	(529)		SOUTHIMP	0	672	(672)
	MISO	(529)	0	(529)	NYIS		(2,845)	(3,066)	220
DUK		(340)	1,195	(1,536)		IMO	0	(92)	92
	DUKEXP	0	(636)	636		NYIS	(2,845)	(2,973)	128
	DUKIMP	0	634	(634)	OVEC		10,104	7,730	2,374
	NCMPAIMP	0	541	(541)		OVEC	10,104	7,730	2,374
	SOUTHEXP	0	(695)	695	TVA		3,993	1,364	2,629
	SOUTHIMP	(340)	1,351	(1,691)		SOUTHEXP	0	(274)	274
HUDS		(444)	(444)	0		SOUTHIMP	3,993	1,638	2,355
	HUDSONTP	(444)	(444)	0	WEC		3,898	(1,258)	5,156
						MISO	3,898	(1,259)	5,158
						SOUTHEXP	0	(1)	1
						SOUTHIMP	0	2	(2)
					Grand Total		(331)	(1,081)	750

Table 9-22 Net scheduled and actual PJM flows by interface pricing point and interface (GWh): January through September, 2014

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
CPLEEXP		0	(216)	216	NORTHWEST		(1,851)	(700)	(1,150)
	CPLE	0	(216)	216		CIN	0	(9)	9
CPLEIMP		0	76	(76)		IPL	0	(1)	1
	CPLE	0	76	(76)		MEC	(1,851)	(690)	(1,161)
DUKEXP		0	(643)	643		MECS	0	(1)	1
	CPLE	0	(7)	7	NYIS		(2,845)	(2,596)	(249)
	DUK	0	(636)	636		CIN	0	377	(377)
DUKIMP		0	641	(641)		NYIS	(2,845)	(2,973)	128
	CPLE	0	7	(7)	OVEC		10,104	7,730	2,374
	DUK	0	634	(634)		OVEC	10,104	7,730	2,374
HUDSONTP		(444)	(444)	0	SOUTHEAST		0	(3)	3
	HUDS	(444)	(444)	0		CPLE	0	(3)	3
IMO		0	3,505	(3,505)	SOUTHEXP		0	(1,035)	1,035
	CIN	0	874	(874)		CIN	0	(2)	2
	IPL	0	901	(901)		CPLE	0	(16)	16
	MEC	0	2	(2)		DUK	0	(695)	695
	MECS	0	1,821	(1,821)		IPL	0	(1)	1
	NYIS	0	(92)	92		LGEE	0	(31)	31
LINDENVFT		(333)	(333)	0		MECS	0	(15)	15
	LIND	(333)	(333)	0		TVA	0	(274)	274
MISO		(11,740)	(16,529)	4,789		WEC	0	(1)	1
	ALTE	(5,641)	(3,521)	(2,120)	SOUTHIMP		10,158	12,315	(2,156)
	ALTW	(1,577)	(404)	(1,173)		ALTE	0	87	(87)
	AMIL	7,674	31	7,643		AMIL	0	5,454	(5,454)
	CIN	(4,019)	(2,914)	(1,105)		CIN	0	807	(807)
	CWLP	(529)	0	(529)		CPLE	5,429	46	5,384
	IPL	850	(1,407)	2,258		CPLW	(1,350)	6	(1,356)
	MEC	0	(3,994)	3,994		DUK	(340)	1,351	(1,691)
	MECS	(8,739)	(3,049)	(5,690)		IPL	0	92	(92)
	NIPS	(3,657)	(11)	(3,645)		LGEE	2,426	1,668	758
	WEC	3,898	(1,259)	5,158		MEC	0	228	(228)
NCMPAIMP		0	541	(541)		MECS	0	263	(263)
	DUK	0	541	(541)		NIPS	0	672	(672)
NEPTUNE		(3,379)	(3,379)	0		TVA	3,993	1,638	2,355
	NEPT	(3,379)	(3,379)	0		WEC	0	2	(2)
					SOUTHWEST		0	(9)	9
						AMIL	0	(9)	9
					Grand Total		(331)	(1,081)	750

Table 9-22 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 9-22 shows that in the first nine months of 2014, 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 (1,821 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 (92 GWh).

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 used the LMP at nine buses within MISO to calculate the PJM/MISO Interface price, prior to the change on June 1, 2014, while MISO uses prices at all of the PJM generator buses to calculate the MISO/PJM Interface price.[29,30] When a M2M constraint binds, PJM's LMP calculations at the nine selected buses that make up PJM's MISO interface pricing point are based on the PJM model's distribution factors of the selected buses to the binding M2M constraint and PJM's shadow price of the binding M2M constraint. PJM's MISO interface pricing point is a weighted average price of the selected bus LMPs.

In 2013, questions were raised in the PJM/MISO Joint and Common Market (JCM) Initiative meetings whether the existing interface definitions utilized by PJM and MISO were accurately reflecting the value of congestion applied to interchange transactions when a M2M constraint is binding in either footprint.

PJM modified the definition of the PJM/MISO Interface effective June 1, 2014. The new interface definition includes ten equally weighted buses that are close to the PJM/MISO border. The ten buses were selected based on PJM's analysis that showed that over 80 percent of the hourly tie line flows between PJM and MISO occurred on ten ties composed of MISO and PJM monitored facilities. PJM selected generator buses electrically close to those ten tie lines. A PJM generator bus was selected for MISO monitored tie lines, and a MISO generator bus was selected for PJM monitored tie lines.

Real-Time and Day-Ahead PJM/MISO Interface Prices

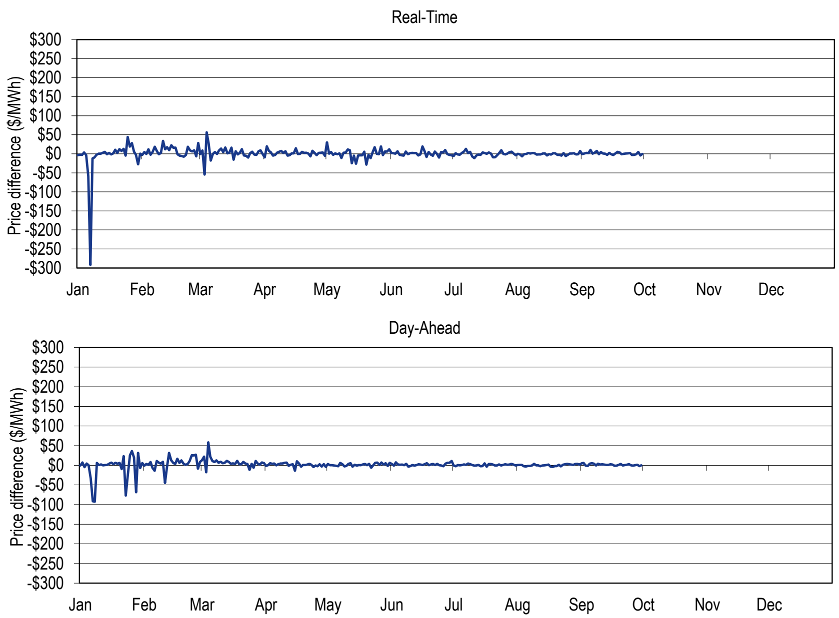
In the first nine months of 2014, the direction of the average hourly flow was consistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. In the first nine months of 2014, the PJM average hourly real-time LMP at the PJM/MISO border was $39.37 while the MISO real-time LMP at the border was $39.40, a difference of $0.03. While the average hourly LMP difference at the PJM/MISO border was $0.03, the average of the absolute values of the hourly differences was $14.21. The average hourly flow in the first nine months of 2014 was -1,792 MW. (The negative sign means that the flow was an export from PJM to MISO, which is consistent with the fact that the average MISO price was higher than the average PJM price.) The direction of flow was consistent with price differentials in 53.0 percent of the hours in the first nine months of 2014. When the MISO/PJM interface price was greater than the PJM/MISO interface price, the average difference was $13.56. When the PJM/MISO interface price was greater than the MISO/PJM interface price, the average difference was $14.94. In the first nine months of 2014, 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 $12.35. 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 $23.99. 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 $44.27. 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 $10.69.

In the first nine months of 2014, the day-ahead PJM average hourly LMP at the PJM/MISO border was $41.16 while the MISO LMP at the border was $42.45, a difference of $1.29 per MWh.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 9-4). 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 9-6).

29 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx> (Accessed October 15, 2014). PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.
30 Based on information obtained from MISO's Extranet <http://extranet.midwestiso.org> (Accessed October 15, 2014).

Figure 9-4 Real-time and day-ahead daily hourly average price difference (MISO Interface minus PJM/MISO): January through September, 2014



Distribution and Prices of Hourly Flows at the PJM/MISO Interface

In the first nine months of 2014, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 3,474 hours (53.0 percent of all hours), and was inconsistent with price differentials in 3,077 hours (47.0 percent of all hours). Table 9-23 shows the distribution of hourly energy flows between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices. Of the 3,077 hours where flows were in a direction inconsistent with price differences, 2,618 of those hours (85.1 percent) had a price difference greater than or equal to $1.00 and 1,410 of those hours (45.8 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $592.36. Of the 3,474 hours where flows were consistent with price differences, 3,036 of those hours (87.4 percent) had a price difference greater than or equal to $1.00 and 1,720 of all such hours (49.5 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $1,576.11.

Table 9-23 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and MISO: January through September, 2014

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Total Hours	Consistent Hours	Percent of Total Hours
$0.00	3,077	100.0%	3,474	100.0%
$1.00	2,618	85.1%	3,036	87.4%
$5.00	1,410	45.8%	1,720	49.5%
$10.00	846	27.5%	1,105	31.8%
$15.00	598	19.4%	798	23.0%
$20.00	445	14.5%	633	18.2%
$25.00	347	11.3%	487	14.0%
$50.00	141	4.6%	209	6.0%
$75.00	70	2.3%	113	3.3%
$100.00	40	1.3%	61	1.8%
$200.00	15	0.5%	20	0.6%
$300.00	4	0.1%	15	0.4%
$400.00	3	0.1%	8	0.2%
$500.00	2	0.1%	8	0.2%

Distribution and Prices of Hourly Flows at the PJM/MISO Interface After June 1, 2014, Interface Pricing Point Modification

PJM modified the definition of the PJM/MISO Interface effective June 1, 2014. The new interface definition includes ten equally weighted buses that are close to the PJM/MISO border. In the first four months of operations under the new interface pricing definition, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 1,606 of the 2,927 hours (54.9 percent of all hours), and was inconsistent with price differentials in 1,321 of the 2,927 hours (45.1 percent of all hours). Table 9-24 shows the distribution of hourly energy flows between PJM and MISO based on the price differences between the PJM/MISO and MISO/PJM prices between June 1, 2014 and September 30, 2014. Of the 1,321 hours where flows were in a direction inconsistent with price differences, 1,021 of those hours (77.3 percent) had a price difference greater than or equal to $1.00 and 434 of those hours (32.9 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $173.18. Of the 1,606 hours where flows were consistent with price differences, 1,329 of those hours (82.8 percent) had a price difference greater than or equal to $1.00 and 534 of all such hours (33.3 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $195.80.

Table 9-24 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and MISO: June 1, 2014 through September 30, 2014

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Total Hours	Consistent Hours	Percent of Total Hours
$0.00	1,321	100.0%	1,606	100.0%
$1.00	1,021	77.3%	1,329	82.8%
$5.00	434	32.9%	534	33.3%
$10.00	243	18.4%	287	17.9%
$15.00	158	12.0%	178	11.1%
$20.00	117	8.9%	129	8.0%
$25.00	87	6.6%	79	4.9%
$50.00	28	2.1%	27	1.7%
$75.00	8	0.6%	8	0.5%
$100.00	3	0.2%	6	0.4%
$200.00	0	0.0%	0	0.0%
$300.00	0	0.0%	0	0.0%
$400.00	0	0.0%	0	0.0%
$500.00	0	0.0%	0	0.0%

PJM and NYISO Interface Prices

If interface prices were defined in a comparable manner by PJM and the NYISO, if identical rules governed external transactions in PJM and the NYISO, if time lags were not built into the rules governing such transactions and if no risks were associated with such transactions, then prices at the interfaces would be expected to be very close and the level of transactions would be expected to be related to any price differentials. The fact that none of these conditions exists is important in explaining the observed relationship between interface prices and inter-RTO/ISO power flows, and those price differentials.[31]

Real-Time and Day-Ahead PJM/NYISO Interface Prices

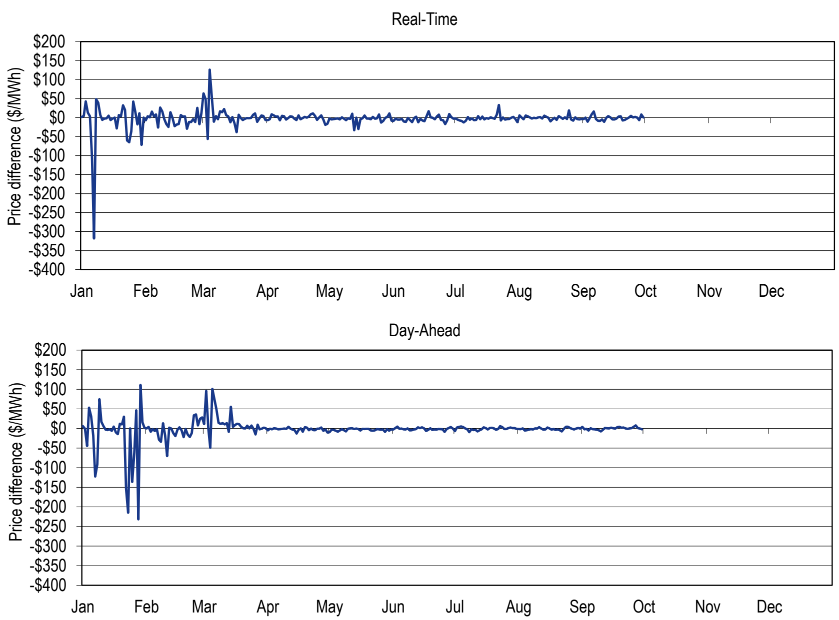
In the first nine months of 2014, the relationship between prices at the PJM/NYIS Interface and at the NYISO/PJM proxy bus and the relationship between interface price differentials and power flows continued to be affected by differences in institutional and operating practices between PJM and the NYISO. In the first nine months of 2014, 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 nine months of 2014, the PJM average hourly LMP at the PJM/NYISO border was $57.36 while the NYISO LMP at the border was $55.13, a difference of $2.22. While the average hourly LMP difference at the PJM/NYISO border was $2.22, the average of the absolute value of the hourly difference was $21.73. The average hourly flow in the first nine months of 2014 was -434 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 56.0 percent of the hours in the first nine months of 2014. In the first nine months of 2014, when the NYIS/PJM proxy bus price was greater than the PJM/NYIS interface price, the average difference was $20.53. When the PJM/NYIS interface price was greater than the NYIS/PJM proxy bus price, the average difference was $22.84. In the first nine months of 2014, 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 $21.00. 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 $18.78. 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 $24.55. 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 $21.90.

31 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

In the first nine months of 2014, the day-ahead PJM average hourly LMP at the PJM/NYIS border was $61.18 while the NYIS LMP at the border was $58.81, a difference of $2.37.

The simple average interface price difference does not reflect the underlying hourly variability in prices (Figure 9-5). 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 9-6).

Figure 9-5 Real-time and day-ahead daily hourly average price difference (NY proxy - PJM/NYIS): January through September, 2014



Distribution and Prices of Hourly Flows at the PJM/NYISO Interface

In the first nine months of 2014, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 3,667 (56.0 percent of all hours), and was inconsistent with price differences in 2,884 hours (44.0 percent of all hours). Table 9-25 shows the distribution of hourly energy flows between PJM and NYISO based on the price differences between the PJM/NYISO and NYISO/PJM prices. Of the 2,884 hours where flows where flows were in a direction inconsistent with price differences, 2,574 of those hours (89.3 percent) had a price difference greater than or equal to $1.00 and 1,719 of all those hours (59.6 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $577.83. Of the 3,667 hours where flows were consistent with price differences, 3,379 of those hours (92.1 percent) had a price difference greater than or equal to $1.00 and 2,308 of all such hours (62.9 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $1,311.87.

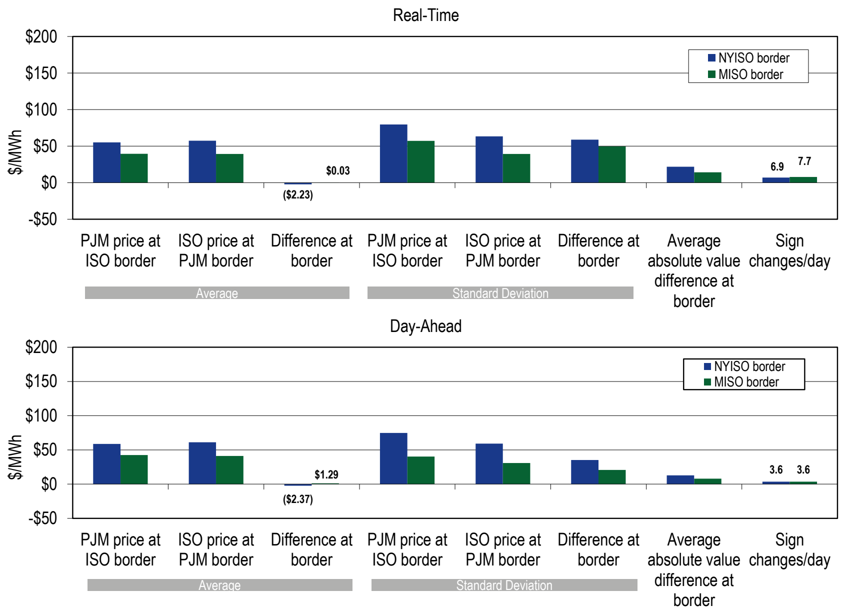
Table 9-25 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and NYISO: January through September, 2014

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Total Hours	Consistent Hours	Percent of Total Hours
$0.00	2,884	100.0%	3,667	100.0%
$1.00	2,574	89.3%	3,379	92.1%
$5.00	1,719	59.6%	2,308	62.9%
$10.00	1,134	39.3%	1,488	40.6%
$15.00	849	29.4%	1,073	29.3%
$20.00	662	23.0%	845	23.0%
$25.00	560	19.4%	704	19.2%
$50.00	290	10.1%	366	10.0%
$75.00	184	6.4%	233	6.4%
$100.00	121	4.2%	144	3.9%
$200.00	42	1.5%	48	1.3%
$300.00	17	0.6%	20	0.5%
$400.00	7	0.2%	10	0.3%
$500.00	2	0.1%	8	0.2%

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 9-6, including average prices and measures of variability.

Figure 9-6 PJM, NYISO and MISO real-time and day-ahead border price averages: January through September, 2014



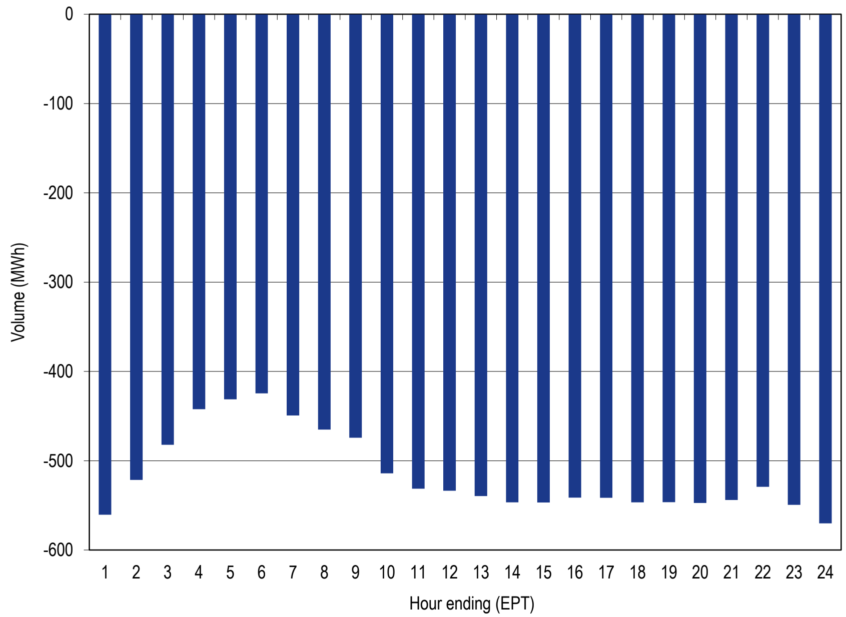
Neptune Underwater Transmission Line to Long Island, New York

The Neptune line is a 65 mile direct current (DC) merchant 230 kV transmission line, with a capacity of 660 MW, providing a direct connection between PJM (Sayreville, New Jersey), and NYISO (Nassau County on Long Island). Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. In the first nine months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Neptune Interface and the NYISO Neptune Bus. In the first nine months of 2014, the PJM average hourly LMP at the Neptune Interface was $58.43 while the NYISO LMP at the Neptune Bus was $68.62, a difference of $10.18.[32] While the average hourly LMP difference at the PJM/Neptune border was $10.18, the average of the absolute value of the hourly difference was $32.62. The average hourly flow during the first nine months of 2014 was -516 MW.[33] (The negative sign means that the flow was an export from PJM to NYISO.) The flows were consistent with price differentials in 58.9 percent of the hours in the first nine months of 2014. When the NYISO/Neptune bus price was greater than the PJM/NEPT interface price, the average hourly price difference was $35.98. When the PJM/NEPT interface price was greater than the NYISO/Neptune bus price, the average price difference was $27.72.

32 In the first nine months of 2014, there were 590 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 $58.04 while the NYISO LMP at the Neptune Bus during non-zero flows was $66.75, a difference of $8.71.

33 The average hourly flow in the first nine months of 2014, ignoring hours with no flow, on the Neptune DC Tie line was -567 MW.

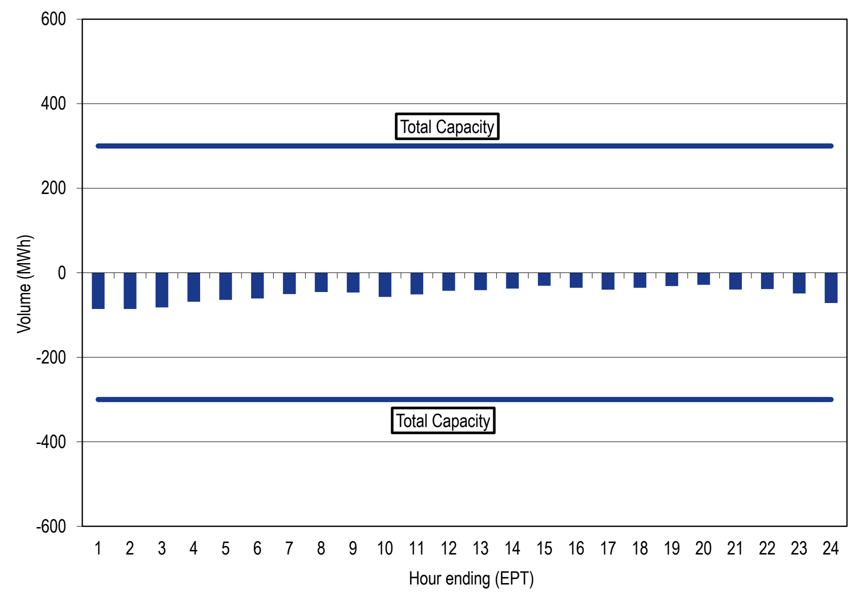
Figure 9-7 Neptune hourly average flow: January through September, 2014



Linden Variable Frequency Transformer (VFT) facility

The Linden VFT facility is a controllable AC 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 nine months of 2014, the average hourly flow (PJM to NYISO) was consistent with the real-time average hourly price difference between the PJM Linden Interface and the NYISO LMP Linden Bus. In the first nine months of 2014, the PJM average hourly LMP at the Linden Interface was $59.39 while the NYISO LMP at the Linden Bus was $60.42, a difference of $1.04.[34] While the average hourly LMP difference at the PJM/Linden border was $1.04, the average of the absolute value of the hourly difference was $26.20. The average hourly flow in the first nine months of 2014 was -51 MW.[35] (The negative sign means that the flow was an export from PJM to NYISO.) The flows were consistent with price differentials in 56.2 percent of the hours in the first nine months of 2014. When the NYISO/Linden bus price was greater than the PJM/LIND interface price, the average hourly price difference was $24.64. When the PJM/LIND interface price was greater than the NYISO/Linden bus price, the average price difference was $28.12.

Figure 9-8 Linden hourly average flow: January through September, 2014[36]



Hudson Direct Current (DC) Merchant Transmission Line

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

34 In the first nine months of 2014, there were 1,510 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 $63.82 while the NYISO LMP at the Neptune Bus during non-zero flows was $66.24, a difference of $2.42.

35 The average hourly flow in the first nine months of 2014, ignoring hours with no flow, on the Linden VFT line was -66 MW.

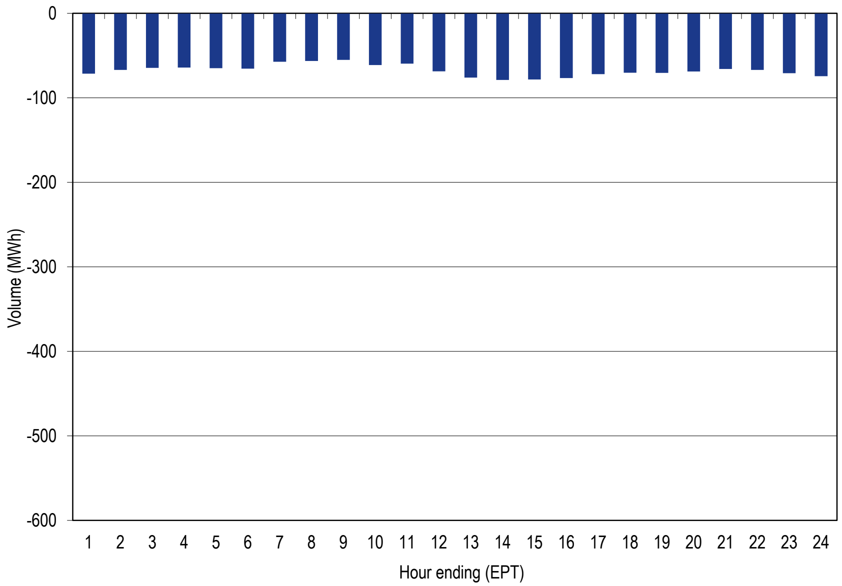
36 The Linden VFT line is a bidirectional facility. The "Total Capacity" lines represent the maximum amount of interchange possible in either direction. These lines were included to maintain a consistent scale, for comparison purposes, with the Neptune DC Tie line.

(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 the first nine months of 2014, the average hourly flow (PJM to NYISO) was inconsistent 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 $67.19 while the NYISO LMP at the Hudson Bus was $64.77, a difference of $2.42.[37] While the average hourly LMP difference at the PJM/Hudson border was $2.42, the average of the absolute value of the hourly difference was $29.70. The average hourly flow during the first nine months of 2014 was -68 MW.[38] (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 flows were consistent with price differentials in 59.3 percent of the hours in the first nine months of 2014. When the NYISO/Hudson bus price was greater than the PJM/HUDS interface price, the average hourly price difference was $25.80. When the PJM/HUDS interface price was greater than the NYISO/Hudson bus price, the average price difference was $34.10.

37 In the first nine months of 2014, there were 4,840 hours where there was no flow on the Hudson line. The PJM average hourly LMP at the Hudson Interface during non-zero flows was $111.11 while the NYISO LMP at the Hudson Bus during non-zero flows was $114.83, a difference of $3.72.

38 The average hourly flow during the first nine months of 2014, ignoring hours with no flow, on the Hudson line was -260 MW.

Figure 9-9 Hudson hourly average flow: January through September, 2014



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 implemented operating agreements with MISO and the NYISO, 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[39]

The Joint Operating Agreement between MISO and PJM Interconnection, L.L.C. was executed on December 31, 2003. The PJM/MISO JOA includes

39 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) <http://www.pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed October 15, 2014).

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.[40]

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 ten 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.[41]

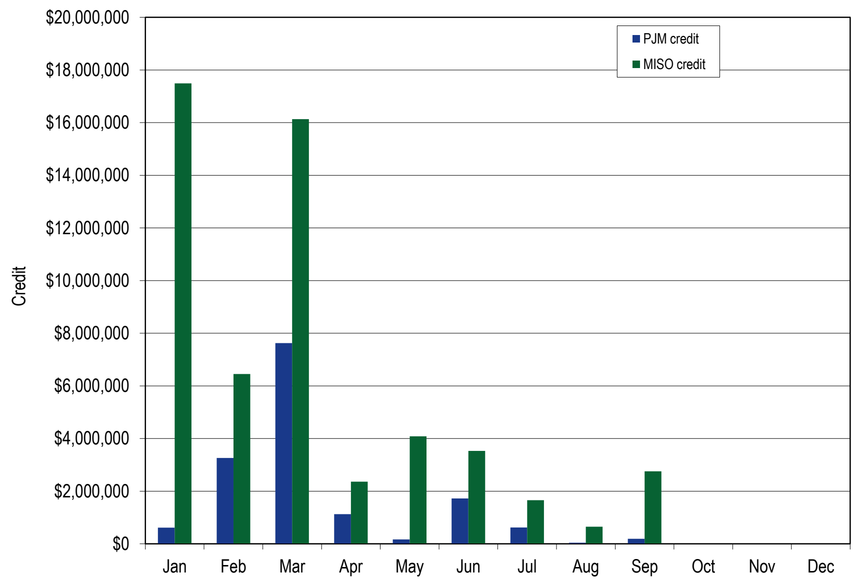
Coordinated flowgates (CF) are flowgates that are monitored or controlled by either PJM or MISO, in which only one has a significant impact (defined as a greater than 5 percent impact based on transmission distribution factors and generation to load distribution factors). A reciprocal coordinated flowgate (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 January 1, 2014, PJM had 159 flowgates eligible for M2M (Market to Market) coordination. Between January 1, 2014 and September 30, 2014, PJM added 22 and deleted 92 flowgates, leaving 89 flowgates eligible for M2M coordination as of September 30, 2014. As of January 1, 2014, MISO had 265 flowgates eligible for M2M coordination. Between January 1, 2014 and September 30, 2014, MISO added 85 and deleted 76 flowgates, leaving 274 flowgates eligible for M2M coordination as of September 30, 2014. The timing of the addition of new M2M flowgates may contribute to FTR underfunding. MISO's ability to add flowgates dynamically throughout the planning period, which were not modeled in any PJM FTR auction, may result in oversold FTRs in PJM, and as a direct consequence, contribute to FTR underfunding.

40 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>.
41 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

In the first nine months of 2014, 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 9-10 shows credits for coordinated congestion management between PJM and MISO.

Figure 9-10 Credits for coordinated congestion management: January through September, 2014[42]



PJM and New York Independent System Operator Joint Operating Agreement (JOA)[43]

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

42 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.
43 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (June 15, 2014) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed October 15, 2014).

factor impacts. PJM uses two buses within NYISO to calculate the PJM/NYIS interface pricing point LMP while The NYISO calculates the PJM interface price (represented by the Keystone proxy bus) based on 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.

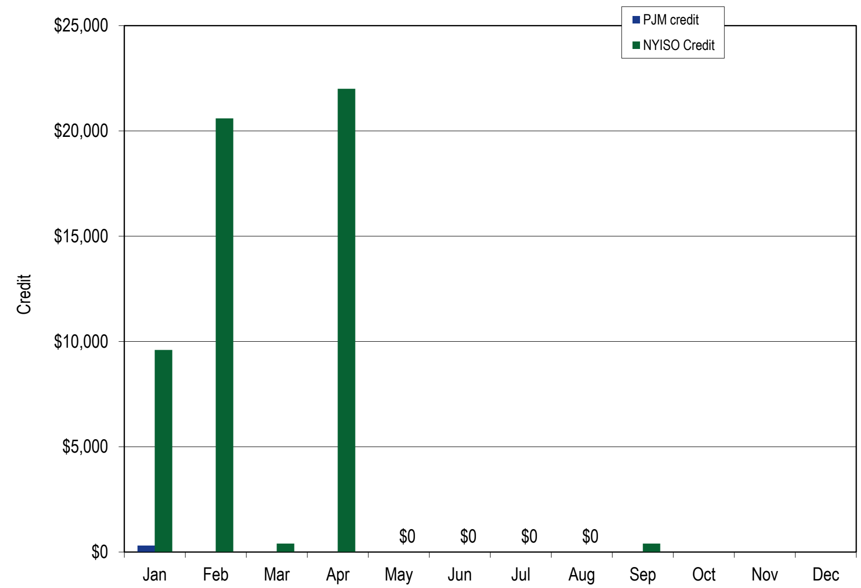
Coordinated flowgates (CF) are flowgates that are monitored or controlled by either PJM or NYISO, on which only one has a significant impact (defined as a greater than 5 percent impact based on transmission distribution factors and generation to load distribution factors). A reciprocal coordinated flowgate (RCF) is a CF that is monitored and controlled by either PJM or NYISO, on which both have significant impacts. Only RCFs are subject to the market to market congestion management process.

In the first nine months of 2014, 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.

In the first nine months of 2014, 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 9-11 shows credits for coordinated congestion management between PJM and NYISO.

Figure 9-11 Credits for coordinated congestion management (flowgates): January through September, 2014[44]



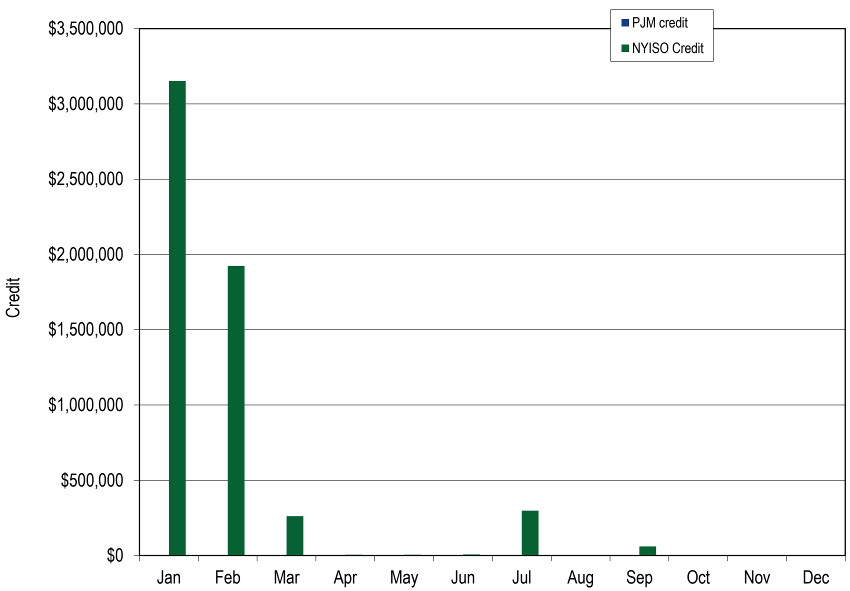
The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on the M2M Flowgates in a more cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the Ramapo PARs that are located at the PJM/NYIS border. 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.[45] For each M2M flowgate, a Ramapo PAR settlement will occur for each interval during

44 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

45 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (June 15, 2014) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed October 15, 2014).

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 nine months of 2014, PAR settlements resulted in monthly payments from PJM to NYISO. Figure 9-12 shows the Ramapo PAR credits for coordinated congestion management between PJM and NYISO.

Figure 9-12 Credits for coordinated congestion management (Ramapo PARs): January through September, 2014[46]



46 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

The PJM/NYISO JOA includes a provision that allows either party to suspend M2M operations when daily congestion charges exceed $500,000. On July 8, 2013, M2M congestion charges exceeded $500,000. These congestion charges were the result of its inability to meet the Ramapo PAR target values during thunderstorm alerts (TSA) called by the NYISO. During times when actual or anticipated severe weather conditions exist in the New York City area, the NYISO issues a TSA and operates in a more conservative manner, by reducing transmission transfer limits, which affects PJM's ability to meet the PAR targets. On July 12, 2013, PJM requested the suspension of M2M coordination for all TSA flowgates. On May 2, 2014, PJM and the NYISO submitted revisions to the PJM/NYISO JOA that proposed a set of new operating requirements and settlement rules to be utilized when a TSA is in effect in New York.[47] Under the new approach, PJM and the NYISO are required to maintain flow on the ABC and JK lines to within a control band ordinarily set at +/- 100 MW of the real time market desired flows, or otherwise to attempt to direct flows by adjusting the phase angle at least twice every 15 minutes. PJM and MISO are required to maintain flow on the Ramapo PARs at or above the target into New York, or otherwise to take at least two taps every 15 minutes. Under these revised rules, PJM will not be subject to an M2M Ramapo PAR settlement obligation as long as it satisfies the operating requirements on the JK PARs. Additionally, PJM will not be subject to an M2M Ramapo PAR settlement obligation if the NYISO fails to satisfy the operating requirements on the ABC or Ramapo PARs. The NYISO will not be subject to an M2M Ramapo PAR settlement obligation as long as it satisfies the operating requirements on the ABC and Ramapo PARs. In short, if both RTOs follow the operating requirements for the PARs for which they are responsible, there will be no M2M Ramapo PAR settlements during a TSA. On June 4, 2014, FERC accepted the proposed JOA modifications with an effective date of June 11, 2014.[48]

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

47 See *New York Independent System Operator, Inc. and PJM Interconnection, L.L.C* Docket No. ER14-1868 (May 2, 2014).
48 See *New York Independent System Operator, Inc. and PJM Interconnection, L.L.C* Docket No. ER14-1868 (June 4, 2014).

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. The agreement continued to be in effect in the first nine months of 2014.

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.[49] On January 20, 2011, the Commission conditionally accepted the compliance filing.

On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. While the individual companies planned to operate separately for a period of time, they have a joint dispatch agreement, and a joint open access transmission tariff.[50] On October 3, 2014, Duke Energy Progress (DEP) and PJM submitted revisions to the JOA to include a new Appendix B, update references to DEP's current legal name, and incorporate other revisions.[51] The MMU submitted a protest to this filing noting that the existing JOA depends on the specific characteristics of PEC as a standalone company, and the assumptions reflected in the current JOA no longer apply under the DEP joint dispatch agreement.[52] As noted in the 2010 filing, "the terms and conditions of the bilateral agreement among PEC and PJM are grounded in an appreciation of their respective systems as they exist at the time of the effective date of the JOA, but they fully expect that evolving circumstances, protocols and requirements will require that they negotiate, in good faith, a response to such changes."[53] The joint dispatch agreement changed the unique operational relationship that existed when the congestion management protocol was established. However, the merged company has not engaged in discussions with PJM as to whether the congestion management protocol that was "tailored to their [PJM and PEC] unique operational relationship" is still appropriate, or whether the congestion management protocol needs to be revised. The existing JOA does not apply to the merged company and should be terminated. The MMU recommends that PJM immediately provide the required 12-month notice to PEC to unilaterally terminate the Joint Operating Agreement.

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. It provides for system and outage coordination, emergency procedures and the exchange of data. The parties meet on a yearly basis. The agreement continued to be in effect in the first nine months of 2014.

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.

The PJM/PEC JOA allows for the PECIMP and PECEXP interface pricing points to be calculated using the "Marginal Cost Proxy Pricing" methodology.[54] The DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP interface pricing points are calculated based on the "high-low" pricing methodology as defined in the PJM Tariff.

49 See *PJM Interconnection, L.L.C and Progress Energy Carolinas, Inc.* Docket No. ER10-713-000 (February 2, 2010).
50 See "Duke Energy Carolinas, LLC, Carolina Power & Light tariff filing," Docket No. ER12-1338-000 (July 12, 2012) and "Duke Energy Carolinas, LLC, Carolina Power & Light Joint Dispatch Agreement filing," Docket No. ER12-1343-000 (July 11, 2012).
51 See *Duke Energy Progress, Inc. and PJM Interconnection, L.L.C*, Docket No. ER15-29-000 (October 3, 2014).
52 See Protest and Motion for Rehearing of the Independent Market Monitor for PJM in Docket No. ER15-29-000 (October 24, 2014).
53 Joint Motion for Leave to Answer and Answer of PJM Interconnection, L.C.C. and Progress Energy Carolinas, Inc., Docket No. ER10-713-000 (March 10, 2010) at 2. Section 3.3 of the PJM-Progress JOA.
54 See *PJM Interconnection, L.L.C*, Docket No. ER10-2710-000 (September 17, 2010).

Table 9-26 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through September, 2014

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$48.24	$49.60	$46.24	$46.24	$2.01	$3.36
PEC	$49.08	$51.71	$46.24	$46.24	$2.84	$5.48
NCMPA	$48.99	$49.22	$46.24	$46.24	$2.75	$2.98

Table 9-27 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through September, 2014

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$48.78	$50.08	$46.03	$45.97	$2.75	$4.11
PEC	$50.69	$51.83	$46.03	$45.97	$4.66	$5.86
NCMPA	$49.53	$49.64	$46.03	$45.97	$3.50	$3.67

Other Agreements with Bordering Areas

Consolidated Edison Company of New York, Inc. (Con Edison) and Public Service Electric and Gas Company (PSE&G) Wheeling Contracts

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.[55] 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.[56]

After years of litigation concerning whether or on what terms Con Edison's protocol would be renewed, PJM filed on February 23, 2009, a settlement on behalf of the parties to resolve remaining issues with these contracts and their proposed rollover of the agreements under the PJM OATT.[57] By order issued September 16, 2010, the Commission approved this settlement,[58] which extends Con Edison's special protocol indefinitely. The Commission approved transmission service agreements provide for Con Edison to take firm point-to-point service going forward under the PJM OATT. The Commission rejected objections raised first by NRG and FERC trial staff, and later by the MMU, that this arrangement is discriminatory and inconsistent with the Commission's open access transmission policy.[59] The settlement defined Con Edison's cost responsibility for upgrades included in the PJM Regional Transmission Expansion Plan. Con Edison 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.[60] Con Edison's rolled over service became effective on May 1, 2012. At that time, Con Edison became responsible for the entire 1,000 MW of transmission service and all associated charges and credits.

On December 11, 2013, the PJM Board approved changes to the Regional Transmission Expansion Plan (RTEP), which included approximately $1.5 billion in additional baseline transmission enhancements and expansions.[61] On January 10, 2014, in accordance with Schedule 12 of the PJM Tariff,[62] PJM filed cost assignments for those upgrades. Using the hybrid cost allocation methodology approved by the Commission in Docket No. ER13-90-000 on March 22, 2013, PJM calculated Con Edison's cost responsibility assignment as approximately $629 million. On February 10, 2014, Con Edison filed a protest to the cost allocation proposal.[63] Con Edison asserted that the cost allocation proposal is not permitted under the service agreement for transmission service under the PJM Tariff and related settlement agreement, and that PJM's allocation of costs of the PSE&G upgrade to the Con Edison zone is unjust and unreasonable. On March 7, 2014, PJM submitted a motion for leave to answer and limited answer to the protest submitted by Con Edison.[64] PJM's response points out that the filed and approved RTEP cost allocation process

55 See "Section 4 – Energy Market Uplift" of this report for the operating reserve credits paid to maintain the power flow established in the Con Edison/PSE&G wheeling contracts.
56 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.
57 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.
58 132 FERC ¶ 61,221 (2010).
59 *See, e.g.,* Motion to Intervene Out-of-Time and Comments of the Independent Market Monitor for PJM in Docket No. ER08-858-000, et al. (May 11, 2010).
60 The terms of the settlement state that Con Edison 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.
61 See the *2013 State of the Market Report for PJM*, Volume II, Section 12, "Planning," for a more detailed discussion.
62 See PJM OATT, Schedule 12, Transmission Enhancement Charges, (February 1, 2013) pp 581-595.
63 See *Consolidated Edison Company of New York, Inc.* Docket No. ER14-972-000 (February 10, 2014).
64 See *PJM Interconnection L.L.C.* Docket No. ER14-972-000 (March 7, 2014).

was followed, and that Con Edison's cost assignment responsibilities were addressed by the Settlement agreement and Schedule 12 of the PJM Tariff.

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 five TLRs of level 3a or higher in the first nine months of 2014, compared to 45 such TLRs issued in the first nine months of 2013.[65] The number of different flowgates for which PJM declared a TLR 3a or higher decreased from 23 in the first nine months of 2013 to four in the first nine months of 2014. The total MWh of transaction curtailments decreased by 97.6 percent from 133,869 MWh in the first nine months of 2013 to 3,104 MWh in the first nine months of 2014.

MISO issued 124 TLRs of level 3a or higher in the first nine months of 2014, compared to 285 such TLRs issued in the first nine months of 2013. The number of different flowgates for which MISO declared a TLR 3a or higher decreased from 77 in the first nine months of 2013 to 32 in the first nine months of 2014. The total MWh of transaction curtailments decreased by 56.4 percent from 593,751 MWh in the first nine months of 2013 to 258,945 MWh in the first nine months of 2014.

NYISO issued two TLRs of level 3a or higher in the first nine months of 2014, compared to 3 such TLRs issued in the first nine months of 2013. The number of different flowgates for which NYISO declared a TLR 3a or higher increased from 1 in the first nine months of 2013 to two in the first nine months of 2014. The total MWh of transaction curtailments decreased by 80.8 percent from 5,147 MWh in the first nine months of 2013 to 991 MWh in the first nine months of 2014.

65 TLR Level 3a is the first level of TLR that results in the curtailment of transactions. See the *2013 State of the Market Report for PJM*, Volume II, Appendix E, "Interchange Transactions," for a more complete discussion of TLR levels.

Table 9-28 PJM MISO, and NYISO TLR procedures: January, 2011 through September, 2014

	Number of TLRs Level 3 and Higher			Number of Unique Flowgates That Experienced TLRs			Curtailment Volume (MWh)		
Month	PJM	MISO	NYISO	PJM	MISO	NYISO	PJM	MISO	NYISO
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
Jul-13	12	28	0	2	9	0	88,623	80,328	0
Aug-13	4	19	0	4	8	0	3,469	38,608	0
Sep-13	6	33	0	5	14	0	7,716	90,188	0
Oct-13	2	42	0	1	20	0	534	72,121	0
Nov-13	2	27	0	2	8	0	11,561	52,508	0
Dec-13	0	16	0	0	5	0	0	20,257	0
Jan-14	3	19	0	3	10	0	1,852	11,683	0
Feb-14	0	29	1	0	10	1	0	33,189	991
Mar-14	0	11	0	0	7	0	0	14,842	0
Apr-14	0	6	0	0	3	0	0	1,233	0
May-14	0	9	0	0	4	0	0	53,153	0
Jun-14	0	19	0	0	7	0	0	24,614	0
Jul-14	1	13	1	1	6	1	317	26,616	0
Aug-14	0	7	0	0	3	0	0	6,319	0
Sep-14	1	11	0	1	4	0	935	87,296	0

Table 9-29 Number of TLRs by TLR level by reliability coordinator: January through September, 2014

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2014	MISO	56	38	1	15	14	0	124
	NYIS	2	0	0	0	0	0	2
	ONT	3	0	0	0	0	0	3
	PJM	3	2	0	0	0	0	5
	SOCO	4	1	0	0	0	0	5
	SWPP	198	61	0	38	27	0	324
	TVA	23	35	2	20	24	0	104
	VACS	7	15	2	2	0	0	26
Total		296	152	5	75	65	0	593

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.[66]

Following elimination of the requirement to procure and pay for 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 Energy Market increased by 80.1 percent, from 105,472 bids per day in the first nine months of 2013 to 189,997 bids per day in the first nine months of 2014. The average cleared volume of up-to congestion bids increased by 22.6 percent, from 1,221,114 MWh per day in the first nine months of 2013 to 1,496,675 MWh per day in the first nine months of 2014. But the increases all occurred prior to September 8, 2014, after which the number and volume of bids declined sharply.

Up-to congestion transactions impact the day-ahead dispatch and unit commitment. Despite that, up-to congestion transactions do not pay operating reserves charges. Up-to congestion transactions also significantly affect FTR funding.[67]

On August 29, 2014, FERC issued an Order Instituting Section 206 Proceeding and Establishing Procedures which, among other things, created an obligation for UTCs to pay any uplift determined to be appropriate in the Commission review, effective September 8, 2014.[68] In the Order, FERC directed the Commission staff to convene a technical conference to determine how uplift is allocated to all virtual transactions, including up-to congestion transactions.

As a result of the requirement to pay uplift charges and the uncertainty about the level of the required uplift charges, market participants reduced up-to congestion trading effective September 8, 2014. The average number of up-to congestion bids submitted in the Day-Ahead Energy Market decreased by 79.5 percent, from 192,097 bids per day in three week period prior to the September 8, 2014, refund effective date to 39,429 bids per day in three week period following the September 8, 2014, refund effective date. The average cleared volume of up-to congestion bids decreased by 79.9 percent, from 1,633,746 MWh per day in the in three week period prior to the September 8, 2014, refund effective date to 328,041 MWh per day in three week period following the September 8, 2014, refund effective date (See Figure 9-13).

66 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

67 For more information on up-to congestion transaction impacts on FTRs, see the *2014 Quarterly State of the Market Report for PJM: January through September*, Volume 2, Section 13: FTRs and ARRs, "FTR Forfeitures".

68 *Order Instituting Section 206 Proceeding and Establishing Procedures*, 148 FERC ¶ 61,144 (2014).

Figure 9-13 Monthly up-to congestion cleared bids in MWh: January, 2005 through September, 2014

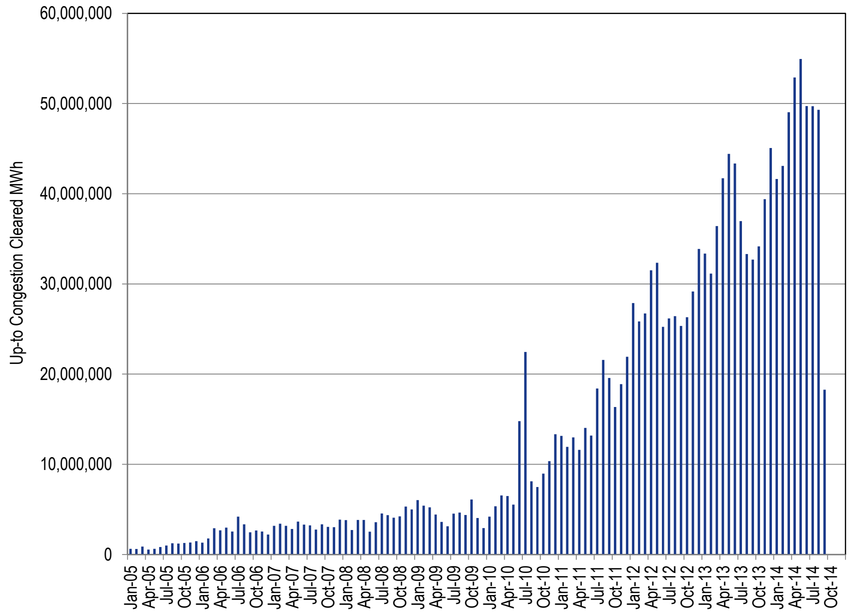


Table 9-30 Monthly volume of cleared and submitted up-to congestion bids: January, 2009 through September, 2014

	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	44,972,628	45,204,886	931,161	-	91,108,675	1,054,472	987,293	31,580	-	2,073,345	12,768,023	13,354,850	300,038	-	26,422,911	377,146	343,717	12,738	-	733,601
Sep-12	40,796,522	39,411,713	957,800	-	81,166,035	1,037,179	949,941	29,246	-	2,016,366	12,089,136	12,961,955	292,095	-	25,343,186	341,925	329,217	9,620	-	680,762
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	22,597,985	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
Jul-13	15,436,914	16,428,662	1,473,144	116,673,912	150,012,631	430,120	387,969	49,712	3,075,624	3,943,425	3,250,706	3,502,990	320,374	29,883,430	36,957,500	131,535	127,032	17,948	957,260	1,233,775
Aug-13	12,332,984	14,354,140	1,370,624	89,306,595	117,364,344	328,835	326,637	40,325	2,223,269	2,919,066	2,862,764	3,232,565	309,069	26,900,995	33,305,393	111,715	122,061	16,299	848,490	1,098,565
Sep-13	10,767,257	11,322,974	729,332	75,686,010	98,505,573	264,095	262,486	21,968	1,976,741	2,525,290	2,962,619	3,467,611	221,329	26,044,742	32,696,300	102,984	107,604	10,233	792,766	1,013,587
Oct-13	9,081,257	11,106,943	853,397	86,857,535	107,899,131	280,821	338,374	31,031	2,524,127	3,174,353	2,201,219	3,532,253	186,113	28,243,584	34,163,168	108,189	145,667	11,551	1,002,832	1,268,239
Nov-13	9,219,216	15,052,563	1,307,989	98,027,480	123,607,248	267,704	394,031	39,095	3,167,638	3,868,468	2,640,001	3,986,788	332,814	32,437,908	39,397,511	112,850	154,379	13,958	1,238,589	1,519,776
Dec-13	9,934,234	16,089,101	1,696,981	118,916,149	146,636,465	286,295	404,788	42,367	3,691,770	4,425,220	3,189,261	3,234,196	503,666	38,150,077	45,077,200	119,954	122,683	14,318	1,382,736	1,639,691
Jan-14	10,359,891	16,047,391	2,326,490	119,848,848	148,582,620	350,248	469,176	47,801	4,382,482	5,249,707	2,594,374	3,172,914	460,495	35,413,440	41,641,223	116,316	143,021	15,323	1,537,418	1,812,078
Feb-14	11,351,094	14,846,332	1,854,617	126,008,272	154,060,316	382,148	480,055	47,526	5,151,647	6,061,376	2,764,565	3,247,481	362,670	36,715,916	43,090,631	132,870	147,766	14,045	1,897,337	2,192,018
Mar-14	14,669,735	17,135,117	1,949,978	147,142,336	180,897,166	515,877	516,871	54,575	7,026,221	8,113,544	3,442,624	3,293,865	341,620	41,962,312	49,040,421	165,663	148,671	15,214	2,290,716	2,620,264
Apr-14	12,056,167	15,453,126	1,744,523	132,691,464	161,945,280	408,540	404,498	48,279	5,179,680	6,040,997	3,037,393	3,483,465	347,165	46,018,100	52,886,123	136,314	129,838	12,743	2,036,904	2,315,799
May-14	14,145,892	17,305,057	2,132,591	153,504,853	187,088,393	456,708	452,060	54,954	5,628,483	6,592,205	3,077,932	4,477,545	319,825	47,071,415	54,946,717	136,627	162,321	14,724	1,960,618	2,274,290
Jun-14	13,404,498	13,716,736	1,499,317	141,004,417	169,624,968	407,769	372,275	44,035	5,095,316	5,919,395	3,598,712	3,000,215	349,700	42,767,010	49,715,637	137,256	115,610	16,994	1,732,262	2,002,122
Jul-14	11,820,001	11,811,311	1,278,719	133,179,154	158,089,185	396,433	388,463	38,402	5,021,819	5,845,117	3,541,889	3,118,746	336,003	42,702,334	49,698,971	143,527	131,968	13,699	1,834,684	2,123,878
Aug-14	10,808,911	12,150,513	874,609	135,912,394	159,746,426	375,703	385,705	32,368	5,108,340	5,902,116	3,054,727	3,315,313	140,171	42,796,063	49,306,273	146,179	139,431	11,706	1,937,025	2,234,341
Sep-14	5,105,355	5,291,842	467,670	51,226,017	62,090,885	174,241	156,046	18,095	1,796,453	2,144,835	1,500,083	1,232,520	103,304	15,430,477	18,266,384	73,100	56,651	5,915	735,658	871,324
TOTAL	1,118,184,641	1,119,017,635	63,459,847	2,444,956,826	4,745,618,949	26,482,951	24,562,848	1,522,961	79,642,984	132,211,744	398,017,509	392,596,508	23,815,282	744,501,618	1,558,930,918	10,692,413	9,784,552	590,812	28,569,704	49,637,481

In the first nine months of 2014, the cleared MW volume of up-to congestion transactions was comprised of 6.5 percent imports, 6.9 percent exports, 0.7 percent wheeling transactions and 85.9 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 which 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's proposed validation rules would address sham scheduling.

Elimination of Ontario Interface Pricing Point

An interface pricing point defines the price at which transactions are priced, and is based on the path of the actual, physical transfer of energy. While a market participant designates a scheduled market path from a generation control area (GCA) to a load control area (LCA), this market path reflects the scheduled path as defined by the transmission reservations only, and may not reflect how the energy actually flows from the GCA to LCA. The challenge is to create interface prices, composed of external pricing points, which accurately represent flows between PJM and external sources of energy.

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.[69] 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. Transactions between PJM and external balancing authorities need to be priced at the PJM border.

The IMO interface pricing point (Ontario) was created to reflect the fact that transactions that originate or sink in the IESO balancing authority create actual energy flows that are split between the MISO and NYISO interface pricing points. 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.

The IMO interface pricing point is defined as the LMP at the Bruce bus, which is located in IESO. The LMP at the Bruce bus includes a congestion and loss component across the MISO and NYISO balancing authorities.

The non-contiguous nature of the Ontario interface pricing point creates overpayments or additional credits for congestion across MISO and the NYISO and does not reflect how an LMP market should operate. Of the 3,690 GWh of the net scheduled transactions between PJM and IESO, 3,598 GWh wheeled through MISO in the first nine months of 2014 (see Table 9-22).

The MMU recommends that PJM eliminate the IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the MISO interface pricing point.[70]

69 See "Interface Pricing Point Assignment Methodology," (August 28, 2014) <http://www.pjm.com/~/media/etools/exschedule/interface-pricing-point-assignment-methodology.ashx> (Accessed October 16, 2014). PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

70 On October 1, 2013, a sub-group of PJM's Market Implementation Committee started stakeholder discussions to address this inconsistency in market pricing.

PJM and NYISO Coordinated Interchange Transaction Proposal

The coordinated transaction scheduling (CTS) proposal provides the option for market participants to submit intra-hour transactions between the NYISO and PJM that include an interface spread bid on which transactions are evaluated. The evaluation will be based on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (ITSCED) and the NYISO's real-time commitment (RTC) tool. PJM shares its PJM/NYISO interface price from the ITSCED results with the NYISO. The NYISO compares the PJM/NYISO Interface Price with its RTC calculated NYISO/PJM Interface price. If the PJM and NYISO interface price spread is greater than the market participant's CTS bid, the transaction is approved. If the PJM and NYISO interface price spread is less than the CTS bid, the transaction is denied.

On December 13, 2013, PJM submitted proposed revisions to the PJM Operating Agreement, and parallel provisions of the PJM Tariff, to implement CTS.[71] This filing requested that the Commission issue an order accepting the proposed revisions by no later than February 13, 2014 to allow for adequate time to develop the infrastructure necessary to implement CTS in November, 2014. The Commission issued an order conditionally accepting the tariff revisions on February 20, 2014, for implementation on the later of November, 2014, or the date that CTS becomes operational, subject to the submission of an informational filing informing the Commission of the acceptance of ITSCED forecasting accuracy standards, and an additional revised tariff no later than fourteen days prior to the official implementation date of CTS.[72]

To evaluate the accuracy of ITSCED forecasts, the forecasted PJM/NYIS interface price for each 15 minute interval from ITSCED was compared to the actual real-time interface LMP for the first nine months of 2014.[73] Table 9-30 shows that over all forecast ranges ITSCED predicted the real-time PJM/NYIS interface LMP within the range of $0.00 to $5.00 in 28.1 percent of all intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.80. In 10.1 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00, with an average price difference of $109.26, and in 11.0 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was greater than -$20.00, with an average price difference of $90.41.

Table 9-31 ITSCED/real-time LMP - PJM/NYIS interface price comparison (all intervals): January through September, 2014

Range	Percent of All Intervals	Average Price Difference
> $20	10.1%	$109.26
$10 to $20	4.9%	$14.26
$5 to $10	6.6%	$7.05
$0 to $5	28.1%	$1.80
-$5 to $0	27.4%	$1.84
-$10 to -$5	6.8%	$7.07
-$20 to -$10	5.1%	$14.24
< -$20	11.0%	$90.41

The ITSCED application runs approximately every 5 minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various ITSCED solutions will produce 12 forecasted PJM/NYIS interface prices. Table 9-32 shows how the accuracy of the ITSCED forecasted LMPs change as the cases approach real-time.

71 See PJM Interconnection, L.L.C., OA Schedule 1 and Attachment K Revisions, Docket No. ER14-623-000. (December 13, 2013).
72 146 FERC ¶ 61,096 (2014).
73 See the *2014 Quarterly State of the Market Report for PJM: January through March*, Section 9, "PJM and NYISO Coordinated Interchange Transaction Proposal" for ITSCED accuracy statistics for the calendar year 2013.

Table 9-32 ITSCED/real-time LMP - PJM/NYIS interface price comparison (by interval): January through September, 2014

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	12.4%	$101.37	9.4%	$98.04	7.5%	$94.53	10.0%	$124.23
$10 to $20	5.8%	$14.31	4.9%	$14.29	4.1%	$14.08	4.4%	$14.31
$5 to $10	7.0%	$7.08	6.9%	$7.05	6.4%	$6.97	6.1%	$7.00
$0 to $5	25.5%	$1.89	28.6%	$1.87	30.4%	$1.75	30.3%	$1.69
-$5 to $0	25.9%	$1.95	26.8%	$1.87	28.7%	$1.75	28.5%	$1.76
-$10 to -$5	7.3%	$7.03	6.9%	$7.08	6.6%	$7.06	6.2%	$7.09
-$20 to -$10	5.2%	$14.21	5.0%	$14.31	5.3%	$14.23	4.8%	$14.38
< -$20	10.9%	$95.48	11.5%	$93.98	11.1%	$88.22	9.9%	$83.77

Table 9-32 shows that while there is some improvement as the forecast gets closer to real time, a substantial range of forecast errors remain even in the thirty-minute ahead forecast. In the final ITSCED results prior to real time, in 58.8 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/NYIS interface real-time LMP, compared to 51.4 percent in the 135 minute ahead ITSCED results.

In 19.9 percent of all intervals, the absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00 in the thirty-minute ahead cases, the average price differences were $124.23 when the price difference was greater than $20.00, and $83.77 when the price difference was greater than -$20.00.

The NYISO will utilize PJM's ITSCED forecasted LMPs to compare against the NYISO Real-Time Commitment (RTC) results in its evaluation of CTS transactions. The NYISO will approve CTS (spread bid) transactions when the offered spread is less than or equal to the spread between the ITSCED forecast PJM/NYIS interface LMP and the NYISO RTC forecast NYIS/PJM interface LMP. The large differences in forecasted LMPs in the intervals closest to real-time could cause CTS transactions to be approved that would contribute to transactions being scheduled counter to real-time economic signals, and contribute to inefficient scheduling across the PJM/NYIS border.

CTS transactions are evaluated based on the spread bid, which limits the amount of price convergence that can occur. As long as balancing operating reserve payments are applied and CTS transactions are optional, there is no reason not to implement the CTS proposal. The 75 minute time lag associated with scheduling energy transactions in the NYISO should be addressed to improve the efficiency of interchange transaction pricing at the PJM/NYISO seam. Minimizing this time lag is more likely to improve pricing efficiency at the PJM/NYISO border than the CTS transaction approach.

It does not appear that ITSCED can accurately predict real-time PJM/NYIS interface prices. As long as the risk associated with CTS transactions remains entirely with market participants, it is the participants who need to account for the accuracy of the forecasts.

PJM and MISO Coordinated Interchange Transaction Proposal

PJM and MISO have proposed the implementation of coordinated interchange transactions, similar to the PJM/NYISO approach, through the Joint and Common Market initiative. While the mechanics of transaction evaluation have yet to be determined, the coordinated transaction scheduling (CTS) proposal would provide the option for market participants to submit intra-hour transactions between the MISO and PJM that include an interface spread bid on which transactions are evaluated. Similar to the PJM/NYISO approach, the evaluation would be based, in part, on the forward-looking prices as determined by PJM's intermediate term security constrained economic dispatch tool (ITSCED).

To evaluate the accuracy of ITSCED forecasts, the forecasted PJM/MISO interface price for each 15 minute interval from ITSCED was compared to the actual real-time interface LMP for the first nine months of 2014. Table 9-33 shows that over all forecast ranges ITSCED predicted the real-time PJM/MISO interface LMP within the range of $0.00 to $5.00 in 29.8 percent of all intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.73. In 8.4 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00, with an average price difference of $88.83, and in 8.3 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was greater than -$20.00, with an average price difference of $82.99.

Table 9-33 ITSCED/real-time LMP - PJM/MISO interface price comparison (all intervals): January through September, 2014

Range	Percent of All Intervals	Average Price Difference
> $20	8.4%	$88.83
$10 to $20	5.6%	$14.28
$5 to $10	7.1%	$7.12
$0 to $5	29.8%	$1.73
-$5 to $0	28.9%	$1.74
-$10 to -$5	6.9%	$7.13
-$20 to -$10	5.0%	$14.09
< -$20	8.3%	$82.99

The ITSCED application runs approximately every five minutes and each run produces forecast LMPs for the intervals approximately 30 minutes, 45 minutes, 90 minutes and 135 minutes ahead. Therefore, for each 15 minute interval, the various ITSCED solutions will produce 12 forecasted PJM/MISO interface prices. Table 9-34 shows how the accuracy of the ITSCED forecasted LMPs change as the cases approach real-time.

Table 9-34 ITSCED/real-time LMP - PJM/MISO interface price comparison (by interval): January through September, 2014

	~ 135 Minutes Prior to Real-Time		~ 90 Minutes Prior to Real-Time		~ 45 Minutes Prior to Real-Time		~ 30 Minutes Prior to Real-Time	
Range	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference	Percent of Intervals	Average Price Difference
> $20	10.7%	$78.61	7.6%	$77.45	6.0%	$75.75	7.6%	$107.91
$10 to $20	6.2%	$14.30	5.7%	$14.30	4.9%	$14.26	5.1%	$14.14
$5 to $10	7.3%	$7.17	7.5%	$7.07	6.8%	$7.08	6.5%	$7.04
$0 to $5	27.6%	$1.81	30.7%	$1.77	31.9%	$1.69	31.2%	$1.61
-$5 to $0	27.8%	$1.83	28.2%	$1.74	30.0%	$1.65	30.0%	$1.68
-$10 to -$5	7.0%	$7.14	6.9%	$7.17	6.9%	$7.14	6.8%	$7.11
-$20 to -$10	5.1%	$14.17	4.9%	$13.98	5.0%	$14.06	4.9%	$14.03
< -$20	8.3%	$87.79	8.6%	$84.62	8.6%	$82.27	7.9%	$76.59

Table 9-34 shows that while there is some improvement as the forecast gets closer to real time, a substantial range of forecast errors remain even in the thirty-minute ahead forecast. In the final ITSCED results prior to real time, in 61.2 percent of all intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP fell within +/- $5.00 of the actual PJM/MISO interface real-time LMP, compared to 55.4 percent in the 135 minute ahead ITSCED results.

The absolute value of the average price difference between the ITSCED forecasted LMP and the actual real-time interface LMP was greater than $20.00 in the thirty-minute ahead cases in 15.5 percent of all intervals, the average price difference was $107.91 when the price difference was greater than $20.00, and the average price difference was $76.59 when the price difference was greater than -$20.00.

It does not appear that ITSCED can accurately predict real-time PJM/MISO interface prices. But as long as the risk associated with CTS transactions remains entirely with market participants, it is the participants who need to account for the accuracy of the forecasts.

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.

The MMU recommended that PJM modify the not willing to pay congestion product to 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 (Table 9-35 shows that there have been no uncollected congestion charges since the inception of the business rule change on April 12, 2013.) 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 9-35 Monthly uncollected congestion charges: January, 2010 through September, 2014

Month	2010	2011	2012	2013	2014
Jan	$148,764	$3,102	$0	$5	$0
Feb	$542,575	$1,567	($15)	$249	$0
Mar	$287,417	$0	$0	$0	$0
Apr	$31,255	$4,767	($68)	($3,114)	$0
May	$41,025	$0	($27)	$0	$0
Jun	$169,197	$1,354	$78	$0	$0
Jul	$827,617	$1,115	$0	$0	$0
Aug	$731,539	$37	$0	$0	$0
Sep	$119,162	$0	$0	$0	$0
Oct	$257,448	($31,443)	($6,870)	$0	
Nov	$30,843	($795)	($4,678)	$0	
Dec	$127,176	($659)	($209)	$0	
Total	$3,314,018	($20,955)	($11,789)	($2,860)	$0

Spot Imports

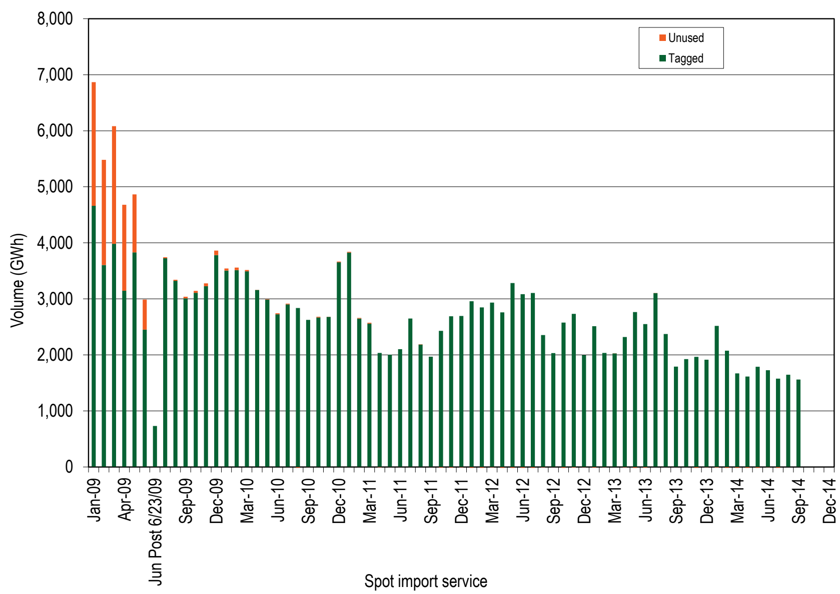
Prior to April 1, 2007, PJM did not limit non-firm service imports that were willing to pay congestion, including spot imports, secondary network service imports and bilateral imports using non-firm point-to-point service. Spot market imports, non-firm point-to-point and network services that are willing 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.

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> (Accessed July 18, 2014).

The new spot import rules provided incentives to hoard spot import capability. PJM and the MMU jointly addressed this issue through the stakeholder process, recommending that all unused spot import service be retracted if not associated with a valid NERC Tag within two hours when reserved the day prior to the scheduled flow, or within 30 minutes when reserved on the day of the scheduled flow. On June 23, 2009, PJM implemented the new business rules. Since the implementation of the rule changes, the spot import service usage (defined as utilized on a NERC Tag) has been over 99 percent, compared to 70 percent prior to the modification (See Figure 9-14).

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.

Figure 9-14 Spot import service utilization: January, 2009 through September, 2014



Interchange Optimization

When PJM prices are higher than prices in surrounding balancing authorities, imports will flow into PJM until the prices are approximately equal. This is an appropriate market response to price differentials. Given the nature of interface pricing and the treatment of interface transactions, it is not possible to reliably predict the quantity or sustainability of such imports. The inability to predict interchange volumes creates additional challenges for PJM dispatch in trying to meet loads, especially on high-load days. If all external transactions were submitted as real-time dispatchable transactions during emergency conditions, PJM would be able to include interchange transactions in its supply stack, and dispatch only enough interchange to meet the demand.

The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1200 on the prior day to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be utilized to meet load in the most economic manner.

In addition to changing prices, transmission line loading relief procedures (TLRs), market participants' curtailments for economic reasons, and external balancing authority curtailments all affect the duration of interchange transactions. The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that removes the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized joint dispatch approach that treats seams between balancing authorizes as a constraint, similar to any other constraint within an LMP market.

45 Minute Schedule Duration Rule

PJM limits the change in interchange volumes on 15 minute intervals. These changes are referred to as ramp. The purpose of imposing a ramp limit is to help ensure the reliable operation of the PJM system. The 1,000 MW ramp limit per 15 minute interval was based on the availability of ramping capability by generators in the PJM system. The limit is consistent with the view that the available generation in the PJM system can only move 1,000 MW over any 15 minute period. The PJM ramp limit is designed to limit the change in the amount of imports or exports in each 15 minute interval to account for the physical characteristics of the generation to respond to changes in the level of imports and exports. For example, if at 0800 Eastern Prevailing Time (EPT) the sum of all external transactions were -3,000 MW (negative sign indicates net exporting), the limit for 0815 would be -2,000 MW to -4,000 MW. In other words, the starting or ending of transactions would be limited so that the overall change from the previous 15 minute period would not exceed 1,000 MW in either direction.

In 2008, there was an increase in 15 minute external energy transactions that caused swings in imports and exports submitted in response to intra-hour LMP changes. This activity was due to market participants' ability to observe price differences between RTOs in the first third of the hour, and predict the direction of the price difference on an hourly integrated basis. Large quantities of MW would then be scheduled between the RTOs for the last 15 minute interval to capture those hourly integrated price differences with little risk of prices changing. This increase in interchange on 15 minute intervals created operational control issues, and in some cases led to an increase in uplift charges due to calling on resources with minimum run times greater than 15 minutes needed to support the interchange transactions. As a result, a new business rule was proposed and approved that required all transactions to be at least 45 minutes in duration.

On June 22, 2012, FERC issued Order No. 764.[75] This order proposed to give transmission customers the ability to adjust their transmission schedules to reflect more accurate power production forecasts, load and system conditions, by requiring each public utility transmission provider to offer intra-hourly transmission scheduling. Order No. 764 required transmission providers to provide transmission customers the option to schedule transmission service at 15 minute intervals.[76]

On November 12, 2013, PJM submitted its compliance filing to Order 764.[77] PJM noted that its current business practices already comply with the 15 minute scheduling interval mandate, but pointed out the 45 minute minimum duration rule that was put in place to protect against the previously observed market abuses.[78] PJM concluded that a return to a 15 minute duration rule would cause an increase in imbalance charges/Balancing Operating Reserve costs if market participants engaged in the behaviors that the 45 minute requirement eliminated.

On April 17, 2014, FERC issued its order accepting in part and rejecting in part PJM's proposed tariff revisions.[79] The Commission found that PJM's 45 minute duration rule was inconsistent with Order 764.[80]

Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule to become compliant with Order No. 764.[81,82,83]

PJM and the MMU issued a statement indicating that both remain concerned about market participants' scheduling behavior, and will continue to monitor and address any scheduling behavior that raises operational or market manipulation concerns.[84]

75 *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).
76 Order No. 764 at P 51.

77 See PJM Interconnection L.L.C. filing, Docket No. ER14-383-000 (November 12, 2013).
78 See *Id.* at 5–7.
79 147 FERC ¶ 61,045 (2014).
80 *See Id.* at P 12.
81 *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246 (2012), *order on reh'g*, Order No. 764-A, 141 FERC ¶ 61231 (2012).
82 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).
83 See Letter Order, Docket No. ER14-381-000 (June 30, 2014).
84 *See* joint statement of PJM and the MMU re Interchange Scheduling issued July 29, 2014, which can be accessed at: <http://www.pjm.com/~/media/documents/reports/20140729-pjm-imm-joint-statement-on-interchange-scheduling.ashx>.

Ancillary Service Markets

The United States Federal Energy Regulatory Commission (FERC) defined six ancillary services in Order No. 888: scheduling, system control and dispatch; reactive supply and voltage control from generation service; regulation and frequency response service; energy imbalance service; operating reserve – synchronized reserve service; and operating reserve – supplemental reserve service.[1] PJM provides scheduling, system control and dispatch and reactive on a cost basis. PJM provides regulation, energy imbalance, synchronized reserve, and supplemental reserve services through market mechanisms.[2] 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.

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 nine months of 2014.

Table 10-1 The Regulation Market results were competitive

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

- 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 97 percent of the hours in the first nine months of 2014.
- Participant behavior in the Regulation Market was evaluated as competitive for the first nine months of 2014 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 competitive, after the introduction of the new market design, despite significant issues with the market design.
- Market design was evaluated as flawed. While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market results continue to include the incorrect definition of opportunity cost. Further, the market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement.

Table 10-2 The Synchronized Reserve Markets results were competitive

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

- The Synchronized Reserve Market structure was evaluated as not competitive because of high levels of supplier concentration.
- 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 participant behavior with the market design results in competitive prices.
- Market design was evaluated as mixed. Market power mitigation rules result in competitive outcomes despite high levels of supplier concentration. However, Tier 1 reserves are inappropriately compensated when the non-synchronized reserve market clears with a non-zero price.

Table 10-3 The Day-Ahead Scheduling Reserve Market results were competitive

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

1 75 FERC ¶ 61,080 (1996).
2 Energy imbalance service refers to the Real-Time Energy Market.

- 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, a significant proportion 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

Primary Reserve

Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement. PJM's primary reserves are made up of resources, both synchronized and non-synchronized, that can provide energy within ten minutes.

Market Structure

- **Supply.** Primary reserve is satisfied by both synchronized reserve (generation or demand response currently synchronized to the grid and available within ten minutes), and non-synchronized reserve (generation currently off-line but can be started and provide energy within ten minutes).
- **Demand.** The PJM primary reserve requirement is 150 percent of the largest contingency. The primary reserve requirement in the RTO Reserve Zone is currently 2,063 MW of which at least 1,700 MW must be available within the Mid-Atlantic Dominion (MAD) subzone. Adjustments to the primary reserve requirement can occur when grid maintenance or outages change the largest contingency. The actual demand for primary reserve in the RTO for the first nine months of 2014 was 2,078 MW. The actual demand for primary reserve in the MAD subzone in the first nine months of 2014 was 1,700 MW.

Tier 1 Synchronized Reserve

Synchronized reserve is energy or demand reduction synchronized to the grid and capable of increasing output or decreasing load within ten minutes. Synchronized reserve is of two distinct types, tier 1 and tier 2. Tier 1 synchronized reserve is part of primary reserve and is comprised of all on-line resources following economic dispatch and able to ramp up from their current output in response to a synchronized reserve event.

- **Supply.** In the first nine months of 2014, an average supply of 1,442.0 MW of tier 1 was identified hourly for the entire RTO synchronized reserve zone, and an average supply of 568.5 MW of tier 1 was identified hourly for the Mid-Atlantic Dominion subzone.
- **Demand.** There is no fixed required amount of tier 1 synchronized reserve. Tier 1 synchronized reserve is estimated and not assigned.
- **Price and Cost.** The price for tier 1 synchronized reserves is typically zero, as there is no incremental cost associated with providing the ability to ramp up from the current economic dispatch point. However, a tariff change included in the shortage pricing tariff changes (October 1, 2012) modified the pricing of tier 1 so that tier 1 synchronized reserve is paid the tier 2 synchronized reserve market clearing price whenever the non-synchronized reserve market clearing price rises above zero. The rationale for this change was and is unclear but it has had a significant impact on the cost of tier 1 synchronized reserves, resulting in a windfall payment of $85,069,062 to tier 1 resources between January 1 and September 30, 2014.

  The additional payments to tier 1 synchronized reserves can be considered a windfall because the additional payment does not create an incentive to provide more tier 1 synchronized reserves and the additional payment is not a payment for performance as there is no requirement to perform and all estimated tier 1 synchronized reserves receive the payment regardless of whether they provided any response.

- **Tier 1 Synchronized Reserve Spinning Event Response.** Tier 1 synchronized reserve is awarded credits when a spinning event occurs and it responds. These spinning event response credits for tier 1 response are independent of the tier 1 estimated, independent of the synchronized reserve market clearing price, and independent of the non-synchronized reserve market clearing price.

  Only 29.5 percent of tier 1 synchronized reserve identified as available for both synchronized reserve and primary reserve actually responded to spinning events.

Tier 2 Synchronized Reserve Market

Tier 2 synchronized reserve is part of primary reserve (ten minute availability) and is comprised of resources that are synchronized to the grid, that incur costs to synchronized and that must be dispatched in order to satisfy the synchronized reserve requirement. When the synchronized reserve requirement cannot be filled with tier 1 synchronized reserve, PJM conducts a market to satisfy the requirement with tier 2 synchronized reserve. The Tier 2 Synchronized Reserve Market includes the PJM RTO Reserve Zone and a subzone, the Mid-Atlantic Dominion Reserve subzone (MAD).

Market Structure

- **Supply.** In the first nine months of 2014, the supply of offered and eligible synchronized reserve was sufficient to cover the requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone, except for two hours on January 6, 2014, and eight hours on January 7, 2014.
- **Demand.** The default hourly required synchronized reserve requirement is 1,375 MW in the RTO Reserve Zone and 1,300 MW for the Mid-Atlantic Dominion Reserve subzone.
- **Market Concentration.** In the first nine months of 2014, the weighted average HHI for cleared inflexible tier 2 synchronized reserve in the Mid-Atlantic Dominion subzone was 5427 which is classified as highly concentrated. The HHI for flexible synchronized reserve cleared during real-time market solutions (which was only 11.6 percent of all tier 2 synchronized reserve) was 8643. The MMU calculates that during the first nine months of 2014, 38.7 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion subzone and 33.1 percent of hours would have failed a three pivotal supplier test in the RTO Synchronized Reserve Zone.

  The MMU concludes from these results that both the Mid-Atlantic Dominion subzone Tier 2 Synchronized Reserve Market and the RTO Synchronized Reserve Zone Market were characterized by structural market power in the first nine months of 2014.

Market Conduct

- **Offers.** Synchronized reserve offers from generating units are subject to an offer cap of marginal cost plus $7.50 per MW, plus opportunity cost, which is calculated by PJM. As of September 30, 2014, 3.4 percent of eligible resources had no tier 2 synchronized reserve offer. This is an improvement over the same period in 2013 when 14.0 percent of eligible resources had no tier 2 synchronized reserve offer.

Market Performance

- **Price.** The cleared synchronized reserve weighted average price for tier 2 synchronized reserve in the Mid-Atlantic Dominion (MAD) subzone was $15.42 per MW in the first nine months of 2014, an increase of $8.31 (85.6 percent) from the first nine months of 2013.

  The cleared synchronized reserve weighted average price for tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was $13.40 per MW in the first nine months of 2014, an increase of $6.54 (95.3 percent) over the first nine months of 2013.

Non-Synchronized Reserve Market

Non-synchronized reserve is a component of primary reserve and includes the same two markets, the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone (MAD). After the hour ahead market solution satisfies the requirement for synchronized reserve the remainder of the primary reserve requirement is satisfied with non-synchronized reserve. Non-synchronized reserve is comprised of non-emergency energy resources not currently synchronized to the grid that can provide energy within ten minutes at the direction of PJM dispatch.

Market Structure

- **Supply.** In the first nine months of 2014, the supply of eligible non-synchronized reserve was sufficient to cover the primary reserve requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone, except for two hours on January 6, 2014, and eight hours on January 7, 2014.
- **Demand.** In the RTO Zone, the market cleared an hourly average of 680.9 MW of non-synchronized reserve during the first nine months of 2014. In 95.9 percent of hours the market clearing price was $0. In the MAD subzone, the market cleared an hourly average of 683.0 MW of non-synchronized reserve. In 93.7 percent of hours the market clearing price was $0.

Market Conduct

- **Offers.** No offers are made for non-synchronized reserve. Non-emergency generation resources that are available to provide energy and can start in 10 minutes or less are considered available for non-synchronized reserves by the market solution software.

Market Performance

- **Price.** Prices are a function of the opportunity costs of any resources taken for non-synchronized reserves. The cleared non-synchronized reserve weighted average price in the RTO Reserve Zone was $0.57 per MW for the first nine months of 2014, compared to $0.03 for the first nine months of 2013. The cleared non-synchronized reserve weighted average price in the Mid-Atlantic Dominion (MAD) subzone was $11.65 per MW, compared to $10.17 over the same period in 2013.

Secondary Reserve

PJM maintains a day-ahead, offer based market for 30-minute secondary reserve, designed to provide price signals that encourage resources to provide 30-minute reserve.[3] The DASR Market has no performance obligations.

Market Structure

- **Concentration.** In the first nine months of 2014, zero hours in the DASR Market would have failed the three pivotal supplier test.
- **Supply.** The DASR Market is a must offer market. Any resources that do not make an offer have their offer set to $0 per MW. DASR is calculated by the day-ahead market solution as the lesser of the thirty minute energy ramp rate or the emergency maximum MW minus the day-ahead dispatch point for all on-line units. For the first nine months of 2014, the average available hourly DASR was 45,282 MW.
- **Demand.** The DASR requirement in 2014 is 6.27 percent of peak load forecast, down from 6.91 percent in 2013. The average DASR MW purchased was 6,419 MW per hour for the first nine months of 2014.

Market Conduct

- **Withholding.** Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. All offers greater than zero constitute economic withholding. As of September 30, 2014, 9.8 percent of resources offered DASR at levels above $5 per MW, compared to 11.5 percent of resources offering above $5.00 at the same time in 2013.

3 See PJM. "Manual 35, Definitions and Acronyms," Revision 35, (April 11, 2014), p. 89.

- **DR.** Demand resources are eligible to participate in the DASR Market. As of September 30, 2014, six demand resources have entered offers for DASR.

Market Performance

- **Price.** The weighted average DASR market clearing price in the first nine months of 2014 was $1.02 per MW. This is a $0.09 per MW (9.7 percent) increase from the first nine months of 2013, which had a weighted price of $0.93 per MW.

Regulation Market

The PJM Regulation Market is a single market for the RTO. Regulation is provided by demand response and generation resources that must qualify to follow a regulation signal (RegA or RegD). PJM jointly optimizes regulation with synchronized reserve and energy to provide all three of these services at least cost. The PJM Regulation Market design includes three clearing price components (capability, performance, and lost opportunity cost), the rate of substitution between RegA and RegD resources (marginal benefit factor) and a measure of the quality of response (performance score) by a regulation resource to a regulation signal. The marginal benefit factor and performance score translate a resource's capability (actual) MW into effective MW.

Market Structure

- **Supply.** In the first nine months of 2014, the average hourly eligible supply of regulation was 1,300 actual MW (938 effective MW). This is a decrease of 152 actual MW (214 effective MW) from the first nine months of 2013, when the average hourly eligible supply of regulation was 1,453 actual MW (1,152 effective MW).
- **Demand.** The average hourly regulation demand was 664 actual MW in the first nine months of 2014. This is a 127 actual MW (38 effective MW) decrease in the average hourly regulation demand of 791 actual MW (702 effective MW) in the same period of the first nine months of 2013.
- **Supply and Demand.** The ratio of offered and eligible regulation to regulation required averaged 1.96. This is a 6.4 percent increase over the first nine months of 2013 when the ratio was 1.84.
- **Market Concentration.** In the first nine months of 2014, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 1836 which is classified as highly concentrated. In the first nine months of 2014, the three pivotal supplier test was failed in 97 percent of hours.

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. Offers include both a capability offer and a performance offer. Owners must specify which signal type the unit will be following, RegA or RegD.[4] In the first nine months of 2014, there were 290 resources following the RegA signal and 43 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $49.77 per MW of regulation in the first nine months of 2014, an increase of $17.05 per MW of regulation, or 52.1 percent, from the first nine months of 2013. The cost of regulation in the first nine months of 2014 was $60.42 per MW of regulation, an increase of $23.07 per MW of regulation, or 61.8 percent, from the first nine months of 2013.
- **RMCP Credits.** RegD resources continue to be underpaid relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment, pricing, and settlement processes. In the first nine months of 2014, RegA resources received RMCP credits per effective MW on average 1.9 times higher than RegD resources. If the Regulation Market were functioning correctly, RegD and RegA resources would be paid equally per effective MW.

4 See the *2013 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

Black Start Service

Black start service is required for 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.[5]

In the first nine months of 2014, total black start charges were $44.6 million with $18.0 million in revenue requirement charges and $26.6 million in operating reserve charges. Black start revenue requirements for black start units consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor. Black start operating reserve charges are paid for scheduling in the Day-Ahead Energy Market or committing in real time units that provide black start service. Black start zonal charges in the first nine months of 2014 ranged from $0.03 per MW-day in the ATSI Zone (total charges were $123,375) to $4.09 per MW-day in the AEP Zone (total charges were $25,535,875).

Reactive

Reactive service, reactive supply and voltage control from generation or other sources service, is provided by generation and other sources of reactive power (measured in VAR). Reactive power helps maintain appropriate voltages on the transmission system and is essential to the flow of real power (measured in MW).

In the first nine months of 2014, total reactive service charges were $237.9 million with $210.5 million in revenue requirement charges and $27.4 million in operating reserve charges. Reactive service revenue requirements are based on FERC-approved filings. Reactive service operating reserve charges are paid for scheduling in the Day-Ahead Energy Market and committing in real time units that provide reactive service. Total charges in the first nine months of 2014 ranged from $1,700 in the RECO Zone to $30.7 million in the AEP Zone.

5 OATT Schedule 1 § 1.3BB.

Ancillary Services Costs per MWh of Load: January through June, 2003 through 2014

Table 10-4 shows PJM ancillary services costs for the first nine months of years 2003 through 2014, on a per MWh of load basis. The rates are calculated as the total charges for the specified ancillary service divided by the total PJM real time load in MWh for the first nine months of 2014 (593.3 million MWh). 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. The cost per MWh of load in Table 10-4 is a different metric than the cost of each ancillary service per MW of that service. The cost per MWh of load includes the effects both of price changes per MW of the ancillary service and also changes in total load. As an example, the regulation market clearing price increased 52.1 percent (from $32.72 to $49.77 per MW of regulation capability) while the cost of regulation per MWh of real time load increased only 25.9 percent, from $0.27 to $0.34 per MWh of real time load.

Table 10-4 History of ancillary services costs per MWh of Load: January through September, 2003 through 2014

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve	Total
2003	$0.53	$0.59	$0.23	$0.09	$0.88	$2.32
2004	$0.50	$0.64	$0.25	$0.14	$0.90	$2.43
2005	$0.78	$0.47	$0.25	$0.11	$0.88	$2.49
2006	$0.55	$0.48	$0.28	$0.07	$0.44	$1.82
2007	$0.65	$0.47	$0.29	$0.06	$0.58	$2.05
2008	$0.75	$0.34	$0.29	$0.07	$0.55	$2.00
2009	$0.36	$0.36	$0.36	$0.05	$0.47	$1.60
2010	$0.37	$0.38	$0.36	$0.06	$0.75	$1.92
2011	$0.35	$0.36	$0.39	$0.09	$0.87	$2.06
2012	$0.23	$0.44	$0.44	$0.03	$0.75	$1.89
2013	$0.27	$0.41	$0.69	$0.04	$0.66	$2.07
2014	$0.34	$0.37	$0.36	$0.25	$1.43	$2.75

Recommendations

- The MMU recommends that the Regulation Market be modified to incorporate a consistent application of the marginal benefit factor throughout the optimization, assignment and settlement process. (Priority: High. First reported 2013.)
- The MMU recommends that the rule requiring the payment of tier 1 synchronized reserve resources when the non-synchronized reserve price is above zero be eliminated immediately. (Priority: High. First reported 2013.)
- To the extent that PJM continues to pay tier 1 synchronized reserve the SRMCP when the non-synchronized reserve market clearing price is above $0 (e.g. the above recommendation is not implemented), the MMU recommends that the amount of tier 1 MW paid when the non-synchronized reserve market clearing price (NSRMCP) goes above $0 be equal to the tier 1 MW estimated by the RT-SCED market solution. (Priority: High. New recommendation.)
- The MMU recommends that the tier 2 synchronized reserve must-offer provision of scarcity pricing be enforced. As of the end of September 2014 compliance with the tier 2 must-offer provision is 96.6 percent. (Priority: Medium. First reported 2013.)
- The MMU recommends that PJM be more explicit about why tier 1 biasing is used in the optimized solution to the Tier 2 Synchronized Reserve Market. 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. (Priority: Low. First reported 2013.)
- The MMU recommends that PJM determine why secondary reserve was either unavailable or not dispatched on September 10, 2013, January 6, 2014, and January 7, 2014, and that PJM replace the DASR Market with a real time secondary reserve product that is available and dispatchable in real time. (Priority: Low. First reported 2013.)
- The MMU recommends that 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. (Priority: Low. First reported 2013.)
- The MMU recommends that the three pivotal supplier test be incorporated in the DASR Market. (Priority: Low. First reported 2012.)

Conclusion

While the design of the Regulation Market was significantly improved with changes introduced October 1, 2012, a number of issues remain. The market results continue to include the incorrect definition of opportunity cost. Further, the market design has failed to correctly incorporate a consistent implementation of the marginal benefit factor in optimization, pricing and settlement. Instead, the market design makes use of the marginal benefit factor in the optimization and pricing, but a mileage ratio multiplier in settlement. This failure to correctly incorporate marginal benefit factor into the current Regulation Market design is causing effective MW provided by RegD resources to be underpaid per effective MW. These issues have led to the MMU's conclusion that the Regulation Market design, as currently implemented, is flawed.

The structure of each Tier 2 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. 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 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.

The MMU concludes that the new Regulation Market results were competitive. The MMU concludes that the Synchronized Reserve Market results were competitive. The MMU concludes that the DASR Market results were competitive.

Primary Reserve

Primary reserve is to ensure reliability in the event of contingencies. Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement. The NERC requirement is to carry sufficient contingency reserves to meet load requirements reliably and economically and provide reasonable protection against instantaneous load variations due to load forecasting error or loss of system capability due to generation malfunction.[6] PJM implements the NERC requirement conservatively as primary reserve available within ten minutes.

Market Structure

Supply

PJM's primary reserve requirement is 2,063 MW for the RTO Zone, and 1,700 MW for the MAD subzone. It is satisfied by synchronized tier 1 reserves, synchronized tier 2 reserves and non-synchronized reserves, subject to the requirement that synchronized reserve equal 100 percent of the largest contingency, currently 1,300 MW in the Mid-Atlantic Dominion subzone, and 1,375 MW in the RTO Zone. After the synchronized reserve requirement is satisfied, the remainder can come from non-synchronized reserves.

Estimated Tier 1 is credited against PJM's primary reserve requirement. In the MAD subzone an average of 569 MW of tier 1 was identified by the ASO market solution as available hour ahead (Table 10-6). This tier 1 reduced the amount of tier 2 and non-synchronized reserve needed to fill the synchronized reserve and primary reserve requirements. There was enough tier 1 to satisfy the MAD subzone synchronized reserve requirement in only 33 hours in the first three quarters of 2014. In the RTO Zone an average of 1,440 MW of tier 1 was available (Table 10-6). The RTO Zone synchronized reserve requirement was satisfied by tier 1 in 59.9 percent of all hours.

There is usually enough tier 2 synchronized reserve (all resources capable of supplying tier 2 must make a tier 2 synchronized reserve offer) to fulfill the synchronized reserve requirement. In the MAD subzone, there was an average of 4,687 MW of tier 2 synchronized reserve available (Figure 10-11) to meet the average tier 2 hourly demand of 390 MW (Table 10-5). In the RTO Zone, there was an average of 5,765 MW of Tier 2 supply available to meet the average hourly demand of 495 MW (Table 10-6).

In the MAD subzone, there was an average of 2,196 MW of non-synchronized reserve supply available to meet the average hourly demand of 620 MW (Table 10-6). In the RTO Zone, an hourly average of 2,241 MW supply was available to meet the average hourly demand of 982 MW (Table 10-5).

Demand

PJM requires that 150 percent of the largest contingency on the system be maintained as primary reserve. The primary reserve requirement in the RTO Reserve Zone is 2,063 MW. Adjustments to this value can occur when grid maintenance or outages change the largest contingency (Figure 10-1).[7]

In two hours between January 1 and September 30, 2014, PJM increased the primary reserve requirement for the RTO Zone. The actual hourly average RTO primary reserve requirement was 2,080 MW in January through September, 2014. In 20 hours between January 1 and September 30, 2014, PJM increased the primary reserve requirement for the MAD subzone. The actual hourly

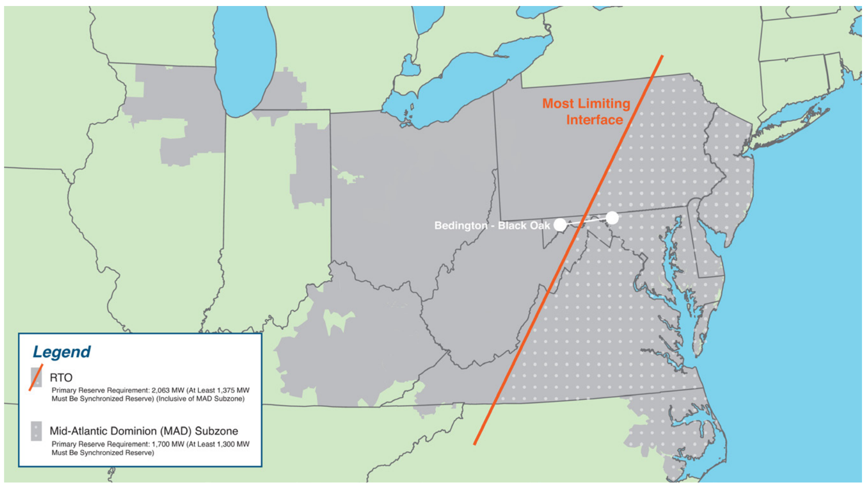
6 NERC, IVGTF Task 2.4 Report; Operating Practices, Procedures, and Tools, March 2011, p. 20

7 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 68 (August 21, 2014), p. 66, 67. PJM's Markets and Reliability Committee approved a temporary rule change effective June 1, 2014, allowing operators to increase the primary reserve requirement when a Hot or Cold Weather Alert, Maximum Emergency Generation Alert, or Load Management Alert is issued. This rule will sunset on September 30, 2014. Between January 1 and June 30, 2014, no changes were made to the synchronized reserve requirement based on this rule change.

demand for primary reserve in the MAD subzone in the first nine months of 2014 was 1,701 MW.

Transmission constraints limit the deliverability of reserves within the RTO, requiring the definition of the Mid-Atlantic Dominion (MAD) subzone.[8] Of the 2,063 MW RTO primary reserve requirement, 1,700 MW (Table 10-16) must be deliverable to the MAD subzone (Figure 10-1).

Figure 10-1 PJM RTO geography and primary reserve requirement: January through September 2014



The Mid-Atlantic Dominion Reserve (MAD) subzone is defined dynamically by the most limiting constraint separating MAD from the PJM RTO Reserve Zone.[9] In 63.0 percent of hours in January through September, 2014, that constraint was the AP South interface. The Bedington – Black Oak transfer interface constraint was the limiting constraint in 34.6 percent of hours.

PJM requires that synchronized reserves equal at least 100 percent of the largest contingency. For the RTO Reserve Zone this means that 1,375 MW of the primary reserve requirement must be synchronized reserve and for the Mid Atlantic Dominion Reserve subzone that means that 1,300 MW must be synchronized reserve.

Table 10-5 Average tier 1 and tier 2 synchronized reserve, plus non-synchronized reserve used to satisfy the primary reserve requirement, MAD Subzone: January through September, 2014

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Non-Synchronized Reserve MW
2014	Jan	243	1,079	508
2014	Feb	842	468	643
2014	Mar	974	334	639
2014	Apr	877	510	523
2014	May	1,049	282	621
2014	Jun	1,089	219	627
2014	Jul	1,216	92	702
2014	Aug	1,056	247	696
2014	Sep	1,019	283	593
2014	Average	929	390	617

Table 10-6 Average tier 1 and tier 2 synchronized reserve, plus non-synchronized reserve used to satisfy the primary reserve requirement, RTO Zone: January through September, 2014

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Non-Synchornized Reserve MW
2014	Jan	389	1,237	889
2014	Feb	1,203	502	931
2014	Mar	1,343	384	1,096
2014	Apr	1,140	853	980
2014	May	1,342	394	1,053
2014	Jun	1,769	316	984
2014	Jul	2,231	127	949
2014	Aug	1,910	292	972
2014	Sep	1,636	353	909
2014	Average	1,440	495	974

8 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 68 (August 21, 2014), p. 66.
9 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 68 (August 21, 2014), p. 66.

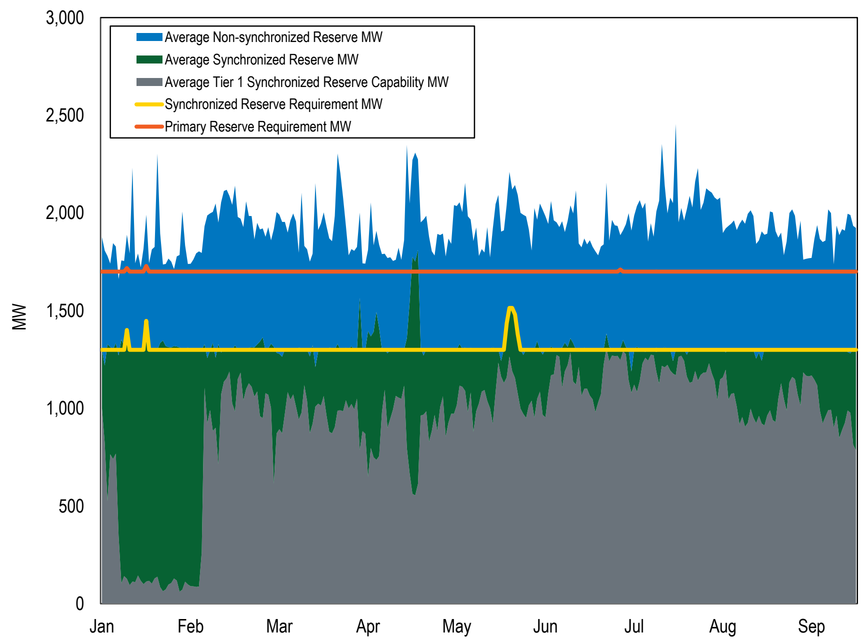
Supply and Demand

The market solution software relevant to reserves consists of: the Ancillary Services Optimizer (ASO) solving hourly, the intermediate term security constrained economic dispatch market solution (IT-SCED) solving every 15 minutes and the real time (short term) security constrained economic dispatch market solution (RT-SCED) solving every five minutes.

The ASO jointly optimizes energy, synchronized reserves, non-synchronized reserves, and regulation based on forecast system conditions to determine the most economic set of reserve resources to commit for the upcoming operating hour (before the hour commitments). IT-SCED runs at 15 minute intervals and jointly optimizes energy and reserves given the ASO's inflexible unit commitments. IT-SCED estimates available tier 1 synchronized reserve and can commit additional inflexible reserves if its forecasts indicate a need. RT-SCED runs at five minute intervals and produces load forecasts up to 20 minutes ahead. The RT-SCED estimates the available tier 1, provides a real time ancillary services solution and can commit additional within hour flexible tier 2 resources if its forecasts indicate a need.

Figure 10-2 illustrates how the ASO satisfies the primary reserve requirement (orange line) for the Mid-Atlantic Dominion subzone. For the Mid-Atlantic Dominion Reserve Zone primary reserve solution the ASO must first satisfy the synchronized reserve requirement (yellow line) which is generally 1,300 MW in the MAD subzone. Since tier 1 synchronized reserve has a price of zero, ASO first estimates how much tier 1 synchronized reserve (gray area) is available. If there is 1,300 MW of tier 1 available then ASO jointly optimizes synchronized reserve and non-synchronized reserve to assign the remaining primary reserve up to 1,700 MW. If there is not 1,300 MW of tier 1 then the remaining synchronized reserve requirement up to 1,300 MW is filled with tier 2 synchronized reserve (dark green area). After 1,300 MW of synchronized reserve are assigned, the remaining 400 MW of the primary reserve requirement is filled by jointly optimizing synchronized reserve and non-synchronized reserve (light blue area). Since non-synchronized reserve is priced lower or equal to synchronized reserve, almost all primary reserve between 1,300 MW and 1,700 MW is filled by non-synchronized reserve.

Figure 10-2 Mid-Atlantic Dominion subzone primary reserve MW by source (Daily Averages): January through September 2014



The solution methodology is similar for the RTO Reserve Zone (Figure 10-3) except that the required synchronized reserve is 1,375 MW and the required primary reserve MW is 2,063 MW.[10] Figure 10-3 shows how the hour ahead ASO satisfies the primary reserve requirement for the RTO Zone.

10 Although tier 1 has a price of zero, changes made with shortage pricing on November 1, 2012, have given tier 1 a very high cost in some hours. This high cost raises questions about the economics of the solution methodology used by the ASO, IT-SCED, and RT-SCED market solutions which assume zero cost.

Figure 10-3 RTO subzone primary reserve MW by source (Daily Averages): January through September 2014

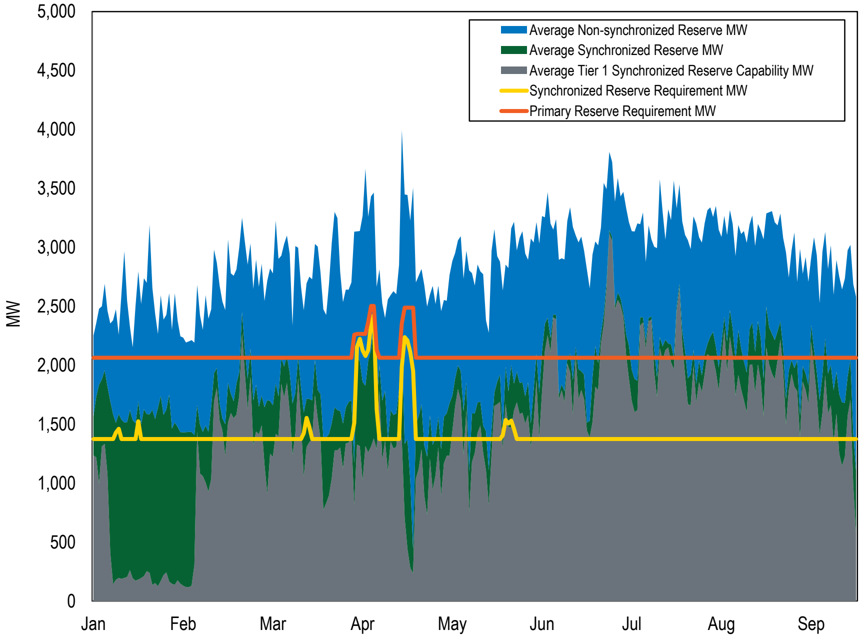


Figure 10-2 and Figure 10-3 show that tier 1 synchronized reserve remains the major contributor to satisfying the synchronized reserve requirements both in the RTO Zone and the Mid-Atlantic Dominion (MAD) subzone.

Price and Cost

Tier 1 synchronized reserves are on line resources able to ramp up from their existing economic dispatch. In the market solution, the price for tier 1 synchronized reserves is zero except in defined circumstances, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point. Tier 1 is credited when it responds to a spinning event. In addition, in any hour that the non-synchronized reserve market clears with a price above $0, tier 1 synchronized reserves are paid the tier 2 synchronized reserve market price. As available primary reserve approaches the primary reserve requirement the cost to serve the next MW of primary reserve is the non-synchronized reserve market clearing price (blue area in both Figure 10-2 and Figure 10-3).

The non-synchronized reserve market clearing price was above $0 in 407 hours during the first nine months of 2014. For those 407 hours, tier 1 synchronized reserve resources were paid the tier 2 MW weighted synchronized reserve market clearing price of $64.59 per MW and earned $85,069,062 in credits.

In times of non-synchronized reserve shortage, the price of non-synchronized reserve will be capped at the currently effective penalty factor. From June 1, 2013, through May 31, 2014, the penalty factor was $400 per MW for both tier 2 synchronized reserve and non-synchronized reserve. Effective June 1, 2014, through May 31, 2015, the penalty factor for both products is $550 per MW. In January 2014, cold weather resulted in high loads which, combined with unit outages, contributed to volatility and high prices in the primary reserve (synchronized and non-synchronized) markets.

Figure 10-4 shows daily average synchronized and non-synchronized market clearing prices from January through September, 2014.

Figure 10-4 Daily average market clearing prices for synchronized reserve and non-synchronized reserve: January through September 2014

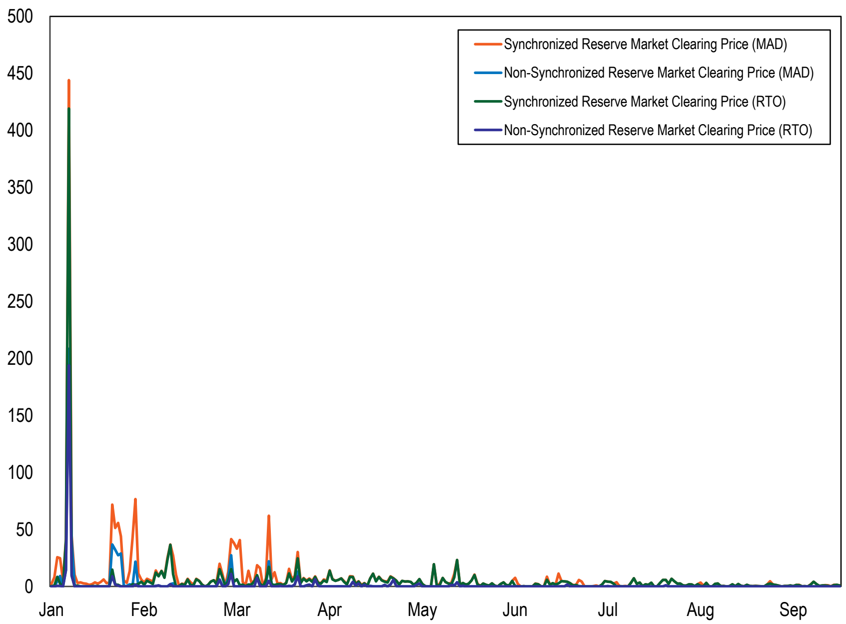


Table 10-7 MW credited, price, cost, and all-in price for primary reserve and its component products, full RTO Reserve Zone, January through September, 2014

Product	Share of Primary Reserve Requirement	MW Credited	Credits Paid	Price Per MW	Cost Per MW	All-In Cost
Tier 1 Synchronized Reserve Response	NA	14,062	$1,163,339	NA	$82.73	$0.00
Tier 1 Synchronized Reserve	49.7%	1,415,741	$85,069,062	$60.09	$60.09	$0.14
Tier 2 Synchronized Reserve	14.3%	1,954,573	$52,495,326	$13.40	$26.86	$0.09
Non-synchronized Reserve	36.1%	8,874,479	$12,163,758	$1.09	$1.37	$0.02
Primary Reserve	141.3%	12,258,855	$150,891,485	$9.88	$12.31	$0.25

The cost of meeting PJM's primary reserve requirement (Figure 10-3) is shown in Table 10-7. Under most market conditions, most primary reserve identified by the hour ahead market solution is provided at no incremental cost by non-synchronized reserve (blue area in Figure 10-3) and tier 1 synchronized reserve (gray area in Figure 10-3). The "Cost per MW" column is the total credits divided by the total MW of reserves. The "All-In Cost" column is the total credits paid divided by the load, or the total cost per MWh of energy to satisfy the primary reserve requirement.

If the unnecessary payments for Tier 1 were removed per the MMU's recommendation, the cost for primary reserve would have been reduced by $85,069,062 for the first nine months of 2014. This is a 56.4 percent reduction in the cost of primary reserve.

Tier 1 Synchronized Reserve

Tier 1 synchronized reserve is a component of primary reserve comprised of all on-line resources following economic dispatch and able to ramp up from their current output in response to a synchronized reserve event. The tier 1 synchronized reserve for a unit is measured as the lower of the available ten minute ramp and the difference between the economic dispatch point and the economic maximum output. Tier 1 resources are identified by the market solution and the sum of their ten minute availability equals available tier 1 synchronized reserve (gray area of Figure 10-2 and Figure 10-3). Tier 1 Synchronized Reserve is the first element of primary reserve identified by the market software and is available at zero incremental cost unless called to respond or unless the non-synchronized reserve market clearing price is above $0.

The tier 1 estimate used by the market solution can be biased by PJM dispatch to make the solution solve for more or less tier 2 synchronized reserve than the market solution.

The MMU has recommended that instead of using tier 1 biasing, PJM improve the accuracy of the tier 1 estimates. The MMU recommends that PJM provide a reason for every use of tier 1 biasing, to provide increased transparency and facilitate analysis designed to improve the estimation methodology.

Market Structure

Supply

All generating resources operating on the PJM system with the exception of those assigned to tier 2 synchronized reserve are available for tier 1 synchronized reserve. Demand resources are not available for tier 1 synchronized reserve.

For the first nine months of 2014, in the RTO Reserve Zone the average hour ahead estimated tier 1 synchronized reserve was 1,440.3 MW (Table 10-8). In 1,610 hours the estimated tier 1 synchronized reserve was greater than 2,063 MW primary reserve requirement, meaning that the primary reserve requirement was met entirely by tier 1 synchronized reserve.

Table 10-8 Monthly average market solution Tier 1 Synchronized Reserve identified hourly, January through September, 2014

Mid-Atlantic Dominion Reserve Zone						
Year	Month	Average Hourly Tier 1 Local to MAD	Synchronized Reserve Available from RTO	Average Hourly Tier 1 Used	Minimum Hourly Tier 1 Used	Maximum Hourly Tier 1 Used
2014	Jan	149.5	93.2	242.6	0.0	1,117.7
2014	Feb	582.5	259.0	841.5	0.0	1,383.4
2014	Mar	515.7	458.3	974.0	90.5	1,411.5
2014	Apr	523.9	353.4	877.4	162.2	1,195.0
2014	May	698.2	351.1	1,049.4	461.2	1,550.9
2014	Jun	713.9	375.1	1,089.0	302.6	1,637.2
2014	Jul	808.3	407.7	1,215.9	0.0	1,734.0
2014	Aug	605.4	450.1	1,055.5	443.1	1,398.7
2014	Sep	522.0	497.7	1,019.0	488.1	1,298.8

RTO Reserve Zone						
Year	Month	Average Hourly Tier 1 Local to RTO	Synchronized Reserve Available from RTO	Average Hourly Tier 1 Used	Minimum Hourly Tier 1 Used	Maximum Hourly Tier 1 Used
2014	Jan	388.7	NA	388.7	0.0	2,081.9
2014	Feb	1,203.2	NA	1,203.2	38.2	2,963.8
2014	Mar	1,343.4	NA	1,343.4	88.6	3,202.9
2014	Apr	1,139.8	NA	1,139.8	0.0	2,711.1
2014	May	1,341.5	NA	1,341.5	0.0	3,166.8
2014	Jun	1,768.7	NA	1,768.7	0.0	3,839.9
2014	Jul	2,230.7	NA	2,230.7	0.0	4,209.3
2014	Aug	1,910.2	NA	1,910.2	0.0	3,783.8
2014	Sep	1,636.0	NA	1,636.0	0.0	3,974.6

For the first nine months of 2014, in the MAD reserve subzone the average hour ahead estimated tier 1 synchronized reserve was 929.4 MW (Table 10-8). In five hours the estimated tier 1 synchronized reserve was zero. In 82 hours the estimated tier 1 synchronized reserve was greater than the subzone requirement for synchronized reserve of 1,300 MW and no tier 2 synchronized reserve market was needed. In two hours the estimated tier 1 synchronized reserve was greater than the subzone primary reserve requirement of 1,700 MW.

Demand

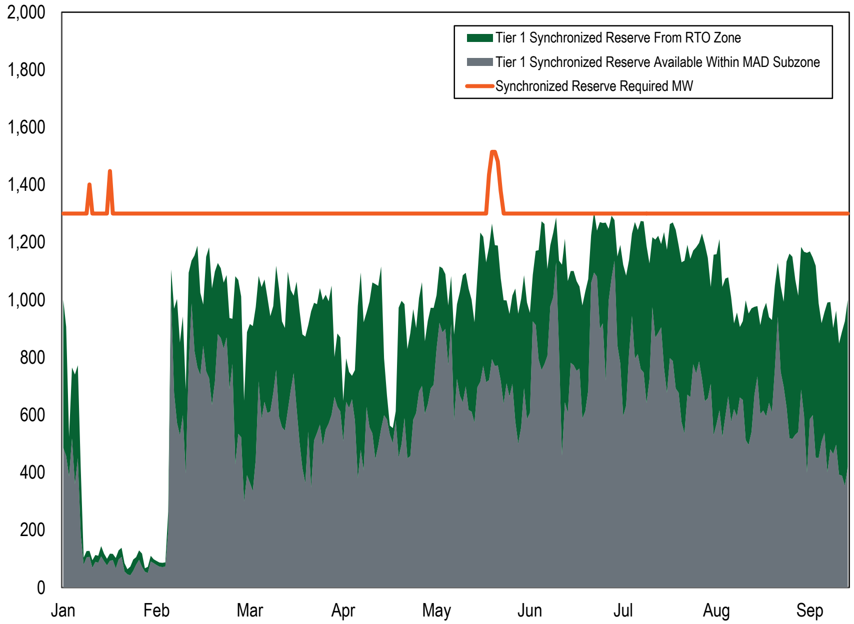
There is no fixed required amount of tier 1 synchronized reserve. Tier 1 synchronized reserve is estimated as part of each market solution and not assigned. Given estimated tier 1, the market software (ASO) completes the primary reserve assignments under the assumption that the estimated tier 1 will be available if needed. The ancillary services market solution treats the cost of estimated tier 1 synchronized reserve as $0.

Supply and Demand

When solving for the synchronized reserve requirement the market solution first subtracts the amount of self-scheduled synchronized reserve from the requirement and then estimates the amount of tier 1.

In the MAD subzone the market solution takes all tier 1 MW estimated to be available within the MAD subzone (gray area of Figure 10-5). It then adds the tier 1 MW estimated to be available within the MAD subzone from the RTO Zone (green area of Figure 10-5) up to the synchronized reserve requirement. If the total tier 1 synchronized reserve is less than the synchronized reserve requirement, the remainder of the synchronized reserve requirement is filled with tier 2 synchronized reserve (white area below the Synchronized Reserve Required line in Figure 10-5).

Figure 10-5 Daily average tier 1 synchronized reserve supply in the MAD subzone: January through September, 2014[11]



From January through September 2014, the average amount of tier 1 synchronized reserve MW used in the hour-ahead market solution for the MAD subzone was 934.5 MW, compared to the average synchronized reserve requirement of 1,304.0 MW. In five hours the market solution used no tier 1 synchronized reserve to satisfy the synchronized reserve requirement and in 56 hours the market solution used tier 1 synchronized reserve for the entire synchronized reserve requirement.

From January through September 2014, the average amount of tier 1 synchronized reserve MW used in the hour-ahead market solution for the RTO Zone was 1,562.2 MW, compared to the average synchronized reserve requirement of 1,415.9 MW. In 146 hours the market solution used no tier 1 synchronized reserve to satisfy the synchronized reserve requirement and in 46.8 percent of hours the market solution used tier 1 synchronized reserve for the entire synchronized reserve requirement.

Tier 1 Settlement Issues

The MMU has identified two issues with PJM's current rules for the compensation of tier 1 resources when non-synchronized reserve market clearing price (NSRMCP) is above $0. PJM pays tier 1 MW the tier 2 SRMCP when the NSRMCP is above $0. This is an unnecessary windfall. The amount of tier 1 MW that PJM pays in settlements is not equal to the amount of tier 1 MW estimated in the market solution. This multiplies the windfall by paying a price to too many MW.

The MMU recommends that, in the absence of a spinning event, payments to tier 1 for hours in which the NSRMCP is above $0 make no economic sense and should be eliminated. In addition, to the extent tier 1 is paid during hours when the NSRMCP is above $0, the MMU recommends payment be limited to those tier 1 MW estimated in the market solution.[12]

The MMU's position remains that tier 1 should be compensated only for a response to spinning events, as it was before the shortage pricing changes. This compensation requires that when a spinning event is called, all tier 1 response is paid the average of five-minute LMPs during the event plus $50/MW (Synchronized Energy Premium Price). A summary of PJM's current tier 1 compensation rules are presented in Table 10-9. The MMU's recommended compensation rules for tier 1 MW are in Table 10-10.

11 Hours in which the tier 1 estimate was biased by PJM dispatch are excluded from this graph. Tier 1 estimate biasing was used in 244 hours for the MAD subzone and 597 hours in the RTO zone in the first nine months of 2014.

12 PJM has taken some steps to address part of this issue related to the MW of tier 1 that are paid, but has not made a public statement about all these issues. See: Tier 1 MW Estimation Proposed Language Inclusion, August, 2014 <http://wired.pjm.com/~/media/committees-groups/committees/mic/20140903/20140903-item-04a-synchronized-reserve-tier-1-presentation.ashx>.

Table 10-9 Tier 1 compensation as currently implemented by PJM

Tier 1 Compensation by Type of Hour as Currently Implemented by PJM		
Hourly Parameters	No Spin Event	Spin Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MW
NSRMCP>$0	T1 credits = T2 SRMCP * calculated tier 1 MW	T1 credits = T2 SRMCP * min(calculated tier 1 MW, actual response MW)

Table 10-10 Tier 1 compensation as recommended by MMU

Tier 1 Compensation by Type of Hour as Recommended by MMU		
Hourly Parameters	No Spin Event	Spin Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MW
NSRMCP>$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MW

Impact of Paying Tier 1 for Hours When Non-synchronized Reserve Market Clearing Price (NSRMCP) is Above $0

Tier 1 synchronized reserve, as currently implemented by PJM, receives different payments depending on whether there is a spinning event and whether the NSRMCP is greater than $0. When there is no spinning event, tier 1 is paid $0 when the NSRMCP is $0 and tier 1 is paid the tier 2 price (SRMCP) when the NSRMCP is above $0. When there is a spinning event, tier 1 is paid the Synchronized Energy Premium when the NSRMCP is $0 and tier 1 is paid the tier 2 price when the NSRMCP is greater than $0.[13,14]

It is inappropriate to pay tier 1 synchronized reserve resources the tier 2 price when the price of nonsynchronized reserves is greater than zero. The MMU recommends that the related rule be fixed immediately.

The rule implies an obligation where none exists. Synchronized reserve is called by dispatch during spinning events. Tier 2 synchronized reserve is paid to be available, is obligated to respond, is not paid for the actual response, and is penalized for non-response. Tier 1 resources are not obligated to respond to spinning events and do not pay a penalty for failure to respond but are paid the tier 2 price under certain conditions whether they respond or not.

The rule makes no economic sense. There is no reason to pay tier 1 MW when tier 1 MW do not respond to a spinning event. Tier 1 is estimated by the market solution but not assigned. Both tier 2 and nonsynchronized reserves are assigned, paid to be available, paid LOC if appropriate, contractually obligated to respond, and penalized for non-response. Tier 1 is a different product that is defined entirely by its response. The existing rule that pays an identified price to all tier 1 response to spinning events is appropriate. Paying tier 1 when there is no spinning event is paying for nothing and should be eliminated immediately.

The rule pays resources that are not part of the economic market solution. Tier 1 estimated by the market solution affects the final price of tier 2 and nonsynchronized reserves. The market solution identifies tier 1 that is unlikely to respond to spinning events and does not include it in its estimate. But the rule pays for all tier 1 including tier 1 that is not part of the market solution because the rule states that all tier 1 is paid. This is paying for MW that have nothing to do with the market solution.

Paying tier 1 MW compromises the integrity of the market solution price. The market solution evaluates tier 1 MW at a zero cost. If the synchronized reserve requirement can be satisfied entirely by tier 1 MW then the clearing price equals $0. If there is not enough tier 1 to satisfy the synchronized reserve requirement, the remainder of the synchronized reserve requirement is filled by tier 2, and the remainder of the primary reserve requirement by an optimized combination of tier 2 and nonsynchronized reserve. When the next MW of NSR required to satisfy the primary reserve requirement increases in price from $0.00 per MW to $0.01 per MW, the effective price of all tier 1 MW (typically thousands of MW) increases from zero to thousands, often hundreds of thousands, of dollars. The optimization does not reflect the actual cost of that one incremental MW of nonsynchronized reserve.

13 See M-28, Rev 65, 04/24/2014 p. 40. "Effective 10/1/2012, Tier 1 synchronized reserve resources are also compensated when the Non-Synchronized Reserve Market Clear Price is non-zero."

14 See Tariff, 02/22/2013 p.1762. "i) Credits for Synchronized Reserve provided by generation resources that are then subject to the energy dispatch signals and instructions of the Office of the Interconnection and that increase their current output or Demand Resources that reduce their load in response to a Synchronized Reserve Event ("Tier 1 Synchronized Reserve") shall be at the Synchronized Energy Premium Price, with the exception of those hours in which the Non-Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone is not equal to zero. During such hours, Tier 1 Synchronized Reserve resources shall be compensated at the Synchronized Reserve Market Clearing Price for the applicable Reserve Zone or Reserve Sub-zone for the lesser of the hourly integrated amount of Tier 1 Synchronized Reserve attributed to the resource as calculated by the Office of the Interconnection, or the actual amount of Tier 1 Synchronized Reserve provided should a Synchronized Reserve Event occur."

The dollar impact of this rule is shown in Table 10-11.

Table 10-11 Dollar Impact of Paying Tier 1 Synchronized Reserve the SRMCP When the NSRMCP Goes Above $0

Year	Month	MAD Tier 1 Credits When NSRMCP > $0	RTO Tier 1 Credits When NSRMCP > $0	Tier 1 Credits Paid When NSRMCP > $0
2012	Oct	$655,254.26	$1,603.24	$656,857.50
2012	Nov	$3,865,259.34	$140,127.75	$4,005,387.09
2012	Dec	$439,237.82	$0.00	$439,237.82
2013	Jan	$1,099,270.92	$0.00	$1,099,270.92
2013	Feb	$180,210.84	$0.00	$180,210.84
2013	Mar	$2,408,969.22	$0.00	$2,408,969.22
2013	Apr	$1,185,455.48	$47,812.11	$1,233,267.59
2013	May	$681,357.31	$16,688.22	$698,045.53
2013	Jun	$247,187.86	$1,519.63	$248,707.49
2013	Jul	$2,178,730.80	$17,716.40	$2,196,447.20
2013	Aug	$1,213,298.83	$581,718.27	$1,795,017.10
2013	Sep	$2,056,147.14	$279,570.14	$2,335,717.28
2013	Oct	$84,208.06	$14,694.77	$98,902.83
2013	Nov	$6,459.27	$3,304.03	$9,763.30
2013	Dec	$100,461.11	$70,196.95	$170,658.06
2014	Jan	$43,637,117.68	$18,679,374.56	$62,316,492.24
2014	Feb	$1,766,396.74	$858,905.98	$2,625,302.72
2014	Mar	$7,800,330.76	$2,639,757.36	$10,440,088.12
2014	Apr	$2,648,455.99	$2,304,402.56	$4,952,858.55
2014	May	$1,659,371.64	$2,352,913.38	$4,012,285.02
2014	Jun	$227,197.77	$339,093.85	$566,291.62
2014	Jul	$65,759.59	$89,984.57	$155,744.16
2014	Aug	$0.00	$0.00	$0.00
2014	Sep	$0.00	$0.00	$0.00
	Total	$74,206,138.42	$28,439,383.78	$102,645,522.20

Erroneous Implementation of the Tier 1 MW Calculation Used by Settlements

The amount of tier 1 MW paid whenever the non-synchronized reserve price goes above $0 is much greater than is estimated to be available by both the hour ahead and the short term market solutions (ASO and RT-SCED). For hours when the non-synchronized reserve price goes above $0 the market solution estimated tier 1 MW is not used by PJM Settlements to pay tier 1 resource owners. Rather, a separate application (Power Meter) calculates actual tier 1 MW available at market hour time. This is the amount of tier 1 that is paid. This MW value is usually two to three times higher than is estimated to be available by ASO or RT-SCED at the time the optimized energy and reserves market solution is solved. As a result, much more tier 1 MW is paid than is actually used in the market solution.

If PJM pays any tier 1 when the nonsynchronized reserve price is greater than zero, the MMU recommends that PJM pay only the tier 1 estimate value established by the market solution.

The purpose of tier 1 is response during spinning events. Most tier 1 ramp MW are unavailable to respond if called for an emergency. It makes no sense to pay resources for a response that is not available. Because such response is critical to grid operations, the tier 1 MW estimated by the market solutions is finely tuned based on factors unavailable to PJM Settlements Power Meter.

Paying tier 1 MW calculated by Power Meter rather than the market solution estimated tier 1 MW is inconsistent with the price signal established for tier 2 synchronized reserve which is calculated in the market solution. This price is based on an optimization of the primary reserve components tier 1, tier 2, non-synchronized reserve and energy. If more tier 1 were actually available it would result in a lower price for tier 2 resources.

Table 10-12 shows the actual dollars paid to tier 1 resource owners for hours when the NSRMCP is greater than $0. These dollars are determined by the actual amount of tier 1 calculated by PJM settlements times the tier 2 price. In determining the correct amount of credits that should be paid to tier 1 resource owners the MMU uses the tier 1 MW estimated by RT-SCED in the market solution times the SRMCP. This includes all hours when the NSRMCP was above $0 and there was not a spinning event.

Table 10-12 Actual Payments Made to Tier 1 Resources Compared with Correct Tier 1 Payments

Year	Month	MAD T1 Credits	Correct MAD T1 Credits	RTO T1 Credits	Correct RTO T1 Credits	Total T1 Credits	Correct Total T1 Credits	Overpayments
2012	Oct	$655,254.26	$233,764.29	$1,603.24	$458.26	$656,857.50	$234,222.55	$422,634.95
2012	Nov	$3,865,259.34	$1,277,486.30	$140,127.75	$45,750.68	$4,005,387.09	$1,323,236.98	$2,682,150.11
2012	Dec	$439,237.82	$209,864.45	$0.00	$0.00	$439,237.82	$209,864.45	$229,373.38
2013	Jan	$1,099,270.92	$254,694.90	$0.00	$0.00	$1,099,270.92	$254,694.90	$844,576.02
2013	Feb	$180,210.84	$73,781.02	$0.00	$0.00	$180,210.84	$73,781.02	$106,429.82
2013	Mar	$2,408,969.22	$952,776.41	$0.00	$0.00	$2,408,969.22	$952,776.41	$1,456,192.81
2013	Apr	$1,185,455.48	$479,172.76	$47,812.11	$14,773.43	$1,233,267.59	$493,946.20	$739,321.40
2013	May	$681,357.31	$215,650.85	$16,688.22	$5,259.62	$698,045.53	$220,910.46	$477,135.07
2013	Jun	$247,187.86	$61,479.16	$1,519.63	$321.34	$248,707.49	$61,800.50	$186,906.99
2013	Jul	$2,178,730.80	$421,123.58	$17,716.40	$3,367.38	$2,196,447.20	$424,490.96	$1,771,956.24
2013	Aug	$1,213,298.83	$278,124.50	$581,718.27	$110,763.99	$1,795,017.10	$388,888.49	$1,406,128.61
2013	Sep	$2,056,147.14	$216,590.74	$279,570.14	$52,282.46	$2,335,717.28	$268,873.20	$2,066,844.08
2013	Oct	$84,208.06	$20,082.60	$14,694.77	$2,146.75	$98,902.83	$22,229.35	$76,673.48
2013	Nov	$6,459.27	$1,215.90	$3,304.03	$1,471.17	$9,763.30	$2,687.07	$7,076.23
2013	Dec	$100,461.11	$9,219.11	$70,196.95	$8,914.83	$170,658.06	$18,133.94	$152,524.12
2014	Jan	$43,637,117.68	$3,568,086.85	$18,679,374.56	$1,306,226.95	$62,316,492.24	$4,874,313.80	$57,442,178.44
2014	Feb	$1,766,396.74	$228,578.93	$858,905.98	$109,323.98	$2,625,302.72	$337,902.91	$2,287,399.81
2014	Mar	$7,800,330.76	$1,188,554.62	$2,639,757.36	$325,081.26	$10,440,088.12	$1,513,635.89	$8,926,452.23
2014	Apr	$2,648,455.99	$525,691.46	$2,304,402.56	$390,583.11	$4,952,858.55	$916,274.57	$4,036,583.98
2014	May	$1,659,371.64	$483,967.33	$2,352,913.38	$315,943.76	$4,012,285.02	$799,911.09	$3,212,373.93
2014	Jun	$227,197.77	$73,257.74	$339,093.85	$45,015.30	$566,291.62	$118,273.04	$448,018.58
2014	Jul	$65,759.59	$37,223.90	$89,984.57	$29,853.64	$155,744.16	$67,077.53	$88,666.63
2014	Aug	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2014	Sep	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	Total	$74,206,138.42	$10,810,387.39	$28,439,383.78	$2,767,537.88	$102,645,522.20	$13,577,925.27	$89,067,596.93

To ensure sufficient synchronized reserves are realized in real time operations, PJM routinely deselects resources that cannot, or do not, reliably provide tier 1 reserve during spinning events from the tier 2 market solution. Prior to June 24, 2014, when the NSRMCP was above $0, PJM settlement erroneously paid deselected resources along with tier 1 eligible resources. As of June 24, 2014, it appears that PJM took steps to ensure that deselected resources are no longer paid as tier 1 when NSRMCP was above $0 but there has been no public statement.

Tier 1 Estimate Bias

PJM dispatch can apply tier 1 estimate bias to each element of the market solution software (ASO, IT-SCED, and RT-SCED). Biasing means manually modifying (increasing or decreasing) the tier 1 synchronized reserve estimate of the market solution. This forces the market clearing engine to clear more or less tier 2 synchronized reserve and non-synchronized reserve to satisfy the synchronized reserve and primary reserve requirements than the market solution.

During the first nine months of 2014, PJM used tier 1 estimate biasing in the MAD subzone ASO (Table 10-13) and RT-SCED market solutions, and in the RTO Zone ASO and RT-SCED market solutions. Tier 1 biasing was not used in any IT-SCED solutions. Tier 1 biasing was used in the RT-SCED solution in 244 five-minute periods in amounts between -100 MW and -400 MW. All of the periods were on the days of extreme cold, January 7 and January 8.[15]

15 The number of five minute periods was reported incorrectly as 328 in the *2014 Quarterly State of the Market Report for PJM: January through March, p 318.*

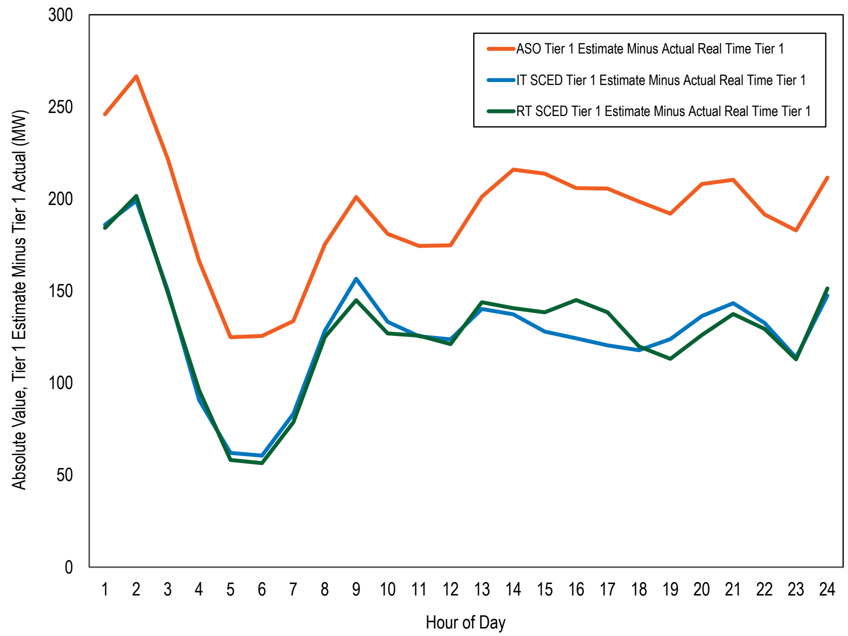
Table 10-13 MAD subzone ASO tier 1 estimate biasing, January through September, 2014

Year	Month	Number of Hours Biased Negatively	Average Negative Bias (MW)	Number of Hours Biased Positively	Average Positive Bias (MW)
2014	Jan	13	(1,419.23)	2	250
2014	Feb	36	(1,036.11)	1	100
2014	Mar	37	(1,281.11)	4	500
2014	Apr	32	(1,387.50)	0	NA
2014	May	23	(909.78)	0	NA
2014	Jun	17	(1,179.41)	3	667
2014	Jul	36	(1,011.11)	0	NA
2014	Aug	31	(891.94)	1	750
2014	Sep	15	(1,206.67)	0	NA
2014	Total	240	(1,146.98)	11	453

Tier 1 biasing is not mentioned in the PJM manuals and does not appear to be defined in any public document. PJM dispatchers use tier 1 biasing to compensate for uncertainty in short-term load forecasting, generator performance, or uncertainty in the accuracy of the market solution's tier 1 estimate. Tier 1 estimate biasing directly affects the required amount of tier 2.

The accuracy of the tier 1 estimate increases as the market solution gets closer to real time (Figure 10-6). The tier 1 estimate from the hour ahead solution differs from the actual value by 193 MW. The tier 1 estimate from the intermediate term solution differs from the actual value by 128 MW. The tier 1 estimate from the real time solution differs from the actual value by 127 MW.

Figure 10-6 Absolute value of the tier 1 estimate minus the actual value by market hour, January through September 2014



Tier 1 biasing is generally done on a short-term basis. In January 2014, PJM dispatch found that the amount of tier 1 estimated by the ASO was not actually available when needed during the cold weather on January 6 and 7. As a result, PJM dispatch reset the tier 1 estimate value used by the ASO to be ten percent of the value estimated by the ASO for the entire period of January 7 through February 7. The effect of this change can be seen in Figure 10-2 and Figure 10-3. The dip in the gray area is the reduction of tier 1, forcing the ASO to fill the synchronized reserve requirement (yellow line) with tier 2 (green area).

Price and Cost

The price for tier 1 synchronized reserves is typically zero, as there is no incremental cost associated with providing the ability to ramp up from the current economic dispatch point. However, a tariff change included in the shortage pricing tariff changes (October 1, 2012) modified the pricing of tier 1 so that tier 1 synchronized reserve is paid the tier 2 synchronized reserve market clearing price whenever the non-synchronized reserve market clearing price rises above zero. The rationale for this change was and is unclear but it has had a significant impact on the cost of tier 1 synchronized reserves. The non-synchronized reserve market clearing price was above $0 in 407 hours during the first nine months of 2014. For those 407 hours tier 1 synchronized reserve resources were paid a tier 1 MW weighted synchronized reserve market clearing price of $64.59 per MW and earned $85,069,063 in credits for an average cost of $64.59 per MW (Table 10-14).

Table 10-14 Weighted price of tier 1 synchronized reserve attributable to a non-synchronized reserve price above zero; January through September, 2014

Year	Month	Total Number of Hours When NSRMCP Greater Than $0	Tier 1 MW Weighted Average SRMCP for Hours When NSRMCP Greater than $0	Total Tier 1 Credits for Hours When NSRMCP Greater Than $0	Total Tier 1 MW Credited for Hours When NSRMCP Greater Than $0	Average Tier 1 MW Credited Per Hour
2014	Jan	155	$109.81	$62,316,492	692,263	4,466.2
2014	Feb	15	$42.57	$2,625,303	65,332	4,355.5
2014	Mar	67	$46.49	$10,440,088	241,508	3,604.6
2014	Apr	99	$16.36	$4,952,859	320,743	3,239.8
2014	May	61	$15.85	$4,012,285	253,352	4,153.3
2014	Jun	4	$35.46	$566,292	15,970	3,992.5
2014	Jul	5	$14.20	$155,744	9,149	1,829.8
2014	Aug	0	$0.00	$0	0	NA
2014	Sep	0	$0.00	$0	0	NA
2014	Total	407	$64.59	$85,069,063	1,598,317	3,663.1

Tier 1 resources are not obligated to respond to spinning events. Only 56.3 percent of the market solution's estimated tier 1 resource MW actually responded during spinning events in the first three quarters of 2014. Only 14.9 percent of those market settlements paid tier 1 MW for hours when there was no spinning event was likely to respond to a spinning event. The accuracy of the tier 1 estimate and the response level of tier 1 during spinning events is important to grid reliability. The accuracy of the tier 1 MW paid in relation to the tier 1 MW estimated by the market solution is important for keeping the costs of primary reserve within the price of primary reserve. Since the shortage pricing rule paying tier 1 the SRMCP whenever the NSRMCP is above $0 (October 1, 2012), the ratio of tier 1 MW estimated at market solution time to tier 1 MW calculated in market settlements is 39.5 percent in the MAD subzone, and 50.3 percent in the RTO Zone. Tier 1 MW was paid under this rule in 767 hours since October 1, 2012.

The additional payments to tier 1 synchronized reserves under the shortage pricing rule can be considered a windfall. The additional payment does not create an incentive to provide more tier 1 synchronized reserves. The additional payment is not a payment for performance as all estimated tier 1 receives the payment regardless of whether they provided any response. Thus, 85.0 percent of tier 1 resources do not respond but are paid when the non-synchronized reserve price is greater than zero. Tier 2 synchronized reserve resources are paid the market clearing price for tier 2 because they stand ready to respond and incur costs to do so, have an obligation to perform and pay penalties for nonperformance. The MMU recommends that the additional payments to tier 1 be eliminated.

Tier 1 Synchronized Reserve Spinning Event Response

Tier 1 synchronized reserve is awarded credits when a spinning event occurs and it responds. These spinning event response credits for tier 1 response are independent of the tier 1 estimated, independent of the synchronized reserve market clearing price, and independent of the non-synchronized reserve market clearing price. Credits are awarded to tier 1 synchronized reserve resources equal to the increase in MW output (or decrease in MW of consumption for demand resources) for each five minute interval times the five minute LMP plus $50 per MW.

For January through September 2014, Tier 1 synchronized reserve spinning event response credits (Table 10-15) were paid during 30 hours (in 15 of those hours the non-synchronized reserve market clearing price was also greater than zero). For January through September 2014, $1,163,339 was paid for 14,779 MW of tier 1 response during 30 hours at an average cost per MW of $82.73.

Table 10-15 Tier 1 synchronized reserve spinning event response costs, January through September, 2014

Year	Month	Spinning Event Response Hours	Total Tier 1 Spinning Event Response MW	Total Tier 1 Spinning Event Response Credits	Tier 1 Spinning Event Response Cost
2014	Jan	15	7,821	$823,972	$105.36
2014	Feb	1	273	$11,147	$40.80
2014	Mar	5	3,029	$174,612	$57.65
2014	Apr	2	388	$6,322	$16.29
2014	May	3	717	$34,900	$48.67
2014	Jun	0	0	$0	$0.00
2014	Jul	2	616	$34,860	$56.63
2014	Aug	0	0	$0	$0.00
2014	Sep	2	1,219	$77,525	$63.60
2014	Total	30	14,062	$1,163,339	$82.73

Tier 2 Synchronized Reserve Market

Synchronized reserve is energy or demand reduction synchronized to the grid and capable of increasing output or decreasing load within ten minutes. Synchronized reserve is of two distinct types, tier 1 and tier 2. Tier 2 synchronized reserve is primary reserve (ten minute availability) that must be dispatched in order to satisfy the synchronized reserve requirement. When the synchronized reserve requirement cannot be filled with tier 1 synchronized reserve, PJM clears a market to satisfy the requirement with tier 2 synchronized reserve.

PJM operates a Tier 2 Synchronized Reserve Market in both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Reserve subzone. Market solutions provided by the ASO, IT-SCED and RT-SCED first estimate the amount of tier 1 synchronized reserve available from the current energy price based economic dispatch and subtract that amount from the synchronized reserve requirement to determine how much tier 2 synchronized reserve is needed. Tier 2 synchronized reserve is provided by on-line resources, either synchronized to the grid but not producing energy, or dispatched to provide synchronized reserve at an operating point below their economic dispatch. Tier 2 synchronized reserves are committed to be available in the event of a synchronized reserve event.

Tier 2 synchronized reserve committed by the hour ahead market solution is inflexible. Resources are scheduled by the ASO sixty minutes before the operating hour, are committed to provide synchronized reserve for the entire hour, and are paid the higher of the SRMCP or their offer price plus lost opportunity cost (LOC) (demand response resources are paid SRMCP).

During the operating hour the IT-SCED and the RT-SCED market solutions have the ability to dispatch additional resources inflexibly or flexibly depending on the current forecast need for synchronized reserve. A flexible commitment is one in which the IT-SCED or RT-SCED redispatches generating resources to meet the synchronized and primary reserve requirements. Such resources can be recommitted to generation by subsequent market solutions or kept as synchronized reserve depending on market conditions.

Market Structure

Supply

All non-emergency generating resources are required to submit tier 2 synchronized reserve offers. All online, non-emergency generating resources are deemed available to provide both tier 1 and tier 2 synchronized reserve. 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.[16] This rule is intended to increase the accuracy of estimates of available synchronized reserve and primary reserve.

For January through September 2014, the Mid Atlantic Dominion subzone averaged 3,865 MW in synchronized reserve offers, and the RTO Zone averaged 10,498 MW of synchronized reserve offers (Figure 10-11).

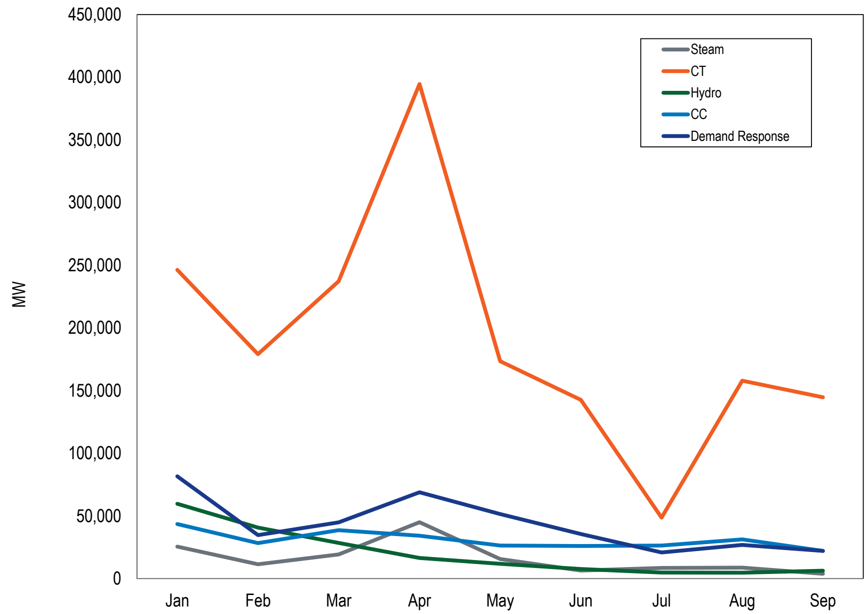
16 See PJM. "Manual 11: Energy and Ancillary Services Market Operations" Revision 68, (August 21, 2014), p. 62.

With the exception of several hours on January 6 and 7, the supply of tier 2 synchronized reserve for the first nine months of 2014 was sufficient to cover the requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone. On January 6, hours 19 and 20, an RTO-wide shortage pricing event was triggered by a Voltage Reduction Action implemented in response to RTO-wide synchronized reserve levels falling below the 1,375 MW synchronized reserve requirement. On January 7, deficient synchronized reserves in the RTO Reserve Zone caused shortage pricing in hours 7 through 11. On January 7, deficient synchronized reserves in the Mid-Atlantic Dominion Reserve subzone caused shortage pricing in hours 7 through 12, 17 and 18.

Demand resources remain a significant part of market scheduled synchronized reserve although their share of total cleared synchronized reserve declined significantly as the amount of tier 2 has increased. The DR MW share of the total cleared MAD subzone Tier 2 Synchronized Reserve Market was 14.3 percent in the first nine months of 2014.[17] This is a reduction of 27.7 percentage points from the DR MW share of 42.0 percent of all cleared MAD tier 2 synchronized reserve for the first nine months of 2013.

17 The cap on demand response participation is defined in MW terms. There is no cap on the proportion of cleared demand response consistent with the MW cap.

Figure 10-7 Cleared Tier 2 Synchronized Reserve by Unit Type, Full RTO Zone, January through September, 2014



Demand

The default hourly required synchronized reserve requirement is 1,375 MW in the RTO Reserve Zone and 1,300 MW for the Mid-Atlantic Dominion Reserve subzone (Table 10-16). There are two circumstances in which PJM may alter the synchronized reserve requirement from its default value. Between June 1, 2014, and September 30, 2014, PJM reserved the right to change the requirement in either the MAD subzone or the RTO Zone in the event of a Hot or Cold Weather Alert, Maximum Emergency Generation Alert, or Load Management Alert.[18] In the first nine months of 2014, PJM did not change the synchronized reserve requirement for this reason.

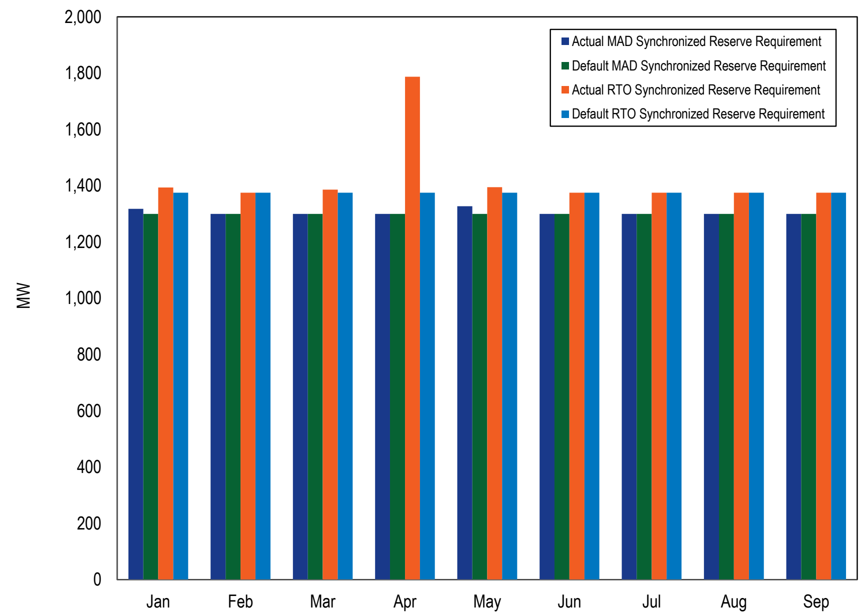
18 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 68 (August 21, 2014), p. 65.

Table 10-16 Default Tier 2 Synchronized Reserve Markets required MW, RTO Zone and Mid-Atlantic Dominion Subzone

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	Dec 31, 2012	1,300	Mar 15, 2010	Nov 12, 2012	1,350
			Nov 12, 2012		1,375

PJM may also change the synchronized reserve requirement from its default value (Figure 10-1) when grid maintenance or outages change the largest contingency. All changes to the synchronized reserve requirements during the first nine months of 2014 were for this reason. In the first nine months of 2014, PJM increased the synchronized reserve requirement in 98 hours in both the MAD subzone and the RTO Reserve Zone (Figure 10-8). The average actual synchronized reserve requirement in the MAD subzone was 1,305 MW. The average actual synchronized reserve requirement in the RTO Reserve Zone was 1,431 MW.

Figure 10-8 Monthly average actual vs default synchronized reserve requirements, RTO and MAD: January through September, 2014



The market demand for tier 2 synchronized reserve in the Mid-Atlantic Dominion subzone is determined by subtracting the amount of forecast tier 1 synchronized reserve available in the subzone from the subzone requirement each five-minute period. Market demand is also reduced by subtracting the amount of self-scheduled tier 2 resources.

Between October 1, 2013, and December 31, 2013, PJM implemented several changes in the way tier 1 available MW is estimated in order to improve the accuracy of the estimates.[19] The effect of these changes in both the RTO Zone and MAD subzone was to reduce the estimates of tier 1 and to increase the amount of tier 2 MW cleared (Figure 10-2). The changes included capping the tier 1 estimate at the lesser of a generator's economic maximum or its spinning maximum value. Some hydro units were excluded (deselected) from

19 PJM Operating Committee Meeting, November 5, 2013, <http://www.pjm.com/~/media/committees-groups/committees/oc/20131105/20131105-item-10-oc-tier-1-changes.ashx>.

tier 1 estimates because most hydro units do not respond to spin events. Most combined cycle units are excluded from tier 1 estimates because combined cycles often require additional equipment or operator intervention to respond to spinning events. Units that are assigned to provide regulation and units that are backed down for constraint control are also excluded from tier 1 estimates.

These changes reduced the amount of tier 1 estimated and significantly increased the amount of tier 2 synchronized reserve required. In the RTO Reserve Zone, 32.9 percent of hours cleared a Tier 2 Synchronized Reserve Market in the first nine months of 2014 averaging 751.8 MW compared to less than one percent of hours in the first nine months of 2013.

Figure 10-9 and Figure 10-10 and show the average monthly synchronized reserve required and the average monthly Tier 2 synchronized reserve MW scheduled in the first nine months of 2014, for the RTO Zone and MAD subzone. The month of January 2014 was unusual in that much more tier 2 synchronized reserve was cleared than prior years. As a result of the extreme weather and reserve shortages on the cold weather days, which reduced the tier 1 available, the dispatchers biased the tier 1 estimate down. The hour ahead tier 1 estimate was biased in 253 hours during the first nine months of 2014 with an average negative bias below (1,100) MW per hour.

Figure 10-9 Mid-Atlantic Dominion Reserve subzone monthly average synchronized reserve required vs. tier 2 synchronized reserve scheduled MW: January through September 2014

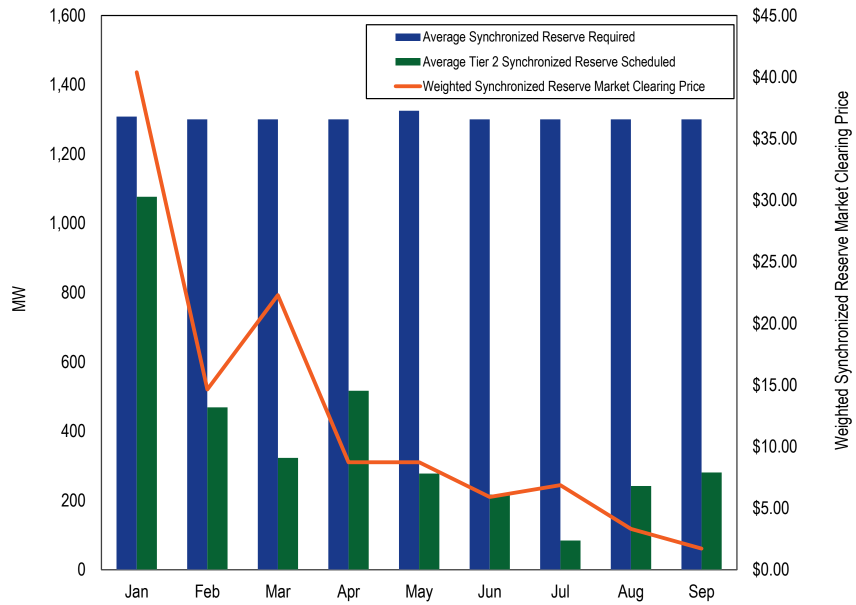
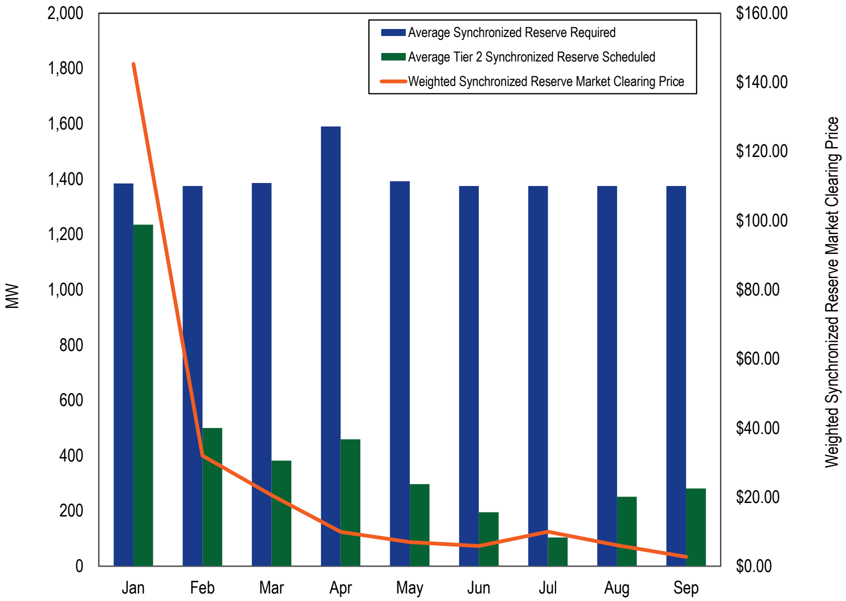


Figure 10-10 RTO Reserve zone monthly average synchronized reserve required vs. tier 2 synchronized reserve scheduled MW: January through September 2014



Market Concentration

The HHI for all settled tier 2 synchronized reserve during cleared hours of the Mid-Atlantic Dominion subzone Tier 2 Synchronized Reserve Market for the first nine months of 2014 was 5427, which is defined as highly concentrated. The largest hourly market share was 100 percent and 73.8 percent of all hours had a maximum market share greater than or equal to 40 percent.

The HHI for settled tier 2 synchronized reserve during cleared hours of the RTO Zone Tier 2 Synchronized Reserve Market for the first nine months of 2014 was 5412, which is defined as highly concentrated. The largest hourly market share was 100 percent and 77.6 percent of hours had a maximum market share greater than or equal to 40 percent.

In the MAD subzone, flexible synchronized reserve was 11.6 percent of all tier 2 synchronized reserve in the first nine months of 2014. In the RTO Zone, flexible synchronized reserve assigned was 20.2 percent of all tier 2 synchronized reserve in the first nine months of 2014. For flexible resources only, the hourly average HHI in the first nine months of 2014 in the MAD subzone was 8643. For flexible resources only the hourly average HHI in the first nine months of 2014 in the RTO Zone was 9426.

The MMU calculates that 38.7 percent of hours failed the three pivotal supplier test in the MAD subzone in the first nine months of 2014 for the inflexible synchronized reserve market (excluding self-scheduled synchronized reserve) in the hour ahead market (Table 10-17) and 33.1 percent of hours failed a three pivotal supplier test in the RTO Zone in the first nine months of 2014.

Table 10-17 Three Pivotal Supplier Test Results for the RTO Zone and MAD Subzone, January through September, 2014

Year	Month	Mid Atlantic Dominion Reserve Subzone Pivotal Supplier Hours	RTO Reserve Zone Pivotal Supplier Hours
2014	Jan	90.7%	72.7%
2014	Feb	46.6%	22.6%
2014	Mar	37.9%	17.3%
2014	Apr	31.9%	51.6%
2014	May	22.3%	44.0%
2014	Jun	31.5%	31.3%
2014	Jul	41.6%	16.2%
2014	Aug	21.1%	17.6%
2014	Sep	25.0%	24.5%
	Average	38.7%	33.1%

The market structure results indicate that the RTO Zone and Mid-Atlantic Dominion subzone Tier 2 Synchronized Reserve Markets are not structurally competitive.

Market Behavior

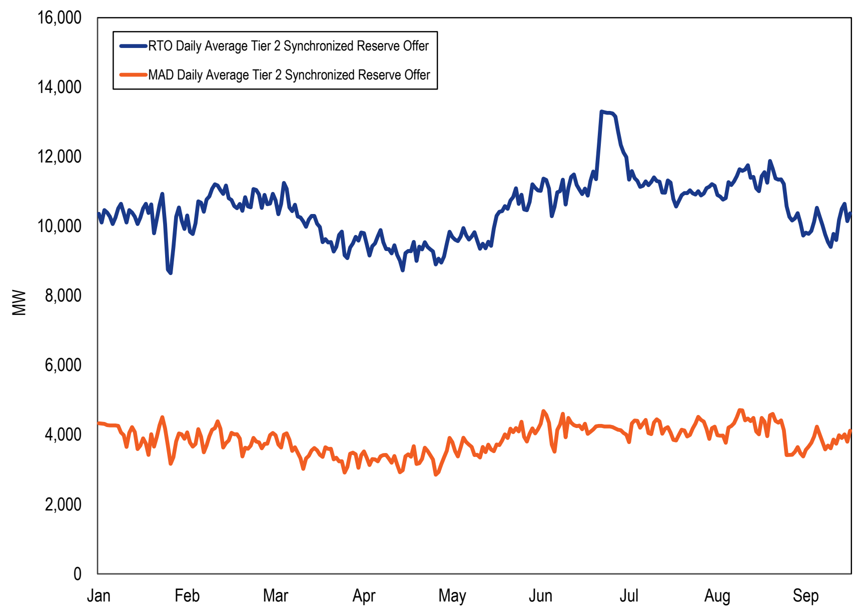
Offers

Daily cost based offer prices are submitted for each unit by the unit owner. For generators the offer price must include tier 1 synchronized reserve ramp rate, a tier 1 synchronized reserve maximum, self-scheduled status, synchronized reserve availability, synchronized reserve offer quantity (MW), tier 2 synchronized reserve offer price, energy use for tier 2 condensing resources (MW), condense to gen cost, shutdown costs, condense startup cost, condense hourly cost, condense notification time, and spin as a condenser status (a field to identify if a running CT can be dispatched for spinning reserve). The synchronized reserve offer price made by the unit owner is subject to an offer cap of marginal cost plus $7.50 per MW. All suppliers are paid the higher of the market clearing price or their offer plus their unit specific opportunity cost. The offer includes the synchronized reserve offer quantity (MW). The offer quantity is limited to the economic maximum or less if a spin maximum value less than economic maximum is supplied (subject to prior authorization by PJM). PJM monitors this offer by checking to ensure that all offers are greater than or equal to 90 percent of the resource's ramp rate times ten minutes. A resource that is unable to participate in the synchronized reserve market during a given hour may set its hourly offer to 0 MW. A resource that cannot reliably provide synchronized reserve may offer 0 MW, e.g. nuclear, wind, solar, and batteries.

Figure 10-11 shows the daily average of hourly offered tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve subzone. In the first nine months of 2014, the ratio of on-line and eligible tier 2 synchronized reserve to synchronized reserve required in the Mid-Atlantic Dominion subzone was 2.97 averaged over all hours. For the RTO Synchronized Reserve Zone the ratio was 7.64.

After October 1, 2012, PJM adopted a new rule creating a must offer requirement for synchronized reserve for all generation that is online, non-emergency, and available to produce energy. Changes to hourly and daily offer levels are the result of on-line status, minimum/maximum runtimes, minimum notification times, maintenance status and grid conditions including constraints.

Figure 10-11 Tier 2 synchronized reserve daily average offer and eligible volume (MW): January through September 2014



Synchronized reserve is offered by steam, CT, CC, hydroelectric and DR resources. Figure 10-12 shows average offer MW volume by market and unit type for the MAD subzone and Figure 10-13 shows average offer MW volume by market and unit type for the RTO Zone.

Figure 10-12 Mid-Atlantic Dominion subzone average daily tier 2 synchronized reserve offer by unit type (MW): January through September 2012 through 2014

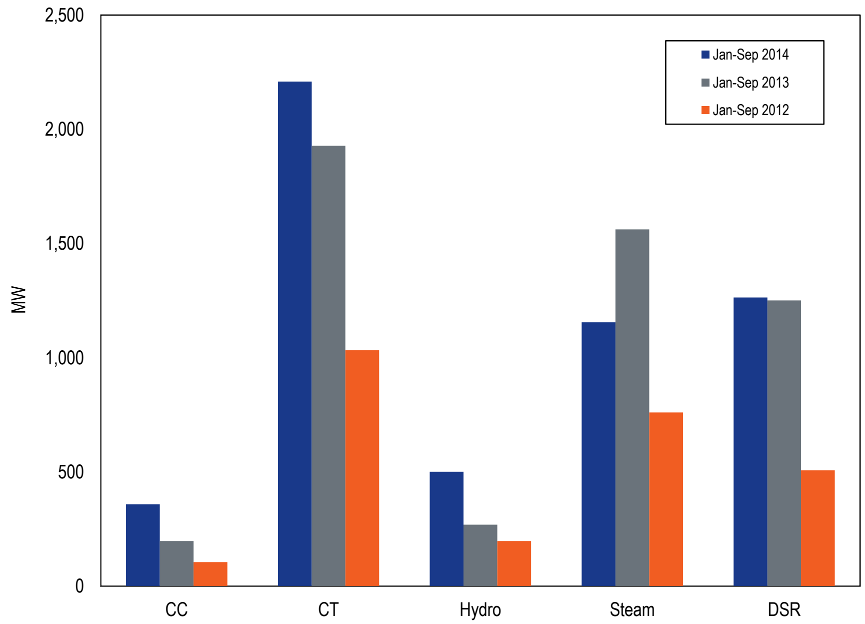
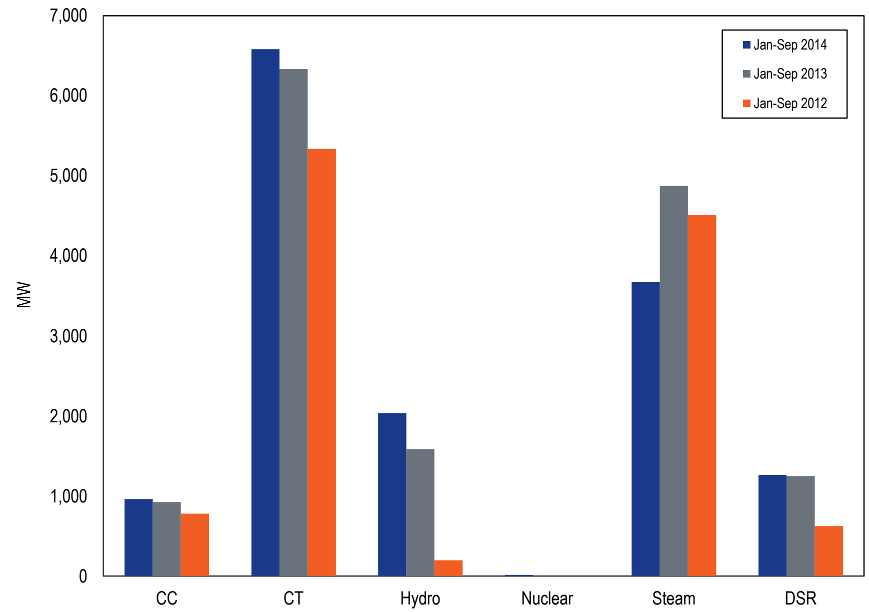


Figure 10-13 RTO Zone average daily tier 2 synchronized reserve offer by unit type (MW): January through September 2012 through 2014



Market Performance

Price

The price of tier 2 synchronized reserve is calculated in real time every five minutes and averaged each hour for the RTO Reserve Zone and the MAD subzone.

The MAD subzone cleared a Tier 2 Synchronized Reserve Market in 99.0 percent of hours in the first nine months of 2014, compared to 67.0 percent of hours in the first nine months of 2013.

In the first nine months of 2014, the weighted average Tier 2 synchronized reserve market clearing price in the RTO Zone only for all cleared hours was \$13.85. In the first nine months of 2013, the weighted average synchronized reserve market clearing price in the RTO Zone (only cleared in 33 hours) was $6.86.

In the first nine months of 2014, the weighted average Tier 2 synchronized reserve market clearing price in the MAD subzone for all cleared hours was $15.42. In the first nine months of 2013, the weighted average synchronized reserve market clearing price in the MAD subzone was $7.11.

Both the RTO Zone and the MAD subzone experienced a primary reserve shortage and resulting shortage pricing event on January 6 in hour 19 and 20 and on January 7 in hours 7 through 12, 17 and 18. Shortage pricing for synchronized reserve was triggered on January 6 and 7. On January 6, hours 19 and 20, an RTO-wide shortage pricing event was triggered by a Voltage Reduction Action implemented in response to RTO-wide synchronized reserve levels falling below 1,375 MW synchronized reserve requirement. On January 7 deficient synchronized reserves in the RTO Reserve Zone caused shortage pricing in hours 7 through 11. On January 7, deficient synchronized reserves in the Mid-Atlantic Dominion Reserve Subzone caused Shortage Pricing in hours 7 through 12, 17 and 18.

Supply, performance, and demand are reflected in the price of synchronized reserve (Figure 10-9 and Figure 10-10). In January 2014, cold weather meant that on-line resources were generating at or near their economic maximum. As a result, there was little tier 1 synchronized reserve available and more tier 2 synchronized reserve were required.

Table 10-18 Mid-Atlantic Dominion Subzone, weighted SRMCP and cleared MW: January through September 2014

Year	Month	Weighted Average Tier 2 Synchronized Reserve Market Clearing Price	Average Hourly Tier 1 Synchronized Reserve Estimated Hour Ahead	Average Hourly Demand Response Cleared (MW)	Average Tier 2 Generation Synchronized Reserve Cleared (MW)
2014	Jan	$40.39	243.2	113.7	1,078.7
2014	Feb	$14.64	842.3	53.2	468.3
2014	Mar	$22.30	974.0	61.5	272.9
2014	Apr	$8.73	876.6	97.8	510.9
2014	May	$8.73	1,050.6	70.9	282.3
2014	Jun	$5.91	1,090.2	42.3	219.0
2014	Jul	$6.86	1,216.1	30.7	92.3
2014	Aug	$3.31	1,056.6	37.7	247.1
2014	Sep	$1.71	1,019.2	40.1	283.1

The RTO Zone cleared a Tier 2 Synchronized Reserve Market in 40.2 percent of hours in the first nine months of 2014 compared to less than one percent of hours in the first nine months of 2013. For all cleared hours, the average amount of tier 2 synchronized reserve cleared was 362.0 MW at a weighted average SRMCP of $13.85 (compared with $6.86 for the first nine months of 2013).

In the MAD subzone, for the first nine months of 2014 (Table 10-18), an average of 283 MW of tier 2 synchronized reserve was cleared at a weighted average price $15.42. For the first nine months of 2013, the weighted average price for tier 2 synchronized reserve in the RTO Reserve Zone was $7.11.

Table 10-19 RTO zone weighted SRMCP and cleared MW: January through September, 2014

Year	Month	Weighted Average Tier 2 Synchronized Reserve Market Clearing Price	Average Tier 1 Synchronized Reserve Estimated Hour Ahead	Average Hourly Demand Response Cleared (MW)	Average Tier 2 Generation Synchronized Reserve Cleared (MW)
2014	Jan	$45.14	391.3	113.7	602.0
2014	Feb	$16.25	1,208.9	53.2	349.0
2014	Mar	$22.04	1,345.9	61.5	447.0
2014	Apr	$9.16	1,413.0	97.8	708.0
2014	May	$8.22	1,487.8	70.9	301.0
2014	Jun	$5.88	2,053.7	44.6	234.0
2014	Jul	$7.93	2,291.3	29.7	143.0
2014	Aug	$4.09	1,994.6	36.9	219.0
2014	Sep	$1.89	1,767.2	39.2	257.0
2014	Average	$15.42	1,550.4	60.8	362.2

Price and Cost

As a result of changing grid conditions, load forecasts, and unexpected generator performance, prices do not always cover the full cost and final LOC for each resource. Because price formation occurs within the hour (on five minute basis integrated over the hour) but the synchronized reserve commitment occurs prior to the hour, the realized within hour price can be zero even when some tier 2 synchronized reserve is cleared. All resources cleared in the market are guaranteed to be made whole and are paid if the SRMCP does not compensate them for their offer plus LOC.

The full cost of tier 2 synchronized reserve including payments for the clearing price and out of market costs is calculated and compared to the price. The closer the price to cost ratio is to one hundred percent, the more the market price reflects the full cost of tier 2 synchronized reserve. A price to cost ratio close to one hundred percent is an indicator of an efficient synchronized reserve market design.

For the first nine months of 2014, the price to cost ratio of the full RTO Zone Tier 2 Synchronized Reserve Market averaged 62.9 percent; the price to cost ratio of the RTO Zone excluding MAD averaged 59.4 percent; the price to cost ratio of the MAD subzone averaged 63.8 percent.

Table 10-20 Full RTO, RTO, Mid-Atlantic Subzone Tier 2 synchronized reserve MW, credits, price, and cost: January through September, 2014

Synchronized Reserve Market	Year	Month	Total MW	Total Credits	Weighted Synchronized Reserve Market Clearing Price	Cost	Price / Cost Ratio
Full RTO Zone	2014	Jan	445,496	$23,844,697	$45.14	$53.52	84.3%
Full RTO Zone	2014	Feb	258,309	$5,821,713	$16.25	$22.54	72.1%
Full RTO Zone	2014	Mar	331,076	$10,886,718	$22.04	$32.88	67.0%
Full RTO Zone	2014	Apr	523,600	$6,802,832	$9.16	$12.99	70.5%
Full RTO Zone	2014	May	222,982	$3,040,617	$8.22	$13.64	60.3%
Full RTO Zone	2014	Jun	173,110	$2,098,749	$5.88	$12.12	48.5%
Full RTO Zone	2014	Jul	105,641	$2,073,770	$7.93	$19.63	40.4%
Full RTO Zone	2014	Aug	162,348	$2,351,274	$4.09	$14.48	28.2%
Full RTO Zone	2014	Sep	155,789	$1,544,579	$1.88	$9.91	19.0%
Full RTO Zone	Total		2,378,350	$58,464,948	$13.40	$21.30	62.9%
RTO Only	2014	Jan	20,161	$4,625,280	$145.29	$229.42	63.3%
RTO Only	2014	Feb	24,106	$1,005,403	$31.97	$41.71	76.7%
RTO Only	2014	Mar	49,150	$1,483,557	$20.55	$30.18	68.1%
RTO Only	2014	Apr	189,103	$2,651,007	$9.93	$14.02	70.8%
RTO Only	2014	May	64,474	$1,263,484	$6.97	$19.60	35.6%
RTO Only	2014	Jun	59,849	$802,216	$5.82	$13.40	43.4%
RTO Only	2014	Jul	36,502	$568,835	$9.95	$15.58	63.9%
RTO Only	2014	Aug	46,264	$903,706	$6.04	$19.53	30.9%
RTO Only	2014	Sep	26,481	$517,254	$2.69	$19.53	13.8%
RTO Only	Total		516,090	$13,820,742	$26.58	$44.78	59.4%
MAD Subzone	2014	Jan	425,336	$19,219,418	$40.39	$45.19	89.4%
MAD Subzone	2014	Fen	234,203	$4,816,310	$14.64	$20.56	71.2%
MAD Subzone	2014	Mar	281,925	$9,403,161	$22.30	$33.35	66.9%
MAD Subzone	2014	Apr	334,497	$4,151,824	$8.73	$12.41	70.3%
MAD Subzone	2014	May	158,507	$1,777,133	$8.73	$11.21	77.8%
MAD Subzone	2014	Jun	113,261	$1,296,534	$5.91	$11.45	51.6%
MAD Subzone	2014	Jul	69,139	$1,504,934	$6.86	$21.77	31.5%
MAD Subzone	2014	Aug	116,084	$1,447,568	$3.31	$12.47	26.6%
MAD Subzone	2014	Sep	129,308	$1,027,325	$1.71	$7.94	21.6%
MAD Subzone	Total		1,862,260	$44,644,206	$12.51	$19.60	63.8%

Compliance

Synchronized reserve non-compliance has two components: failure to deliver scheduled 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 identified and quantified the failure of scheduled tier 2 synchronized reserve resources to deliver during spinning events since 2011.[20] When synchronized reserve resources self schedule or clear the Tier 2 Synchronized Reserve Market they are obligated to provide their full scheduled Tier 2 MW during a spinning event. Actual spinning event response is determined by final output minus initial output where final output is the largest output between 9 and 11 minutes after start of the event, and initial output is the lowest output between one minute before the event and one minute after the event.[21] Tier 2 resources are obligated to sustain their final output for the shorter of the length of the event or 30 minutes.

The MMU has reported the wide range of spinning event response levels and recommended that PJM take action to increase compliance rates. An enhanced penalty structure became effective January 1, 2014. Penalties can be assessed for any spinning event greater than 10 minutes during which flexible or inflexible synchronized reserve was scheduled either by the resource owner or by PJM. In the first nine months of 2014, 15 spinning events occurred that met these criteria.

20 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at pg. 250.
21 See PJM, "Manual 11, Energy & Ancillary Services Market Operations," Rev. 67, June 1, 2014 Settlements, p. 75.

Table 10-21 Synchronized reserve events greater than 10 minutes, Tier 2 Response Compliance, RTO Reserve Zone, January through September 2014

2014 Qualifying Spinning Events (DD-MON-YYYY HR)	Event Duration (Minutes)	Total Scheduled Tier 2 MW	Tier 2 Response Shortfall MW	Percent Compliance
06-Jan-2014 22	68	1,190	353	70.3%
07-Jan-2014 02	25	1,170	94	92.0%
07-Jan-2014 04	34	1,205	235	80.5%
07-Jan-2014 11	11	548	79	85.6%
07-Jan-2014 13	41	1,472	327	77.8%
10-Jan-2014 16	12	550	43	92.1%
31-Jan-2014 15	13	410	46	88.8%
01-Mar-2014 05	26	196	28	85.7%
27-Mar-2014 10	56	511	75	85.4%
01-May-2014 10	13	549	104	81.0%
01-May-2014 15	13	487	100	79.5%
03-May-2014 17	13	304	57	81.3%
06-Sep-2014 10	18	224	165	26.4%
20-Sep-2014 20	14	361	126	65.1%
29-Sep-2014 05	15	112	109	2.7%

For the qualifying spinning events that occurred in the first nine months of 2014, 20.0 percent of all scheduled synchronized reserve MW were not delivered and were penalized.

Tier 1 resource owners are credited for the amount of synchronized reserve they provide in response to a spinning event.[22] Tier 2 resources owner are not credited for spinning event response. Tier 2 resources owners are penalized in the amount of their shortfall at SRMCP for the lesser of the average number of days between events, or the number of days since the previous event in which the resource did respond. The average number of days between events calculated by PJM Performance Compliance for 2014 is 15 days. In addition, a resource will be penalized for the amount of MW it falls short of its offer for the entire hour, not just for the portion of the hour covered by the spinning event.[23] Resource owners are permitted to aggregate the response of multiple units to offset an underresponse from one unit with an overresponse from a different unit for the purpose of reducing an underresponse penalty.

22 See PJM, "Manual 11, Energy & Ancillary Services Market Operations," Rev. 67, June 1, 2014 Non Performance, p. 76.

23 See PJM "M-28 Operating Agreement Accounting," Rev. 64, April 11, 2014, p. 42. See also "Manual 11, Energy & Ancillary Services Market Operations," Rev. 67, June 1, 2014 Non Performance, p. 76.

A second compliance issue is the failure to comply with the must offer requirement. The shortage pricing rules include a must offer requirement for Tier 2 synchronized reserve for most generators under normal conditions, and an expanded set of generators under defined 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 a tier 2 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, off-line available generation capacity resources must have a tier 2 offer and be available for reserve. As of September 30, 2014, the MMU estimates that 3.4 percent of eligible energy resources are not in compliance with the synchronized reserve must-offer requirement.

PJM is to monitor every generator subject to the must offer requirement to ensure that it has submitted a tier 2 synchronized reserve offer greater than or equal to ninety percent of its ramp rate time 10 minutes.[24]

History of Spinning Events

Synchronized reserve is designed to provide relief for disturbances.[25] In the absence of a disturbance, PJM dispatchers have used synchronized reserve as a source of energy to provide relief from low ACE. Such an event occurred on January 6, 2014. Three extended (68, 25, and 34 minutes) spinning events were declared during afternoon and evening hours of January 6 for low ACE. The 56 minute spinning event of March 27, 2014 was to supply reactive transfer voltage support. Spinning events of 56 and 68 minutes for low ACE are indicative of either an inadequate supply of primary reserve or the use of primary reserve when secondary reserve would be more appropriate. The first nine months of 2014 saw two short duration spinning events for low ACE (July 8, 03:07, and September 29, 10:08). This is an expensive solution during an hour when the hour ahead market solution and reserve dispatch indicated no shortage of primary reserve. PJM's primary reserve levels have been sufficient to recover from disturbances and should remain available in

24 See PJM, "Manual 11, Energy & Ancillary Services Market Operations," Rev. 67, June 1, 2014 Section 4.2.1, p. 62.

25 2013 State of the Market Report for PJM, Appendix F – PJM's DCS Performance, pp 451-452.

the absence of disturbance. The risk of using synchronized reserves for energy or any non-disturbance is that it reduces the amount of synchronized reserve available for a disturbance.

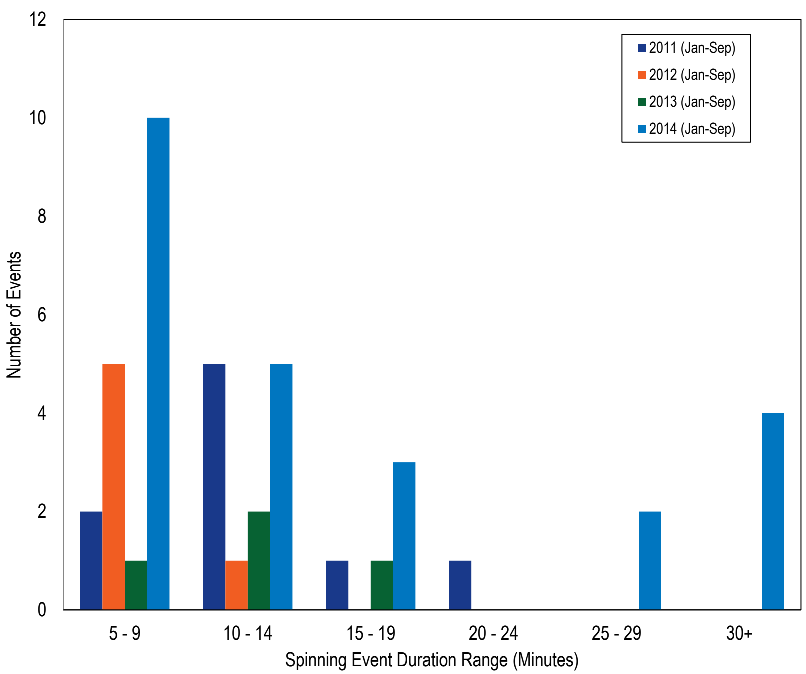
Table 10-22 Spinning events, 2010 through 2014

Effective Time	Region	Duration (Minutes)	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	JAN-06-2014 22:01	RTO	68
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	JAN-07-2014 02:20	RTO	25
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	JAN-07-2014 04:18	RTO	34
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	JAN-07-2014 11:27	RTO	11
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	JAN-07-2014 13:20	RTO	41
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	JAN-10-2014 16:46	RTO	12
MAY-15-2010 03:03	RFC	6	FEB-25-2011 14:12	RFC	10	APR-16-2012 00:20	Mid-Atlantic	9	MAY-07-2013 17:33	RTO	8	JAN-21-2014 18:52	RTO	6
MAY-28-2010 04:06	Mid-Atlantic	5	MAR-30-2011 19:13	RFC	12	APR-16-2012 11:18	RFC	8	JUN-05-2013 18:54	RTO	20	JAN-22-2014 02:26	RTO	7
JUN-15-2010 00:46	RFC	34	APR-02-2011 13:13	Mid-Atlantic	11	APR-19-2012 11:54	RFC	16	JUN-08-2013 15:19	RTO	9	JAN-22-2014 22:54	RTO	8
JUN-19-2010 23:49	Mid-Atlantic	9	APR-11-2011 00:28	RFC	6	APR-20-2012 11:08	Mid-Atlantic	7	JUN-12-2013 17:35	RTO	10	JAN-25-2014 05:22	RTO	10
JUN-24-2010 00:56	RFC	15	APR-16-2011 22:51	RFC	9	JUN-20-2012 13:35	RFC	7	JUN-30-2013 01:22	RTO	10	JAN-26-2014 17:11	RTO	6
JUN-27-2010 19:33	Mid-Atlantic	15	APR-21-2011 20:02	Mid-Atlantic	6	JUN-26-2012 17:51	RFC	7	JUL-03-2013 20:40	RTO	13	JAN-31-2014 15:05	RTO	13
JUL-07-2010 15:20	RFC	8	APR-27-2011 01:22	RFC	8	JUL-23-2012 21:45	RFC	18	JUL-15-2013 18:43	RTO	29	FEB-02-2014 14:03	RTO	8
JUL-16-2010 20:45	Mid-Atlantic	19	MAY-02-2011 00:05	Mid-Atlantic	21	AUG-03-2012 12:44	RFC	10	JUL-28-2013 14:20	RTO	10	FEB-08-2014 06:05	RTO	18
AUG-11-2010 19:09	RFC	17	MAY-12-2011 19:39	RFC	9	SEP-08-2012 04:34	RFC	12	SEP-10-2013 19:48	RTO	68	FEB-22-2014 23:05	RTO	7
AUG-13-2010 23:19	RFC	6	MAY-26-2011 17:17	Mid-Atlantic	20	SEP-27-2012 17:19	Mid-Atlantic	7	OCT-28-2013 10:44	RTO	33	MAR-01-2014 05:18	RTO	26
AUG-16-2010 07:08	RFC	17	MAY-27-2011 12:51	RFC	6	OCT-17-2012 10:48	RTO	10	DEC-01-2013 11:17	RTO	9	MAR-05-2014 21:25	RTO	8
AUG-16-2010 19:39	Mid-Atlantic	11	MAY-29-2011 09:04	RFC	7	OCT-23-2012 22:29	RTO	19	DEC-07-2013 19:44	RTO	7	MAR-13-2014 20:39	RTO	8
SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27	OCT-30-2012 05:12	RTO	14				MAR-27-2014 10:37	RTO	56
SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7	NOV-25-2012 16:32	RTO	12				APR-14-2014 01:16	RTO	10
OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9	DEC-16-2012 07:01	RTO	9				APR-25-2014 17:33	RTO	6
OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8	DEC-21-2012 05:51	RTO	7				MAY-01-2014 14:18	RTO	13
OCT-16-2010 03:25	RFCNonMA	7	JUN-26-2011 22:03	Mid-Atlantic	10	DEC-21-2012 10:29	RTO	5				MAY-03-2014 17:11	RTO	13
OCT-27-2010 10:35	RFC	7	JUL-10-2011 11:20	RFC	10							MAY-14-2014 01:36	RTO	5
OCT-27-2010 12:50	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12							JUL-08-2014 03:07	RTO	9
NOV-26-2010 14:24	RFC	13	AUG-02-2011 01:08	RFC	6							JUL-25-2014 19:19	RTO	7
NOV-27-2010 11:34	RFC	8	AUG-18-2011 06:45	Mid-Atlantic	6							SEP-06-2014 13:32	RTO	18
DEC-08-2010 01:19	RFC	11	AUG-19-2011 14:49	RFC	5							SEP-20-2014 23:42	RTO	14
DEC-09-2010 20:07	RFC	5	AUG-23-2011 17:52	RFC	7							SEP-29-2014 10:08	RTO	15
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									

Spinning events (Table 10-22) are usually caused by a sudden generation outage or transmission disruption (disturbance) requiring PJM to load synchronized reserve.[26] PJM also calls spinning events for non-disturbance events, which it characterizes as low ACE. The reserve remains loaded until system balance is recovered. From 2010 through the first nine months of 2014, PJM experienced 120 spinning events, between two and three events per month. Spinning events had an average length of 12 1/2 minutes.

Compliance by tier 2 synchronized reserve to the 68 minute spinning event of January 6 was very poor (Table 10-21) at 45.4 percent non-compliance among MAD subzone resources and 29.7 percent non-compliance overall.

Figure 10-14 Spinning events duration distribution curve, January through September 2011 through 2014



26 See PJM, "Manual 12, Balancing Operations," Revision 30 (December 1, 2013), pp. 36-37.

Non-Synchronized Reserve Market

Non-synchronized reserve is reserve MW available within ten minutes but not synchronized to the grid. There is no defined requirement for non-synchronized reserves. It is available to meet the primary reserve requirement. Generation resources that have designated their entire output as emergency are not eligible to provide non-synchronized reserves. Generation resources that are not available to provide energy are not eligible to provide non-synchronized reserves.

There are no offers for non-synchronized reserve. The market solution software evaluates all eligible resources and schedules them economically.

Startup time for non-synchronized reserve resources is not subject to testing. There is no non-synchronized reserve offer MW or offer price. Prices are determined solely by the lost opportunity cost created by any deviation from economic merit order required to maintain the non-synchronized reserve commitment. Since non-synchronized reserve is a lower quality product, its clearing price is always less than or equal to the synchronized reserve market clearing price. In most hours, the non-synchronized reserve clearing price is zero.

Market Structure

Demand

PJM specifies that 1,700 MW of ten minute primary reserve must be available in the Mid-Atlantic Dominion Reserve subzone of which 1,300 MW must be synchronized reserve, and that 2,063 MW of ten minute primary reserve must be available in the RTO Reserve Zone of which 1,375 MW must be synchronized reserve (Figure 10-2). The balance of primary reserve can be made up by the most economic combination of synchronized and non-synchronized reserve.

Supply

Figure 10-2 shows that most of the primary reserve requirement (orange line) in excess of the synchronized reserve requirement (yellow line) is satisfied by non-synchronized reserve (light blue area). Except for four hours on January 7, 2014 there was always enough non-synchronized reserve available to meet the primary reserve requirement.

There are no offers for non-synchronized reserve. Neither MW nor price is offered for non-synchronized reserve. The market solution software evaluates all eligible resources and schedules them economically. Examples of equipment that generally qualifies as non-synchronized reserve are run of river hydro, pumped hydro, combustion turbines, combined cycles and diesels.[27] For the first nine months of 2014 an average of 684.9 MW of non-synchronized reserve was scheduled hourly in the Mid-Atlantic Dominion subzone. For the first nine months of 2014, an average of 682.8 MW of non-synchronized reserve was scheduled hourly in the RTO Zone.

CTs provided 53.1 percent and hydro 44.7 percent of cleared non-synchronized reserve MW in the first nine months of 2014. The remaining 2.1 percent of cleared non-synchronized reserve was provided by diesel resources.

Market Concentration

The supply of non-synchronized reserves in the Mid-Atlantic Dominion subzone was highly concentrated. The supply of non-synchronized reserves in the RTO Zone was also highly concentrated.

Table 10-23 Non-synchronized reserve market HHIs, January through September 2014

Year	Month	Mid Atlantic Dominion HHI	RTO HHI
2014	Jan	3034	3468
2014	Feb	2703	3610
2014	Mar	2859	2396
2014	Apr	4366	5333
2014	May	3784	6445
2014	Jun	3470	4054
2014	Jul	2927	6230
2014	Aug	4348	7761
2014	Sep	5376	8439
2014	Average	3652	5304

27 See PJM. "Manual 11, Energy & Ancillary Services Market Operations" Revision 67 (June 1, 2014), p. 79.

Table 10-24 Non-synchronized reserve market pivotal supply test, January through September 2014

Year	Month	Mid Atlantic Dominion Three Pivotal Supplier Hours	RTO Three Pivotal Supplier Hours
2014	Jan	97.2%	88.8%
2014	Feb	100.0%	95.7%
2014	Mar	99.2%	93.3%
2014	Apr	100.0%	92.6%
2014	May	100.0%	90.8%
2014	Jun	100.0%	95.5%
2014	Jul	99.7%	99.6%
2014	Aug	100.0%	98.0%
2014	Sep	100.0%	86.8%
2014	Average	99.6%	93.5%

Price

The price of non-synchronized reserve is calculated in real time every five minutes and averaged each hour for the RTO Reserve Zone and the Mid Atlantic Dominion Reserve subzone. Resources eligible for non-synchronized reserve make no price offer or MW offer.

Figure 10-15 shows the daily average hour ahead non-synchronized reserve market clearing price and average scheduled MW for the MAD subzone. The MAD subzone non-synchronized reserve market had a clearing price greater than zero in 406 (7.5 percent) hours in the first nine months of 2014, at an average price of $33.44 per MW. The weighted non-synchronized reserve market clearing price for all hours in the MAD subzone, including cleared hours when the price was zero, was $2.14 per MW. The maximum clearing price was the shortage pricing non-synchronized reserve maximum of $400 per MW for four consecutive hours on January 7, 2014. Figure 10-16 shows the daily average hour ahead non-synchronized reserve market clearing price and average scheduled MW for the RTO Zone. The RTO Zone non-synchronized reserve market had a clearing price greater than zero in 262 (4.1 percent) hours in the first nine months of 2014 at an average price of $29.55. The weighted non-synchronized reserve market clearing price for all hours in the RTO Zone including cleared hours when the price was zero, was $0.86. The maximum clearing price was the shortage pricing non-synchronized reserve maximum of $400 for four consecutive hours on January 7, 2014.

Figure 10-15 Daily average MAD subzone Non-Synchronized Reserve Market clearing price and MW purchased: January through September 2014

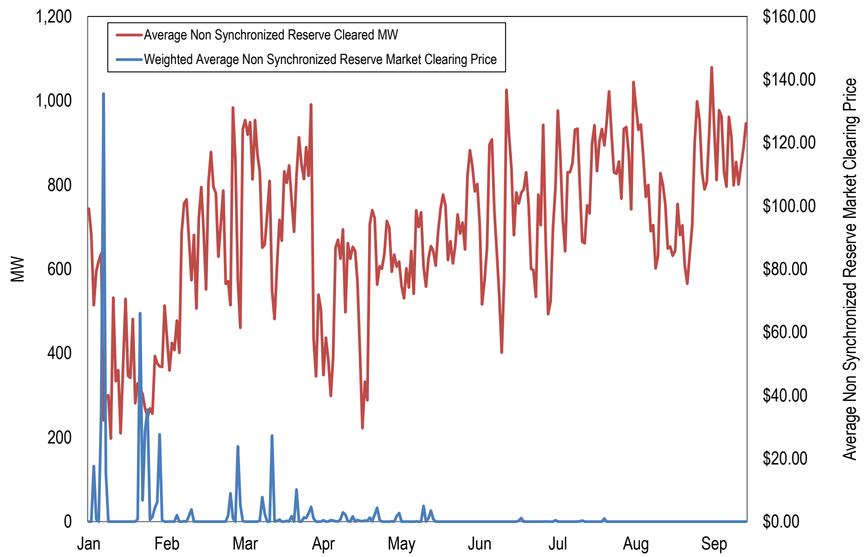
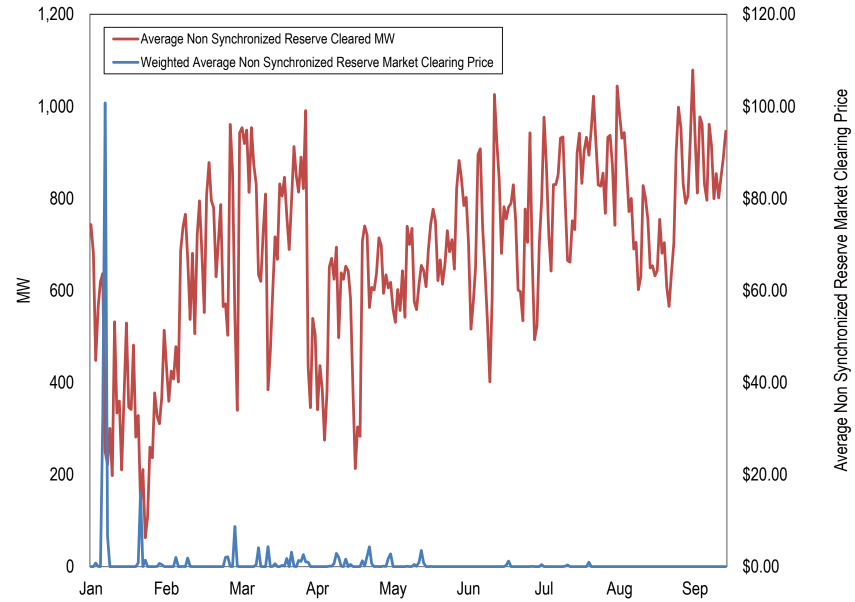


Figure 10-16 Daily average RTO Zone Non-Synchronized Reserve Market clearing price and MW purchased: January through September 2014



Price and Cost

As a result of changing grid conditions, load forecasts, and unexpected generator performance, prices sometimes do not cover the full cost and final LOC for each resource. All resources cleared in the market are guaranteed to be made whole and are paid uplift credits if the SRMCP does not fully compensate them.

The full cost of non-synchronized reserve including payments for the clearing price and uplift costs is calculated and compared to the price (Table 10-25). The closer the price to cost ratio comes to one, the more the market price reflects the full cost of non-synchronized reserve.

For the first nine months of 2014, the price to cost ratio of the full RTO Zone non-synchronized reserve market averaged 40.5 percent; the price to cost ratio of the RTO Zone excluding MAD averaged 47.3 percent; the price to cost ratio of the MAD subzone averaged 53.6 percent.

Table 10-25 Full RTO, RTO, Mid-Atlantic Subzone non-synchronized reserve MW, credits, price, and cost: January through September, 2014

Market	Year	Month	Total Non-Synchronized Reserve MW	Total Charges	Weighted Non-Synchronized Reserve Market Clearing Price	Cost
Full RTO Zone	2014	Jan	537,450	$5,756,058	$7.16	$10.71
Full RTO Zone	2014	Feb	830,551	$871,881	$0.30	$1.05
Full RTO Zone	2014	Mar	1,146,330	$2,771,506	$0.95	$2.42
Full RTO Zone	2014	Apr	772,288	$464,952	$0.93	$0.60
Full RTO Zone	2014	May	955,433	$1,015,507	$0.36	$1.06
Full RTO Zone	2014	Jun	1,065,981	$227,613	$0.05	$0.21
Full RTO Zone	2014	Jul	1,147,341	$553,232	$0.07	$0.48
Full RTO Zone	2014	Aug	1,200,793	$317,683	$0.00	$0.26
Full RTO Zone	2014	Sep	1,218,312	$185,324	$0.00	$0.15
Total	2014		8,874,479	$12,163,758	$1.09	$1.37
RTO Only	2014	Jan	254,704	$1,945,725	$5.45	$7.64
RTO Only	2014	Feb	414,234	$406,812	$0.25	$0.98
RTO Only	2014	Mar	566,368	$1,011,285	$0.70	$1.79
RTO Only	2014	Apr	380,225	$246,437	$0.87	$0.65
RTO Only	2014	May	477,219	$603,341	$0.34	$1.26
RTO Only	2014	Jun	532,990	$135,670	$0.05	$0.25
RTO Only	2014	Jul	573,670	$308,849	$0.07	$0.54
RTO Only	2014	Aug	600,397	$95,544	$0.00	$0.16
RTO Only	2014	Sep	609,156	$44,875	$0.00	$0.07
Total	2014		4,408,964	$4,798,537	$0.86	$1.09
MAD Subzone	2014	Jan	282,746	$2,705,884	$14.30	$9.57
MAD Subzone	2014	Feb	416,317	$658,706	$0.64	$1.58
MAD Subzone	2014	Mar	579,962	$1,758,222	$2.63	$3.03
MAD Subzone	2014	Apr	392,063	$80,410	$1.14	$0.21
MAD Subzone	2014	May	478,214	$812,728	$0.49	$1.70
MAD Subzone	2014	Jun	532,990	$200,618	$0.05	$0.38
MAD Subzone	2014	Jul	573,670	$515,342	$0.06	$0.90
MAD Subzone	2014	Aug	600,397	$158,842	$0.00	$0.26
MAD Subzone	2014	Sep	609,156	$92,662	$0.00	$0.15
Total	2014		4,465,515	6,983,415	$2.14	$1.56

Secondary Reserve (DASR)

PJM maintains a day-ahead, offer based market for 30-minute secondary reserve.[28] The DASR market has no performance obligations. The MMU recommends elimination of the Day-Ahead Market and its replacement with a Real-Time Market for a dispatchable reserve product beyond the 30-minute limit for primary reserves.

DASR 30-minute reserve requirements are determined by PJM for each reliability region.[29] In the Reliability*First* (RFC) region, secondary reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[30] The RFC and Dominion secondary reserve requirements are added together to form a single RTO DASR requirement defined as a percentage of the daily peak load forecast, currently 6.27 percent. The requirement is applicable for all hours of the operating day. If the DASR Market does not result in procuring adequate scheduling reserves, PJM is required to schedule additional operating reserves.[31]

Market Structure

Supply

The amount of DASR available is the lesser of the energy ramp rate for all on-line units times thirty minutes, or the emergency maximum minus the day-ahead dispatch point. For off-line resources capable of being online in thirty minutes, the DASR quantity is emergency maximum. For the first nine months of 2014, the average available hourly DASR was 42,261 MW. The DASR MW purchased averaged 6,379 MW per hour for the first nine months of 2014, a decrease from 6,895 MW per hour in the first nine months of 2013. Although there was no shortage of DASR in the market solution, the market does not guarantee the availability of scheduled reserve during real time hours. There were several hours in September 2013 and January 2014 when secondary reserve was needed but was not available in real time.

28 See PJM. "Manual 35, Definitions and Acronyms," Revision 35, (April 11, 2014), p. 89.
29 See PJM. "Manual 13, Emergency Requirements," Revision 56 (June 1, 2014), p. 11.
30 See PJM. "Manual 13, Emergency Requirements," Revision 56 (June 1, 2014), p. 11.
31 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.

Market Concentration

In the first nine months of 2014, no hours would have failed a three pivotal supplier test in the DASR Market. No hours would have failed the three pivotal supplier test in the first nine months of 2013.

All generation resources are required to offer DASR.[32] Load response resources which are registered in PJM's Economic Load Response and are dispatchable by PJM are eligible to provide DASR. In the first nine months of 2014 six demand resources offered into the DASR market.

Market Conduct

PJM rules allow any unit with reserve capability that can be converted into energy within 30 minutes to offer into the DASR Market.[33] Units that do not offer have their offers set to $0.00 per MW.

Economic withholding remains an issue in the DASR Market. The direct marginal cost of providing DASR is zero. All offers greater than zero constitute economic withholding. On September 30, 2014, 9.8 percent of resources offered DASR at levels above $5 per MW.

Market Performance

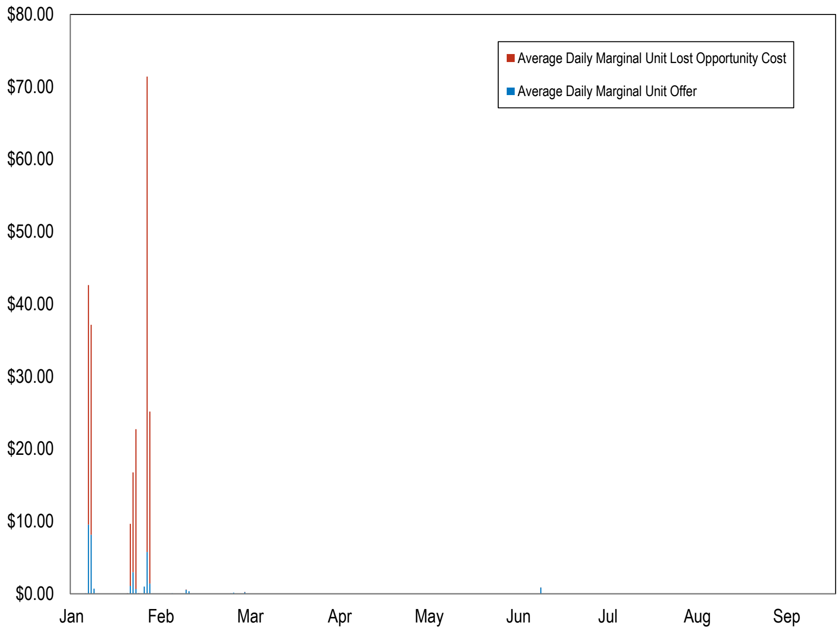
For 92.3 percent of hours in the first nine months of 2014, DASR cleared at a price of $0.00 per MWh (Figure 10-17). For the first nine months of 2014, the weighted average DASR price was $1.02. The highest DASR price was $534.66 on January 8, 2014. DASR prices are calculated as the sum of the offer price plus the opportunity cost.

Table 10-26 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: January 2012 Through September 2014

Year	Month	Average Required Hourly DASR (MW)	Minimum Clearing Price	Maximum Clearing Price	Weighted Average Clearing Price	Total DASR MW Purchased	Total DASR Credits
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
2012	Jul	8,811	$0.00	$155.15	$3.69	6,520,522	$20,723,970
2012	Aug	8,007	$0.00	$55.55	$0.51	5,956,318	$2,601,271
2012	Sep	6,656	$0.00	$7.80	$0.12	4,805,769	$540,586
2012	Oct	6,022	$0.00	$0.04	$0.00	4,454,997	$5,878
2012	Nov	6,371	$0.00	$1.00	$0.02	4,584,792	$75,561
2012	Dec	6,526	$0.00	$0.05	$0.00	5,179,876	$5,975
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
2013	Jul	8,129	$0.00	$230.10	$6.76	6,015,476	$37,265,364
2013	Aug	7,559	$0.00	$1.00	$0.01	5,623,824	$55,766
2013	Sep	6,652	$0.00	$119.62	$1.23	4,789,728	$5,245,835
2013	Oct	6,077	$0.00	$0.05	$0.00	4,497,258	$2,363
2013	Nov	6,479	$0.00	$0.10	$0.00	4,665,156	$5,123
2013	Dec	7,033	$0.00	$0.80	$0.01	5,232,625	$25,192
2014	Jan	6,218	$0.00	$534.66	$8.30	5,212,272	$35,349,968
2014	Feb	5,804	$0.00	$5.00	$0.05	4,541,860	$188,937
2014	Mar	5,303	$0.00	$3.00	$0.01	4,647,607	$47,749
2014	Apr	4465	$0.00	$0.05	$0.00	3,894,178	$1,241
2014	May	5531	$0.00	$0.10	$0.00	4,105,788	$7,386
2014	Jun	6901	$0.00	$7.80	$0.04	4,795,078	$163,325
2014	Jul	6933	$0.00	$0.25	$0.00	5,158,032	$9,358
2014	Aug	6788	$0.00	$0.01	$0.00	5,049,987	$1,286
2014	Sep	6057	$0.00	$0.04	$0.00	4,361,383	$2,444

32 See PJM "Manual 11," Revision 67, (June 1, 2014) p. 144 at Day-ahead Scheduling Reserves Market Rules.
33 See PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 67 (June 1,, 2014), p. 142.

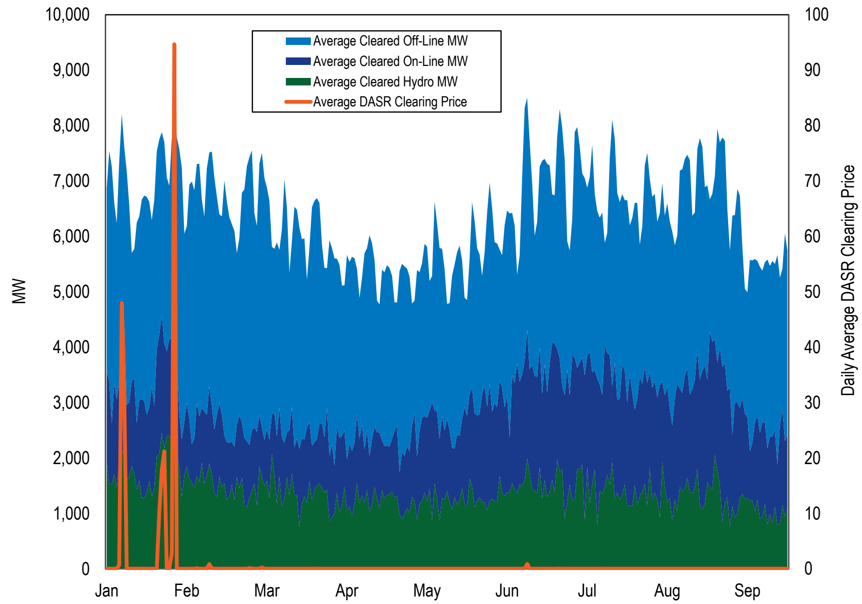
Figure 10-17 Daily average components of DASR clearing price, marginal unit offer and LOC: January through September 2014



When energy demand is high the reserve requirement cannot be filled without redispatching online resources which significantly affects the price. Figure 10-17 shows the impact of LOC on price when online resources must be redispatched to satisfy the DASR requirement.

Figure 10-18 illustrates the sensitivity of DASR prices to high energy dispatch and the resource types (on-line, off-line, and hydro) used for secondary reserve. DASR prices remain very low even at high energy dispatch levels. DASR prices increase very suddenly at peak loads as a result of high LOCs (Figure 10-17).

Figure 10-18 Daily average DASR prices and MW by classification: January through September, 2014



On September 10, 2013, a 68-minute spinning event was declared as a result of low ACE. On January 6, 2014, another 68-minute spinning event was declared, this time as the result of a unit trip. Different classes of reserve exist for different classes of imbalance. A 68-minute inability to bring ACE into balance with or without a sudden generator outage is the type of imbalance that 30-minute secondary reserve was created to recover from. On January 6, 2014, the average required DASR was 7,162 MW. On September 10, 2013, the 30-minute reserve requirement was 8,893 MW. Those required amounts of DASR were cleared day-ahead.

It is not clear why secondary reserve (DASR) was either unavailable to the dispatchers or was never called on the operating day when it was needed. PJM dispatch called on tier 1, tier 2, and non-synchronized reserve and was unable to restore balance for 68 minutes. It is not clear why the secondary reserve, already paid for, was not called or not callable.

The MMU recommends that PJM determine why secondary reserve was either unavailable or not dispatched on September 10, 2013, and January 6, 2014, and that PJM evaluate replacing the DASR Market with a real time secondary reserve product that is available and dispatchable in real time. PJM has conducted months of discussion, study, and analysis and proposed several changes to the DASR Market through its Energy/Reserve Pricing and Interchange Volatility (MIC) meeting.

Regulation Market

Regulation matches generation with very short term changes in load by moving the output of selected resources up and down via an automatic control signal. Regulation is provided by generators with a short-term response capability (less than five minutes) or by demand response (DR). The PJM Regulation Market is operated as a single market. Significant technical and structural changes were made to the Regulation Market in 2012.[34]

Market Design

The Regulation Market includes resources following two signals: RegA and RegD. Resources responding to either signal help control ACE. RegA is PJM's slow-oscillation regulation signal and is designed for resources with the ability to sustain energy output for long periods of time, but with limited ramp rates. RegD is PJM's fast-oscillation regulation signal and is designed for resources with the ability to quickly adjust energy output, but with limited ability to sustain energy output for long periods of time. Resources must qualify to follow the RegA and RegD signals. Resources must qualify for one signal or both signals, but will be assigned by the market clearing engine to follow only one signal within a given market hour. The PJM Regulation Market design includes three clearing price components (capability, performance, and lost opportunity cost), the rate of substitution between RegA and RegD resources (marginal benefit factor) and a measure of the quality of response (performance score) by a regulation resource to a regulation signal.

Regulation in PJM is generally provided by fleets of resources rather than by individual units. The regulation signals (RegA or RegD) are sent every two seconds to the fleet local control centers. A fleet is a set of resources owned or operated by a common entity. Fleet owners may allocate their assigned regulating capability to individual resources as they wish as long as the total allocated RegA capability and total allocated RegD capability match the totals assigned to them. Fleet local control centers report to PJM every two seconds the fleet response to the RegA and RegD signals.

There is no clear reason why PJM should continue to procure regulation on a fleet basis rather than on an individual resource basis, comparable to the energy market.

Regulation performance scores (0.0 to 1.0) measure the response of a regulating resource 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 correlation between the regulating resource output and the regulation signal; and precision, the difference between the regulation response and the regulation requested.[35]

While resources following RegA and RegD can both provide regulation service in PJM's regulation market, PJM's joint optimization is designed to determine and assign the optimal mix of RegA and RegD MW to meet the hourly regulation requirement. The optimal mix is a function of the relative effectiveness and cost of available RegA and RegD resources. The optimization of RegA and RegD assignments is dependent on the conversion of RegA and RegD resources into a common unit of measure via a marginal benefit factor (MBF).[36] The marginal benefit factor is a measure of the substitutability of RegD resources for RegA resources in satisfying the regulation requirement. The marginal benefit factor and the performance score of the resource are used to convert RegA and RegD resource regulation capability MW into comparable

34 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services," p. 271.

35 PJM "Manual 12: Balancing Operations" Rev. 30 (December 1, 2013); 4.5.6, p 52.

36 See the *2013 State of the Market Report for PJM*, Volume II, Section 10, "Issues Related to the Marginal Benefits Factor", pp. 294-8.

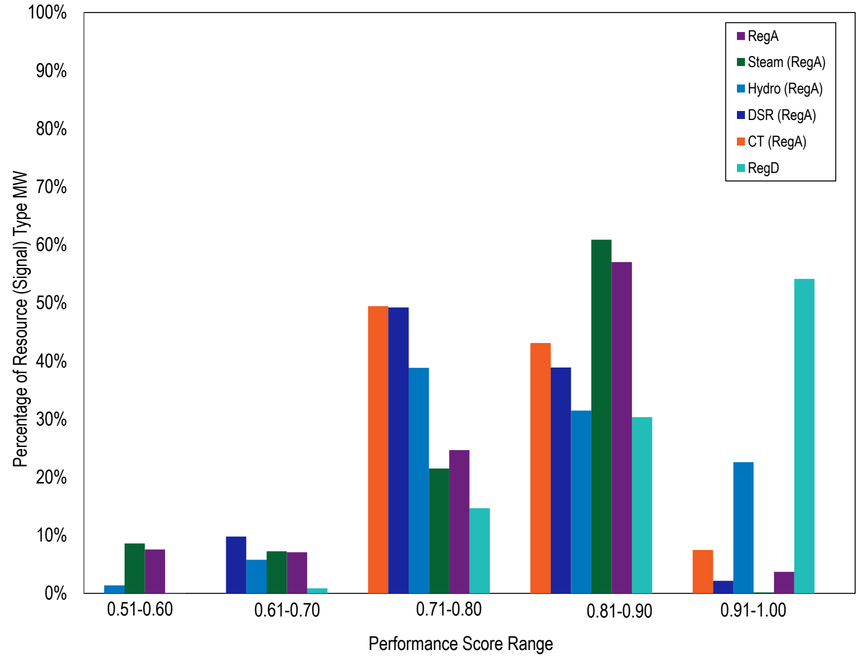
units, termed effective MW. Resource-specific marginal benefit factors are defined for each resource separately while the market marginal benefit factor is the marginal benefit factor of the last RegD resource cleared in the market. Effective MW, supplied from RegA or RegD resources, are defined in terms of RegA MW. Except where expressly referred to as effective MW or effective regulation MW, MW means regulation capability MW unadjusted for either marginal benefit factor or performance factor.

PJM posts clearing prices for the Regulation Market (RMCCP, RMPCP and RMCP) in dollars per unadjusted regulation capability MW. The regulation market clearing price (RMCP) for the hour is the simple average of the twelve five-minute RMCPs within the hour. The five-minute RMCP is the sum of 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 RMCP for the hour and the RMPCP for the hour.

Resources are paid by RMCP credits (the sum of RMCCP credits and RMPCP credits) and lost opportunity cost credits. RMCCP credits are calculated as MW of regulation capability times performance score times RMCCP. RMPCP credits are calculated as MW of regulation capability times performance score times RegD to RegA mileage ratio times RMPCP. RMCP credits are calculated as RMCCP credits plus RMPCP credits. If a resource's lost opportunity costs for an hour are greater than its RMCP credits, that resource receives lost opportunity cost credits equal to the difference.

Figure 10-19 shows the average performance score by resource type and signal followed for the first nine months of 2014. In this figure, the MW used are unadjusted regulation capability MW and the performance score is the actual within hour (as opposed to the historic 100-hour moving average) performance score of the regulation resource. Each category (color bar) adds up to 100 percent so that the full performance score distribution for each resource (or signal) type is shown. Resources following the RegD signal tend to follow the RegD signal more closely than resources following the RegA signal follow the RegA signal. That is, RegD resources tend to have higher performance scores. As the figure shows, 54.1 percent of RegD resources have average performance scores within the 0.91-1.00 range, whereas only 3.7 percent of RegA resources have average performance scores within that range.

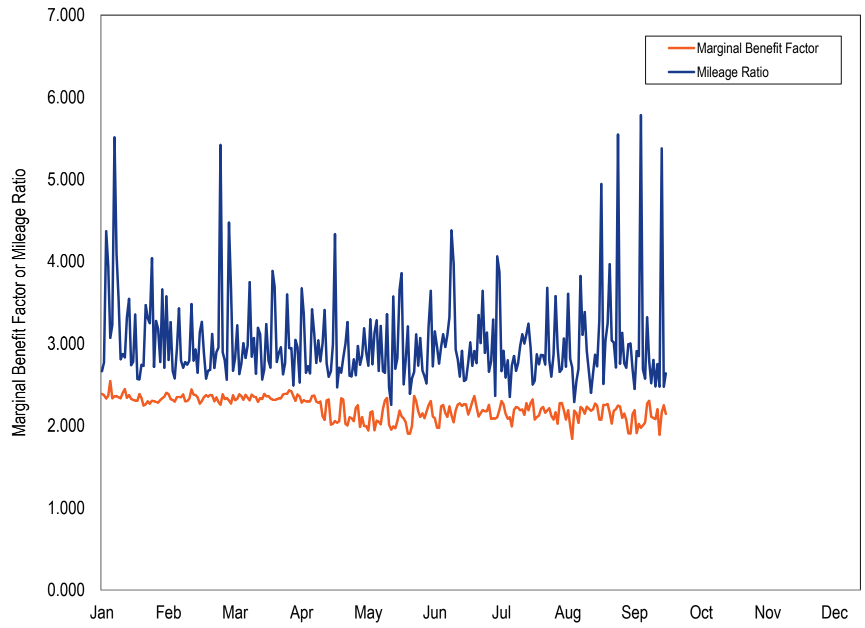
Figure 10-19 Hourly average performance score by unit type and regulation signal type: January through September 2014



From October 1, 2012, through October 31, 2013, PJM adhered to a FERC order that required the marginal benefit factor be fixed at one for settlement calculations only. As Figure 10-20 shows, the true marginal benefit factor, as used in the optimization and commitment process for regulation in the first nine months of 2014, was always higher than one. This caused resources following the RegD signal to be underpaid. Resources following the RegD signal should have been paid the true market marginal benefit factor times the amount that they were actually paid. The market marginal benefit factor should have been applied to the capability and the performance payments of RegD resources.

On October 2, 2013, FERC directed PJM to eliminate the use of the marginal benefit factor completely from settlement calculations of the capability and performance credits and replace it with RegD to RegA mileage ratio in the performance credit paid to RegD resources, effective November 1, 2013, and retroactively to October 1, 2012.[37] As Figure 10-20 demonstrates, the RegD to RegA mileage ratio is generally higher than the actual marginal benefit factor and much more variable. In this figure the mileage ratio is the actual hourly mileage ratio, calculated as the mileage provided by RegD resources divided by the mileage provided by RegA resources. The mileage multiplier has not brought total payment of RegD resources in line with RegA resources on a dollar per effective MW basis. This is, in part, due to the fact that the performance related price per MW of capability, which is the only part multiplied by the mileage ratio, is a relatively small portion of the total price per MW of capability.

Figure 10-20 Daily average marginal benefit factor and mileage ratio: January through September 2014



Market Structure

Supply

Table 10-27 shows capability MW (actual), average daily offer MW (actual), average hourly eligible MW (actual and effective), and average hourly cleared MW (actual and effective) for all hours in January through September 2014. In this table, actual MW are unadjusted regulation capability MW and effective MW are adjusted by the historic 100-hour moving average performance score and resource-specific benefit factor. A resource must be either generation or demand. But a resource can (and several resources currently do) choose to follow both signals. For that reason, the sum of each signal type's capability can exceed the full regulation capability.

37 145 FERC ¶ 61,011 (2013).

Table 10-27 PJM regulation capability, daily offer and hourly eligible: January through September 2014[38,39]

		By Resource Type		By Signal Type	
Metric	All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Capability MW	8,331.5	8,317.5	14.0	8,269.2	381.3
Offered MW	3,796.0	3,789.3	6.6	3,716.8	79.2
Actual Eligible MW	1,299.3	1,294.0	5.4	1,128.9	170.4
Effective Eligible MW	937.2	929.5	7.7	706.2	231.0
Actual Cleared MW	663.9	660.8	3.1	556.1	107.8
Effective Cleared MW	663.7	657.3	6.4	443.4	220.2

Total regulation capability MW provided by coal units decreased from 456,289 MW in the first nine months of 2013 to 410,956 MW in the first nine months of 2014, but the proportion of regulation provided by coal increased, from 13.1 percent of regulation in the first nine months of 2013 to 13.4 percent of regulation in the first nine months of 2014. Coal unit revenues were $38.8 million in the first nine months of 2014, 1.4 times the $27.0 million in revenues in the first nine months of 2013. The increase in coal unit revenues was a result of the high regulation market clearing prices and out of market opportunity cost credits in January. Table 10-28 provides monthly data on the number of coal units providing regulation, the scheduled regulation in MW provided by coal units, the total scheduled regulation in MW provided by all resources, the percent of scheduled regulation provided by coal units, and the total credits received by coal units. In Table 10-28, the MW have been adjusted by the actual within hour performance score since this adjustment forms the basis of payment for coal units providing regulation.

Table 10-28 PJM regulation provided by coal units

Year	Period	Number of Coal Units Providing Regulation	Adjusted Settled Regulation from Coal Units (MW)	Adjusted Settled Regulation from All Resources (MW)	Percent of Scheduled Regulation from Coal Units	Total Coal Unit Regulation Credits
2013	Jan	117	80,766	401,101	20.1%	$5,376,060
2013	Feb	101	64,164	365,249	17.6%	$3,071,878
2013	Mar	96	44,443	372,154	11.9%	$2,473,951
2013	Apr	80	26,964	297,782	9.1%	$1,559,309
2013	May	97	27,970	307,455	9.1%	$1,856,919
2013	Jun	106	42,345	387,670	10.9%	$2,332,995
2013	Jul	109	72,701	447,273	16.3%	$5,613,629
2013	Aug	95	56,338	430,879	13.1%	$2,619,858
2013	Sep	89	40,600	358,971	11.3%	$2,084,078
2013	Average	99	50,699	374,282	13.3%	$2,998,742
2014	Jan	109	70,441	360,513	19.5%	$15,780,551
2014	Feb	102	51,033	309,976	16.5%	$4,690,694
2014	Mar	101	52,368	341,089	15.4%	$6,860,625
2014	Apr	76	52,780	351,763	15.0%	$2,805,943
2014	May	76	36,989	324,871	11.4%	$2,023,258
2014	Jun	82	31,369	330,376	9.5%	$1,591,779
2014	Jul	88	42,754	336,232	12.7%	$1,765,050
2014	Aug	77	37,950	352,366	10.8%	$1,276,055
2014	Sep	78	35,271	345,852	10.2%	$2,012,589
2014	Average	88	45,662	339,226	13.4%	$4,311,838

The supply of regulation can be affected by regulating units retiring from service. Table 10-29 shows what the impact on the Regulation Market would be if all units retire that are requesting retirement through the end of 2015. These retirements will reduce the supply of regulation in PJM by one percent. The MW in Table 10-29 have been adjusted by the actual within-hour performance score.

38 Average Daily Offer MW excludes units that have offers but are unavailable for the day.
39 Total offer capability is defined as the sum of the maximum daily offer volume for each offering unit during the period, without regard to the actual availability of the resource or to the day on which the maximum was offered.

Table 10-29 Impact on PJM Regulation Market of currently regulating units scheduled to retire through 2015

Current Regulation Units, January through September 2014	Adjusted Settled MW, January through September 2014	Units Scheduled To Retire Through 2015	Adjusted Settled MW of Units Scheduled To Retire Through 2015	Percent Of Regulation MW To Retire Through 2015
294	4,343,270	35	46,106	1.06%

Although the marginal benefit factor for slow (RegA) resources is 1.0, the effective MW of RegA following resources was lower than the offered MW in the first nine months of 2014 because the average performance score was less than 1.00 (Figure 10-21). For the first nine months of 2014, the MW-weighted average RegA performance score was 0.80 and from January through September 2014, there were 290 resources following the RegA signal.

In Figure 10-21 and Figure 10-22, actual MW are unadjusted for either performance score or benefit factor and effective MW are adjusted for the historic 100-hour moving average performance score and the resource-specific benefit factor. Whereas Figure 10-21 shows the results for the Regulation Market as a whole, Figure 10-22 shows the results for only RegD resources.

Figure 10-21 All (RegA and RegD) cleared regulation: Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score: January through September 2014

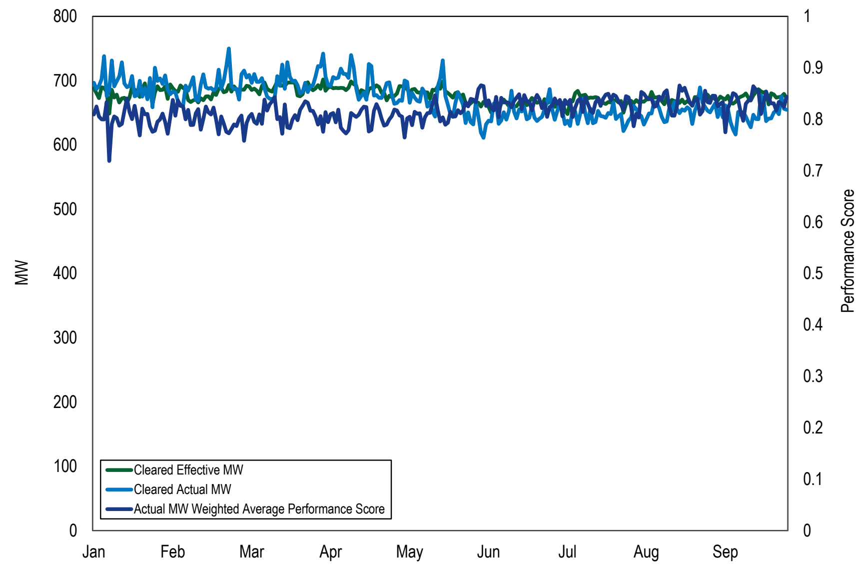
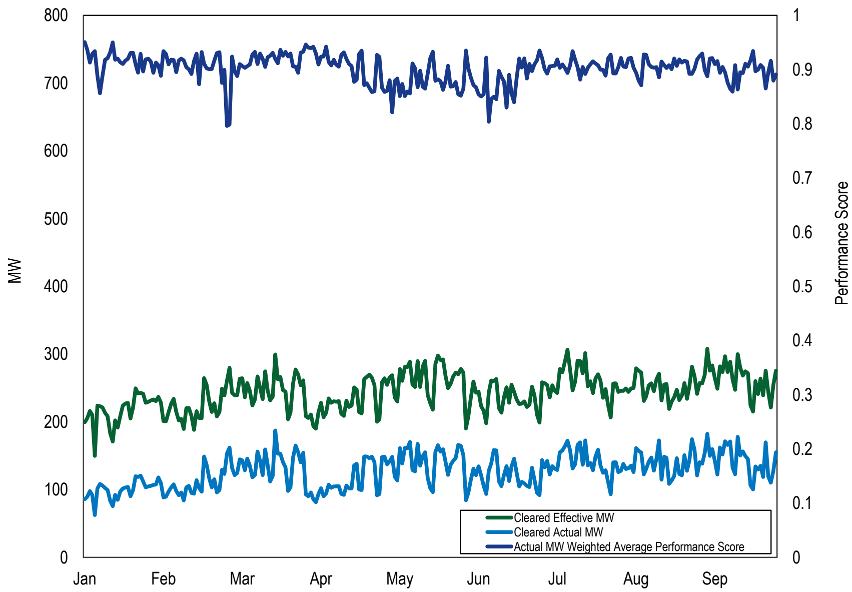


Figure 10-22 Only RegD cleared regulation: Daily average actual cleared MW of regulation, effective cleared MW of regulation, and average performance score; RegD units: January through September 2014



For RegD resources, the effective MW are higher than the actual MW because their marginal benefit factor at current participation levels is significantly greater than 1.0. In the first nine months of 2014, the marginal benefit factor for cleared RegD following resources ranged from 0.548 to 2.751 with an average over all hours of 2.220. For the first nine months of 2014, the MW-weighted average RegD resource performance score was 0.90 and from January through September 2014, there were 43 resources following the RegD signal.

The cost of each unit is calculated using its offer price, lost opportunity cost, capability MW, and the miles to MW ratio of the signal type offered, modified by resource marginal benefit factor and historic performance score. (The miles to MW ratio of the signal type offered is the historic 30-day moving average of requested mileage for that signal type per unadjusted regulation capability MW.)

As of October 1, 2012, a regulation resource's total offer is equal to the sum of its capability offer ($/MW) and performance offer ($/MW) and its estimated lost opportunity cost ($/MW). As of October 1, 2012, the within hour five minute clearing price for regulation is determined by the total offer, including the actual opportunity cost and any applicable benefit factor, of the most expensive cleared regulation resource in each interval.

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, (Table 10-36). Throughout the first nine months of 2014, the price and cost of regulation have remained high relative to prior years. The weighted average regulation price for the first nine months of 2014 was $49.77/MW. The regulation cost for the first nine months of 2014 was $60.42/MW. The ratio of price to cost is lower (82 percent) than in the same period in 2013 (88 percent) due to the extreme market conditions in January that resulted in increased out of market payments based on lost opportunity costs.

Demand

The demand for regulation does not change with price. The regulation requirement is set by PJM to meet NERC control standards, based on reliability objectives, which means that a significant amount of judgment is exercised by PJM in determining the actual demand. 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 1.0 percent of peak load forecast to 0.9 percent on October 1, 2012, but instead it was changed from 1.0 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 and reduced again to 0.70 percent of peak load forecast on December 18,

2012. On December 1, 2013, it was reduced to 700 effective MW during peak hours and 525 effective MW during off peak hours.

Table 10-30 shows the average hourly required regulation by month and its relationship to the supply of regulation for both actual (unadjusted) and effective MW. The average hourly required regulation by month is an average across all of the hours in that month. The average hourly required effective MW of regulation is a weighted average of the requirement of 700 effective MW during peak hours and the requirement of 525 effective MW during off peak hours.

PJM's performance as measured by CPS1 and BAAL standards is shown in Figure 10-23 for every month from January 2011 through June 2014 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[40] The horizontal dashed lines represent PJM internal goals for CPS1 and BAAL performance. While PJM did not meet its internal goal for BAAL performance in January, PJM remained in compliance with the applicable NERC standards.

Figure 10-23 PJM monthly CPS1 and BAAL performance: January 2011 through September 2014

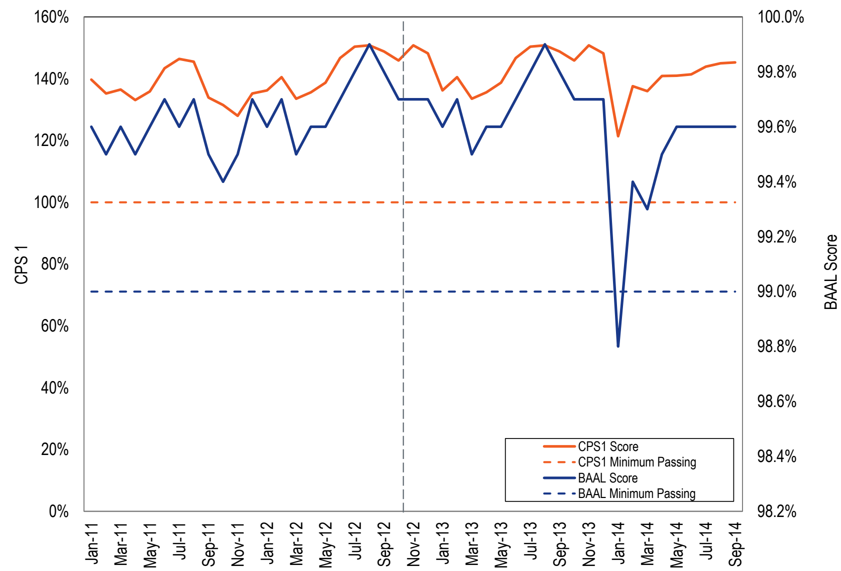


Table 10-30 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through September, 2013 and 2014

Month	Average Required Regulation (MW), 2013	Average Required Regulation (MW), 2014	Average Required Regulation (Effective MW), 2013	Average Required Regulation (Effective MW), 2014	Ratio of Supply MW to MW Requirement, 2013	Ratio of Supply MW to MW Requirement, 2014	Ratio of Supply Effective MW to Effective MW Requirement, 2013	Ratio of Supply Effective MW to Effective MW Requirement, 2014
Jan	862	690	720	664	1.80	2.05	1.72	1.60
Feb	875	681	724	664	1.85	2.00	1.73	1.51
Mar	774	683	681	664	1.67	1.99	1.56	1.48
Apr	663	682	594	664	1.75	2.04	1.64	1.54
May	683	658	616	664	1.67	1.93	1.57	1.44
Jun	808	647	731	664	1.76	1.89	1.65	1.29
Jul	920	642	823	664	1.69	1.88	1.62	1.29
Aug	835	650	757	664	2.11	1.93	1.66	1.30
Sep	697	643	670	664	2.25	1.91	1.60	1.26

40 See the *2013 State of the Market Report for PJM*, Appendix F: Ancillary Services.

Market Concentration

Table 10-31 shows Herfindahl-Hirschman Index (HHI) results for the first nine months of 2013 and the first nine months of 2014, based on market shares of effective MW, defined as regulation capability MW adjusted by performance score and resource-specific benefit factor, consistent with the metrics used to clear the regulation market. The weighted average HHI of 1836 is classified as highly concentrated, but is lower than the HHI for the same period in the first nine months of 2013 of 2039. For the first nine months of 2014, the weighted average HHI of RegA resources was 2635 (highly concentrated and higher than the 2013 value of 2514) and the weighted average HHI of RegD resources was 5150 (highly concentrated and lower than the 2013 value of 7490). The HHI of RegA resources and the HHI of RegD resources are both substantially higher than the HHI of the Regulation Market as a result of the fact that different owners have large market shares in the RegA and RegD markets.

Table 10-31 PJM cleared regulation HHI: January through September 2013 and 2014

Period	Minimum HHI	Weighted Average HHI	Maximum HHI
2013 (Jan-Sep)	973	2039	4925
2014 (Jan-Sep)	955	1836	3943

Figure 10-24 compares the frequency distribution of HHI for the first nine months of 2014 with the first nine months of 2013.

Figure 10-24 PJM Regulation Market HHI distribution: January through September 2013 and 2014

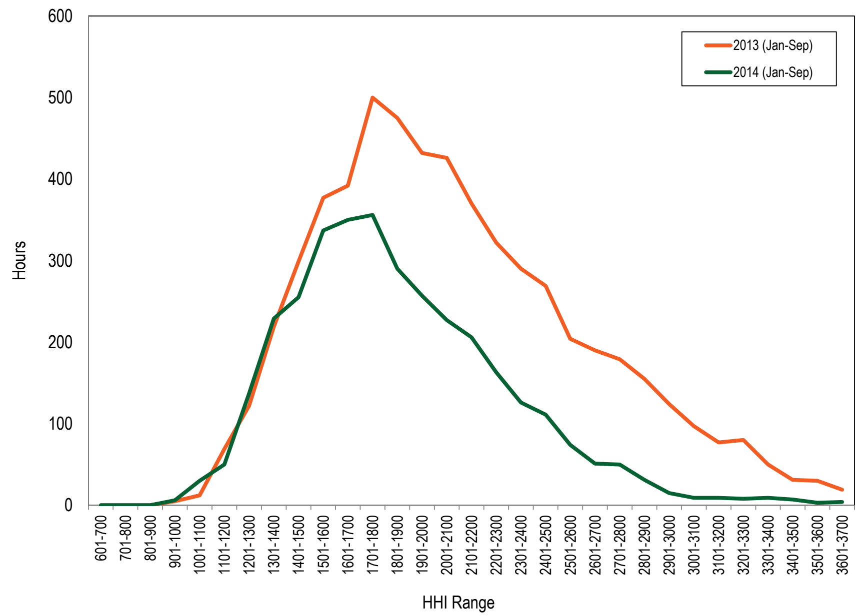


Table 10-32 includes a monthly summary of three pivotal supplier results. In the first nine months of 2014, 97 percent of hours had one or more pivotal suppliers which failed PJM's three pivotal supplier test. The impact of offer capping in the regulation market is limited because of the role of LOC in price formation (Figure 10-26).

The MMU concludes from these results that the PJM Regulation Market in the first nine months of 2014 was characterized by structural market power in 97 percent of hours.

Table 10-32 Regulation market monthly three pivotal supplier results: January through September, 2012 through 2014

	2012	2013	2014
Month	Percent of Hours Pivotal	Percent of Hours Pivotal	Percent of Hours Pivotal
Jan	71%	83%	97%
Feb	67%	82%	99%
Mar	64%	97%	95%
Apr	41%	88%	89%
May	37%	93%	96%
Jun	40%	95%	99%
Jul	13%	94%	100%
Aug	32%	92%	100%
Sep	35%	90%	99%
Average	44%	91%	97%

Market Conduct

Offers

Resources seeking to regulate must qualify to follow a regulation signal by passing a test for that signal with at least a 75 percent performance score. The regulating resource must be able to supply at least 0.1 MW of regulation and must not allow the sum of its regulating ramp rate and energy ramp rate to exceed its economic ramp rate. When offering into the Regulation Market, regulating resources must submit a cost offer and, optionally, a price offer (capped at $100/MW) by 6:00 pm the day before the operating day.

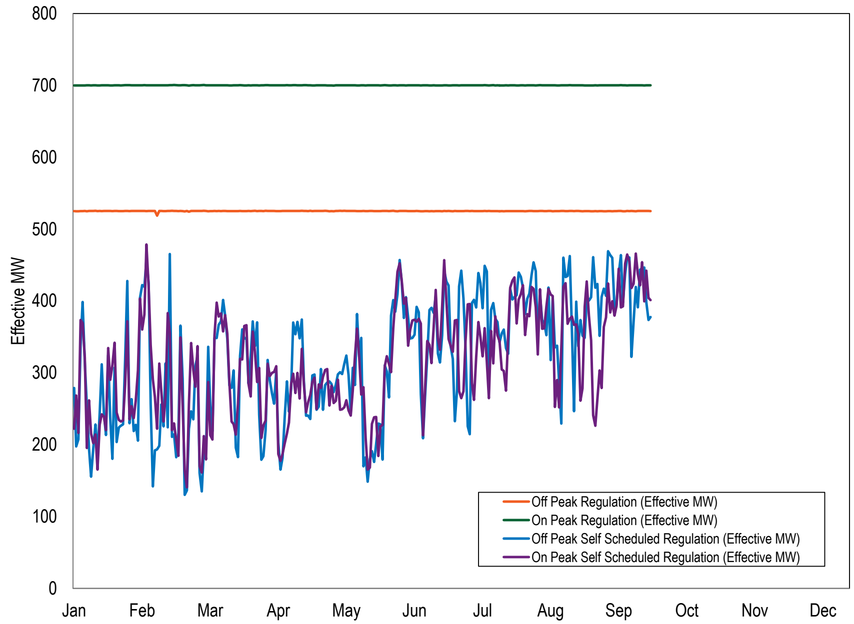
Offers in the Regulation Market consist of a capability component for the MW of regulation capability provided and a performance component for the miles (ΔMW of regulation movement) provided. The capability component for cost offers is not to exceed the increased costs (specifically, increased fuel costs and lower efficiency) resulting from operating the regulating unit at a lower output level than its economically optimal output level plus a $12.00/MW adder. The performance component for cost offers is not to exceed the increased costs (specifically, increased VOM and lower efficiency) resulting from operating the regulating unit in a non-steady state. For batteries and flywheels only, there is zero cost for lower efficiency. Instead, batteries and flywheels calculate an energy storage unit loss reflecting the net energy consumed to provide regulation service.[41]

Up until one hour before the operating hour, the regulating resource must input or, if already inputted, may change the following: status (available, unavailable, or self-scheduled); capability (movement up and down in MW); regulation maximum and regulation minimum (the highest and lowest levels of energy output while regulating in MW); and the regulation signal type (RegA or RegD). Resources may offer regulation for both the RegA and RegD signals, but will be assigned to follow only one signal for a given operating hour. Resources have the option to submit a minimum level of regulation they require to regulate.[42]

All LSEs are required 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 10-33).[43] Figure 10-25 compares average hourly regulation and self scheduled regulation during on peak and off peak hours on an effective MW basis. The average hourly regulation is the amount of regulation that actually cleared and is not the same as the regulation requirement because PJM clears the market within a two percent band around the requirement.[44] Self scheduled regulation during on peak and off peak hours varies from hour to hour and comprises a large portion of total effective regulation per hour (on average 45.1 percent during on peak and 61.2 percent during off peak hours in the first nine months of 2014).

41 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 68, (August 21, 2014); para 3.2.1, p 47.
42 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 68, (August 21, 2014); para 3.2.2, pp 48.
43 See PJM. "Manual 28: Operating Agreement Accounting," Revision 65, (April 24, 2014); para 4.1, p 15.
44 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 68, (August 21, 2014); para 3.2.9, p 59.

Figure 10-25 Off peak and on peak regulation levels: January through September 2014



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 the first nine months of 2014, 51.8 percent was purchased in the PJM market, 43.5 percent was self-scheduled, and 4.7 percent was purchased bilaterally (Table 10-33). From 2010 through the first nine months of 2014, Table 10-34 shows the total regulation by market regulation, self-scheduled regulation, and bilateral regulation. These tables are based on settled (purchased) MW, but are not adjusted for either performance score or benefit factor to maintain consistency with January through September in years 2010 through 2012 when these constructs were not part of the Regulation Market.

Table 10-33 Regulation sources: spot market, self-scheduled, bilateral purchases: January through September 2013 and 2014

Year	Month	Spot Market Regulation (MW)	Spot Market Percent of Total	Self-Scheduled Regulation (MW)	Self-Scheduled Percent of Total	Bilateral Regulation (MW)	Bilateral Percent of Total	Total Regulation (MW)	RegA Regulation (MW)	RegA Percent of Total	RegD Regulation (MW)	RegD Percent of Total
2013	Jan	413,304	83.6%	72,880	14.7%	8,070	1.6%	494,253	484,937	98.1%	9,317	1.9%
2013	Feb	338,990	74.7%	102,005	22.5%	12,808	2.8%	453,803	443,118	97.6%	10,685	2.4%
2013	Mar	275,880	60.0%	165,987	36.1%	17,554	3.8%	459,421	445,518	97.0%	13,903	3.0%
2013	Apr	219,793	57.6%	147,858	38.8%	13,860	3.6%	381,510	369,556	96.9%	11,954	3.1%
2013	May	235,849	57.0%	161,270	38.9%	16,934	4.1%	414,053	401,277	96.9%	12,776	3.1%
2013	Jun	254,215	53.4%	198,617	41.8%	22,816	4.8%	475,647	460,222	96.8%	15,425	3.2%
2013	Jul	349,047	63.2%	182,452	33.0%	21,201	3.8%	552,699	536,191	97.0%	16,508	3.0%
2013	Aug	258,550	50.7%	230,441	45.2%	21,351	4.2%	510,342	488,955	95.8%	21,386	4.2%
2013	Sep	181,609	43.8%	214,945	51.9%	17,647	4.3%	414,200	387,407	93.5%	26,793	6.5%
2014	Jan	259,686	63.7%	125,234	30.7%	22,737	5.6%	407,656	395,755	97.1%	11,900	2.9%
2014	Feb	217,755	59.4%	132,385	36.1%	16,530	4.5%	366,670	355,909	97.1%	10,761	2.9%
2014	Mar	245,991	59.8%	148,162	36.0%	17,524	4.3%	411,677	399,207	97.0%	12,470	3.0%
2014	Apr	248,323	62.8%	135,399	34.2%	11,890	3.0%	395,612	367,207	92.8%	28,405	7.2%
2014	May	242,328	61.0%	141,443	35.6%	13,641	3.4%	397,411	359,344	90.4%	38,067	9.6%
2014	Jun	155,366	40.1%	207,856	53.7%	23,881	6.2%	387,102	343,855	88.8%	43,247	11.2%
2014	Jul	172,095	43.5%	203,841	51.5%	19,930	5.0%	395,865	353,540	89.3%	42,325	10.7%
2014	Aug	162,399	40.4%	221,373	55.1%	17,901	4.5%	401,673	357,482	89.0%	44,191	11.0%
2014	Sep	131,860	34.5%	227,657	59.6%	22,690	5.9%	382,207	332,208	86.9%	49,999	13.1%

Table 10-34 Regulation sources by year: January through September, 2010 through 2014

Year (Jan-Sep)	Spot Market Regulation (MW)	Spot Market Percent of Total	Self-Scheduled Regulation (MW)	Self-Scheduled Percent of Total	Bilateral Regulation (MW)	Bilateral Percent of Total	Total Regulation (MW)
2010	4,771,703	82.7%	864,823	15.0%	130,009	2.3%	5,766,535
2011	5,020,724	84.2%	784,861	13.2%	156,861	2.6%	5,962,446
2012	5,112,139	79.7%	1,121,924	17.5%	179,765	2.8%	6,413,827
2013	2,527,235	60.8%	1,476,441	35.5%	152,240	3.7%	4,155,916
2014	1,835,802	51.8%	1,543,350	43.5%	166,721	4.7%	3,545,872

In the first nine months of 2014, DR provided an average of 3.12 MW of regulation per hour (2.04 MW of regulation per hour in the first nine months of 2013). Generating units supplied an average of 662.91 MW of regulation per hour (787.03 MW of regulation per hour in the first nine months of 2013).

Market Performance

Price

The weighted average RMCP for the first nine months of 2014 was $49.77 per MW. This is the average price per unadjusted capability MW. This is a 52.1 percent increase from the weighted average RMCP of $32.72/MW in first nine months of 2013. Figure 10-26 shows the daily average regulation market clearing price and the opportunity cost component for the marginal units in the PJM Regulation Market on an unadjusted regulation capability MW basis.

Figure 10-26 PJM Regulation Market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2014

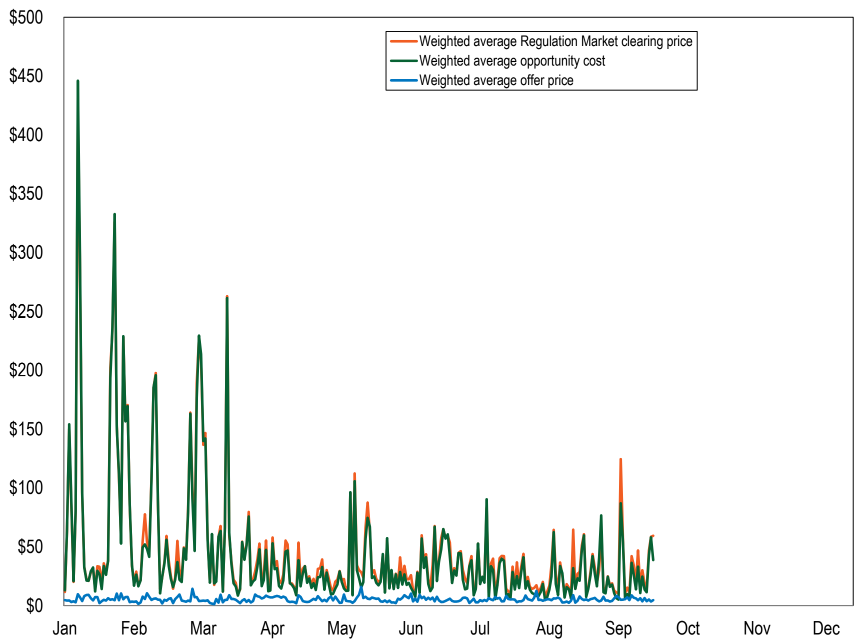


Table 10-35 shows monthly average regulation market clearing price, average marginal unit offer price, and average marginal unit LOC on an unadjusted capability MW basis.

Table 10-35 PJM Regulation Market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2014

Month	Weighted Average Regulation Market Clearing Price	Weighted Average Regulation Marginal Unit Offer	Weighted Average Regulation Marginal Unit LOC
Jan	$132.49	$5.44	$101.27
Feb	$62.61	$4.72	$60.76
Mar	$80.73	$4.79	$71.35
Apr	$31.80	$5.56	$25.58
May	$34.47	$5.22	$31.94
Jun	$30.44	$5.23	$31.54
Jul	$29.80	$4.71	$27.84
Aug	$20.54	$5.27	$20.41
Sep	$25.06	$5.31	$30.35

Total scheduled regulation MW, total regulation charges, regulation price and regulation cost are shown in Table 10-36. Total scheduled regulation is based on settled (unadjusted capability) MW.

Table 10-36 Total regulation charges: January through September, 2013 and 2014

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	86.3%
2013	Feb	453,803	$15,273,604	$29.51	$33.66	87.7%
2013	Mar	459,421	$16,678,410	$31.64	$36.30	87.2%
2013	Apr	381,510	$11,930,098	$26.49	$31.27	84.7%
2013	May	414,053	$15,599,491	$33.42	$37.68	88.7%
2013	Jun	475,647	$15,999,677	$29.81	$33.64	88.6%
2013	Jul	552,699	$31,386,733	$50.12	$56.79	88.3%
2013	Aug	510,342	$15,866,117	$27.60	$31.09	88.8%
2013	Sep	414,200	$12,203,834	$25.98	$29.46	88.2%
2014	Jan	407,656	$65,714,049	$132.49	$161.20	82.2%
2014	Feb	366,670	$27,293,638	$62.61	$74.44	84.1%
2014	Mar	411,667	$40,104,102	$80.73	$97.42	82.9%
2014	Apr	395,612	$15,241,038	$31.80	$38.53	82.5%
2014	May	397,411	$16,952,817	$34.47	$42.66	80.8%
2014	Jun	387,102	$14,312,991	$30.44	$36.97	82.3%
2014	Jul	395,865	$14,482,844	$29.80	$36.59	81.5%
2014	Aug	401,673	$10,006,979	$20.54	$24.91	82.5%
2014	Sep	382,207	$11,888,482	$25.06	$31.10	80.6%

The capability, performance, and opportunity cost components of the cost of regulation are shown in Table 10-37. Total scheduled regulation is based on settled (unadjusted capability) MW.

Table 10-37 Components of regulation cost: 2014

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	407,656	$124.57	$11.60	$25.03	$161.20
Feb	366,670	$57.80	$6.41	$10.23	$74.44
Mar	411,667	$76.75	$5.71	$14.96	$97.42
Apr	395,612	$28.50	$4.49	$5.54	$38.53
May	397,411	$31.24	$4.64	$6.78	$42.66
Jun	387,102	$26.96	$4.57	$5.44	$36.97
Jul	395,865	$26.23	$4.74	$5.62	$36.59
Aug	401,673	$17.19	$4.34	$3.39	$24.91
Sep	382,207	$21.79	$4.45	$4.87	$31.10

A comparison of monthly average RMCP credits per Effective MW earned by RegA and RegD resources from October 1, 2012, (the implementation date of the performance-based Regulation Market) through the first nine months of 2014 is shown in Figure 10-27. On November 1, 2013, PJM removed the marginal benefit factor from all settlement calculations. In its place, PJM inserted the mileage ratio for the performance credit only. In Figure 10-27, the RegA RMCP Credit per effective MW is, on average, 2.6 times higher than the RegD RMCP Credit per effective MW from October 2012 through October 2013. However, since November 1, 2013, the RegA RMCP Credit per effective MW is only, on average, 1.8 times higher than the RegD RMCP Credit per effective MW. Were the marginal benefit factor correctly applied to settlements, the average RegD RMCP Credit per effective MW would be higher and equal to the RegA RMCP Credit per effective MW.

Figure 10-27 Comparison of monthly average RegA and RegD RMCP Credits per Effective MW: October 2012 through September 2014[45]

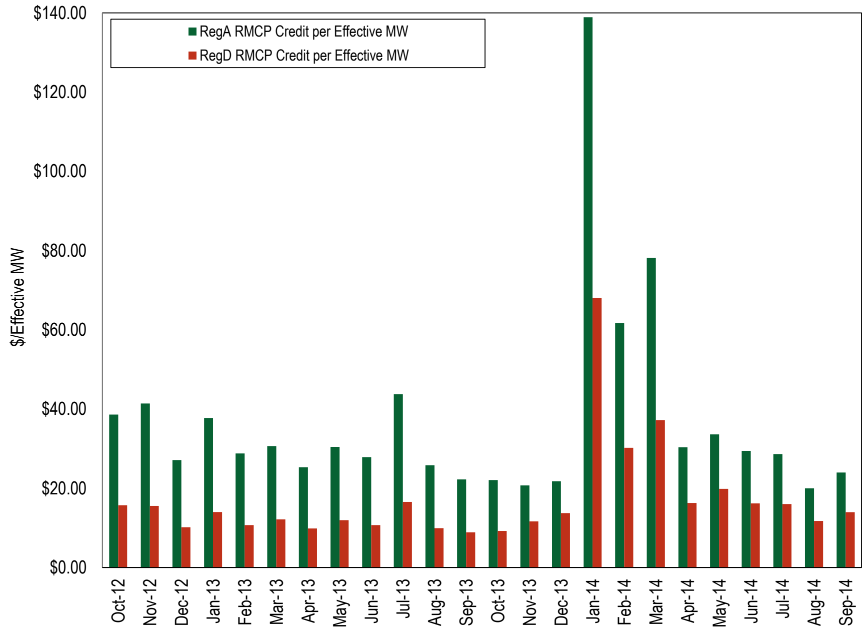


Table 10-38 provides a comparison of the average price and cost for PJM Regulation. The ratio of regulation market price to the actual cost of regulation decreased to 82 percent in the first nine months of 2014 from 88 percent in the first nine months of 2013. This was in part a result of extreme market conditions in January.

45 These values are credits before PJM makes its retroactive adjustments to RMCP credits.

Table 10-38 Comparison of average price and cost for PJM Regulation, January through September, 2008 through 2014

Year (Jan-Sep)	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2008	$42.09	$64.43	65%
2009	$23.56	$29.87	79%
2010	$18.08	$32.07	56%
2011	$17.03	$32.71	52%
2012	$14.92	$20.58	72%
2013	$32.72	$37.35	88%
2014	$49.77	$60.42	82%

Black Start Service

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

PJM does not have a market to provide black start service, but compensates black start resource owners on the basis of an incentive rate or for the costs associated with providing this service.

PJM 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. Substantial rule changes to the black start restoration and procurement strategy were implemented on February 28, 2013, following a stakeholder process in the System Restoration Strategy Task Force (SRSTF) and the Markets and Reliability Committee (MRC) that approved the PJM and MMU joint proposal for system restoration. These changes give PJM substantial flexibility in procuring black start resources and make PJM responsible for black start resource selection.

On July 1, 2013, PJM initiated its first RTO-wide request for proposals (RFP) under the new rules.[46] PJM set a September 30, 2013, deadline for resources submitting proposals and requested that resources be able to provide black

46 See PJM. "RTO-Wide Five-Year Selection Process Request for Proposal for Black Start Service," (July 1, 2013).

start by April 1, 2015. PJM identified zones with black start shortages, prioritized its selection process accordingly, and began awarding proposals on January 14, 2014. (The selection process was completed in the first half of 2014.) PJM and the MMU coordinated closely during the selection process.

Black start payments are non-transparent payments made to units by load to maintain adequate reliability to restart the system in case of a blackout. Current rules appear to prevent publishing detailed data regarding these black start resources, hindering transparency and competitive replacement RFPs. The MMU recommends that the current confidentiality rules be revised to allow disclosure of information regarding black start resources and their associated payments.

Total black start charges is the sum of black start revenue requirement charges and black start operating reserve charges. Black start revenue requirements for black start units consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive factor. Section 18 of Schedule 6A of the OATT specifies how to calculate each component of the revenue requirement formula. Black start resources can choose to recover fixed costs under a formula rate based on zonal Net CONE and unit ICAP rating, a cost recovery rate based on incremental black start NERC-CIP compliance capital costs, or a cost recovery rate based on incremental black start equipment capital costs. Black start operating reserve charges are paid for scheduling in the Day-Ahead Energy Market or committing in real time units that provide black start service. Total black start charges are allocated monthly to PJM customers proportionally to their zone and non-zone peak transmission use and point to point transmission reservations.

In the first nine months of 2014, total black start charges were $44.6 million, a $40.0 million (47.3 percent) decrease from the January through September 2013 level of $84.7 million. Operating reserve charges for black start service declined from $68.9 million in the first nine months of 2013 to $26.6 million in the first nine months of 2014. This decrease was due to higher LMPs that caused more ALR black start units to run economically rather than out of merit. Table 10-39 shows total revenue requirement charges from the first nine months of years 2009 through 2014. (Prior to December 2012, PJM did not define a black start operating reserve category.)

Table 10-39 Black start revenue requirement charges: January through September, 2009 through 2014

Year (Jan-Sep)	Revenue Requirement Charges
2009	$10,703,353
2010	$8,527,000
2011	$9,996,898
2012	$13,288,491
2013	$15,782,838
2014	$17,971,024

Black start zonal charges in the first nine months of 2014 ranged from $0.03 per MW-day in the ATSI Zone (total charges were $123,375) to $4.09 per MW-day in the AEP Zone (total charges were $25,535,875). For each zone, Table 10-40 shows black start charges, the sum of monthly zonal peak loads multiplied by the number of days of the month in which the peak load occurred, and black start rates (calculated as charges per MW-day). For black start service, point-to-point transmission customers paid on average $0.05 per MW of reserve capacity during the first nine months of 2014.

Table 10-40 Black start zonal charges for network transmission use: January through September, 2013 and 2014

Zone	Jan-Sep 2013 Revenue Requirement Charges	Jan-Sep 2013 Operating Reserve Charges	Jan-Sep 2013 Total Charges	Jan-Sep 2013 Peak Load (MW-day)	Jan-Sep 2013 Black Start Rate ($/MW-day)	Jan-Sep 2014 Revenue Requirement Charges	Jan-Sep 2014 Operating Reserve Charges	Jan-Sep 2014 Total Charges	Jan-Sep 2014 Peak Load (MW-day)	Jan-Sep 2014 Black Start Rate ($/MW-day)
AECO	$424,259	$41,138	$465,397	766,857	$0.61	$477,115	$33,266	$510,381	747,802	$0.68
AEP	$479,970	$65,163,413	$65,643,383	6,363,248	$10.32	$663,321	$24,872,554	$25,535,875	6,237,040	$4.09
APS	$197,314	$3,063	$200,377	2,327,134	$0.09	$211,840	$3,027	$214,867	2,368,930	$0.09
ATSI	$95,598	$0	$95,598	3,689,568	$0.03	$90,889	$32,487	$123,375	3,587,520	$0.03
BGE	$4,904,223	$10,301	$4,914,524	1,911,546	$2.57	$5,564,794	$2,462	$5,567,256	1,864,672	$2.99
ComEd	$3,051,454	$12,677	$3,064,131	6,443,046	$0.48	$3,161,466	$20,220	$3,181,686	6,079,437	$0.52
DAY	$179,258	$5,252	$184,510	957,438	$0.19	$179,831	$6,511	$186,342	930,739	$0.20
DEOK	$379,689	$8,662	$388,352	1,487,339	$0.26	$856,581	$15,022	$871,602	1,404,858	$0.62
Dominion	$254,195	$21,152	$275,348	2,367,627	$0.12	$752,064	$0	$752,064	5,122,299	$0.15
DPL	$418,210	$18,665	$436,875	1,123,149	$0.39	$424,039	$17,593	$441,631	1,097,105	$0.40
DLCO	$43,447	$7,928	$51,375	833,769	$0.06	$44,491	$0	$44,491	805,760	$0.06
EKPC	$122,585	$0	$122,585	290,702	$0.42	$301,990	$4,438	$306,429	691,400	$0.44
JCPL	$424,224	$14,945	$439,168	1,697,896	$0.26	$378,813	$6,257	$385,070	1,741,440	$0.22
Met-Ed	$576,085	$49,477	$625,562	828,937	$0.75	$638,321	$58,199	$696,519	822,358	$0.85
PECO	$1,036,416	$28,121	$1,064,537	2,333,877	$0.46	$1,124,927	$13,614	$1,138,541	2,352,823	$0.48
PENELEC	$385,908	$6,835	$392,743	793,884	$0.49	$388,233	$3,497	$391,730	842,833	$0.46
Pepco	$223,087	$24,095	$247,182	1,834,751	$0.13	$235,150	$17,347	$252,497	1,783,618	$0.14
PPL	$146,901	$0	$146,901	2,015,150	$0.07	$164,313	$0	$164,313	2,018,071	$0.08
PSEG	$1,649,818	$32,992	$1,682,810	2,858,255	$0.59	$1,287,034	$32,643	$1,319,677	2,843,131	$0.46
RECO	$0	$0	$0	0	NA	$0	$0	$0	0	NA
(Imp/Exp/Wheels)	$790,195	$3,454,643	$4,244,838	2,155,311	$1.97	$1,025,814	$1,504,923	$2,530,737	2,672,837	$0.95
Total	$15,782,838	$68,903,357	$84,686,194	43,079,484	$1.97	$17,971,024	$26,644,059	$44,615,083	46,014,672	$0.97

Table 10-41 shows new black start NERC critical infrastructure protection (CIP) capital costs being recovered by black start units in PJM. These costs were located in multiple zones, including ComEd, DEOK, DLCO, JCPL, Met-Ed, PENELEC and Pepco. These costs are recoverable through Schedule 6A of the tariff, and include both physical security and cyber security investments in order to protect black start units deemed critical. This included equipment necessary to restrict access to both physical sites, as well as firewall and software upgrades necessary protect cyber assets and monitor unit operations.

Table 10-41 NERC CIP Costs: January through September 2014

Capital Cost Requested	Cost Recovered in Jan-Sep 2014	Number of Units	MW
$1,736,971	$472,890	33	678

Reactive Service

Reactive Service, Reactive Supply and Voltage Control from Generation or Other Sources Service, is provided by generation and other sources (such as static VAR compensators and capacitor banks) of reactive power (measured in VAR).[47] Reactive power helps maintain appropriate voltages on the transmission system and is essential to the flow of real power (measured in MW). Without Reactive Service in the necessary amounts across the RTO

47 PJM OATT. Schedule 2 "Reactive Supply and Voltage Control from Generation Sources Service," (Effective Date: February 18, 2012).

footprint, transmission system voltages fall, generating units and transmission lines shut down, and no real power flows.

Total reactive service charges are the sum of reactive service revenue requirement charges and reactive service operating reserve charges. Reactive service revenue requirements are based on FERC-approved filings. Reactive service revenue requirement charges are allocated monthly to PJM customers in the zone or zones where the reactive service was provided proportionally to their zone and non-zone peak transmission use and point to point transmission reservations. Reactive service operating reserve charges are paid for scheduling in the Day-Ahead Energy Market and committing in real time units that provide reactive service. These operating reserve charges are allocated daily to the zone or zones where the reactive service was provided.

In the first nine months of 2014, total reactive service charges were $237.9 million, a 39.1 percent decrease from the January through September 2013 level of $390.6 million.[48] While revenue requirement charges increased from $207.1 million to $210.5 million, operating reserve charges fell from $183.5 million to $27.4 million. The decrease in operating reserve charges was due to higher LMPs that caused more units that provide reactive service to be run economically rather than out of merit. Total charges in the first nine months of 2014 ranged from $1.7 thousand in the RECO Zone to $30.7 million in the AEP Zone. For each zone in the first nine months of 2013 and 2014 Table 10-42 shows Reactive Service operating reserve charges, revenue requirement charges and total charges (the sum of operating reserve and revenue requirement charges).

Table 10-42 Reactive zonal charges for network transmission use: January through September 2013 and 2014

Zone	Jan-Sep 2013 Operating Reserve Charges	Jan-Sep 2013 Revenue Requirement Charges	Jan-Sep 2013 Total Charges	Jan-Sep 2014 Operating Reserve Charges	Jan-Sep 2014 Revenue Requirement Charges	Jan-Sep 2014 Total Charges
AECO	$3,256,193	$3,848,838	$7,105,030	$103,587	$4,672,079	$4,775,666
AEP	$16,204,347	$30,219,883	$46,424,230	$817,028	$29,924,711	$30,741,739
APS	$4,609,933	$16,284,830	$20,894,763	$282,909	$14,409,129	$14,692,039
ATSI	$37,394,400	$11,688,901	$49,083,301	$11,794,420	$11,580,691	$23,375,110
BGE	$7,851,246	$5,827,371	$13,678,617	$55,339	$5,770,452	$5,825,791
ComEd	$10,067,289	$18,422,929	$28,490,219	$146,570	$18,242,984	$18,389,554
DAY	$1,649,436	$6,326,740	$7,976,176	$29,971	$6,264,943	$6,294,915
DEOK	$2,691,914	$4,318,432	$7,010,346	$29,413	$4,276,252	$4,305,665
Dominion	$1,467,765	$22,439,905	$23,907,670	$15,712	$22,220,724	$22,236,436
DPL	$11,313,410	$7,492,241	$18,805,652	$3,407,131	$8,055,797	$11,462,928
DLCO	$28,126,559	$0	$28,126,559	$7,020,627	$0	$7,020,627
EKPC	$789,913	$534,605	$1,324,518	$12,873	$1,589,155	$1,602,029
JCPL	$9,884,745	$4,692,314	$14,577,060	$24,412	$5,291,430	$5,315,842
Met-Ed	$1,761,822	$5,608,742	$7,370,564	$46,087	$5,619,758	$5,665,845
PECO	$4,688,883	$13,214,290	$17,903,173	$369,729	$13,085,219	$13,454,948
PENELEC	$21,261,415	$3,487,133	$24,748,548	$2,741,923	$4,655,182	$7,397,105
Pepco	$3,363,705	$3,942,396	$7,306,101	$50,913	$3,903,889	$3,954,802
PPL	$4,571,666	$14,055,244	$18,626,909	$45,115	$14,299,580	$14,344,695
PSEG	$12,363,097	$20,446,085	$32,809,183	$389,325	$20,246,378	$20,635,703
RECO	$161,210	$0	$161,210	$1,679	$0	$1,679
(Imp/Exp/Wheels)	$0	$14,275,854	$14,275,854	$0	$16,425,917	$16,425,917
Total	$183,478,949	$207,126,733	$390,605,682	$27,384,764	$210,534,269	$237,919,033

48 See the *2013 State of the Market Report for PJM*, Volume II, Section 4, "Energy Uplift."

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 (SMP) or energy component, the congestion component of LMP (CLMP), and the marginal loss component of LMP (MLMP).[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 and given the choice of reference bus, or LMP net of 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. 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 to one or more areas, and higher cost units in the constrained area(s) must be dispatched to meet the load.[2] The result is that the price of energy in the constrained area(s) 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 costs and marginal loss costs.[3]

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs increased by $1,195.7 million or 234.6 percent, from $509.6 million in the first nine months of 2013 to $1,705.3 million in the first nine months of 2014. Total congestion costs increased because of the cold weather in January 2014, but congestion was also much higher in March 2014 than in March 2013 and congestion was higher in each of the first nine months of 2014 than in the first nine months of 2013 except July.
- **Day-Ahead Congestion.** Day-ahead congestion costs increased by $1,163.2 million or 145.1 percent, from $801.4 million in the first nine months of 2013 to $1,964.6 million in the first nine months of 2014.
- **Balancing Congestion.** Balancing congestion costs increased by $32.5 million or 11.1 percent, from -$291.8 million in the first nine months of 2013 to -$259.3 million in the first nine months of 2014.
- **Monthly Congestion.** Monthly total congestion costs in the first nine months of 2014 ranged from $54.3 million in April to $825.1 million in January.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the AP South Interface, the West Interface, the Bagley – Graceton line, the Bedington - Black Oak Interface, and the Breed – Wheatland flowgate.
- **Congestion Frequency.** Congestion frequency continued to be significantly higher in the Day-Ahead Energy Market than in the Real-Time Energy

1 On June 1, 2013, PJM integrated the East Kentucky Power Cooperative (EKPC) Control Zone. 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 congestion and marginal losses were calculated as of October 18, 2014, and are subject to change, based on continued PJM billing updates.

Market in the first nine months of 2014. The number of congestion event hours in the Day-Ahead Energy Market was about 15 times higher than the number of congestion event hours in the Real-Time Energy Market.

Day-ahead congestion frequency increased by 25.3 percent from 261,702 congestion event hours in the first nine months of 2013 to 327,824 congestion event hours in the first nine months of 2014.

Real-time congestion frequency increased by 44.0 percent from 14,677 congestion event hours in the first nine months of 2013 to 21,139 congestion event hours in the first nine months of 2014.

- **Congested Facilities.** Day-ahead, congestion-event hours increased on all types of congestion facilities. Real-time, congestion-event hours increased on all types of congestion facilities.

  The AP South Interface was the largest contributor to congestion costs in the first nine months of 2014. With $475.3 million in total congestion costs, it accounted for 27.9 percent of the total PJM congestion costs in the first nine months of 2014.

- **Zonal Congestion.** AEP had the largest total congestion costs among all control zones in the first nine months of 2014. AEP had $410.2 million in total congestion costs, comprised of -$761.1 million in total load congestion payments, -$1,225.6 million in total generation congestion credits and -$54.3 million in explicit congestion costs. The AP South Interface, the West Interface, the Breed – Wheatland, Monticello - East Winamac and the Benton Harbor - Palisades flowgates contributed $286.6 million, or 78.0 percent of the total AEP control cone congestion costs.

- **Ownership.** In the first nine months of 2014, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. UTCs are in the explicit cost category and comprise most of that category. Explicit costs are the primary source of congestion credits to financial entities. In the first nine months of 2014, financial companies received $196.4 million in congestion credits, an increase of $114.9 million or 141.1 percent compared to the first nine months of 2013. In the first nine months of 2014, physical companies paid $1,901.7 million in congestion charges, an increase of $1,310.7 million or 221.7 percent compared to the first nine months of 2013.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs increased by $446.2 million or 56.0 percent, from $797.0 million in the first nine months of 2013 to $1,243.1 million in the first nine months of 2014. Total marginal loss costs increased because of the cold weather in January, but marginal loss costs were also significantly higher in February and March 2014 than in February and March 2013. Marginal loss costs were lower in July, August, and September of 2014 than in July, August, and September of 2013. The loss component of LMP remained constant, $0.02 in the first nine months of 2013 and $0.02 in the first nine months of 2014. The loss MW in PJM increased 0.2 percent, from 13,218 GWh in the first nine months of 2013 to 13,241 GWh in the first nine months of 2014.

- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs increased by $476.3 million or 54.6 percent, from $871.6 million in the first nine months of 2013 to $1,347.9 million in the first nine months of 2014.

- **Balancing Marginal Loss Costs.** Balancing marginal loss costs decreased by $30.2 million or 40.4 percent, from -$74.6 million in the first nine months of 2013 to -$104.8 million in the first nine months of 2013.

- **Monthly Total Marginal Loss Costs.** Marginal loss costs in the first nine months of 2014 increased compared to the first nine months of 2013, by 310.2 percent in January, 114.4 percent in February, 95.4 percent in March, 7.9 percent in April, 0.9 percent in May, and 9.1 percent in June but decreased in July, August, and September. Monthly total marginal loss costs in the first nine months of 2014 ranged from $68.7 million in May to $414.6 million in January.

- **Marginal Loss Credits.** Marginal loss credits are calculated as total energy costs plus total marginal loss costs 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.[4] The marginal loss credits increased in the first nine months of 2014 by $136.4 million or 51.0 percent, from $267.3 million in the first nine months of 2013, to $404.1 million in the first nine months of 2014.

Energy Cost

- **Total Energy Costs.** Total energy costs decreased by $306.7 million or 58.2 percent, from -$527.2 million in the first nine months of 2013 to -$833.9 million in the first nine months of 2014.
- **Day-Ahead Energy Costs.** Day-ahead energy costs decreased by $573.2 million or 95.3 percent, from -$601.3 million in the first nine months of 2013 to -$1,174.5 million in the first nine months of 2014.
- **Balancing Energy Costs.** Balancing energy costs increased by $266.0 million or 339.9 percent, from $78.2 million in the first nine months of 2013 to $344.2 million in the first nine months of 2014.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first nine months of 2014 ranged from -$272.7 million in January to -$44.6 million in September.

Conclusion

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, the level and geographic distribution of incremental bids and offers and the geographic and temporal distribution of load.

ARRs and FTRs served as an effective, but not total, offset against congestion for the first four months of the 2014 to 2015 planning period. ARR and FTR revenues offset 80.4 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the first four months of the 2014 to 2015 planning period. In the entire 2013 to 2014 planning period, total ARR and FTR revenues offset 98.2 percent of the congestion costs.

4 See PJM. "Manual 28: Operating Agreement Accounting," Revision 65 (April 24, 2014), pp 64-66. Note that the overcollection is not calculated by subtracting the prior calculation of average losses from the calculated total marginal losses.

Locational Marginal Price (LMP)

Components

Table 11-1 shows the PJM real-time, load-weighted average LMP components for the first nine months of 2009 to 2014. The load-weighted average real-time LMP increased $18.86 or 47.4 percent from $39.75 in the first nine months of 2013 to $58.60 in the first nine months of 2014. The load-weighted average congestion component decreased $0.04 or 434.1 percent from $0.01 in the first nine months of 2013 to -$0.03 in the first nine months of 2014. The load-weighted average loss component ($0.02) did not change in the first nine months of 2013 from the first nine months of 2014. The load-weighted average energy component increased $18.90 or 47.6 percent from $39.72 in the first nine months of 2013 to $58.61 in the first nine months of 2014.

Table 11-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): January through September of 2009 through 2014[5]

(Jan-Sep)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	$39.57	$39.49	$0.04	$0.03
2010	$49.91	$49.81	$0.06	$0.04
2011	$49.48	$49.40	$0.05	$0.03
2012	$35.27	$35.22	$0.04	$0.01
2013	$39.75	$39.72	$0.01	$0.02
2014	$58.60	$58.61	($0.03)	$0.02

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for the first nine months of 2009 through 2014. The load-weighted average day-ahead LMP increased $19.60 or 49.6 percent from $39.49 in the first nine months of 2013 to $59.08 in the first nine months of 2014. The load-weighted average congestion component increased $0.12 or 82.3 percent from $0.14 in the first nine months of 2013 to $0.26 in the first nine months of 2014. The load-weighted average loss component decreased $0.01 or 9,330.1 percent from $0.00 in the first nine months of 2013 to -$0.01 in the first nine months of 2014. The load-weighted average energy component increased $19.50 or

5 Calculated values shown in Section 11, "Congestion and Marginal Losses," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

49.5 percent from $39.35 in the first nine months of 2013 to $58.84 in the first nine months of 2014.

Table 11-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through September of 2009 through 2014

(Jan-Sep)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2009	$39.95	$39.50	($0.05)	($0.10)
2010	$49.12	$49.05	$0.11	($0.03)
2011	$48.34	$48.55	($0.05)	($0.16)
2012	$34.46	$34.36	$0.12	($0.02)
2013	$39.49	$39.35	$0.14	($0.00)
2014	$59.08	$58.84	$0.26	($0.01)

Zonal Components

The real-time components of LMP for each control zone are presented in Table 11-3 for the first nine months of 2013 and the first nine months of 2014.

The day-ahead components of LMP for each control zone are presented in Table 11-4 for the first nine months of 2013 and the first nine months of 2014.

Table 11-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): January through September of 2013 and 2014

	2013 (Jan-Sep)				2014 (Jan-Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$42.09	$40.26	$0.03	$1.80	$62.02	$56.38	$3.32	$2.32
AEP	$36.31	$39.25	($1.98)	($0.96)	$51.76	$59.08	($5.85)	($1.48)
AP	$38.52	$39.43	($0.73)	($0.18)	$58.66	$59.87	($1.31)	$0.10
ATSI	$44.63	$39.50	$4.67	$0.46	$52.74	$57.31	($5.17)	$0.59
BGE	$44.55	$40.05	$2.70	$1.80	$75.84	$60.11	$12.96	$2.77
ComEd	$34.01	$39.78	($3.83)	($1.94)	$44.79	$56.53	($8.79)	($2.95)
DAY	$36.91	$39.70	($2.69)	($0.10)	$51.13	$58.60	($7.51)	$0.04
DEOK	$35.02	$39.62	($2.65)	($1.95)	$48.45	$58.19	($6.89)	($2.84)
DLCO	$36.44	$39.58	($1.85)	($1.29)	$47.04	$56.99	($8.05)	($1.90)
Dominion	$41.77	$39.92	$1.56	$0.29	$70.61	$60.39	$9.72	$0.50
DPL	$43.13	$40.03	$1.10	$2.00	$72.28	$60.55	$8.10	$3.63
EKPC	$35.06	$41.33	($3.93)	($2.35)	$52.51	$63.99	($8.51)	($2.98)
JCPL	$44.45	$40.77	$1.79	$1.89	$62.59	$57.11	$3.05	$2.43
Met-Ed	$40.70	$39.68	$0.24	$0.78	$63.19	$58.96	$2.88	$1.35
PECO	$40.44	$39.84	($0.48)	$1.09	$62.83	$57.98	$3.18	$1.67
PENELEC	$39.51	$39.15	($0.24)	$0.59	$57.50	$58.34	($1.44)	$0.60
Pepco	$43.72	$40.06	$2.47	$1.19	$73.53	$59.33	$12.38	$1.82
PPL	$40.19	$39.46	$0.05	$0.68	$64.58	$59.94	$3.49	$1.15
PSEG	$45.47	$40.04	$3.73	$1.70	$64.49	$56.21	$5.92	$2.36
RECO	$47.74	$40.89	$5.20	$1.65	$62.69	$55.94	$4.54	$2.20
PJM	$39.75	$39.72	$0.01	$0.02	$58.60	$58.61	($0.03)	$0.02

Table 11-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through September of 2013 and 2014

	2013 (Jan-Sep)				2014 (Jan-Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$42.18	$39.88	$0.54	$1.75	$63.56	$56.11	$5.52	$1.93
AEP	$36.92	$39.09	($1.26)	($0.91)	$52.87	$60.29	($6.12)	($1.29)
AP	$38.47	$39.09	($0.40)	($0.23)	$57.95	$60.17	($1.97)	($0.25)
ATSI	$38.50	$39.24	($0.98)	$0.24	$53.70	$57.89	($4.67)	$0.48
BGE	$44.82	$39.72	$3.39	$1.71	$76.47	$60.15	$14.14	$2.18
ComEd	$34.84	$39.53	($2.93)	($1.76)	$46.11	$57.54	($9.48)	($1.96)
DAY	$37.65	$39.48	($1.65)	($0.18)	$53.02	$59.70	($6.96)	$0.29
DEOK	$35.94	$39.24	($1.60)	($1.70)	$49.74	$57.82	($5.96)	($2.13)
DLCO	$36.67	$39.33	($1.37)	($1.29)	$47.80	$57.31	($7.41)	($2.09)
Dominion	$42.02	$39.71	$2.15	$0.16	$67.02	$60.45	$6.64	($0.07)
DPL	$43.19	$39.65	$1.57	$1.97	$74.07	$60.20	$10.81	$3.07
EKPC	$36.83	$41.03	($1.92)	($2.28)	$53.54	$64.49	($8.12)	($2.83)
JCPL	$43.63	$40.13	$1.71	$1.78	$66.58	$57.84	$6.40	$2.35
Met-Ed	$40.57	$39.12	$0.82	$0.63	$64.69	$58.49	$5.31	$0.90
PECO	$40.71	$39.41	$0.28	$1.02	$64.75	$57.90	$5.46	$1.39
PENELEC	$39.56	$38.57	$0.27	$0.72	$56.74	$56.40	($0.29)	$0.63
Pepco	$43.51	$39.20	$3.17	$1.13	$71.65	$58.37	$11.94	$1.34
PPL	$40.12	$39.04	$0.56	$0.52	$67.02	$59.95	$6.35	$0.73
PSEG	$45.51	$39.79	$3.98	$1.75	$68.95	$57.02	$9.62	$2.31
RECO	$46.59	$40.03	$4.92	$1.64	$66.39	$56.24	$7.99	$2.16
PJM	$39.49	$39.35	$0.14	($0.00)	$59.08	$58.84	$0.26	($0.01)

Hub Components

The real-time components of LMP for each hub are presented in Table 11-5 for the first nine months of 2013 and the first nine months of 2014.

Table 11-5 Hub real-time, load-weighted average LMP components (Dollars per MWh): January through September of 2013 and 2014

	2013 (Jan-Sep)				2014 (Jan-Sep)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$34.11	$38.92	($2.61)	($2.20)	$46.05	$57.98	($8.19)	($3.74)
AEP-DAY Hub	$35.96	$39.22	($2.20)	($1.06)	$49.43	$58.55	($7.41)	($1.71)
ATSI Gen Hub	$42.82	$38.66	$4.31	($0.15)	$51.19	$57.24	($5.74)	($0.32)
Chicago Gen Hub	$32.26	$38.87	($4.16)	($2.44)	$42.40	$55.59	($9.49)	($3.70)
Chicago Hub	$34.55	$40.25	($3.81)	($1.88)	$45.47	$57.23	($8.87)	($2.89)
Dominion Hub	$42.06	$40.80	$1.42	($0.16)	$72.01	$62.67	$9.52	($0.17)
Eastern Hub	$42.08	$38.93	$1.13	$2.01	$66.76	$57.17	$6.33	$3.26
N Illinois Hub	$33.36	$39.30	($3.83)	($2.10)	$43.90	$56.24	($9.09)	($3.25)
New Jersey Hub	$44.73	$40.34	$2.65	$1.74	$62.61	$55.97	$4.33	$2.31
Ohio Hub	$36.07	$39.45	($2.43)	($0.96)	$49.53	$58.47	($7.39)	($1.54)
West Interface Hub	$38.47	$38.48	$0.59	($0.60)	$54.38	$55.82	($0.51)	($0.93)
Western Hub	$41.19	$40.63	$0.44	$0.12	$63.04	$60.30	$2.70	$0.04

The day-ahead components of LMP for each hub are presented in Table 11-6 for the first nine months of 2013 and the first nine months of 2014.

Component Costs

Table 11-7 shows the total energy, loss and congestion component costs and the total PJM billing for the first nine months of 2009 through 2014. These totals are actually net energy, loss and congestion costs.

Table 11-7 Total PJM costs by component (Dollars (Millions)): January through September of 2009 through 2014[6 7]

	Component Costs (Millions)					
(Jan - Sep)	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2009	($485)	$992	$544	$1,051	$19,927	5.3%
2010	($619)	$1,259	$1,134	$1,775	$26,249	6.8%
2011	($651)	$1,153	$875	$1,376	$28,836	4.8%
2012	($443)	$758	$425	$740	$22,119	3.3%
2013	($527)	$797	$510	$779	$25,153	3.1%
2014	($834)	$1,243	$1,705	$2,114	$40,760	5.2%

Table 11-6 Hub day-ahead, load-weighted average LMP components (Dollars per MWh): January through September of 2013 and 2014

	2013 (Jan-Sep)				2014 (Jan-Sep)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$33.91	$37.47	($1.65)	($1.92)	$42.38	$49.27	($4.36)	($2.53)
AEP-DAY Hub	$35.99	$38.19	($1.25)	($0.94)	$48.65	$55.47	($5.75)	($1.07)
ATSI Gen Hub	$35.74	$36.52	($0.68)	($0.10)	$50.89	$53.43	($2.67)	$0.13
Chicago Gen Hub	$32.89	$38.16	($3.14)	($2.12)	$43.99	$57.58	($10.76)	($2.82)
Chicago Hub	$33.93	$38.32	($2.76)	($1.63)	$44.51	$55.14	($8.89)	($1.73)
Dominion Hub	$41.62	$39.75	$2.08	($0.21)	$65.27	$59.98	$6.00	($0.71)
Eastern Hub	$43.13	$39.35	$1.63	$2.16	$69.51	$57.58	$8.86	$3.07
N Illinois Hub	$33.76	$38.58	($2.95)	($1.86)	$44.51	$56.28	($9.56)	($2.21)
New Jersey Hub	$44.06	$39.57	$2.79	$1.70	$65.19	$55.87	$7.17	$2.14
Ohio Hub	$36.27	$38.34	($1.24)	($0.83)	$49.03	$55.84	($5.97)	($0.84)
West Interface Hub	$41.37	$41.82	$0.06	($0.51)	$50.50	$51.35	($0.10)	($0.76)
Western Hub	$40.19	$38.84	$1.16	$0.19	$57.35	$54.79	$2.68	($0.12)

6 The energy costs, loss costs and congestion costs include net inadvertent charges.
7 Total PJM billing is provided by PJM, and the MMU is not able to reproduce and verify the calculation.

Congestion

Congestion Accounting

Congestion occurs in the Day-Ahead and Real-Time Energy Markets.[8] Total congestion costs are equal to the net implicit congestion bill plus net explicit congestion costs plus net inadvertent congestion charges, incurred in both the Day-Ahead Energy Market and the balancing energy market.

In the analysis of total congestion costs, load congestion payments are netted against generation congestion credits on an hourly basis, by billing organization, and then summed for the given period.[9]

Load congestion payments and generation congestion credits are calculated for both the Day-Ahead and balancing energy markets.

Total congestion costs in PJM in the first nine months of 2014 were $1,705.3 million, which was comprised of load congestion payments of $578.4 million, generation credits of -$1,273.4 million and explicit congestion of -$146.5 million (Table 11-9).

Total Congestion

Table 11-8 shows total congestion for the first nine months of 2008 through 2014.

Table 11-8 Total PJM congestion (Dollars (Millions)): January through September of 2008 through 2014

	Congestion Costs (Millions)			
(Jan - Sep)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,778.2	NA	$26,979	6.6%
2009	$543.6	(69.4%)	$19,927	2.7%
2010	$1,134.3	108.7%	$26,249	4.3%
2011	$874.9	(22.9%)	$28,836	3.0%
2012	$425.2	(51.4%)	$22,119	1.9%
2013	$509.6	19.9%	$25,153	2.0%
2014	$1,705.3	234.6%	$40,760	4.2%

8 When the term *congestion charges* is used in documents by PJM's Market Settlement Operations, it has the same meaning as the term *congestion costs* as used here.

9 This analysis does not treat affiliated billing organizations as a single organization. Thus, the generation congestion credits from one organization will not offset the load payments of its affiliate.

Total congestion costs in Table 11-8 include congestion costs associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the MISO and in the NYISO.[10] [11]

Table 11-9 shows the congestion costs by accounting category for the first nine months of 2014. In the first nine months of 2014, PJM total congestion costs were comprised of $578.4 million in load congestion payments, -$1,273.4 million in generation congestion credits, and -$146.5 million in explicit congestion costs.

Table 11-9 Total PJM congestion costs by accounting category (Dollars (Millions)): January through September of 2008 through 2014

	Congestion Costs (Millions)				
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2008	$921.9	($880.7)	($24.5)	$0.0	$1,778.2
2009	$210.6	($380.9)	($48.0)	$0.0	$543.6
2010	$290.2	($893.3)	($49.2)	($0.0)	$1,134.3
2011	$442.0	($535.7)	($102.8)	$0.0	$874.9
2012	$103.3	($372.7)	($50.9)	$0.0	$425.2
2013	$234.0	($340.5)	($64.8)	$0.0	$509.6
2014	$578.4	($1,273.4)	($146.5)	$0.0	$1,705.3

10 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).

11 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 11-10 Total PJM congestion costs by accounting category by market (Dollars (Millions)): January through September of 2008 through 2014

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$1,126.9	($971.2)	$152.8	$2,250.9	($204.9)	$90.5	($177.3)	($472.7)	$0.0	$1,778.2
2009	$245.7	($385.0)	$73.8	$704.6	($35.1)	$4.1	($121.9)	($161.0)	$0.0	$543.6
2010	$301.7	($932.7)	$69.5	$1,303.9	($11.5)	$39.3	($118.7)	($169.6)	($0.0)	$1,134.3
2011	$389.3	($628.2)	$45.6	$1,063.2	$52.7	$92.6	($148.4)	($188.3)	$0.0	$874.9
2012	$106.6	($409.8)	$86.7	$603.2	($3.3)	$37.1	($137.6)	($178.0)	$0.0	$425.2
2013	$227.1	($452.6)	$121.6	$801.4	$6.8	$112.2	($186.4)	($291.8)	$0.0	$509.6
2014	$505.4	($1,497.8)	($38.5)	$1,964.6	$73.1	$224.4	($107.9)	($259.3)	$0.0	$1,705.3

Monthly Congestion

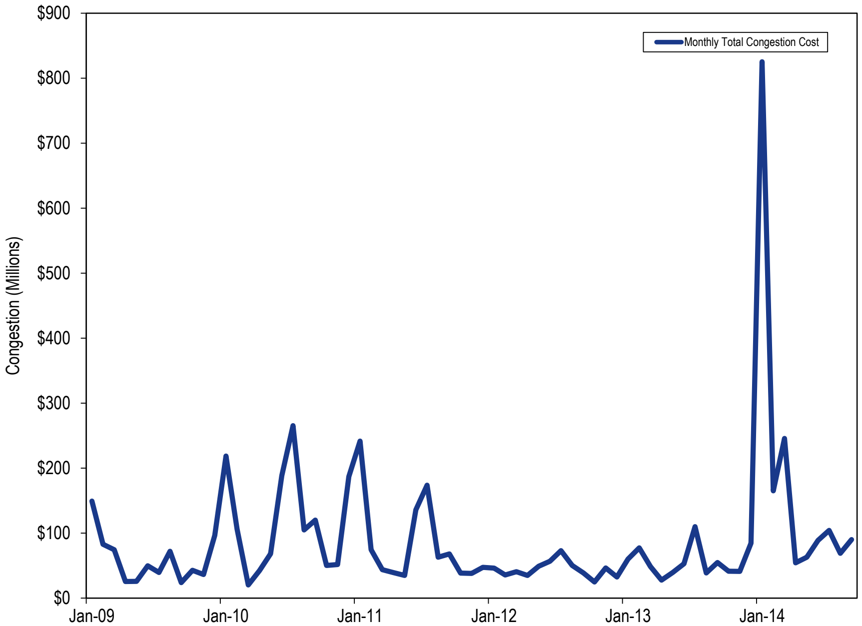
Table 11-11 shows that monthly total congestion costs ranged from $54.3 million to $825.1 million in 2014. Table 11-11 shows that congestions costs in January of 2014 were substantially higher than congestion costs in January of 2013, due to emergency conditions.

Table 11-11 Monthly PJM congestion costs by market (Dollars (Millions)): January through September of 2013 and 2014

	Congestion Costs (Millions)							
	2013 (Jan - Sep)				2014 (Jan - Sep)			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$136.8	($76.8)	$0.0	$60.0	$922.5	($97.4)	$0.0	$825.1
Feb	$125.1	($47.7)	$0.0	$77.4	$203.5	($38.3)	$0.0	$165.2
Mar	$69.9	($21.4)	($0.0)	$48.5	$307.3	($61.6)	$0.0	$245.8
Apr	$37.7	($9.9)	$0.0	$27.8	$66.3	($12.0)	($0.0)	$54.3
May	$75.3	($35.8)	($0.0)	$39.5	$84.9	($21.9)	$0.0	$63.1
Jun	$82.2	($29.4)	($0.0)	$52.8	$107.4	($18.6)	$0.0	$88.8
Jul	$131.3	($21.3)	$0.0	$110.1	$118.1	($14.0)	$0.0	$104.1
Aug	$46.0	($7.3)	$0.0	$38.6	$68.9	$0.0	$0.0	$68.9
Sep	$97.0	($42.1)	$0.0	$54.9	$85.8	$4.4	$0.0	$90.1
Total	$801.4	($291.8)	$0.0	$509.6	$1,964.6	($259.3)	$0.0	$1,705.3

Figure 11-1 shows PJM monthly total congestion cost for 2009 through the first nine months of 2014.

Figure 11-1 PJM monthly total congestion cost (Dollars (Millions)): 2009 through September of 2014



Congested Facilities

A congestion event exists when a unit or units must be dispatched out of merit order to control for the potential 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 usually exceeds the number of constrained hours and the number of congestion-event hours usually exceeds the number of hours in a year.

In order to have a consistent metric for real-time and day-ahead congestion frequency, real-time congestion frequency is measured using the convention that an hour is constrained if any of its component five-minute intervals is constrained. This is consistent with the way in which PJM reports real-time congestion. In the first nine months of 2014, there were 327,824 day-ahead, congestion-event hours compared to 261,702 day-ahead, congestion-event hours in the first nine months of 2013. In the first nine months of 2014, there were 21,139 real-time, congestion-event hours compared to 14,677 real-time, congestion-event hours in the first nine months of 2013.

During the first nine months of 2014, for only 2.8 percent of day-ahead energy market facility constrained hours were the same facilities also constrained in the Real-Time Energy Market. During the first nine months of 2014, for 45.7 percent of real-time energy market facility constrained hours, the same facilities were also constrained in the Day-Ahead Energy Market.

The AP South Interface was the largest contributor to congestion costs in the first nine months of 2014. With $475.3 million in total congestion costs, it accounted for 27.9 percent of the total PJM congestion costs in the first nine months of 2014. The top five constraints in terms of congestion costs together contributed $893.1 million, or 52.4 percent, of the total PJM congestion costs in the first nine months of 2014. The top five constraints were the AP South Interface, the West Interface, the Bagley - Graceton line, the Bedington - Black Oak Interface, and the Breed – Wheatland flowgate.

Congestion by Facility Type and Voltage

In the first nine months of 2014, compared to the first nine months of 2013, day-ahead, congestion-event hours increased on all types of facilities. Real-time, congestion-event hours increased on all types of facilities.

Day-ahead congestion costs increased on all types of facilities in the first nine months of 2014 compared to the first nine months of 2013. Balancing congestion costs decreased on flowgates, interfaces and transformers and increased on transmission lines in the first nine months of 2014 compared to the first nine months of 2013.

Table 11-12 provides congestion-event hour subtotals and congestion cost subtotals comparing the first nine months of 2014 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[12 13] For comparison, this information is presented in Table 11-13 for the first nine months of 2013.[14]

Table 11-12 Congestion summary (By facility type): January through September of 2014

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
Flowgate	($90.5)	($373.1)	($15.3)	$267.3	$2.5	$13.9	($37.6)	($49.0)	$218.3	29,993	5,285
Interface	$353.1	($615.8)	($100.9)	$868.0	$62.0	$143.6	$17.0	($64.5)	$803.4	15,935	3,282
Line	$160.1	($410.8)	$36.4	$607.3	($8.2)	$49.8	($46.2)	($104.2)	$503.1	171,951	10,690
Other	$0.2	($1.8)	$1.0	$3.0	$0.0	$0.0	($0.0)	$0.0	$3.0	6,410	1
Transformer	$80.6	($86.1)	$27.3	$194.0	$10.0	$15.7	($49.8)	($55.5)	$138.6	103,535	1,881
Unclassified	$1.8	($10.2)	$12.9	$24.9	$6.7	$1.5	$8.7	$13.9	$38.9	NA	NA
Total	$505.4	($1,497.8)	($38.5)	$1,964.6	$73.1	$224.4	($107.9)	($259.3)	$1,705.3	327,824	21,139

Table 11-13 Congestion summary (By facility type): January through September of 2013

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
Flowgate	($32.7)	($130.0)	$18.6	$115.9	$0.4	$11.8	($36.0)	($47.4)	$68.5	23,326	4,596
Interface	$142.3	($77.8)	$15.1	$235.2	$22.3	$29.1	($35.2)	($42.0)	$193.2	10,748	1,229
Line	$60.8	($205.9)	$53.9	$320.6	($17.5)	$59.4	($93.7)	($170.7)	$149.9	144,283	7,409
Other	$8.2	($2.0)	$6.6	$16.8	($0.4)	$0.1	($3.0)	($3.5)	$13.3	8,936	121
Transformer	$22.3	($56.1)	$21.3	$99.7	$1.6	$9.6	($19.8)	($27.8)	$71.8	74,409	1,322
Unclassified	$26.3	$19.2	$6.2	$13.3	$0.4	$2.1	$1.3	($0.4)	$12.9	NA	NA
Total	$227.1	($452.6)	$121.6	$801.4	$6.8	$112.2	($186.4)	($291.8)	$509.6	261,702	14,677

12 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.

13 The term flowgate refers to MISO flowgates and NYISO flowgates in this section.

14 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 11-14 and Table 11-15 compare day-ahead and real-time congestion event hours. Among the hours for which a facility is constrained in the Day-Ahead Energy Market, the number of hours during which the facility is also constrained in the Real-Time Energy Market are presented in Table 11-14. In the first nine months of 2014, there were 327,824 congestion event hours in the Day-Ahead Energy Market. Among those day-ahead congestion event hours, only 9,183 (2.8 percent) were also constrained in the Real-Time Energy Market. In the first nine months of 2013, among the 261,702 day-ahead congestion event hours, only 5,958 (2.3 percent) were binding in the Real-Time Energy Market.[15]

Among the hours for which a facility is constrained in the Real-Time Energy Market, the number of hours during which the facility is also constrained in the Day-Ahead Energy Market are presented in Table 11-15. In the first nine months of 2014, there were 21,139 congestion event hours in the Real-Time Energy Market. Among these real-time congestion event hours, 9,665 (45.7 percent) were also constrained in the Day-Ahead Energy Market. In the first nine months of 2013, among the 14,677 real-time congestion event hours, only 6,080 (41.4 percent) were also in the Day-Ahead Energy Market.

Table 11-14 Congestion event hours (Day-Ahead against Real-Time): January through September of 2013 and 2014

	Congestion Event Hours					
	2013 (Jan - Sep)			2014 (Jan - Sep)		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	23,326	1,887	8.1%	29,993	2,981	9.9%
Interface	10,748	910	8.5%	15,935	1,300	8.2%
Line	144,283	2,540	1.8%	171,951	4,335	2.5%
Other	8,936	158	1.8%	6,410	0	0.0%
Transformer	74,409	463	0.6%	103,535	567	0.5%
Total	261,702	5,958	2.3%	327,824	9,183	2.8%

Table 11-15 Congestion event hours (Real-Time against Day-Ahead): January through September of 2013 and 2014

	Congestion Event Hours					
	2013 (Jan - Sep)			2014 (Jan - Sep)		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	4,596	2,022	44.0%	5,285	3,107	58.8%
Interface	1,229	969	78.8%	3,282	1,667	50.8%
Line	7,409	2,535	34.2%	10,690	4,353	40.7%
Other	121	97	80.2%	1	0	0.0%
Transformer	1,322	457	34.6%	1,881	538	28.6%
Total	14,677	6,080	41.4%	21,139	9,665	45.7%

15 Constraints are mapped to transmission facilities. In the Day-Ahead Energy 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 Energy Market. Similarly in the Real-Time Market a facility may account for more than one constraint-hour within a given hour.

Table 11-16 shows congestion costs by facility voltage class for the first nine months of 2014. In comparison to the first nine months of 2013 (shown in Table 11-17), congestion costs decreased for facilities rated at 34 kV, 26 kV and 12 kV.

Table 11-16 Congestion summary (By facility voltage): January through September of 2014

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	$22.7	($38.9)	$3.9	$65.4	$0.5	$1.8	($3.2)	($4.5)	$60.9	11,735	298
500	$364.6	($614.7)	($100.3)	$879.0	$74.0	$159.8	$7.4	($78.4)	$800.5	21,697	2,363
345	($71.2)	($323.3)	$3.0	$255.0	$5.2	$15.3	($28.8)	($38.9)	$216.1	65,481	2,646
230	$109.2	($222.4)	($3.2)	$328.4	$2.6	($2.2)	$2.0	$6.8	$335.2	50,993	5,077
161	($22.6)	($49.3)	($2.8)	$23.9	($1.9)	$0.5	($1.2)	($3.6)	$20.4	5,540	1,054
138	$45.0	($231.7)	$41.6	$318.3	($0.9)	$42.0	($88.3)	($131.2)	$187.1	133,621	7,832
115	$2.8	($18.9)	$4.6	$26.3	($6.1)	$2.7	($3.1)	($11.8)	$14.5	18,157	1,149
69	$53.1	$11.7	$1.6	$43.0	($7.0)	$3.1	($1.4)	($11.5)	$31.6	16,725	720
34	$0.0	($0.0)	$0.1	$0.2	$0.0	$0.0	$0.0	$0.0	$0.2	3,853	0
26	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	13	0
12	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	9	0
Unclassified	$1.8	($10.2)	$12.9	$24.9	$6.7	$1.5	$8.7	$13.9	$38.9	NA	NA
Total	$505.4	($1,497.8)	($38.5)	$1,964.6	$73.1	$224.4	($107.9)	($259.3)	$1,705.3	327,824	21,139

Table 11-17 Congestion summary (By facility voltage): January through September of 2013

	Congestion Costs (Millions)										
	Day Ahead				Balancing					Event Hours	
Voltage (kV)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
765	$4.5	($15.7)	$7.6	$27.8	($0.2)	$0.5	$0.8	$0.1	$27.9	7,756	15
500	$141.8	($89.3)	$17.9	$249.0	$27.8	$34.0	($47.0)	($53.2)	$195.7	14,572	1,632
345	($32.7)	($128.1)	$16.0	$111.4	($0.9)	$14.2	($45.4)	($60.5)	$50.9	45,315	3,168
230	$65.4	($114.4)	$38.3	$218.1	($4.5)	$45.5	($48.2)	($98.2)	$119.9	42,424	2,739
161	($4.5)	($9.1)	($0.9)	$3.7	($1.1)	$0.4	($3.0)	($4.5)	($0.8)	1,783	761
138	($14.3)	($119.7)	$33.5	$138.9	($6.2)	$12.4	($41.4)	($60.0)	$79.0	116,029	4,846
123	$5.5	$2.2	$0.8	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	526	0
115	$13.4	($0.1)	$3.1	$16.5	($2.9)	($0.7)	($4.0)	($6.3)	$10.2	13,597	908
69	$21.9	$2.4	($0.9)	$18.6	($5.8)	$3.7	$0.7	($8.8)	$9.8	13,661	579
34	($0.0)	($0.1)	$0.1	$0.2	$0.0	$0.0	($0.0)	($0.0)	$0.2	6,007	29
12	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	32	0
Unclassified	$26.3	$19.2	$6.2	$13.3	$0.4	$2.1	$1.3	($0.4)	$12.9	NA	NA
Total	$227.1	($452.6)	$121.6	$801.4	$6.8	$112.2	($186.4)	($291.8)	$509.6	261,702	14,677

Constraint Duration

Table 11-18 lists the constraints in the first nine months of 2013 and the first nine months of 2014 that were most frequently binding and Table 11-19 shows the constraints which experienced the largest change in congestion-event hours from the first nine months of 2013 to the first nine months of 2014.

Table 11-18 Top 25 constraints with frequent occurrence: January through September of 2013 and 2014

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2013	2014	Change	2013	2014	Change	2013	2014	Change	2013	2014	Change
1	Miami Fort	Transformer	1,952	8,563	6,611	29	23	(6)	22%	97%	75%	0%	0%	(0%)
2	Tanners Creek	Transformer	4,901	7,752	2,851	0	0	0	56%	88%	32%	0%	0%	0%
3	Braidwood	Transformer	5,710	6,865	1,155	0	0	0	65%	78%	13%	0%	0%	0%
4	Oak Grove - Galesburg	Flowgate	1,451	5,403	3,952	640	938	298	17%	62%	45%	7%	11%	3%
5	Clinch River	Transformer	2,236	6,307	4,071	0	0	0	26%	72%	46%	0%	0%	0%
6	AP South	Interface	4,757	4,685	(72)	915	972	57	54%	53%	(1%)	10%	11%	1%
7	Kendall Co. Energy Ctr.	Transformer	735	5,337	4,602	0	0	0	8%	61%	52%	0%	0%	0%
8	Bagley - Graceton	Line	1,290	3,617	2,327	260	1,381	1,121	15%	41%	26%	3%	16%	13%
9	Wolf Creek	Transformer	773	4,866	4,093	29	129	100	9%	55%	47%	0%	1%	1%
10	Monticello - East Winamac	Flowgate	1,926	3,511	1,585	542	1,440	898	22%	40%	18%	6%	16%	10%
11	Burlington - Croydon	Line	0	4,688	4,688	0	0	0	0%	53%	53%	0%	0%	0%
12	East Bend	Transformer	818	4,613	3,795	0	0	0	9%	53%	43%	0%	0%	0%
13	Mardela - Vienna	Line	2,142	4,441	2,299	199	70	(129)	24%	51%	26%	2%	1%	(1%)
14	Bergen - New Milford	Line	1,355	4,502	3,147	0	0	0	15%	51%	36%	0%	0%	0%
15	Sunbury	Transformer	4,915	4,344	(571)	0	0	0	56%	49%	(7%)	0%	0%	0%
16	Nelson - Cordova	Line	3,919	3,901	(18)	238	268	30	45%	44%	(0%)	3%	3%	0%
17	Gould Street - Westport	Line	6,007	3,803	(2,204)	21	0	(21)	69%	43%	(25%)	0%	0%	(0%)
18	Sporn	Transformer	7,742	3,558	(4,184)	0	0	0	88%	41%	(48%)	0%	0%	0%
19	Huntington Junction - Huntington	Line	2,202	3,375	1,173	0	0	0	25%	38%	13%	0%	0%	0%
20	Breed - Wheatland	Flowgate	1,714	2,810	1,096	293	531	238	20%	32%	12%	3%	6%	3%
21	Howard - Shelby	Line	4,415	3,329	(1,086)	0	0	0	50%	38%	(13%)	0%	0%	0%
22	Fort Robinson - Wolf Hills	Line	734	3,185	2,451	0	0	0	8%	36%	28%	0%	0%	0%
23	Keeney	Transformer	284	3,087	2,803	0	58	58	3%	35%	32%	0%	1%	1%
24	Halifax - Halifax Worsted	Line	2,213	3,061	848	0	1	1	25%	35%	10%	0%	0%	0%
25	Beckjord	Transformer	2,184	3,029	845	0	0	0	25%	34%	10%	0%	0%	0%

Table 11-19 Top 25 constraints with largest year-to-year change in occurrence: January through September of 2013 and 2014

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2013	2014	Change	2013	2014	Change	2013	2014	Change	2013	2014	Change
1	Miami Fort	Transformer	1,952	8,563	6,611	29	23	(6)	22%	97%	75%	0%	0%	(0%)
2	Burlington - Croydon	Line	0	4,688	4,688	0	0	0	0%	53%	53%	0%	0%	0%
3	Kendall Co. Energy Ctr.	Transformer	735	5,337	4,602	0	0	0	8%	61%	52%	0%	0%	0%
4	Oak Grove - Galesburg	Flowgate	1,451	5,403	3,952	640	938	298	17%	62%	45%	7%	11%	3%
5	Wolf Creek	Transformer	773	4,866	4,093	29	129	100	9%	55%	47%	0%	1%	1%
6	Sporn	Transformer	7,742	3,558	(4,184)	0	0	0	88%	41%	(48%)	0%	0%	0%
7	Clinch River	Transformer	2,236	6,307	4,071	0	0	0	26%	72%	46%	0%	0%	0%
8	East Bend	Transformer	818	4,613	3,795	0	0	0	9%	53%	43%	0%	0%	0%
9	Bagley - Graceton	Line	1,290	3,617	2,327	260	1,381	1,121	15%	41%	26%	3%	16%	13%
10	Bergen - New Milford	Line	1,355	4,502	3,147	0	0	0	15%	51%	36%	0%	0%	0%
11	Keeney	Transformer	284	3,087	2,803	0	58	58	3%	35%	32%	0%	1%	1%
12	Tanners Creek	Transformer	4,901	7,752	2,851	0	0	0	56%	88%	32%	0%	0%	0%
13	Joshua Falls	Transformer	19	2,853	2,834	0	13	13	0%	32%	32%	0%	0%	0%
14	Cook - Palisades	Flowgate	0	2,316	2,316	0	308	308	0%	26%	26%	0%	4%	4%
15	Haurd - Steward	Line	3,366	749	(2,617)	0	0	0	38%	9%	(30%)	0%	0%	0%
16	Readington - Roseland	Line	3,206	1,169	(2,037)	713	189	(524)	37%	13%	(23%)	8%	2%	(6%)
17	Monticello - East Winamac	Flowgate	1,926	3,511	1,585	542	1,440	898	22%	40%	18%	6%	16%	10%
18	Fort Robinson - Wolf Hills	Line	734	3,185	2,451	0	0	0	8%	36%	28%	0%	0%	0%
19	Sayreville - Sayreville	Line	0	2,394	2,394	0	0	0	0%	27%	27%	0%	0%	0%
20	Bridgewater - Middlesex	Line	2,395	201	(2,194)	230	31	(199)	27%	2%	(25%)	3%	0%	(2%)
21	Gould Street - Westport	Line	6,007	3,803	(2,204)	21	0	(21)	69%	43%	(25%)	0%	0%	(0%)
22	Mardela - Vienna	Line	2,142	4,441	2,299	199	70	(129)	24%	51%	26%	2%	1%	(1%)
23	Zion	Line	2,565	488	(2,077)	0	0	0	29%	6%	(24%)	0%	0%	0%
24	Prairie State - W Mt. Vernon	Flowgate	1,021	0	(1,021)	840	0	(840)	12%	0%	(12%)	10%	0%	(10%)
25	Cloverdale	Transformer	113	1,937	1,824	0	0	0	1%	22%	21%	0%	0%	0%

Constraint Costs

Table 11-20 and Table 11-21 present the top constraints affecting congestion costs by facility for the periods the first nine months of 2014 and the first nine months of 2013.

Table 11-20 Top 25 constraints affecting PJM congestion costs (By facility): January through September of 2014

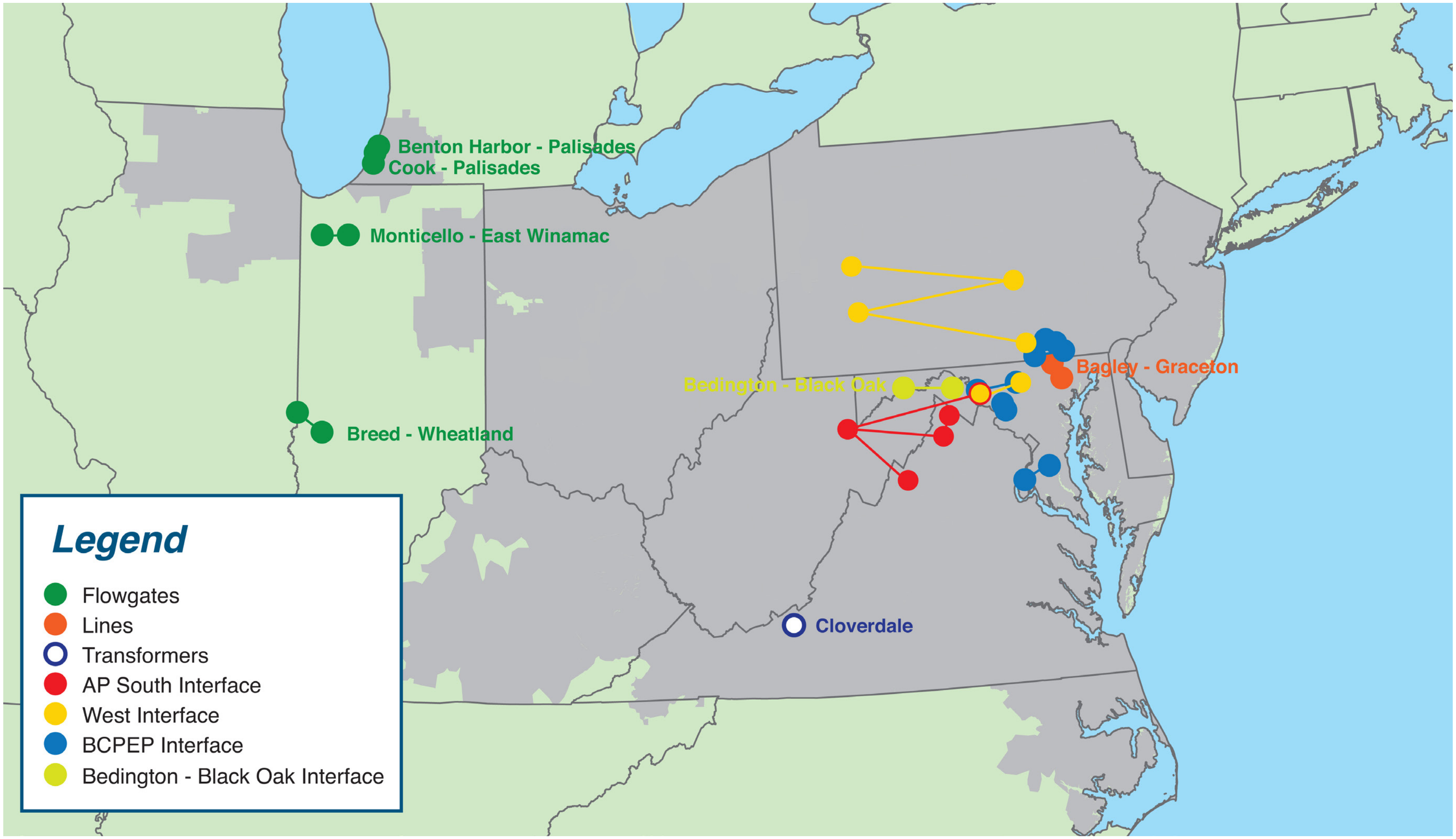
				Congestion Costs (Millions)									Percent of Total PJM Congestion Costs
				Day Ahead				Balancing					
No.	Constraint	Type	Location	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	2014 (Jan - Sep)
1	AP South	Interface	500	$322.0	($196.8)	($10.4)	$508.4	$31.5	$73.5	$8.9	($33.1)	$475.3	27.9%
2	West	Interface	500	($21.3)	($290.9)	($78.6)	$191.0	$16.7	$47.7	$16.8	($14.2)	$176.8	10.4%
3	Bagley - Graceton	Line	BGE	$77.5	($3.8)	($0.9)	$80.4	$4.4	($2.0)	$3.9	$10.3	$90.7	5.3%
4	Bedington - Black Oak	Interface	500	$39.3	($41.0)	$0.2	$80.5	$3.9	$3.5	($2.3)	($1.9)	$78.6	4.6%
5	Breed - Wheatland	Flowgate	MISO	($16.2)	($90.3)	($9.2)	$64.9	$2.3	$1.1	$5.6	$6.8	$71.7	4.2%
6	Cloverdale	Transformer	AEP	$23.0	($27.0)	$0.2	$50.1	$0.0	$0.0	$0.0	$0.0	$50.1	2.9%
7	Benton Harbor - Palisades	Flowgate	MISO	($11.8)	($70.2)	($6.9)	$51.6	($0.2)	$0.7	($1.0)	($1.8)	$49.7	2.9%
8	BCPEP	Interface	Pepco	$13.7	($15.2)	($1.7)	$27.2	($1.6)	($14.2)	$1.5	$14.1	$41.3	2.4%
9	Unclassified	Unclassified	Unclassified	$1.8	($10.2)	$12.9	$24.9	$6.7	$1.5	$8.7	$13.9	$38.9	2.3%
10	Monticello - East Winamac	Flowgate	MISO	($3.8)	($46.7)	$1.6	$44.6	$2.6	$4.3	($10.8)	($12.5)	$32.1	1.9%
11	Cook - Palisades	Flowgate	MISO	($12.6)	($55.3)	($5.3)	$37.4	($1.5)	$1.6	($6.2)	($9.3)	$28.1	1.6%
12	Readington - Roseland	Line	PSEG	($8.9)	($46.1)	($12.2)	$25.1	$0.9	$5.4	$5.8	$1.3	$26.4	1.5%
13	Cloverdale	Transformer	AEP	$22.3	($4.9)	($2.2)	$25.0	$0.0	$0.0	$0.0	$0.0	$25.0	1.5%
14	Wolf Creek	Transformer	AEP	$4.5	$1.3	$4.6	$7.9	$3.6	$5.6	($29.3)	($31.3)	($23.5)	(1.4%)
15	Brambleton - Loudoun	Line	Dominion	($11.2)	($35.1)	($1.3)	$22.6	$0.6	$0.0	$0.1	$0.6	$23.2	1.4%
16	Oak Grove - Galesburg	Flowgate	MISO	($22.5)	($48.6)	($2.5)	$23.5	($0.4)	$0.4	$0.1	($0.7)	$22.8	1.3%
17	Wescosville	Transformer	PPL	$17.6	($0.8)	$2.7	$21.1	($0.0)	$0.0	$0.0	($0.0)	$21.1	1.2%
18	East	Interface	500	($9.2)	($32.3)	($3.2)	$19.9	$0.3	$0.7	$0.5	$0.1	$20.0	1.2%
19	Bergen - New Milford	Line	PSEG	$21.3	$12.7	$11.3	$19.9	$0.0	$0.0	$0.0	$0.0	$19.9	1.2%
20	Bridgewater - Middlesex	Line	PSEG	$0.1	($22.1)	($3.0)	$19.2	($1.5)	$0.1	$1.4	($0.2)	$19.0	1.1%
21	Nelson - Cordova	Line	ComEd	($23.5)	($44.4)	$3.9	$24.8	($0.7)	$1.0	($4.2)	($5.9)	$18.9	1.1%
22	5004/5005 Interface	Interface	500	($0.5)	($22.7)	($3.3)	$18.9	$8.1	$17.5	$7.3	($2.2)	$16.7	1.0%
23	Atlantic - Larrabee	Line	JCPL	$2.0	($14.8)	($0.7)	$16.1	$0.0	$1.3	$1.2	($0.1)	$16.0	0.9%
24	Rising	Flowgate	MISO	($5.1)	($3.8)	$1.4	$0.2	($3.9)	$1.2	($9.3)	($14.3)	($14.1)	(0.8%)
25	Clover	Transformer	Dominion	$0.0	$0.0	$0.0	$0.0	$2.2	$3.9	($10.9)	($12.7)	($12.7)	(0.7%)

Table 11-21 Top 25 constraints affecting PJM congestion costs (By facility): January through September of 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 - Sep)
1	AP South	Interface	500	$117.7	($29.5)	$12.9	$160.0	$7.5	$13.3	($9.2)	($15.1)	$144.9	28.4%
2	West	Interface	500	$3.2	($24.1)	$0.1	$27.4	$2.9	$3.1	($1.1)	($1.2)	$26.2	5.1%
3	ATSI	Interface	ATSI	$0.0	$0.0	$0.0	$0.0	$10.2	$9.0	($24.7)	($23.5)	($23.5)	(4.6%)
4	Bridgewater - Middlesex	Line	PSEG	($0.1)	($23.0)	$1.9	$24.8	$1.8	$4.5	($1.8)	($4.4)	$20.4	4.0%
5	Cloverdale	Transformer	AEP	$8.0	($3.6)	$4.9	$16.6	$0.0	$0.0	$0.0	$0.0	$16.6	3.2%
6	Readington - Roseland	Line	PSEG	($1.8)	($49.5)	$5.2	$52.9	($10.5)	$38.1	($20.7)	($69.3)	($16.3)	(3.2%)
7	BCPEP	Interface	Pepco	$11.9	($1.8)	$1.9	$15.6	$0.0	$0.0	$0.0	$0.0	$15.6	3.1%
8	Breed - Wheatland	Flowgate	MISO	($2.8)	($16.0)	$1.8	$15.0	$0.1	($0.1)	($1.3)	($1.1)	$13.9	2.7%
9	Bagley - Graceton	Line	BGE	$11.1	($0.7)	$1.8	$13.7	$0.3	($1.0)	($1.9)	($0.6)	$13.1	2.6%
10	Laporte - Michigan City	Line	AEP	$0.0	$0.0	$0.0	$0.0	($6.7)	$1.3	($4.9)	($12.9)	($12.9)	(2.5%)
11	Unclassified	Unclassified	Unclassified	$26.3	$19.2	$6.2	$13.3	$0.4	$2.1	$1.3	($0.4)	$12.9	2.5%
12	Clover	Transformer	Dominion	$0.0	$0.0	$0.0	$0.0	($0.2)	$5.1	($6.8)	($12.1)	($12.1)	(2.4%)
13	Monticello - East Winamac	Flowgate	MISO	($2.3)	($26.8)	$4.0	$28.5	$0.2	$5.4	($11.3)	($16.5)	$12.0	2.4%
14	Byron - Cherry Valley	Flowgate	MISO	($3.9)	($14.0)	$0.1	$10.2	$0.0	$0.0	$0.0	$0.0	$10.2	2.0%
15	5004/5005 Interface	Interface	500	$0.8	($11.7)	($0.4)	$12.2	$1.4	$3.9	$0.3	($2.2)	$10.0	2.0%
16	Bedington - Black Oak	Interface	500	$6.2	($3.1)	$0.8	$10.0	$0.1	($0.0)	($0.3)	($0.2)	$9.8	1.9%
17	Crete - St Johns Tap	Flowgate	MISO	($0.5)	($7.1)	$2.7	$9.3	$0.0	$0.0	$0.0	$0.0	$9.3	1.8%
18	South Canton	Transformer	AEP	($3.4)	($11.1)	$1.1	$8.8	($0.2)	$0.5	$0.8	$0.1	$8.9	1.7%
19	Conastone - Graceton	Line	BGE	$5.4	($2.0)	$1.6	$9.0	($0.0)	($0.1)	($0.2)	($0.2)	$8.8	1.7%
20	Byron - Cherry Valley	Line	ComEd	($0.0)	($0.1)	$0.0	$0.1	($1.2)	$2.5	($5.0)	($8.7)	($8.6)	(1.7%)
21	Bedington	Transformer	AP	$3.5	($5.1)	($0.0)	$8.6	$0.0	$0.4	$0.3	($0.1)	$8.5	1.7%
22	Braidwood	Transformer	ComEd	($0.2)	($7.4)	$1.2	$8.4	$0.0	$0.0	$0.0	$0.0	$8.4	1.6%
23	New Dover - Westfield	Line	PSEG	$0.5	($5.8)	$0.9	$7.1	$0.0	$0.0	$0.0	$0.0	$7.1	1.4%
24	Michigan City - Laporte	Flowgate	MISO	($6.0)	($10.6)	$2.5	$7.1	$0.0	$0.0	$0.0	$0.0	$7.1	1.4%
25	AEP - DOM	Interface	500	$4.0	($2.5)	$0.3	$6.8	($0.1)	$0.1	($0.0)	($0.2)	$6.6	1.3%

Figure 11-2 shows the locations of the top 10 constraints affecting PJM congestion costs in the first nine months of 2014.

Figure 11-2 Location of the top 10 constraints affecting PJM congestion costs: January through September of 2014[16]



16 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates in this section.

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.[17] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[18] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch.

As of September 30, 2014, PJM had 89 flowgates eligible for M2M (Market to Market) coordination and MISO had 274 flowgates eligible for M2M coordination.

Table 11-22 and Table 11-23 show the MISO flowgates which PJM and/or MISO took dispatch action to control during the first nine months of 2014 and the first nine months of 2013, and which had the greatest congestion cost impact on PJM. Total congestion costs are the sum of the day-ahead and balancing congestion cost components. Total congestion costs associated with a given constraint may be positive or negative in value. The top congestion cost impacts for MISO flowgates affecting PJM and MISO dispatch are presented by constraint, in descending order of the absolute value of total congestion costs. Among MISO flowgates in the first nine months of 2014, the Breed - Wheatland flowgate made the most significant contribution to positive congestion while the Rising flowgate made the most significant contribution to negative congestion.

Table 11-22 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through September of 2014

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Breed - Wheatland	($16.2)	($90.3)	($9.2)	$64.9	$2.3	$1.1	$5.6	$6.8	$71.7	2,810	527
2	Benton Harbor - Palisades	($11.8)	($70.2)	($6.9)	$51.6	($0.2)	$0.7	($1.0)	($1.8)	$49.7	2,528	137
3	Monticello - East Winamac	($3.8)	($46.7)	$1.6	$44.6	$2.6	$4.3	($10.8)	($12.5)	$32.1	3,511	1,440
4	Cook - Palisades	($12.6)	($55.3)	($5.3)	$37.4	($1.5)	$1.6	($6.2)	($9.3)	$28.1	2,316	308
5	Oak Grove - Galesburg	($22.5)	($48.6)	($2.5)	$23.5	($0.4)	$0.4	$0.1	($0.7)	$22.8	5,403	938
6	Rising	($5.1)	($3.8)	$1.4	$0.2	($3.9)	$1.2	($9.3)	($14.3)	($14.1)	386	105
7	Wake - Carso	$0.0	$0.0	$0.0	$0.0	$4.2	$2.7	($10.7)	($9.3)	($9.3)	0	115
8	Michigan City - Laporte	($4.5)	($11.2)	$2.2	$8.9	$0.0	$0.0	$0.0	$0.0	$8.9	1,850	0
9	Crete - St Johns Tap	($1.4)	($6.5)	$1.3	$6.4	$0.0	$0.0	$0.0	$0.0	$6.4	606	0
10	Cumberland - Bush	($0.2)	($3.2)	$0.5	$3.5	$0.0	$0.0	$0.0	$0.0	$3.5	470	0
11	Batesville - Hubble	($1.7)	($5.6)	($0.9)	$2.9	($0.0)	($0.0)	$0.1	$0.1	$3.0	438	16
12	Todd Hunter	($0.7)	($3.0)	$0.7	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	867	0
13	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($1.4)	$0.0	($1.0)	($2.5)	($2.5)	0	73
14	Paddock - Townline	$0.1	($2.4)	($0.3)	$2.2	$0.0	$0.0	$0.1	$0.1	$2.3	670	38
15	Rantoul - Rantoul Jct	($2.7)	($4.5)	$0.3	$2.1	$0.0	$0.0	$0.0	$0.0	$2.1	930	0
16	Bunsonville - Eugene	($4.2)	($7.4)	$0.2	$3.4	($0.1)	($0.1)	($1.2)	($1.2)	$2.1	2,060	534
17	Nelson	($2.7)	($5.1)	($0.4)	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	165	0
18	Edwards - Kewanee	($1.6)	($3.6)	$0.0	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	1,789	0
19	Pana North	$0.1	($0.2)	$0.1	$0.4	$0.0	$0.3	($2.0)	($2.3)	($1.9)	157	8
20	Magnetation - Monticello	($0.0)	($1.0)	$0.4	$1.3	$0.3	$0.3	$0.3	$0.4	$1.7	112	20

17 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>.

18 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 11-23 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through September of 2013

		Congestion Costs (Millions)										
		Day Ahead				Balancing					Event Hours	
No.	Constraint	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Grand Total	Day Ahead	Real Time
1	Breed - Wheatland	($2.8)	($16.0)	$1.8	$15.0	$0.1	($0.1)	($1.3)	($1.1)	$13.9	1,714	293
2	Monticello - East Winamac	($2.3)	($26.8)	$4.0	$28.5	$0.2	$5.4	($11.3)	($16.5)	$12.0	1,926	542
3	Byron - Cherry Valley	($3.9)	($14.0)	$0.1	$10.2	$0.0	$0.0	$0.0	$0.0	$10.2	72	0
4	Crete - St Johns Tap	($0.5)	($7.1)	$2.7	$9.3	$0.0	$0.0	$0.0	$0.0	$9.3	1,165	0
5	Michigan City - Laporte	($6.0)	($10.6)	$2.5	$7.1	$0.0	$0.0	$0.0	$0.0	$7.1	2,304	0
6	Benton Harbor - Palisades	($1.4)	($7.5)	$2.5	$8.6	($0.1)	$0.8	($2.1)	($2.9)	$5.7	1,700	117
7	Rocky - Battlebo	$5.5	$2.2	$0.8	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	526	0
8	Rantoul - Rantoul Jct	($3.7)	($5.8)	$1.6	$3.7	$0.0	$0.0	$0.0	$0.0	$3.7	1,673	0
9	Edwards - Kewanee	($2.5)	($4.1)	$2.0	$3.6	$0.0	$0.0	$0.0	$0.0	$3.6	2,095	12
10	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
11	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($0.7)	$0.1	($2.6)	($3.4)	($3.4)	0	83
12	Miami Fort	($0.9)	($3.7)	($0.0)	$2.8	$0.0	$0.0	$0.0	$0.0	$2.8	1,098	0
13	Volunteer - Phipps Bend	$0.0	$0.0	$0.0	$0.0	$0.8	$0.0	($2.9)	($2.1)	($2.1)	0	63
14	Stillwell	$0.0	$0.0	$0.0	$0.0	($0.2)	$0.4	($1.4)	($1.9)	($1.9)	0	64
15	Oak Grove - Galesburg	($3.8)	($7.1)	($0.3)	$3.0	($0.3)	$0.3	($0.6)	($1.2)	$1.8	1,451	640
16	Rantoul Jct - Sidney	$0.0	$0.0	$0.0	$0.0	($0.5)	$0.7	($0.5)	($1.7)	($1.7)	0	193
17	Hennepin	($0.2)	($0.5)	($0.1)	$0.1	($0.2)	$0.0	($1.4)	($1.6)	($1.5)	82	161
18	Pleasant Prairie - Zion	($0.5)	($1.6)	$0.7	$1.8	($0.0)	($0.0)	($0.5)	($0.5)	$1.3	855	76
19	Roxana - Praxair	($2.3)	($2.6)	$0.4	$0.7	$0.3	$0.4	($1.4)	($1.4)	($0.7)	648	92
20	Bunsonville - Eugene	($1.9)	($3.6)	$0.1	$1.8	($0.0)	$0.1	($1.0)	($1.1)	$0.7	710	261

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.[19] 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.[20]

Table 11-24 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during the first nine months of 2014, and which had the greatest congestion cost impact on PJM.

19 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).

20 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).

Table 11-24 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): January through September of 2014

				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	Central East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.5	$2.0	($0.1)	($1.6)	($1.6)	0	128
2	Dysinger East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.0)	($0.0)	$0.0	$0.0	0	4

Table 11-25 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): January through September of 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	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	$0.1	$0.1	($0.1)	($0.2)	($0.2)	0	31

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 11-26 and Table 11-27 show the 500 kV constraints affecting congestion costs in PJM for the first nine months of 2014 and the first nine months of 2014. 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 affecting congestion costs in PJM are presented by constraint, in descending order of the absolute value of total congestion costs.

Table 11-26 Regional constraints summary (By facility): January through September of 2014

				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	$322.0	($196.8)	($10.4)	$508.4	$31.5	$73.5	$8.9	($33.1)	$475.3	4,685	967
2	West	Interface	500	($21.3)	($290.9)	($78.6)	$191.0	$16.7	$47.7	$16.8	($14.2)	$176.8	1,395	347
3	Bedington - Black Oak	Interface	500	$39.3	($41.0)	$0.2	$80.5	$3.9	$3.5	($2.3)	($1.9)	$78.6	2,386	311
4	East	Interface	500	($9.2)	($32.3)	($3.2)	$19.9	$0.3	$0.7	$0.5	$0.1	$20.0	1,710	17
5	5004/5005 Interface	Interface	500	($0.5)	($22.7)	($3.3)	$18.9	$8.1	$17.5	$7.3	($2.2)	$16.7	495	333
6	SENECA	Interface	500	$4.3	$7.7	($3.9)	($7.2)	$0.0	$0.0	$0.0	$0.0	($7.2)	1,737	0
7	AEP - DOM	Interface	500	$9.7	($10.6)	$3.9	$24.2	$5.4	$13.1	($9.6)	($17.3)	$6.9	2,186	59
8	Central	Interface	500	($5.1)	($13.7)	($3.8)	$4.8	$0.2	$0.5	$0.0	($0.3)	$4.5	325	10
9	Juniata	Transformer	500	$0.1	($0.2)	$0.1	$0.5	$0.1	($0.0)	($0.1)	$0.0	$0.5	253	9
10	Branchburg - Elroy	Line	500	($0.0)	($0.2)	$0.0	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	43	0

Table 11-27 Regional constraints summary (By facility): January through September of 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	$117.7	($29.5)	$12.9	$160.0	$7.5	$13.3	($9.2)	($15.1)	$144.9	4,757	915
2	West	Interface	500	$3.2	($24.1)	$0.1	$27.4	$2.9	$3.1	($1.1)	($1.2)	$26.2	1,387	79
3	5004/5005 Interface	Interface	500	$0.8	($11.7)	($0.4)	$12.2	$1.4	$3.9	$0.3	($2.2)	$10.0	505	150
4	Bedington - Black Oak	Interface	500	$6.2	($3.1)	$0.8	$10.0	$0.1	($0.0)	($0.3)	($0.2)	$9.8	1,172	16
5	AEP - DOM	Interface	500	$4.0	($2.5)	$0.3	$6.8	($0.1)	$0.1	($0.0)	($0.2)	$6.6	1,317	10
6	Conemaugh - Hunterstown	Line	500	$0.4	($2.6)	$0.3	$3.4	$0.5	$0.7	($0.7)	($0.9)	$2.5	153	68
7	Central	Interface	500	($0.9)	($3.3)	($0.4)	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	167	0
8	East	Interface	500	($0.5)	($1.7)	($0.0)	$1.2	($0.0)	$0.0	($0.0)	($0.0)	$1.1	254	4
9	Juniata	Transformer	500	$0.2	($0.3)	$0.2	$0.7	$0.4	$0.1	($0.4)	($0.1)	$0.6	227	6
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	6

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 nine months of 2014, financial companies as a group were net recipients of congestion credits, and physical companies were net payers of congestion charges. UTCs are in the explicit cost category and comprise most of that category. Explicit costs are the primary source of congestion credits to financial entities. In the first nine months of 2014, financial companies received $196.4 million in net congestion credits, an increase of $114.9 million or 141.1 percent compared to the first nine months of 2013. In the first nine months of 2014, physical companies paid $1,901.7 million in congestion charges, an increase of $1,310.7 million or 221.7 percent compared to the first nine months of 2013.

Table 11-28 Congestion cost by type of participant: January through September of 2014

	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	$64.7	$65.5	($77.6)	($78.4)	($31.4)	($4.3)	($90.9)	($118.0)	$0.0	($196.4)
Physical	$440.7	($1,563.2)	$39.1	$2,043.0	$104.4	$228.7	($17.1)	($141.3)	$0.0	$1,901.7
Total	$505.4	($1,497.8)	($38.5)	$1,964.6	$73.1	$224.4	($107.9)	($259.3)	$0.0	$1,705.3

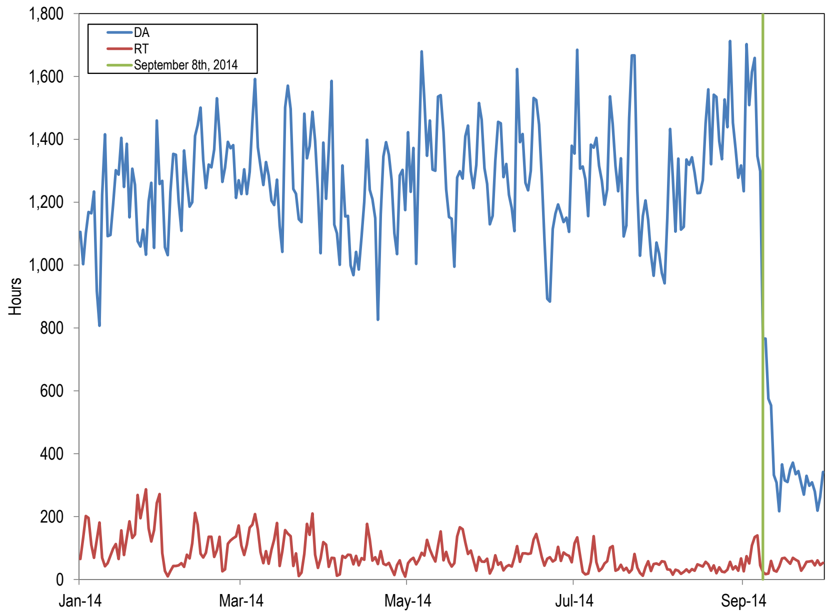
Table 11-29 Congestion cost by type of participant: January through September of 2013

	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	$44.3	$35.5	$76.9	$85.7	($28.5)	$0.9	($137.7)	($167.1)	$0.0	($81.4)
Physical	$182.9	($488.1)	$44.7	$715.7	$35.4	$111.3	($48.7)	($124.6)	$0.0	$591.1
Total	$227.1	($452.6)	$121.6	$801.4	$6.8	$112.2	($186.4)	($291.8)	$0.0	$509.6

Congestion-Event Summary before and after September 8th, 2014

The day-ahead congestion event hours decreased significantly corresponding with a significant reduction in UTC activity related to FERC's UTC uplift refund notice, effective September 8, 2014.[21] Figure 11-3 shows the daily day-ahead and real-time congestion event hours for the first nine months of 2014.

Figure 11-3 Daily congestion event hours: January through September 2014



21 See 18 CFR § 385.213 (2014).

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 marginal 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 nine months of 2014 was $1,243.1 million, which was comprised of load loss payments of -$47.6 million, generation loss credits of -$1,343.7 million, explicit loss costs of -$53.0 million and inadvertent loss charges of $0.0 million. Monthly marginal loss costs in the first nine months of 2014 ranged from $68.7 million in May to $414.6 million in January. Marginal loss credits increased in the first nine months of 2014 by $136.4 million or 51.0 percent from the first nine months of 2013, from $267.6 million to $404.1 million.

Total Marginal Loss Costs

Table 11-30 shows the total marginal loss component costs for the first nine months of 2009 through 2014.

Total marginal loss costs for the first nine months of 2009 through 2014 are shown in Table 11-31 and Table 11-32. Table 11-31 shows PJM total marginal loss costs by accounting category for the first nine months of 2009 through 2014. Table 11-32 shows PJM total marginal loss costs by accounting category by market for the first nine months of 2009 through 2014.

Table 11-30 Total marginal loss component costs (Dollars (Millions)): January through September of 2009 through 2014[22]

(Jan-Sep)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	$992	NA	$19,927	5.0%
2010	$1,259	26.9%	$26,249	4.8%
2011	$1,153	(8.5%)	$28,836	4.0%
2012	$758	(34.3%)	$22,119	3.4%
2013	$797	5.2%	$25,153	3.2%
2014	$1,243	56.0%	$40,760	3.0%

Table 11-31 Total PJM marginal loss costs by accounting category (Dollars (Millions)): January through September of 2009 through 2014

	Marginal Loss Costs (Millions)				
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	($62.0)	($1,028.3)	$26.1	$0.0	$992.4
2010	($73.8)	($1,301.6)	$31.5	($0.0)	$1,259.3
2011	($138.8)	($1,277.7)	$13.7	$0.0	$1,152.6
2012	($17.3)	($790.0)	($15.1)	$0.0	$757.6
2013	($3.3)	($834.4)	($34.1)	($0.0)	$797.0
2014	($47.6)	($1,343.7)	($53.0)	$0.0	$1,243.1

Table 11-32 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): January through September of 2009 through 2014

	Marginal Loss Costs (Millions)									
	Day Ahead				Balancing					
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	($65.9)	($1,025.7)	$53.2	$1,013.0	$3.9	($2.6)	($27.1)	($20.6)	$0.0	$992.4
2010	($94.4)	($1,307.1)	$61.5	$1,274.2	$20.6	$5.6	($30.0)	($14.9)	($0.0)	$1,259.3
2011	($174.3)	($1,313.6)	$51.7	$1,191.1	$35.5	$36.0	($38.0)	($38.5)	$0.0	$1,152.6
2012	($42.2)	($805.6)	$12.7	$776.0	$24.9	$15.6	($27.8)	($18.5)	$0.0	$757.6
2013	($30.3)	($857.9)	$44.0	$871.6	$27.0	$23.5	($78.1)	($74.6)	($0.0)	$797.0
2014	($95.5)	($1,380.8)	$62.7	$1,347.9	$47.9	$37.1	($115.6)	($104.8)	$0.0	$1,243.1

22 The loss costs include net inadvertent charges.

Monthly Marginal Loss Costs

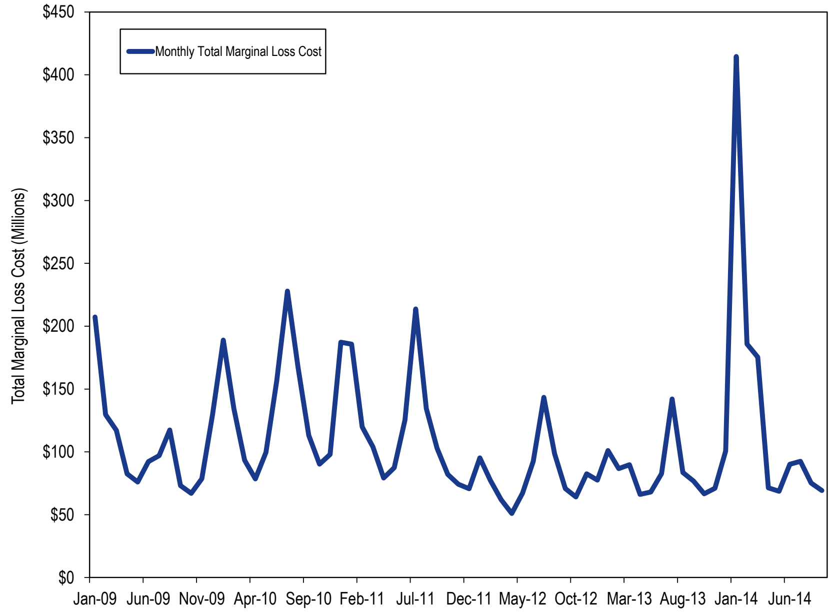
Table 11-33 shows a monthly summary of marginal loss costs by market type for the first nine months of 2013 and the first nine months of 2014.

Table 11-33 Monthly marginal loss costs by market (Dollars (Millions)): January through September of 2013 and 2014

	Marginal Loss Costs (Millions)							
	2013				2014			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$105.8	($4.7)	$0.0	$101.1	$431.1	($16.5)	$0.0	$414.6
Feb	$93.2	($6.5)	($0.0)	$86.7	$202.1	($16.3)	$0.0	$185.8
Mar	$97.2	($7.4)	($0.0)	$89.8	$198.0	($22.6)	($0.0)	$175.4
Apr	$77.7	($11.5)	($0.0)	$66.2	$83.2	($11.8)	($0.0)	$71.4
May	$80.5	($12.4)	($0.0)	$68.1	$80.3	($11.5)	$0.0	$68.7
Jun	$91.7	($9.0)	($0.0)	$82.7	$100.4	($10.2)	$0.0	$90.2
Jul	$149.2	($7.1)	($0.0)	$142.1	$102.1	($9.6)	$0.0	$92.5
Aug	$91.3	($7.8)	($0.0)	$83.6	$80.5	($5.3)	$0.0	$75.2
Sep	$85.0	($8.2)	($0.0)	$76.8	$70.3	($1.1)	$0.0	$69.2
Total	$871.6	($74.6)	($0.0)	$797.0	$1,347.9	($104.8)	$0.0	$1,243.1

Figure 11-4 shows PJM monthly marginal loss costs for January 2009 through September 2014.

Figure 11-4 PJM monthly marginal loss costs (Dollars (Millions)): January 2009 through September 2014



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 (load energy payments minus generation energy credits) 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.

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 11-34 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 nine months of 2009 through 2014. The total marginal loss credits increased $136.4 million in the first nine months of 2014 from the first nine months of 2013.

Table 11-34 Marginal loss credits (Dollars (Millions)): January through September of 2009 through 2014[23]

	Loss Credit Accounting (Millions)			
(Jan - Sep)	Total Energy Charges	Total Marginal Loss Charges	Adjustments	Loss Credits
2009	($484.6)	$992.4	$0.7	$508.5
2010	($618.6)	$1,259.3	($1.2)	$639.6
2011	($651.3)	$1,152.6	$0.7	$502.1
2012	($442.6)	$757.6	($1.7)	$313.3
2013	($527.2)	$797.0	($2.1)	$267.6
2014	($833.9)	$1,243.1	($5.2)	$404.1

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.

The total energy cost for the first nine months of 2014 was -$833.9 million, which was comprised of load energy payments of $50,415.3 million, generation energy credits of $51,245.6 million, explicit energy costs of $0.0 million and inadvertent energy charges of -$3.6 million. The monthly energy costs for the first nine months of 2014 ranged from -$272.7 million in January to -$44.6 million in September.

Total Energy Costs

Table 11-35 shows total energy component costs and total PJM billing, for the first nine months of 2009 through 2014. The total energy component costs are net energy costs.

Table 11-35 Total PJM costs by energy component (Dollars (Millions)): January through September of 2009 through 2014[24]

(Jan - Sep)	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	($485)	NA	$19,927	(2.4%)
2010	($619)	27.6%	$26,249	(2.4%)
2011	($651)	5.3%	$28,836	(2.3%)
2012	($443)	(32.0%)	$22,119	(2.0%)
2013	($527)	19.1%	$25,153	(2.1%)
2014	($834)	58.2%	$40,760	(2.0%)

Energy costs for the first nine months of 2009 through 2014 are shown in Table 11-36 and Table 11-37. Table 11-36 shows PJM energy costs by accounting category for the first nine months of 2009 through 2014 and Table 11-37 shows PJM energy costs by market category for the first nine months of 2009 through 2014. These energy costs are the actual total energy costs rather than the net energy costs in Table 11-35.

23 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.

24 The energy costs include net inadvertent charges.

Table 11-36 Total PJM energy costs by accounting category (Dollars (Millions)): January through September of 2009 through 2014

	Energy Costs (Millions)				
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	$32,472.4	$32,960.8	$0.0	$3.8	($484.6)
2010	$41,562.3	$42,169.5	$0.0	($11.4)	($618.6)
2011	$38,515.2	$39,193.0	$0.0	$26.5	($651.3)
2012	$28,303.5	$28,754.0	$0.0	$7.9	($442.6)
2013	$32,756.8	$33,279.9	$0.0	($4.2)	($527.2)
2014	$50,415.3	$51,245.6	$0.0	($3.6)	($833.9)

Table 11-37 Total PJM energy costs by market category (Dollars (Millions)): January through September of 2009 through 2014

	Energy Costs (Millions)									
	Day Ahead				Balancing					
(Jan - Sep)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	$32,628.0	$33,162.4	$0.0	($534.4)	($155.6)	($201.6)	$0.0	$45.9	$3.8	($484.6)
2010	$41,665.6	$42,289.1	$0.0	($623.5)	($103.4)	($119.7)	$0.0	$16.3	($11.4)	($618.6)
2011	$38,908.1	$39,530.7	$0.0	($622.6)	($392.9)	($337.7)	$0.0	($55.3)	$26.5	($651.3)
2012	$28,423.3	$28,853.1	$0.0	($429.8)	($119.9)	($99.2)	$0.0	($20.7)	$7.9	($442.6)
2013	$32,797.0	$33,398.3	$0.0	($601.3)	($40.2)	($118.4)	$0.0	$78.2	($4.2)	($527.2)
2014	$50,428.5	$51,603.0	$0.0	($1,174.5)	($13.2)	($357.4)	$0.0	$344.2	($3.6)	($833.9)

Monthly Energy Costs

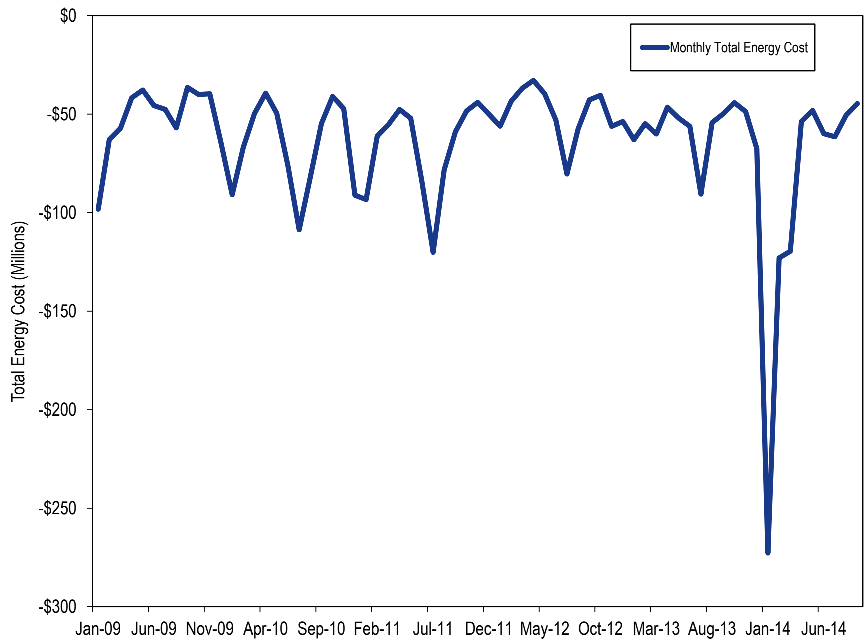
Table 11-38 shows a monthly summary of energy costs by market type for the first nine months of 2013 and the first nine months of 2014.

Table 11-38 Monthly energy costs by market type (Dollars (Millions)): January through September of 2013 and 2014

	Energy Costs (Millions)							
	2013				2014			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($69.2)	$5.8	$0.5	($63.0)	($339.8)	$68.1	($1.0)	($272.7)
Feb	($60.6)	$5.9	($0.1)	($54.8)	($163.7)	$43.5	($2.8)	($123.0)
Mar	($63.9)	$4.2	($0.3)	($60.0)	($167.3)	$50.8	($3.1)	($119.6)
Apr	($46.8)	$0.9	($0.6)	($46.5)	($90.4)	$36.7	($0.1)	($53.7)
May	($48.3)	($3.4)	($0.3)	($52.0)	($92.4)	$44.0	$0.3	($48.1)
Jun	($63.4)	$7.8	($0.6)	($56.2)	($94.7)	$33.4	$1.3	($59.9)
Jul	($110.9)	$21.4	($1.1)	($90.6)	($91.1)	$28.9	$0.7	($61.5)
Aug	($71.0)	$17.4	($0.7)	($54.3)	($79.2)	$28.2	$0.5	($50.6)
Sep	($67.2)	$18.3	($0.9)	($49.8)	($55.8)	$10.5	$0.7	($44.6)
Total	($601.3)	$78.2	($4.2)	($527.2)	($1,174.5)	$344.2	($3.6)	($833.9)

Figure 11-5 shows PJM monthly energy costs of January 2009 through September 2014.

Figure 11-5 PJM monthly energy costs (Dollars (Millions)): January 2009 through September 2014



Generation and Transmission Planning

Overview

Planned Generation and Retirements

- **Planned Generation**. As of September 30, 2014, 60,573.8 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 199,531.9 MW as of September 30, 2014. Of the capacity in queues, 6,617.64 MW, or 10.9 percent, are uprates and the rest are new generation. Wind projects account for 15,549.3 MW of nameplate capacity or 25.7 percent of the capacity in the queues. Combined-cycle projects account for 37,797.2 MW of capacity or 62.4 percent of the capacity in the queues.
- **Generation Retirements.** As shown in Table 12-6, 26,342.1 MW are, or are planned to be, retired between 2011 and 2019, with all but 2,050.5 MW planned to be retired by the end of 2015. The AEP Zone accounts for 6,024.0 MW, or 22.9 percent, of all MW planned for retirement from 2014 through 2019.
- **Generation Mix.** A significant change in the distribution of unit types within the PJM footprint is likely as natural gas fired units continue to be developed and steam units continue to be retired. While only 282.5 MW of coal fired steam capacity are currently in the queue, 10,475.8 MW of coal fired steam capacity are slated for deactivation. Most of these retirements, 9,147 MW, are scheduled to take place by June 1, 2015, in large part due to the EPA's Mercury and Air Toxics Standards (MATS) set to go into effect at that time. In contrast, 39,287.9 MW of gas fired capacity are in the queue, while only 1,793.0 MW of natural gas units are planned to retire. The replacement of steam units by units burning natural gas could significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

Generation and Transmission Interconnection Planning Process

- Any entity that requests interconnection of a new 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. These projects may create barriers to entry for projects that would otherwise be completed by taking up queue positions, increasing interconnection costs and creating uncertainty.
- Many feasibility, impact and facilities studies are delayed for reasons including disputes with developers, circuit and network issues, retooling as a result of projects being withdrawn, and an accumulated backlog in completing studies.
- Where the transmission owner is a vertically integrated company that also owns generation, there is a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is a competitor to the generation of its parent company. There is also a potential conflict of interest when the transmission owner evaluates the interconnection requirements of new generation which is part of the same company.

Regional Transmission Expansion Plan (RTEP)

- Artificial Island is an area in southern New Jersey that includes nuclear units at Salem and at Hope Creek. On April 29, 2013, PJM issued a request for proposal (RFP), seeking technical solutions to improve stability issues, operational performance under a range of anticipated system conditions, and the elimination of potential planning criteria violations in this area.

1 OATT Parts IV & VI.

PJM received 26 individual proposals from seven entities, including proposals from the incumbent transmission owner, PSE&G, and from non-incumbents. After the results of the initial selection process prompted a significant amount of feedback from market participants, PJM deferred the selection of a winner. In response to the feedback, PJM allowed the developers for five of the proposals to submit updated cost estimates, which they have done.

Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects intended to resolve a wide range of reliability criteria violations and congestion issues and which have substantial impacts on energy and capacity markets. The current backbone projects are Mount Storm-Doubs, Jacks Mountain, Susquehanna-Roseland, and Surry Skiffes Creek 500kV.

Recommendations

The MMU recommends additional improvements to the planning process.

- There is no mechanism to permit a direct comparison, or competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. The MMU recommends the creation of such a mechanism. (Priority: Low. First reported 2013.)
- The MMU recommends that rules be implemented to permit competition to provide financing of transmission projects. This competition could reduce the cost of capital for transmission projects and significantly reduce total costs to customers. (Priority: Low. First reported 2013.)
- The MMU recommends that the question of whether Capacity Injection Rights (CIRs) should persist after the retirement of a unit be addressed. Even if the treatment of CIRs remains unchanged, the rules need to ensure that incumbents cannot exploit control of CIRs to block or postpone entry of competitors.2 (Priority: Low. First reported 2013.)
- The MMU recommends outsourcing interconnection studies to an independent party to avoid potential conflicts of interest. Currently, these studies are performed by incumbent transmission owners under PJM's direction. This creates potential conflicts of interest, particularly when transmission owners are vertically integrated and the owner of transmission also owns generation. (Priority: Low. First reported 2013.)
- The MMU recommends improvements in queue management including that PJM establish a review process to ensure that projects are removed from the queue if they are not viable, as well as a process to allow commercially viable projects to advance in the queue ahead of projects which have failed to make progress, subject to rules to prevent gaming. (Priority: Medium. First reported 2013.)
- The MMU recommends an analysis of the study phase of PJM's transmission planning to reduce the need for postponements of study results, to decrease study completion times, and to improve the likelihood that a project at a given phase in the study process will successfully go into service. (Priority: Medium. First reported Q1, 2014.)

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 the energy and capacity markets. But when generating units retire or load increases, there is no market mechanism in place that would require direct competition between transmission and generation to meet loads in the affected area. In addition, despite Order No. 1000, there is not yet a robust mechanism to permit competition to build transmission projects or to obtain least cost financing through the capital markets.

2 See "Comments of the Independent Market Monitor for PJM," <http://www.monitoringanalytics.com/reports/Reports/2012/IMM_Comments_ER12-1177-000_20120312.pdf>.

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 may effectively forestall the ability of generation to compete. But there is no mechanism to permit a direct comparison, let alone competition, between transmission and generation alternatives. There is no mechanism to evaluate whether the generation or transmission alternative is less costly or who bears the risks associated with each alternative. Creating such a mechanism should be an explicit goal of PJM market design.

The PJM queue evaluation process should be improved to ensure that barriers to competition are not created. Issues that need to be addressed include the ownership rights to CIRs, whether transmission owners should perform interconnection studies, and improvements in queue management.

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. On September 30, 2014, 60,573.8 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 199,531.9 MW as of September 30, 2014. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000 (Table 12-1). In the first nine months of 2014, 2,515.0 MW of nameplate capacity were added in PJM.

Table 12-1 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through 2014

	MW
2000	505.0
2001	872.0
2002	3,841.0
2003	3,524.0
2004	1,935.0
2005	819.0
2006	471.0
2007	1,265.0
2008	2,776.7
2009	2,515.9
2010	2,097.4
2011	5,007.8
2012	2,669.4
2013	1,126.8
2014 (through September 30, 2014)	2,515.0

PJM Generation Queues

Generation request queues are groups of proposed projects, including new units, reratings of existing units, capacity resources and energy only resources. Each queue is open for a fixed amount of time. Studies commence on all projects in a given queue when that queue closes. The duration of the queue period has varied. Queues A and B were open for a year. Queues C-T were open for six months. Starting in February 2008, Queues U-Y1 were open for three months. Starting in May 2012, the duration of the queue period was set to six months, starting with Queue Y2. Queue AA1 is currently open.

All projects that have been entered in a queue have a status assigned. Projects listed as active are undergoing one of the studies (feasibility, system impact, facility) required to proceed. Other status options are under construction, suspended, and in-service. Withdrawn projects are removed from the queue and listed separately. A project cannot be suspended until it has reached the status of under construction. Any project that entered the queue before February 1, 2011, can be suspended for up to three years, at which point it is subject to termination of the Interconnection Service Agreement and corresponding cancellation costs. Projects that entered the queue after February 1, 2011 face an additional restriction in that the suspension period is reduced to one year if they affect any project later in the queue.[3]

Table 12-2 shows MW in queues by expected completion date and MW changes in the queues between June 30, 2014 and September 30, 2014 for ongoing projects, i.e. projects with the status active, under construction or suspended.[4] Projects that are already in service are not included here. The total MW in queues decreased by 2,435.7 MW, or 3.9 percent, from 63,009.4 MW at the end of the first quarter of 2014. The change was the result of 3,317.4 MW in new projects entering the queue, 4,234.0 MW in existing projects withdrawing, and 1,487.0 MW going into service. The remaining difference is the result of projects adjusting their expected MW.

Table 12-2 Queue comparison by expected completion year (MW): June 30, 2014 vs. September 30, 2014[5]

	As of 6/30/2014	As of 9/30/2014	Quarterly Change (MW)	Quarterly Change (percent)
≤ 2013	0.0	0.0	0.0	NA
2014	14,313.9	5,321.4	(8,992.5)	(62.8%)
2015	11,741.8	13,098.3	1,356.5	11.6%
2016	12,686.3	15,484.3	2,798.0	18.1%
2017	11,512.5	11,958.1	445.6	3.7%
2018	10,013.0	11,891.5	1,878.5	15.8%
2019	1,148.0	1,148.0	0.0	0.0%
2020	0.0	78.2	78.2	NA
2024	1,594.0	1,594.0	0.0	0.0%
Total	63,009.4	60,573.8	(2,435.7)	(3.9%)

Table 12-3 shows the yearly project status changes in more detail and how scheduled queue capacity has changed between June 30, 2014 and September 30, 2014. For example, 3,317.4 MW entered the queue in the third quarter, 324.8 MW of which were withdrawn before the quarter ended. Of the total 39,458.9 MW marked as active at the beginning of this quarter, 3,276.2 MW were withdrawn, 295.4 MW were suspended, and 2,125.8 MW started construction by the end of the third quarter. The “In Service” column shows that 1,487.0 MW went into service in the third quarter of 2014, in addition to the 36,566.4 MW of capacity that already had the status “in service” at the beginning of the second quarter.

Table 12-3 Change in project status (MW): June 30, 2014 vs. September 30, 2014

		Status at 9/30/2014				
Status at 6/30/2013	Total at 6/30/2014	Active	Suspended	Under Construction	In Service	Withdrawn
(Entered in Q2 2014)		2,992.7	0.0	0.0	0.0	324.8
Active	39,458.9	33,729.4	295.4	2,125.8	0.0	3,276.2
Suspended	4,602.8	0.0	4,022.8	20.0	0.0	560.0
Under Construction	18,947.7	0.0	183.6	17,204.1	1,487.0	73.0
In Service	36,566.4	0.0	0.0	0.0	36,566.4	0.0
Withdrawn	265,030.9	0.0	0.0	0.0	0.0	265,030.9
Total at 9/30/2014		36,722.1	4,501.8	19,349.9	38,053.4	269,264.9

Table 12-4 shows the amount of capacity active, in-service, under construction, suspended, 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. All items in queues A-L are either in service or have been withdrawn. As of September 30, 2014, there are 60,573.8 MW of capacity in queues that are not yet in service, of which 7.4 percent is suspended and 31.9 percent is under construction. The remaining 60.6 percent, or 36,722.1 MW, have not yet begun construction.

3 See “PJM Manual 14C: Generation and Transmission Interconnection Process,” Section 3.7, <http://www.pjm.com/~/media/documents/manuals/m14c.ashx>.
4 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.
5 Wind and solar capacity in Table 12-2 through Table 12-5 have not been adjusted to reflect derating.

Table 12-4 Capacity in PJM queues (MW): At September 30, 2014 [6]

Queue	Active	In-Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	8,103.0	0.0	0.0	17,252.0	25,355.0
B Expired 31-Jan-99	0.0	4,645.5	0.0	0.0	14,956.7	19,602.2
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	3,470.3	4,001.3
D Expired 31-Jan-00	0.0	850.6	0.0	0.0	7,182.0	8,032.6
E Expired 31-Jul-00	0.0	795.2	0.0	0.0	8,021.8	8,817.0
F Expired 31-Jan-01	0.0	52.0	0.0	0.0	3,092.5	3,144.5
G Expired 31-Jul-01	0.0	1,115.6	0.0	0.0	17,933.8	19,049.4
H Expired 31-Jan-02	0.0	702.5	0.0	0.0	8,421.9	9,124.4
I Expired 31-Jul-02	0.0	103.0	0.0	0.0	3,728.4	3,831.4
J Expired 31-Jan-03	0.0	40.0	0.0	0.0	846.0	886.0
K Expired 31-Jul-03	0.0	218.0	0.0	0.0	451.2	669.2
L Expired 31-Jan-04	0.0	256.5	0.0	0.0	4,033.7	4,290.2
M Expired 31-Jul-04	0.0	504.8	150.0	0.0	3,555.6	4,210.4
N Expired 31-Jan-05	0.0	2,398.8	38.0	0.0	8,090.3	10,527.0
O Expired 31-Jul-05	0.0	1,688.2	225.0	212.0	5,466.8	7,592.0
P Expired 31-Jan-06	0.0	3,255.2	62.5	210.0	5,110.5	8,638.2
Q Expired 31-Jul-06	105.0	3,147.9	1,594.0	0.0	9,686.7	14,533.6
R Expired 31-Jan-07	126.0	1,386.4	1,968.3	0.0	19,274.6	22,755.3
S Expired 31-Jul-07	175.0	3,301.3	469.3	490.0	12,156.5	16,592.0
T Expired 31-Jan-08	2,045.0	1,325.0	1,885.0	128.0	22,173.3	27,556.3
U Expired 31-Jan-09	1,565.0	665.3	692.0	459.9	29,974.6	33,356.8
V Expired 31-Jan-10	2,022.4	1,812.8	1,237.6	148.0	11,780.1	17,000.9
W Expired 31-Jan-11	2,927.9	609.3	1,819.5	1,932.5	16,924.9	24,214.1
X Expired 31-Jan-12	5,972.8	302.0	6,839.5	328.8	16,919.1	30,362.2
Y Expired 30-Apr-13	7,120.1	187.8	2,283.8	592.6	15,789.3	25,973.4
Z Expired 30-Apr-14	11,643.8	55.9	85.5	0.0	2,967.8	14,753.1
AA through 30-Sep-14	3,019.1	0.0	0.0	0.0	4.5	3,023.6
Total	36,722.1	38,053.4	19,349.9	4,501.8	269,264.9	367,892.1

6 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.

Distribution of Units in the Queues

Table 12-5 shows the projects under construction, suspended, or active as of September 30, 2014, by unit type, control zone and LDA.[7] As of September 30, 2014, 60,573.8 MW of capacity were in generation request queues for construction through 2024, compared to 63,009.4 MW at June 30, 2014.[8] Table 12-5 also shows the planned retirements for each zone. The geographic distribution of generation in the queues shows that new capacity is being added in all LDAs, but planned retirements are more prevalent in EMAAC than in SWMACC and WMAAC. The net effect is that, by 2024, capacity in WMAAC will increase by more than it will increase in EMAAC and SWMAAC.

A significant change in the distribution of unit types within the PJM footprint is likely as natural gas fired units continue to be developed and steam units continue to be retired. While only 282.5 MW of coal fired steam capacity are currently in the queue, 10,475.8 MW of coal fired steam capacity are slated for deactivation. Most of these retirements, 9,147 MW, are scheduled to take place by June 1, 2015, in large part due to the EPA's Mercury and Air Toxics Standards (MATS) set to go into effect at that time. In contrast, 39,287.9 MW of gas fired capacity are in the queue while only 1,793.0 MW of natural gas units are planned to retire. The replacement of older steam units by units burning natural gas could significantly affect future congestion, the role of firm and interruptible gas supply, and natural gas supply infrastructure.

7 Unit types designated as reciprocating engines are classified here as diesel.
8 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 until there is operational data to support a different conclusion. PJM derates solar resources to 38 percent of installed capacity. Based on the derating of 15,549.3 MW of wind resources and 1,811.0 MW of solar resources, the 60,573.8 MW currently active in the queue would be reduced to 45,923.1 MW.

Table 12-5 Queue capacity by control zone and LDA (MW) at September 30, 2014

LDA	Zone	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total Queue Capacity	Planned Retirements
EMAAC	AECO	1,034.0	137.3	7.5	0.0	0.0	89.5	0.0	0.0	373.0	1,641.3	500.2
	DPL	1,303.2	7.0	0.0	0.0	0.0	345.7	0.0	0.0	279.0	1,934.9	288.0
	JCPL	1,445.0	0.0	0.0	0.0	0.0	718.2	32.0	0.0	0.0	2,195.2	1,095.3
	PECO	980.5	10.0	3.7	0.0	330.0	0.0	0.0	0.0	0.0	1,324.2	1,104.7
	PSEG	3,187.9	286.0	8.0	0.0	0.0	176.6	1.0	3.0	0.0	3,662.5	2,737.4
	EMAAC Total	7,950.6	440.3	19.2	0.0	330.0	1,330.0	33.0	3.0	652.0	10,758.1	5,725.6
SWMAAC	BGE	0.0	256.0	29.0	0.4	0.0	22.0	0.0	132.0	0.0	439.4	189.0
	Pepco	2,643.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,643.6	2,474.0
	SWMAAC Total	2,643.6	256.0	29.0	0.4	0.0	22.0	0.0	132.0	0.0	3,083.0	2,663.0
WMAAC	Met-Ed	891.5	6.0	0.0	0.0	35.0	3.0	0.0	401.0	0.0	1,336.5	652.0
	PENELEC	879.0	121.4	61.8	45.3	0.0	31.8	29.5	0.0	483.3	1,652.0	634.0
	PPL	5,162.0	0.0	5.0	0.0	0.0	19.0	60.0	16.0	778.5	6,040.5	371.0
	WMAAC Total	6,932.5	127.4	66.8	45.3	35.0	53.8	89.5	417.0	1,261.8	9,029.0	1,657.0
Non-MAAC	AE	452.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	452.0	0.0
	AEP	6,501.0	46.0	20.4	7.0	102.0	110.4	36.0	326.5	7,487.8	14,637.1	6,024.0
	APS	3,091.4	25.7	99.6	63.5	0.0	39.9	0.0	49.2	615.0	3,984.2	3,028.0
	ATSI	2,795.0	0.4	1.7	0.0	0.0	0.0	6.0	135.0	617.0	3,555.1	2,266.0
	ComEd	1,625.0	193.3	15.3	22.7	0.0	15.0	60.6	0.0	3,354.0	5,285.9	1,624.0
	DAY	30.0	0.0	1.9	112.0	0.0	23.4	0.0	32.5	300.0	499.8	540.7
	DEOK	540.0	0.0	0.0	0.0	0.0	0.0	16.0	50.0	0.0	606.0	1,071.9
	DLCO	205.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	205.0	614.0
	Dominion	4,896.1	62.0	11.0	0.0	1,594.0	170.9	32.0	62.5	1,113.9	7,942.4	932.9
	EKPC	0.0	207.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	207.8	195.0
	Essential Power	135.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	135.0	0.0
	PotomacEdison	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	69.6	69.6	0.0
	Vepco	0.0	0.0	0.0	0.0	0.0	45.6	0.0	0.0	78.2	123.8	0.0
	Non-MAAC Total	20,270.5	535.2	149.9	205.2	1,696.0	405.2	150.6	655.7	13,635.5	37,703.7	16,296.5
Total		37,797.2	1,358.9	264.9	250.8	2,061.0	1,811.0	273.1	1,207.7	15,549.3	60,573.8	26,342.1

Planned Retirements

As shown in Table 12-6, 26,342.1 MW is planned to be retired between 2011 and 2019, with all but 2,050.5 MW retired by the end of 2015. The AEP Zone accounts for 6,024.0 MW, or 22.9 percent, of all MW planned for deactivation from 2014 through 2019. A map of retirements between 2011 and 2019 is shown in Figure 12-1 and a detailed list of pending deactivations is shown in Table 12-7, totaling 13,862.4 MW.

Table 12-6 Summary of PJM unit retirements (MW): 2011 through 2019

	MW
Retirements 2011	1,129.2
Retirements 2012	6,961.9
Retirements 2013	2,862.6
Retirements 2014	1,526.0
Planned Retirements 2014	1,739.9
Planned Retirements 2015	10,072.0
Planned Retirements Post-2015	2,050.5
Total	26,342.1

Figure 12-1 Map of PJM unit retirements: 2011 through 2019

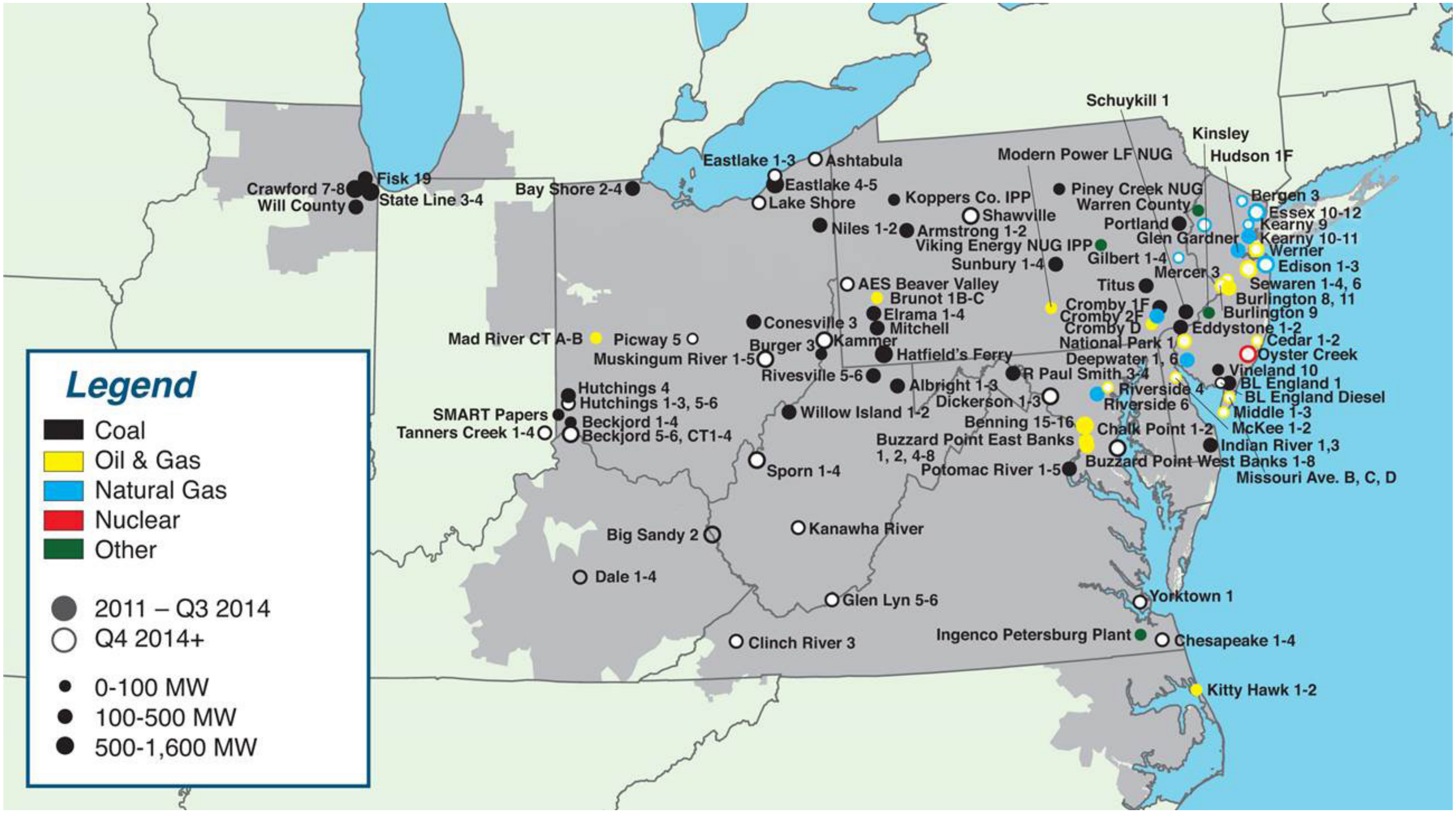


Table 12-7 Planned deactivations of PJM units, as of September 30, 2014

Unit	Zone	MW	Fuel	Unit Type	Projected Deactivation Date
Walter C Beckjord 5-6	DEOK	652.0	Coal	Steam	26-Nov-14
Walter C Beckjord GT1-4	DEOK	188.0	Coal	Steam	25-Dec-14
Chesapeake 1-4	Dominion	576.0	Coal	Steam	31-Dec-14
Kinsley Landfill	PSEG	0.9	Diesel	Diesel	31-Dec-14
Yorktown 1-2	Dominion	323.0	Coal	Steam	31-Dec-14
Eastlake 1-3	ATSI	327.0	Coal	Steam	15-Apr-15
Lake Shore 18	ATSI	190.0	Coal	Steam	15-Apr-15
Will County	Comed	251.0	Coal	Steam	15-Apr-15
Dale 1-4	EKPC	195.0	Coal	Steam	16-Apr-15
Shawville 1-4	PENELEC	603.0	Coal	Steam	16-Apr-15
Gilbert 1-4	JCPL	98.0	Natural gas	Combustion Turbine	01-May-15
Glen Gardner 1-8	JCPL	160.0	Natural gas	Combustion Turbine	01-May-15
Kearny 9	PSEG	21.0	Natural gas	Combustion Turbine	01-May-15
Werner 1-4	JCPL	212.0	Light oil	Combustion Turbine	01-May-15
Cedar 1-2	AECO	65.6	Kerosene	Combustion Turbine	31-May-15
Essex 12	PSEG	184.0	Natural gas	Combustion Turbine	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
Ashtabula	ATSI	210.0	Coal	Steam	01-Jun-15
Bergen 3	PSEG	21.0	Natural gas	Combustion Turbine	01-Jun-15
Big Sandy 2	AEP	800.0	Coal	Steam	01-Jun-15
Burlington 8, 11	PSEG	205.0	Kerosene	Combustion Turbine	01-Jun-15
Clinch River 3	AEP	230.0	Coal	Steam	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
Glen Lyn 5-6	AEP	325.0	Coal	Steam	01-Jun-15
Hutchings 1-3, 5-6	DAY	271.8	Coal	Steam	01-Jun-15
Kammer 1-3	AEP	600.0	Coal	Steam	01-Jun-15
Kanawha River 1-2	AEP	400.0	Coal	Steam	01-Jun-15
Mercer 3	PSEG	115.0	Kerosene	Combustion Turbine	01-Jun-15
Muskingum River 1-5	AEP	1,355.0	Coal	Steam	01-Jun-15
National Park 1	PSEG	21.0	Kerosene	Combustion Turbine	01-Jun-15
Picway 5	AEP	95.0	Coal	Steam	01-Jun-15
Sewaren 1-4,6	PSEG	558.0	Kerosene	Combustion Turbine	01-Jun-15
Sporn 1-4	AEP	580.0	Coal	Steam	01-Jun-15
Tanners Creek 1-4	AEP	982.0	Coal	Steam	01-Jun-15
BL England Diesels	AECO	8.0	Diesel	Diesel	01-Oct-15
Riverside 4	BGE	74.0	Natural gas	Steam	01-Jun-16
McKee 1-2	DPL	34.0	Heavy Oil	Combustion Turbine	31-May-17
AES Beaver Valley	DLCO	124.0	Coal	Steam	01-Jun-17
Chalk Point 1-2	Pepco	667.0	Coal	Steam	31-May-18
Dickerson 1-3	Pepco	537.0	Coal	Steam	31-May-18
Oyster Creek	JCPL	614.5	Nuclear	Steam	31-Dec-19
Total		13,862.4			

Table 12-8 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2019. The majority, 77.8 percent, of all MW retiring during this period are coal steam units. These units have an average age of 56.4 years and an average size of 166.6 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 12-8 Retirements by fuel type, 2011 through 2019

	Number of Units	Avg. Size (MW)	Avg. Age at Retirement (Years)	Total MW	Percent
Coal	123	166.6	56.4	20,496.6	77.8%
Diesel	6	12.5	38.3	74.9	0.3%
Heavy Oil	4	68.5	57.5	274.0	1.0%
Kerosene	20	41.4	45.5	828.2	3.1%
LFG	2	5.9	18.0	11.7	0.0%
Light Oil	15	76.6	43.8	1,148.7	4.4%
Natural Gas	49	57.9	46.8	2,838.5	10.8%
Nuclear	1	614.5	50.0	614.5	2.3%
Waste Coal	1	31.0	20.0	31.0	0.1%
Wood Waste	2	12.0	23.5	24.0	0.1%
Total	223	118.1	51.1	26,342.1	100.0%

Actual Generation Deactivations in 2014

Table 12-9 shows unit deactivations for the first nine months of 2014.[9] A total of 1,526.0 MW were retired during this period.

Table 12-9 Unit deactivations between January 1, 2014 and September 30, 2014

Company	Unit Name	ICAP	Primary Fuel	Zone Name	Age (Years)	Retirement Date
First Energy	Mad River CTs A	25.0	Diesel	ATSI	41	09-Jan-14
First Energy	Mad River CTs B	25.0	Diesel	ATSI	41	09-Jan-14
Duke Energy	Walter C Beckjord 4	150.0	Coal	DEOK	56	17-Jan-14
Modern Mallard Energy	Modern Power Landfill NUG	8.0	Diesel	Met-Ed	56	03-Feb-14
Rockland Capital	BL England 1	113.0	Coal	AECO	51	01-May-14
Calpine Corporation	Deepwater 1	78.0	Natural gas	AECO	55	31-May-14
Calpine Corporation	Deepwater 6	80.0	Natural gas	AECO	60	01-Jun-14
NRG Energy	Portland 1	158.0	Coal	Met-Ed	56	01-Jun-14
NRG Energy	Portland 2	243.0	Coal	Met-Ed	52	01-Jun-14
Exelon Corporation	Riverside 6	115.0	Natural gas	BGE	44	01-Jun-14
PSEG	Burlington 9	184.0	Kerosene	PSEG	42	01-Jun-14
Corona Power	Sunbury 1-4	347.0	Coal	PPL	63	18-Jul-14
Total		1,526.0				

9 See PJM. "*PJM Generator Deactivations*," <http://pjm.com/planning/generation-retirements/gr-summaries.aspx> (Accessed April 05, 2014).

Generation Mix

Currently, PJM has an installed capacity of 199,531.9 MW (Table 12-10) including non-derated solar and wind resources, as well as energy-only units.

Table 12-10 Existing PJM capacity: at September 30, 2014 (By zone and unit type (MW)) [10]

Zone	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	901.9	705.9	22.6	0.0	0.0	0.0	41.7	815.9	0.0	7.5	2,495.5
AEP	4,900.0	3,682.2	63.1	0.0	1,071.9	2,071.0	0.0	24,264.8	0.0	1,753.2	37,806.2
APS	1,129.0	1,214.9	47.9	0.0	86.0	0.0	36.1	5,409.0	27.4	998.5	8,948.8
ATSI	685.0	1,617.4	74.0	0.0	0.0	2,134.0	0.0	6,540.0	0.0	0.0	11,050.4
BGE	0.0	720.0	18.4	0.0	0.0	1,716.0	0.0	2,995.5	0.0	0.0	5,449.9
ComEd	2,270.1	7,244.0	100.2	0.0	0.0	10,473.5	0.0	5,417.1	4.5	2,431.9	27,941.3
DAY	0.0	1,368.5	47.5	0.0	0.0	0.0	1.1	3,179.8	40.0	0.0	4,636.9
DEOK	47.2	842.0	0.0	0.0	0.0	0.0	0.0	3,782.0	0.0	0.0	4,671.2
DLCO	244.0	15.0	0.0	0.0	6.3	1,777.0	0.0	784.0	0.0	0.0	2,826.3
Dominion	1,189.3	1,820.4	96.1	30.0	0.0	0.0	4.0	1,620.0	0.0	0.0	4,759.8
DPL	4,029.6	3,874.8	153.8	0.0	3,589.3	3,581.3	2.7	8,403.0	0.0	0.0	23,634.5
EKPC	0.0	774.0	0.0	0.0	70.0	0.0	0.0	1,882.0	0.0	0.0	2,726.0
EXT	1,471.0	297.9	0.0	0.0	269.1	12.5	0.0	5,483.5	0.0	0.0	7,534.0
JCPL	1,692.5	1,233.1	16.1	0.0	400.0	614.5	59.8	10.0	0.0	0.0	4,026.0
Met-Ed	2,111.0	406.5	41.4	0.0	19.0	805.0	0.0	200.0	0.0	0.0	3,582.9
PECO	3,209.0	836.0	2.9	0.0	1,642.0	4,546.8	3.0	979.1	1.0	0.0	11,219.8
PENELEC	0.0	407.5	45.8	0.0	512.8	0.0	0.0	6,793.5	0.0	930.9	8,690.5
Pepco	1,807.9	616.2	60.5	0.0	706.6	2,520.0	15.0	5,169.9	20.0	219.7	11,135.8
PPL	3,091.3	2,653.8	12.0	0.0	5.0	3,493.0	108.2	2,050.1	2.0	0.0	11,415.4
PSEG	230.0	1,091.7	9.9	0.0	0.0	0.0	0.0	3,649.1	0.0	0.0	4,980.7
Total	29,008.8	31,421.8	812.2	30.0	8,378.0	33,744.6	271.6	89,428.3	94.9	6,341.7	199,531.9

Figure 12-2 and Table 12-11 show the age of PJM generators by unit type. Units older than 30 years comprise 110,568.5 MW, or 55.4 percent, of the total capacity of 199,531.9 MW. Units older than 45 years comprise 34,459.8 MW, or 17.3 percent of the total capacity.

Table 12-11 PJM capacity (MW) by age (years): at September 30, 2014

Age (years)	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 15	23,330.3	20,420.1	508.5	30.0	183.6	0.0	271.6	3,755.4	94.9	6,341.7	54,936.1
16 to 30	5,146.5	4,041.5	98.5	0.0	3,276.2	11,484.5	0.0	9,980.1	0.0	0.0	34,027.3
31 to 45	532.0	5,482.1	82.9	0.0	722.0	22,260.1	0.0	47,029.6	0.0	0.0	76,108.7
46 to 60	0.0	1,478.1	122.3	0.0	2,577.4	0.0	0.0	25,032.9	0.0	0.0	29,210.7
61 to 75	0.0	0.0	0.0	0.0	501.7	0.0	0.0	3,481.3	0.0	0.0	3,983.0
76 and over	0.0	0.0	0.0	0.0	1,117.1	0.0	0.0	149.0	0.0	0.0	1,266.1
Total	29,008.8	31,421.8	812.2	30.0	8,378.0	33,744.6	271.6	89,428.3	94.9	6,341.7	199,531.9

10 The capacity described in this section refers to all installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Figure 12-2 PJM capacity (MW) by age (years): at September 30, 2014

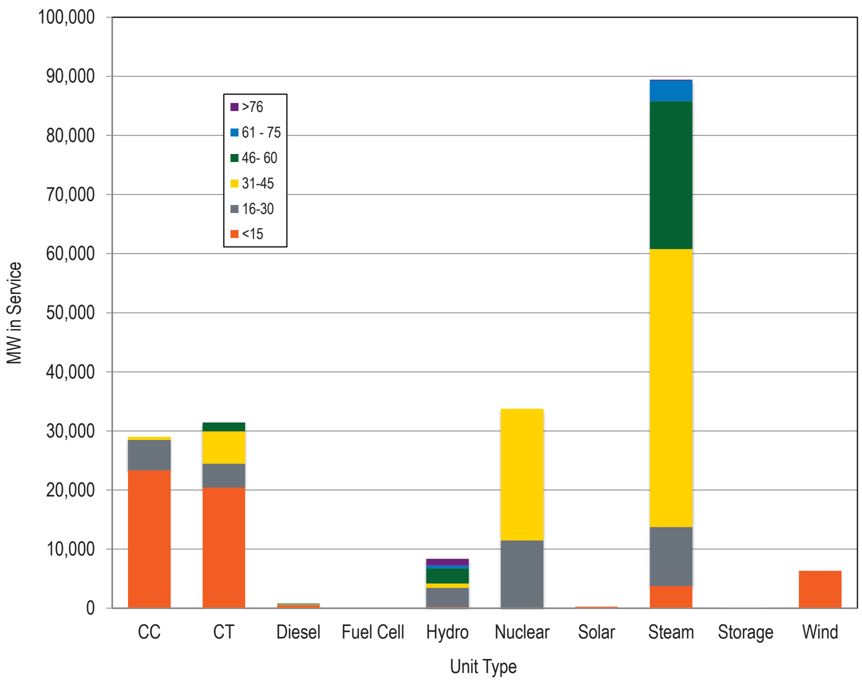


Table 12-12 shows the effect that the new generation in the queues would have on the existing generation mix, assuming that all non-hydroelectric generators in excess of 40 years of age as of September 30, 2014 retire by 2024. The expected role of gas-fired generation depends largely on projects in the queues and continued retirement of coal-fired generation. Existing capacity in SWMAAC is currently 63.7 percent steam; this would be reduced to 44.9 percent by 2024. CC and CT generators would comprise 40.4 percent of total capacity in SWMAAC in 2024.

In Non-MAAC zones, 82.0 percent of all generation 40 years or older, as of September 30, 2014, is steam, primarily coal.[11] If the older coal units retire and if all queued wind MW are built as planned, by 2024, wind farms would account for 11.7 percent of total non-derated ICAP MW in Non-MAAC zones.

Generation and Transmission Interconnection Planning Process

PJM continues to look for ways to improve the planning process, with the most recent set of changes effective in May 2012.[12] These changes include reducing the length of the queues, creating an alternate queue for some small projects, and adjustments to the rules regarding suspension rights and Capacity Interconnection Rights (CIR).

Small Generator Interconnection

Due to the growing number of small generating facilities, FERC issued Order No. 2006 to extend interconnection service to devices used for the production of electricity having a capacity of no more than 20 MW and established the Small Generator Interconnection Procedures (SGIP) and a Small Generator Interconnection Agreement (SGIA).[13] The SGIP and SGIA are consistent with the standard Large Generator Interconnection Procedures document (LGIP) and standard Large Generator Interconnection Agreement (LGIA) for generating facilities larger than 20 MW, established in FERC Order No. 2003.[14]

11 Non-MAAC zones consist of the AEP, AP, ATSI, ComEd, DAY, DEOK, DLCO, and Dominion control zones.

12 See letter from PJM to Secretary Kimberly Bose, Docket No. ER12-1177-000, <http://www.pjm.com/~/media/documents/ferc/2012-filings/20120229-er12-1177-000.ashx>. (Accessed December 4, 2013).

13 See *Standardization of Generator Interconnection Agreements and Procedures*, FERC Stats. & Regs. ¶31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 128 S. Ct. 1468 (2008).

14 See *Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, FERC Stats. & Regs. ¶ 31,180 (2005), *order on reh'g*, Order No. 2006-A, FERC Stats. & Regs. ¶ 31,196 (2005).

Table 12-12 Comparison of generators 40 years and older with slated capacity additions (MW) through 2024, as of September 30, 2014

Area	Unit Type	Capacity of Generators 40 Years or Older	Percent of Area Total	Capacity of Generators of All Ages	Percent of Area Total	Planned Additions	Planned Retirements	Estimated Capacity 2024	Percent of Area Total
EMAAC	Combined Cycle	198.0	1.9%	10,084.0	29.7%	7,950.6	0.0	18,034.6	43.6%
	Combustion Turbine	3,580.2	33.7%	7,249.2	21.4%	440.3	2,196.2	5,493.3	13.3%
	Diesel	58.9	0.6%	149.7	0.4%	19.2	8.9	160.0	0.4%
	Fuel Cell	0.0	0.0%	30.0	0.1%	0.0	0.0	30.0	0.1%
	Hydroelectric	2,042.0	19.2%	2,047.0	6.0%	0.0	0.0	2,047.0	4.9%
	Nuclear	1,739.9	16.4%	8,654.3	25.5%	330.0	0.0	8,984.3	21.7%
	Solar	0.0	0.0%	216.7	0.6%	1,330.0	0.0	1,546.7	3.7%
	Steam	2,995.0	28.2%	5,475.1	16.1%	3.0	1,101.5	4,376.6	10.6%
	Storage	0.0	0.0%	3.0	0.0%	33.0	0.0	36.0	0.1%
	Wind	0.0	0.0%	7.5	0.0%	652.0	0.0	659.5	1.6%
	EMAAC Total	10,614.0	100.0%	33,916.5	100.0%	10,758.1	3,306.6	41,368.0	100.0%
SWMAAC	Combined Cycle	0.0	0.0%	230.0	2.2%	2,643.6	0.0	2,873.6	23.5%
	Combustion Turbine	849.3	17.2%	1,811.7	17.4%	256.0	0.0	2,067.7	16.9%
	Diesel	0.0	0.0%	28.3	0.3%	29.0	0.0	57.3	0.5%
	Hydroelectric	0.0	0.0%	0.0	0.0%	0.4	0.0	0.4	0.0%
	Nuclear	0.0	0.0%	1,716.0	16.5%	0.0	0.0	1,716.0	14.0%
	Solar	0.0	0.0%	0.0	0.0%	22.0	0.0	22.0	0.2%
	Steam	4,098.5	82.8%	6,644.6	63.7%	132.0	1,278.0	5,498.6	44.9%
	SWMAAC Total	4,947.8	100.0%	10,430.6	100.0%	3,083.0	1,278.0	12,235.6	100.0%
WMAAC	Combined Cycle	0.0	0.0%	3,918.9	16.7%	6,932.5	0.0	10,851.4	34.1%
	Combustion Turbine	713.5	7.2%	1,430.2	6.1%	127.4	0.0	1,557.6	4.9%
	Diesel	46.2	0.5%	147.7	0.6%	66.8	6.0	208.5	0.7%
	Hydroelectric	887.2	9.0%	1,238.4	5.3%	45.3	0.0	1,283.7	4.0%
	Nuclear	0.0	0.0%	3,325.0	14.2%	35.0	0.0	3,360.0	10.6%
	Solar	0.0	0.0%	15.0	0.1%	53.8	0.0	68.8	0.2%
	Steam	8,225.5	83.3%	12,163.4	52.0%	417.0	597.0	11,983.4	37.6%
	Storage	0.0	0.0%	20.0	0.1%	89.5	0.0	109.5	0.3%
	Wind	0.0	0.0%	1,150.6	4.9%	1,261.8	0.0	2,412.4	7.6%
	WMAAC Total	9,872.4	100.0%	23,409.2	100.0%	9,029.0	603.0	31,835.1	100.0%
Non-MAAC	Combined Cycle	0.0	0.0%	14,775.9	11.2%	20,270.5	0.0	35,046.4	21.8%
	Combustion Turbine	1,250.6	2.7%	20,930.7	15.9%	535.2	0.0	21,465.9	13.3%
	Diesel	71.8	0.2%	486.5	0.4%	149.9	0.0	636.4	0.4%
	Hydroelectric	1,702.0	3.7%	5,092.6	3.9%	205.2	0.0	5,297.8	3.3%
	Nuclear	5,295.9	11.4%	20,049.3	15.2%	1,696.0	0.0	21,745.3	13.5%
	Solar	0.0	0.0%	40.0	0.0%	405.2	0.0	445.2	0.3%
	Steam	37,968.7	82.0%	65,145.2	49.4%	655.7	8,674.8	57,126.1	35.5%
	Storage	0.0	0.0%	71.9	0.1%	150.6	0.0	222.5	0.1%
	Wind	0.0	0.0%	5,183.6	3.9%	13,635.5	0.0	18,819.1	11.7%
	Non-MAAC Total	46,289.0	100.0%	131,775.7	100.0%	37,703.7	8,674.8	160,804.6	100.0%
All Areas	Total	71,723.2		199,531.9		60,573.8	13,862.4	246,243.3	

FERC Order No. 792 was issued on November 22, 2013, to make several amendments to the SGIP and SGIA.[15] One revision is a provision for the option of a pre-application report of existing information about system conditions at a possible Point of Interconnection. This order also increases the threshold to participate in the Fast Track Process from 2 MW to 5 MW, but only for inverter-based machines.[16] The thresholds for all other eligible types (synchronous & induction) will remain at 2 MW. Another revision is to the customer options meeting and the supplemental review following the failure of the Fast Track screens so that the supplemental review is performed at the discretion of the Interconnection Customer.[17] This includes minimum load and other screens to determine if a Small Generating Facility may be interconnected safely and reliably. In addition, the SGIP Facilities Study Agreement will be revised to allow written comments to the Transmission Provider, similar to what is currently allowed for large generator projects. Finally, the SGIP and SGIA will now specifically include energy storage devices.[18] PJM filed these revisions to the OATT with FERC on August 4, 2014.[19] No protests or comments were filed. An order is pending.

Interconnection Study Phase

In the study phase of the interconnection planning process, a series of studies are performed to determine the feasibility, impact, and cost of projects in the queue. Table 12-13 shows an overview of PJM's study process. In addition to these steps, system impact and facilities studies are often redone, or retooled, when a project is withdrawn because it may affect the investments of the projects remaining in the queue.

PJM's Manual 14A states that it can take up to 739 days in addition to the (unspecified) time it takes to complete the facilities study to obtain an interconnection construction service agreement (ICSA). It further states that a feasibility study should take no longer than 334 days from the day it entered the queue.[20] Manual 14B requires PJM to apply a commercial probability factor at the feasibility study stage to improve the accuracy of capacity and cost estimates. The commercial probability factor is based on the historical incidence of projects dropping out of the queue at the impact study stage.[21] PJM currently uses a value of 53 percent for commercial probability.[22]

Table 12-14 shows the milestone due when projects were withdrawn, for all withdrawn projects. Consistent with PJM's estimate, 48.6 percent of projects withdrawn were withdrawn before the Impact Study was completed.

Table 12-14 Milestone due at time of withdrawal

Milestone Due	Projects Withdrawn	Percent
Feasibility	138	9.2%
Impact	592	39.4%
Facility	355	23.6%
Interconnection/Construction Service Agreement (ISA/CSA)	217	14.4%
Under Construction	202	13.4%
Total	1,504	100.0%

Table 12-13 PJM generation planning process

Process Step	Start on	Financial Obligation	Days for PJM to Complete	Days for Applicant to Decide Whether to Continue
Feasibility Study	Close of current queue	Cost of study (partially refundable deposit)	90	30
System Impact Study	Upon acceptance of the System Impact Study Agreement	Cost of study (partially refundable deposit)	120	30
Facilities Study	Upon acceptance of the Facilities Study Agreement	Cost of study (refundable deposit)	Varies	60
Schedule of Work	Upon acceptance of Interconnection Service Agreement (ISA)	Letter of credit for upgrade costs	Varies	37
Construction (only for new generation)	Upon acceptance of Interconnection Construction Service Agreement (ICSA)	None	Varies	NA

15 See *Small Generator Interconnection Agreements and Procedures*, 145 FERC ¶ 61,159 (2013 (Order No. 792).
16 See Order No. 792 at P 106.
17 See *Id.* at P 106.
18 See Order No. 792 at P 228.
19 See PJM Compliance Filing, FERC Docket No. ER14-2590-000 (August 4, 2014).
20 See PJM. Manual 14A. "Generation and Transmission Interconnection Process," Revision 15 (April 17, 2014), p.37, <http://www.pjm.com/~/media/documents/manuals/m14a.ashx>.
21 See PJM. Manual 14B. "PJM Region Transmission Planning Process," Revision 27 (April 23, 2014), p.82, <http://www.pjm.com/~/media/documents/manuals/m14b.ashx>.
22 See PJM Planning Committee meeting presentation 'Commercial Probability, "October 10, 2013, <http://www.pjm.com/~/media/committees-groups/committees/pc/20131010/20131010-item-09-commercial-probability.ashx>.

Table 12-15 and Table 12-16 show the time spent at various stages in the queue process, as well as the completion time for the studies performed. For completed projects, there is an average time of 3,076 days, or 8.4 years, between entering a queue and going into service. For withdrawn projects, there is an average time of 660 days between entering a queue and withdrawing. It takes an average of 4.6 years to begin construction, with the worst case taking 17.5 years.

Table 12-15 Average project queue times (days) at September 30, 2014

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	1,182	783	154	3,799
In-Service	3,076	1,399	335	6,392
Suspended	1,807	659	607	3,619
Under Construction	1,663	852	335	6,380
Withdrawn	650	656	0	4,249

Table 12-16 presents information on the actual time in the stages of the queue for those projects not yet in service. For the 506 projects in the queue as of September 30, 2014, 29 had reached as far as the milestone of feasibility study completion and 176 were under construction.

Table 12-16 PJM generation planning summary: at September 30, 2014

Milestone Completed	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Not Started	43	8.5%	105	366
Feasibility Study	29	5.7%	1,621	2,704
Impact Study	152	30.0%	1,046	3,068
Facility Study	31	6.1%	1,809	3,495
ISA/CSA	75	14.8%	313	790
Under Construction	176	34.8%	1,393	3,719
Total	506	100.0%		

Regional Transmission Expansion Plan (RTEP)

Artificial Island

PJM has been seeking technical solutions to improve stability and operational performance issues, as well to eliminate potential planning criteria violations in the Artificial Island Area, which includes the Salem and Hope Creek nuclear plants. PJM specified its transmission expansion project solicitation process in two Order No 1000 FERC Compliance filings (dated October 25, 2012 and July 22, 2013.)[23] PJM evaluated 26 proposals based on factors including siting, permitting, line crossings, outage requirements, and impacts to the Salem nuclear plant.

The Transmission Expansion Advisory Committee (TEAC) recommended that PSE&G be selected to proceed with the Artificial Island project.[24] [25] On July 23, 2014, the PJM Board of Managers deferred the selection of a winner in order to review and address issues raised.[26]

On August 12, 2014, PJM requested additional information for five of the submitted proposals. The bidders for these proposals have been given the opportunity to supplement their proposals with updated cost estimates, as a result of PJM's modifications made during the initial evaluation.[27] All of the bidders responded by submitting the supplemental information requested.[28] PJM has engaged FERC's Alternative Dispute Resolution (ADR) process, which includes "an Administrative Law Judge present in a non-decisional role to ensure the fairness and due process" surrounding the final selection for this project.[29]

Other RTEP Proposals

The Transmission Expansion Advisory Committee (TEAC) regularly reviews internal and external proposals to improve transmission reliability throughout PJM. The RTEP proposal window 1 was open from June 27, 2014 through July 28, 2014. During this window, 106 baseline reliability projects were proposed, encompassing 18 target transmission owner zones and 10 states. None of these submissions were by a developer that was not a transmission owner.

23 See "FERC Order 1000 Implementation" at <http://www.pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000.aspx>.

24 The TEAC Charter states: "PJM staff will be ultimately responsible for preparing and issuing all reports, running the committee meeting, management of data, final analytical work, and compilation and publication of other relevant documentation that may be required from time to time." http://www.pjm.com/~/media/committees-groups/committees/teac/postings/teac-charter.ashx.

25 See "Artificial Island Proposal Window," <http://pjm.com/~/media/committees-groups/committees/teac/20140616/20140616-teac-artificial-island-recommendation.ashx>, (June 16, 2014).

26 See "Letter from Steve Herling, dated July 23, 2104 at <http://www.pjm.com/~/media/committees-groups/committees/teac/20140807/20140807-teac-artificial-island-letter.ashx>.

27 See "Letter from Steve Herling, dated August 12, 2104 at http://www.pjm.com/~/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/august-12-2014-supplemental-request-letter.ashx.

28 See "Supplemental Responses" at http://www.pjm.com/planning/rtep-development/expansion-plan-process/ferc-order-1000/rtep-proposal-windows/closed-artificial-island-proposals.aspx.

29 See "Letter from Pauline Foley, dated August 29, 2104 at http://www.pjm.com/~/media/planning/rtep-dev/expan-plan-process/ferc-order-1000/rtep-proposal-windows/pjm-letter-to-chief-judge-wagner-regarding-artificial-island.ashx.

RTEP considered these proposals along with others reviewed at previous sub-regional RTEP (SRRTEP) and TEAC meetings that occurred between February and September, 2014. In the end, 22 projects overall (all transmission owner upgrades) were recommended at the September 25, 2014, TEAC meeting and will be taken to the PJM Board for approval in November 2014.[30]

RTEP's window 2 is open now for additional reliability issues. In compliance with Order 1000, PJM is scheduled to open a proposal window on November 1, 2014, and close it on February 28, 2015, for all long term issues. For this window, PJM will accept proposals addressing not just long term reliability, but also energy market efficiency, capacity market efficiency, and public policy.[31]

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 extra high voltage (EHV) system and resolve a wide range of reliability criteria violations and market congestion issues. The current backbone projects are Mount Storm-Doubs, Jacks Mountain, Susquehanna-Roseland, and Surry Skiffes Creek 500kV. Figure 12-3 shows the location of these four projects.

The Mount Storm-Doubs transmission line, which 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. The rebuild project is complete and was energized on June 3, 2014, one year ahead of schedule.[32] Dominion will complete its Right of Way Rehabilitation by the fall of 2014.

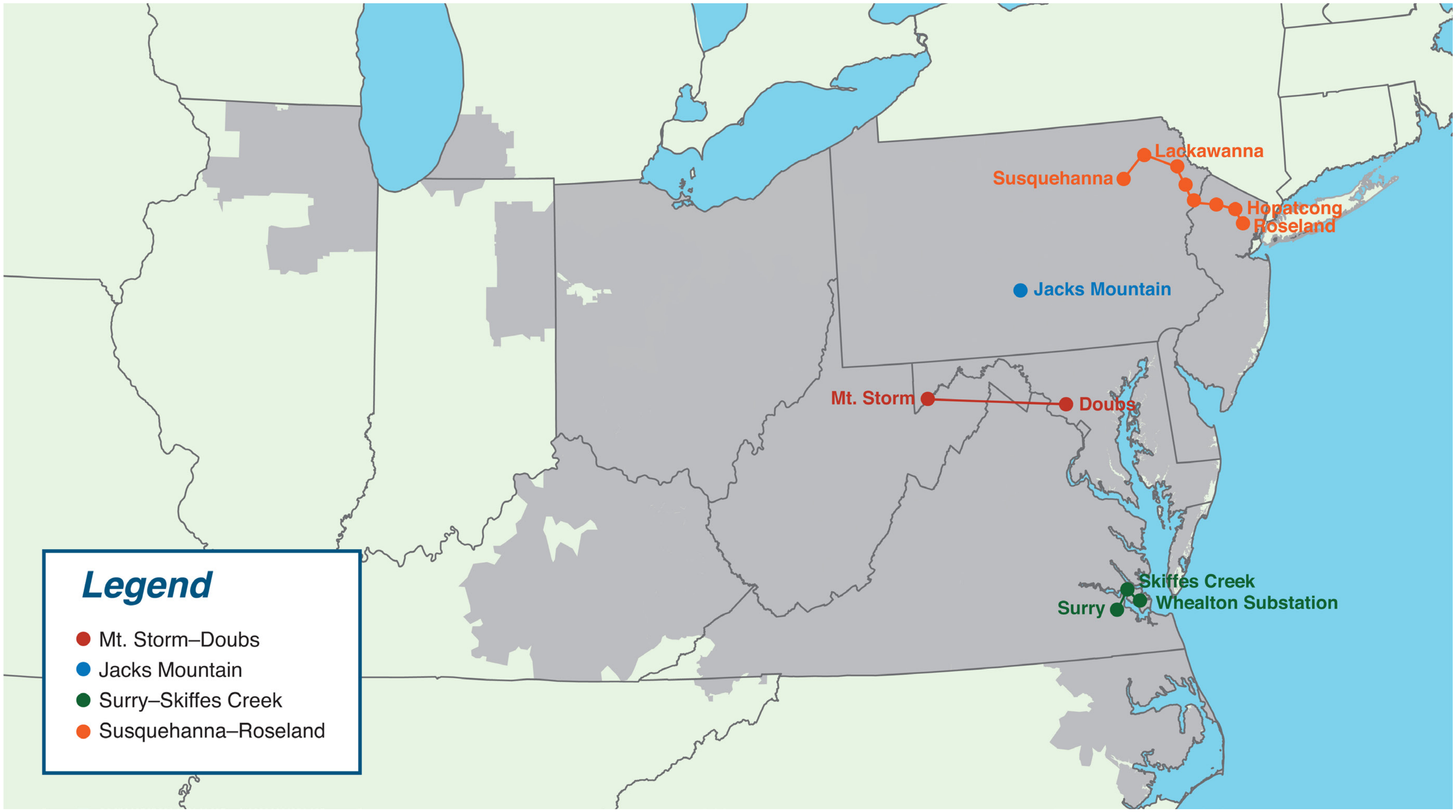
The Jacks Mountain project is required to resolve voltage problems for load deliverability starting June 1, 2017. Jacks Mountain will be a new 500kV substation connected to the existing Conemaugh-Juniata and Keystone-Juniata 500kV circuits. As of June 30, 2014, the project is experiencing order delays of necessary components. Anticipated milestone completion dates have not been adjusted. Transmission foundations are planned for fall 2015. Below grade construction of the sub-station is scheduled to be completed by September 2016, and above grade, relay/control construction, is planned for October 2016-June 2017.[33]

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, and Roseland buses. PPL is responsible for the first two legs. Their expectations as of June 30, 2014, are for the Susquehanna-Lackawanna portion to be in service by December 2014 and the Lackawanna–Hopatcong portion by June, 2015. The remaining leg, Hopatcong – Roseland, is being executed by PSE&G and is anticipated to be in service by June 2015. Engineering and design of the transmission and substations are over 95 percent complete for both parties.[34]

The Surry Skiffes Creek 500kV project is new this quarter. It was initiated to relieve the overload of the James River Crossing Double Circuit Towerline anticipated to result from the retirement of Chesapeake units 1-4 and Yorktown 1, scheduled for December 2014. It will comprise a new 7.7 mile 500kV line between Surry and Skiffes, a new 20.25 mile 230kV line between Skiffes creek and Whealton, and a new Skiffes Creek 500/230kV switching station. Dominion anticipates beginning construction in the fall of 2014 and expects the 500kV line to be completed by January 01, 2016 and the 230kV line to be completed by April 30, 2016.[35]

30 "Transmission Expansion Advisory Committee Reliability Analysis Update," September 25, 2014, at http://www.pjm.com/~/media/committees-groups/committees/teac/20140925/20140925-reliability-analysis-update.ashx.
31 "Transmission Expansion Advisory Committee 2014 Market Efficiency Analysis," October 09, 2014, at < http://www.pjm.com/~/media/committees-groups/committees/teac/20141009/20141009-market-efficiency-analysis-update.ashx>.
32 See Dominion "*Mt. Storm-Doubs 500kV Rebuild Project*," <https://www.dom.com/about/electric-transmission/mtstorm/index.jsp> (March 31, 2014).
33 See "Jacks Mountain," <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/jacks-mountain.aspx>.
34 See "Susquehanna-Roseland," <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/ susquehanna-roseland.aspx>.
35 See "Surry Skiffes Creek," http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/surry-skiffes-creek.aspx.

Figure 12-3 PJM Backbone Projects



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 facts that loads pay for the transmission system which permits low cost generation to be delivered to load. Another way of describing the result is that FTRs and the associated revenues were directly provided to loads in recognition of the fact that load pays locational prices which result in load payments in excess of generation revenues which are the source of the funds available to offset congestion costs in an LMP market.[2] In other words, load payments in excess of generation revenues are the source of the funds to pay FTRs. In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs to pay back to load the difference between the total load payments and the total generation revenues associated with congestion.

The focuses on the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions during the 2013 to 2014 planning period, covering January 1, 2014, through June 30, 2014.

1 *See* 81 FERC ¶ 61,257, at 62,241 (1997).
2 *See Id.* at 62, 259-62,260 & n. 123.

Table 13-1 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 ARR/FTR design including a wide range of options for market participants to acquire FTRs and a competitive auction mechanism, there are several problematic features of the ARR/FTR design which need to be addressed. The market design incorporates widespread cross subsidies which are not consistent with an efficient market design and the market design as implemented results in overselling FTRs. FTR funding levels are reduced as a result of these factors.

Overview

Financial Transmission Rights

Market Structure

- **Supply.** Market participants can sell FTRs. In the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2014 to 2015 planning period, total participant FTR sell offers were 1,431,101 MW, down from 2,217,995 MW for the same period during the 2013 to 2014 planning period.

- **Demand.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2014 to 2015 planning period increased 13.6 percent from 9,765,083 MW for the same time period of the prior planning period, to 11,096,054 MW.
- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 79.4 percent of prevailing flow and 87.8 percent of counter flow FTRs for January through September of 2014. Financial entities owned 69.4 percent of all prevailing and counter flow FTRs, including 60.2 percent of all prevailing flow FTRs and 85.0 percent of all counter flow FTRs during the period from January through September 2014.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the first four months of the 2014 to 2015 planning period were $53,740 for Increment Offers, Decrement Bids and UTC Transactions.
- **Credit Issues.** People's Power and Gas, LLC and CCES, LLC defaulted on their collateral calls and payment obligations in January 2014. Customers of these members have been reallocated accordingly, and neither company held any financial transmission rights. These two load-serving members accounted for 17 of the total 33 default events. People's Power and Gas, LLC defaulted on three collateral calls totaling approximately $687,000 and then defaulted on four related payment obligations totaling approximately $554,000. CCES, LLC defaulted on two collateral calls totaling approximately $308,000 and then defaulted on eight related payment obligations totaling approximately $2.6 million. On March 6, 2014, PJM filed with FERC to terminate membership of these two companies. The FERC authorized this request effective April 24, 2014 and PJM utilized the default allocation assessment to apply their defaulting charges of approximately $1.9 million (total defaults of these two members less collateral held) to PJM's non-defaulting members in accordance with section 15.2.2 of the OATT to non-defaulting members' March 2014 monthly invoices.[3]

3 *See* Default Allocation Assessment. OATT Section 15.2.2

Of the remaining 16 defaults not from People's Power and Gas, LLC and CCES, LLC, in January through March 2014, 13 were from collateral defaults, averaging $822,493, and three were from payment defaults, averaging $2,328. These remaining defaults were all promptly cured. In April through June 2014, CCES, LLC defaulted again for a total of $59,899. The default allocation assessment was assigned to non-defaulting members resulting in 18 payment defaults in April 2014 totaling $4,017, nine of which were promptly cured. There were no collateral or payment defaults in May through September 2014. These defaults were not necessarily related to FTR positions.

Market Performance

- **Volume.** For the first four months of the 2014 to 2015 planning period Monthly Balance of Planning Period FTR Auctions 893,952 MW (8.1 percent) of FTR buy bids and 307,481 MW (21.5 percent) of FTR sell offers cleared.
- **Price.** The weighted-average buy-bid FTR price in the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period was $0.17, up from $0.10 per MW in the 2013 to 2014 planning period.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $4.2 million in net revenue for all FTRs for the first four months of the 2014 to 2015 planning period, down from $7.3 million for the same time period in the 2013 to 2014 planning period.
- **Revenue Adequacy.** FTRs were paid at 100 percent of the target allocation level for the first four months of the 2014 to 2015 planning period. Congestion revenues are allocated to FTR holders based on their portion of FTR target allocations. PJM collected $351.2 million of FTR revenues during the first four months of the 2014 to 2015 planning period and $1,819.5 million during the entire 2013 to 2014 planning period. For the 2014 to 2015 planning period, the top sink and top source with the highest positive FTR target allocations were the Western Hub and the PECO zone. Similarly, the top sink and top source with the largest negative FTR target allocations were the JCPL zone and the Western Hub.

For the first nine months of 2014, total day-ahead congestion was $1,964.6 million while total day-ahead plus balancing congestion was $1,705.3 million, compared to target allocations of $2,174.3 million in the same time period.

Target allocation values are based on FTR MW and the differences between FTR source and sink day ahead CLMPs, not on the actual congestion incurred on FTR paths. Actual congestion incurred is the overpayment by load compared to payments to generation which result from both day-ahead congestion and balancing congestion. Target allocations are therefore not a good measure of congestion incurred on FTR paths and FTR payouts relative to target allocations are not a good measure of the payout performance of FTRs. Target allocations are just a distribution mechanism for congestion collected.

- **ARR and FTR Offset.** ARRs and FTRs served as an effective, but not total, offset to congestion. ARR and FTR revenues offset 80.4 percent of the total congestion costs including the Day-Ahead Energy Market and the balancing energy market in PJM for the first four months of the 2014 to 2015 planning period. In the 2013 to 2014 planning period, total ARR and FTR revenues offset 98.2 percent of the congestion costs.
- **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 $780.4 million in profits for physical entities, of which $420.5 million was from self-scheduled FTRs, and $517.9 million for financial entities. FTRs were undervalued in the auctions compared to their returns from congestion revenue, despite the fact that the payout ratio was less than 1.0. Not every FTR was profitable. FTR profits were high for the first nine months of 2014 due in large part to very high January congestion prices and higher than normal congestion prices in February and March.

Auction Revenue Rights

Market Structure

- **ARR Allocations.** Due to more conservative treatment of transmission outages by PJM in the FTR Auction model designed to reduce revenue inadequacy, ARR allocation quantities were reduced. For the 2014 to 2015 planning period, Stage 1B and Stage 2 ARR allocations were reduced 84.9 percent and 88.1 percent from the 2013 to 2014 planning period.
- **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 first four months of the 2014 to 2015 planning period planning period, PJM allocated a total of 9,826.4 MW of residual ARRs with a total target allocation of $5,109,164.
- **ARR Reassignment for Retail Load Switching.** There were 64,086 MW of ARRs associated with $382,100 of revenue that were reassigned in the 2013 to 2014 planning period. There were 30,323 MW of ARRs associated with $302,600 of revenue that were reassigned for the first four months of the 2014 to 2015 planning period.

Market Performance

- **Revenue Adequacy.** For the first four months of the 2014 to 2015 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $732.2 million while PJM collected $752.9 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. For the 2013 to 2014 planning period, the ARR target allocations were $506.2 million while PJM collected $568.8 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

- **ARRs as an Offset to Congestion.** ARRs served as an effective offset against congestion. The total revenues received by ARR holders, including self-scheduled FTRs, offset 100 percent of the total congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market for the first four months of the 2014 to 2015 planning period and for the 2013 to 2014 planning period.

Recommendations

- Report correct monthly payout ratios to reduce understatement of payout ratios on a monthly basis. (Priority: Low. First reported 2013.)
- Eliminate portfolio netting to eliminate cross subsidies among FTR marketplace participants. (Priority: High. First reported 2013.)
- Eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2013.)
- Eliminate geographic cross subsidies. (Priority: High. First reported 2013.)
- Improve transmission outage modeling in the FTR auction models. (Priority: Low. First reported 2013.)
- Reduce FTR sales on paths with persistent overallocation of FTRs including clear rules for what defines persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013.)
- Implement a seasonal ARR and FTR allocation system to better represent outages. (Priority: Medium. First reported 2013.)
- Eliminate over allocation requirement of ARRs in the Annual ARR Allocation process. (Priority: High. First reported 2013.)
- Apply the FTR forfeiture rule to up to congestion transactions consistent with the application of the FTR forfeiture rule to increment offers and decrement bids. (Priority: High. First reported 2013.)
- The MMU recommends that PJM not use the ATSI Interface or create similar closed loop interfaces to set zonal prices to accommodate the inadequacies of the demand side resource capacity product. Market prices should be a function of market fundamentals. The MMU recommends that, in general, the implementation of closed loop interface constraints be studied in advance and, if there is good reason to implement, implemented so as to include them in the FTR Auction model to minimize their impact on FTR funding. (Priority: Medium. First reported 2013.)

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.

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. Financial transmission rights and the associated revenues were directly provided to loads in recognition of the facts that loads pay for the transmission system which permits low cost generation to be delivered to load. Another way of describing the result is that FTRs and the associated revenues were directly provided to loads in recognition of the fact that load pays locational prices which result in load payments in excess of generation revenues which are the source of the funds available to offset congestion costs in an LMP market. In other words, load payments in excess of generation revenues are the source of the funds to pay FTRs. In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs to pay back to load the difference between the total load payments and the total generation revenues associated with congestion.

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.

For these reasons, load should never be required to subsidize payments to FTR holders, regardless of the reason. Such subsidies have been suggested.[4] One form of recommended subsidies would ignore balancing congestion when calculating total congestion dollars available to fund FTRs. This approach would ignore the fact that loads must pay both day ahead and balancing congestion. To eliminate balancing congestion from the FTR revenue calculation would require load to pay twice for congestion. Load would have to continue paying for the physical transmission system, would have to continue paying in excess of generator revenues and not have balancing congestion included in the calculation of congestion in order to increase the payout to holders of FTRs who are not loads and who therefore did not receive an allocation of ARRs. In other words, load would have to continue providing all the funding of FTRs, while payments to FTR holders who did not receive ARRs exceed total congestion on their FTR paths.

Revenue adequacy has received a lot of attention in the PJM FTR Market. There are several factors that can affect the reporting, 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 balancing 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.

Reported FTR revenue sufficiency uses target allocations as the relevant benchmark. But target allocations are not the relevant benchmark. Target allocations are based on day-ahead congestion only, ignoring the other part of total congestion which is balancing congestion. The difference between the congestion payout using total congestion and the congestion payout using only day-ahead congestion illustrates the issue. For the first nine months of 2014, total day-ahead congestion was $1,964.6 million while total day-ahead plus balancing congestion was $1,705.3 million, compared to target allocations of $2,174.3 million in the same time period.

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, in the 2012 to 2013 planning period, the clearing price was $0.34 per MW, a 52 percent decrease, and in the 2013 to 2014 planning period, the clearing price was $0.30 per MW, a 13.3 percent decrease. For the 2014 to 2015 planning period, the Annual FTR Obligation price was $0.44, a 46.7 percent increase from the previous planning period. In the 2010 to 2011 planning period, the clearing price for FTR Obligation sell offers was $0.22 per MW, in the 2012 to 2013 planning period was $0.15 per MW, a 31.8 percent decrease, and in the 2013 to 2014 planning period the price was $0.05 per MW, a 66.7 percent decrease. For the 2014 to 2015 planning period, the Annual FTR Obligation sell offer price was $0.22, a 340 percent increase from the previous planning period.

The volume of cleared buy bids and self-scheduled bids in the Annual FTR Auctions decreased from 420,489 MW in the 2013 to 2014 planning period to 365,843 MW in the 2014 to 2015 planning period, a decrease of 54,646 MW or 13.0 percent. The volume of cleared sell offers increased from 37,821 MW in the 2013 to 2014 planning period to 41,213 MW in the 2014 to 2015 planning period, an increase of 9.0 percent.

4 See "FirstEnergy Solutions Corp. Allegheny Energy Supply Company, LLC v PJM Interconnection, LLC" EL13-47(February 15, 2013).

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. The bid volume was 7,598,008.5 MW, 7,909,804.6 MW and 9,600,316 MW for June 2012, June 2013 and June 2014, increases of 95.1, 103.1 and 405.7 percent over June 2010. The net bid volume was 6,407,647.2 MW, 6,607,570.4 MW and 8,631,332 MW for June 2012, June 2013 and June 2014, increases of 101.7, 108.0 and 368.1 percent. The net bid volume to bid volume ratio was 0.82, 0.83, 0.84, 0.84 and 0.90 for June 2010, June 2012, June 2013 and June 2014.

The monthly payout ratio reported by PJM 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. PJM's reported monthly payout ratios are based on an estimate of the results for the entire year. The reported monthly payout ratio should be the actual monthly results including all revenue. 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. The FTR market cannot work efficiently if FTR buyers do not receive payments consistent with the performance of their FTRs. Eliminating the portfolio subsidy would be a good first step in that direction.

If netting within portfolios were eliminated and the payout ratio were calculated correctly, the payout ratio in the 2013 to 2014 planning period would have been 87.5 percent instead of the reported 72.8 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 impact of lower payouts 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 FTR market cannot work efficiently if FTR buyers do not receive payments consistent with the performance of their FTRs. Eliminating the counter flow subsidy would be another good step in that direction.

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would have increased the calculated payout ratio in the 2013 to 2014 planning period from the reported 72.8 percent to 91.0 percent. The MMU recommends that counter flow and prevailing flow FTRs should be treated symmetrically with respect to the application of a payout ratio.

The result of removing portfolio netting, applying a payout ratio to counter flow FTRs and eliminating Stage 1A ARR over allocation would increase the payout ratio to 94.6 percent.

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 in the FTR auction model 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, which directly results in differences in congestion between day-ahead and real-time markets; 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, which directly results in differences in congestion between day–ahead and real-time markets; the overallocation of ARRs which directly results in a difference between congestion revenue and the payment obligation; the appropriateness of seasonal ARR allocations to better match actual market conditions with the FTR auction model; geographic subsidies from the holders of positively valued FTRs in some locations to the holders of consistently negatively valued FTRs in other locations; the contribution of up-to congestion transactions to the differences between day-ahead and balancing congestion and thus to FTR payout ratios; and the continued sale of FTR capability on pathways with a persistent difference between FTRs and total congestion revenue. The MMU recommends that these issues be reviewed and modifications implemented. Regardless of how these issues are addressed, funding issues that persist as a result of modeling differences and flaws in the design of the FTR market should be borne by FTR holders operating in the voluntary FTR market and not imposed on load through the mechanism of balancing congestion. The end result of all the modeling differences is that too many FTRs are sold. In addition to addressing the specific modeling issues, PJM should reduce the number of FTRs sold.

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. This value, termed the FTR target allocation, defines the maximum, but not guaranteed, payout for FTRs. 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. But, 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. 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. FTR holders with a negatively valued FTR are required to pay charges equal to their target allocations. 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, payments by holders of negatively valued FTRs, Market to Market payments, excess ARR revenues available at the end of a month and any charges made to day-ahead operating reserves. Depending on the amount of revenues collected, FTR holders with a positively valued FTR may receive congestion credits between zero and their target allocations.

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.

FTRs can be bought, sold and self scheduled. Buy bids are bids to buy FTRs in the auctions; sell offers are offers to sell existing FTRs 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.

The objective function of all FTR auctions is to maximize the bid-based value of FTRs awarded in each auction.

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.

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 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. The fact that outages are modeled at significantly lower than historical levels results in selling too many FTRs which creates downward pressure on revenues paid to each FTR.

5 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p. 38.
6 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p. 55.

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 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 2014 to 2015 Annual FTR Auction were 3,270,311 MW. The total FTR buy bids in the Monthly Balance of Planning Period FTR Auctions for the 2013 to 2014 planning period were 25,088,665 MW.

7 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p. 39.

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.

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 13-2 presents the Monthly Balance of Planning Period FTR Auction cleared FTRs for January through September 2014 by trade type, organization type and FTR direction. Financial entities purchased 79.4 percent of prevailing flow and 87.8 percent of counter flow FTRs for the year, with the result that financial entities purchased 82.5 percent of all prevailing and counter flow FTR buy bids in the Monthly Balance of Planning Period FTR Auction cleared FTRs for January through September 2014.

Table 13-2 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through September 2014

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	20.6%	12.2%	17.5%
	Financial	79.4%	87.8%	82.5%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	34.0%	36.1%	34.4%
	Financial	66.0%	63.9%	65.6%
	Total	100.0%	100.0%	100.0%

Table 13-3 presents the daily net position ownership for all FTRs for January through September 2014, by FTR direction.

Table 13-3 Daily FTR net position ownership by FTR direction: January through September 2014

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	39.8%	15.0%	30.6%
Financial	60.2%	85.0%	69.4%
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 13-1 demonstrates the FTR forfeiture rule for INCs and DECs. The INC or DEC distribution factor (dfax) is compared to the largest impact withdrawal or injection dfax. If the absolute difference between the virtual bid and its counterpart is greater than or equal to 75 percent, the virtual bid is considered for forfeiture. This is the metric in the rule which defines the impact of the virtual bid on the constraint.

In the first part of the example in Figure 13-1, the INC has a dfax of 0.25 and the maximum withdrawal dfax on the constraint is -0.5. The difference between the two dfaxes is -0.75 (0.25 minus -0.5). The absolute value is 0.75. In the second part of the example in, the DEC has dfax of 0.5 and the maximum injection dfax on the constraint is -0.25. The difference between the two dfaxes is 0.75 (-0.25 minus 0.5). The absolute value is also 0.75.

Figure 13-1 Illustration of INC/DEC FTR forfeiture rule

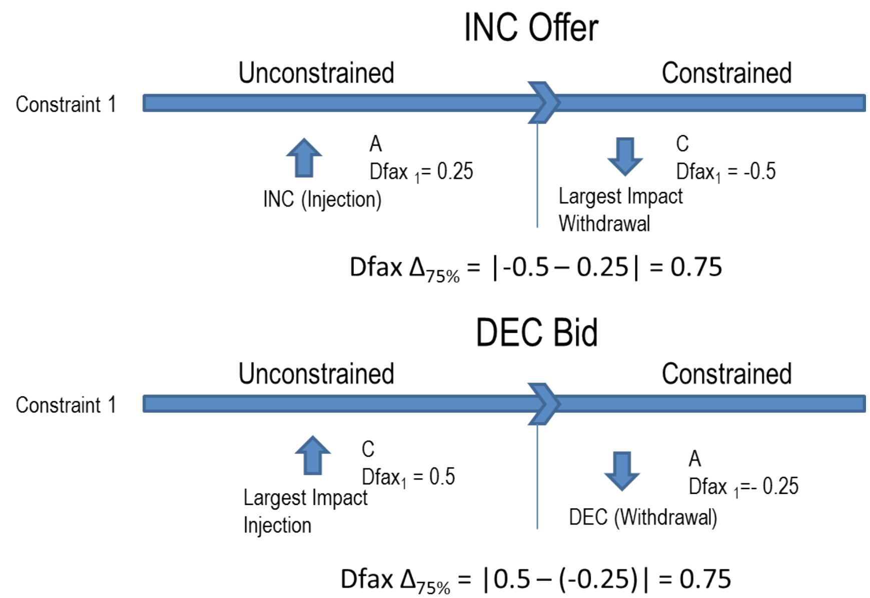


Figure 13-2 shows the FTR forfeiture values for both physical and financial participants for each month of June 2010 through September 2014. Currently, counter flow FTRs are not subject to forfeiture regardless of INC or DEC positions. Total forfeitures for the first four months of the 2014 to 2015 planning period were $0.05 million (0.02 percent of total FTR target allocations).

Figure 13-2 Monthly FTR forfeitures for physical and financial participants: June 2010 through September 2014

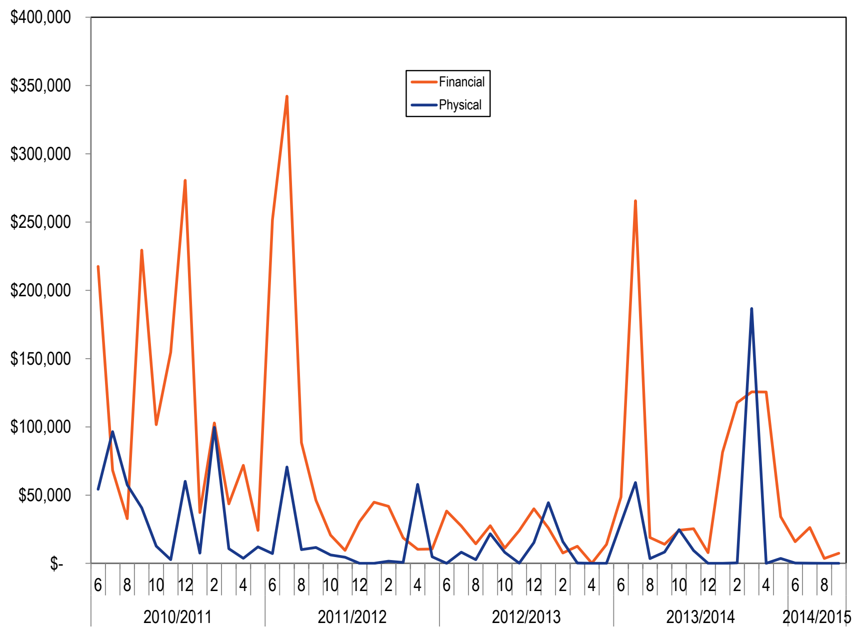


Figure 13-3 FTR forfeitures for INCs/DECs and INCs/DECs/UTCs for both the PJM and MMU methods: January 2013 through September 2014

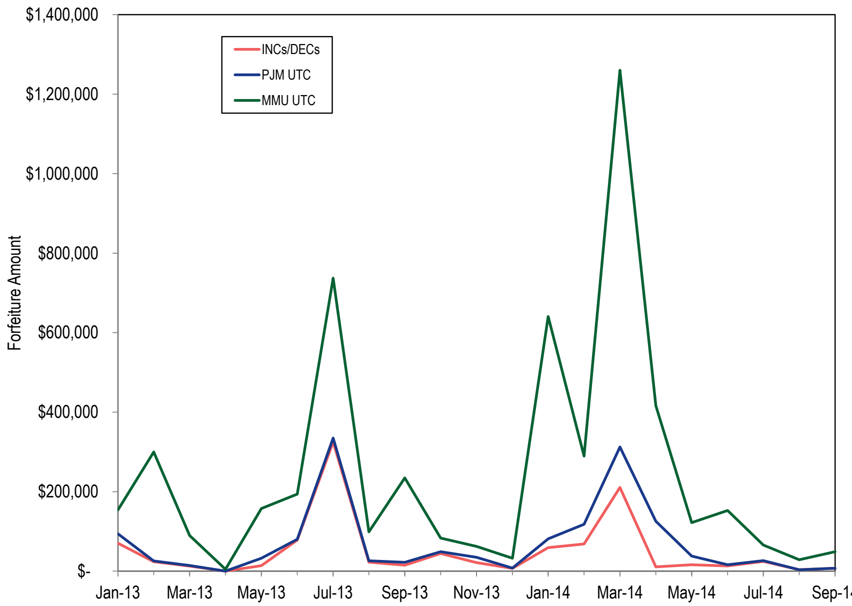


Figure 13-3 shows the FTR forfeitures on just INCs and DECs, FTR forfeitures on INCs, DECs and UTCs using the method proposed by PJM and FTR forfeitures on INCs, DECs and UTCs using the method proposed by the MMU from January 2013 through September 2014. The method proposed by PJM for calculating forfeitures associated with UTCs was implemented on September 1, 2013, and for each month thereafter. UTC forfeitures before September 2013 were not billed, but are included to illustrate the impact of the different methods of calculating forfeitures. The UTC curves include all forfeitures for the month associated with INCs, DECs and UTCs.

Credit Issues

People's Power and Gas, LLC and CCES, LLC defaulted on their collateral calls and payment obligations in January 2014. Customers of these members have been reallocated accordingly, and neither company held any financial transmission rights. These two load-serving members accounted for 17 of the total 33 default events. People's Power and Gas, LLC defaulted on three collateral calls totaling approximately $687,000 and then defaulted on four related payment obligations totaling approximately $554,000. CCES, LLC defaulted on two collateral calls totaling approximately $308,000 and then defaulted on eight related payment obligations totaling approximately $2.6 million. On March 6, 2014, PJM filed with the FERC to terminate membership of these two companies. The FERC authorized this request effective April 24, 2014 and PJM utilized the default allocation assessment to apply their defaulting charges of approximately $1.9 million (total defaults of these two members less collateral held) to PJM's non-defaulting members in accordance with section 15.2.2 of the OATT to non-defaulting members' March 2014 monthly invoices.[8]

Of the remaining 16 defaults not from People's Power and Gas, LLC and CCES, LLC, in January through March 2014, 13 were from collateral defaults, averaging $822,493, and three were from payment defaults, averaging $2,328. These remaining defaults were all promptly cured. In April through June 2014, CCES, LLC defaulted again for a total of $59,899. Also, the default allocation assessment was assigned to non-defaulting members resulting in 18 payment defaults in April 2014 totaling $4,017, nine of which were promptly cured. There were no collateral or payment defaults in May through September 2014. These defaults were not necessarily related to FTR positions.

Market Performance

Volume

In an effort to address reduced FTR payout ratios caused by forced Stage 1A infeasibilities, PJM may use reduced capability limits instead of the increased Stage 1A capability limits in FTR auctions. These capability limits may be reduced if ARR funding is not impacted, all requested self-scheduled FTRs clear and net FTR Auction revenue is positive. If the normal capability limit cannot be reached due to infeasibilities then FTR Auction capability reductions are undertaken pro-rata based on the MW of Stage 1A infeasibility and the availability of appropriate auction bids. Reducing capability limits will reduce the number of oversold FTR facilities due to forced Stage 1A infeasibilities and reduce the FTR funding issues caused by these ARR infeasibilities. The downside to this strategy is that there will be fewer FTRs for sale in the FTR Auctions, and, potentially less auction revenue collected to pay ARR holders.

Also in an effort to reduce FTR funding issues, PJM implemented a new rule stating that PJM may model normal capability limits on facilities which are infeasible due to modeled transmission outages in Monthly Balance of Planning Period FTR Auctions. The capability of these facilities may be reduced if ARR target allocations are fully funded and net auction revenues are greater than zero. This reduction may only take place when there are auction bids available to reduce the infeasibilities. The results of this action should be an increased feasibility of the FTR model, but a possible reduction in FTR Auction revenue due to a lower capability.

Table 13-4 provides the Monthly Balance of Planning Period FTR Auction market volume for the entire 2013 to 2014 planning period and the first four months of the 2014 to 2015 planning period. There were 9,531,039 MW of FTR obligation buy bids and 1,354,922 MW of FTR obligation sell offers for all bidding periods in the first four months of the 2014 to 2015 planning period. The monthly balance of planning period auctions cleared 875,501 MW (9.2 percent) of FTR obligation buy bids and 284,590 MW (21.0 percent) of FTR obligation sell offer.

There were 1,565,015 MW of FTR option buy bids and 76,180 MW of FTR option sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2014 to 2015 planning period. The monthly auctions cleared 18,561 (1.2 percent) of FTR option buy bids, and 22,891 MW (30.0 percent) of FTR option sell offers.

8 *See* Default Allocation Assessment. OATT Section 15.2.2

Table 13-4 Monthly Balance of Planning Period FTR Auction market volume: January through September 2014

Monthly Auction	Type	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-14	Obligations	Buy bids	235,126	1,793,756	257,472	14.4%	1,536,283	85.6%
		Sell offers	103,912	286,684	45,850	16.0%	240,834	84.0%
	Options	Buy bids	6,536	298,300	7,805	2.6%	290,495	97.4%
		Sell offers	14,893	92,294	34,143	37.0%	58,151	63.0%
Feb-14	Obligations	Buy bids	235,697	1,578,788	239,877	15.2%	1,338,911	84.8%
		Sell offers	122,726	315,024	53,406	17.0%	261,619	83.0%
	Options	Buy bids	9,970	400,903	5,716	1.4%	395,187	98.6%
		Sell offers	12,801	75,859	35,021	46.2%	40,837	53.8%
Mar-14	Obligations	Buy bids	208,029	1,544,652	251,291	16.3%	1,293,361	83.7%
		Sell offers	107,355	274,653	50,275	18.3%	224,378	81.7%
	Options	Buy bids	11,027	373,373	10,379	2.8%	362,994	97.2%
		Sell offers	13,120	83,295	41,895	50.3%	41,400	49.7%
Apr-14	Obligations	Buy bids	164,728	1,358,802	213,902	15.7%	1,144,899	84.3%
		Sell offers	98,116	260,343	63,628	24.4%	196,715	75.6%
	Options	Buy bids	4,617	201,185	6,439	3.2%	194,746	96.8%
		Sell offers	8,699	52,533	29,277	55.7%	23,256	44.3%
May-14	Obligations	Buy bids	116,589	829,477	134,897	16.3%	694,580	83.7%
		Sell offers	46,426	147,043	36,569	24.9%	110,473	75.1%
	Options	Buy bids	2,585	105,367	3,312	3.1%	102,055	96.9%
		Sell offers	4,186	30,447	21,039	69.1%	9,408	30.9%
Jun-14	Obligations	Buy bids	372,164	2,711,522	220,555	8.1%	2,490,966	91.9%
		Sell offers	174,060	363,039	75,427	20.8%	287,612	79.2%
	Options	Buy bids	28,961	545,575	3,746	0.7%	541,829	99.3%
		Sell offers	3,136	18,521	6,929	37.4%	11,592	62.6%
Jul-14	Obligations	Buy bids	327,029	2,257,082	188,163	8.3%	2,068,919	91.7%
		Sell offers	138,666	308,296	65,054	21.1%	243,242	78.9%
	Options	Buy bids	24,765	432,159	3,992	0.9%	428,167	99.1%
		Sell offers	2,816	15,684	4,034	25.7%	11,650	74.3%
Aug-14	Obligations	Buy bids	342,144	2,237,508	214,958	9.6%	2,022,550	90.4%
		Sell offers	149,344	303,138	61,081	20.1%	242,057	79.9%
	Options	Buy bids	10,622	276,108	5,840	2.1%	270,269	97.9%
		Sell offers	3,116	18,759	5,326	28.4%	13,433	71.6%
Sep-14	Obligations	Buy bids	333,748	2,324,928	251,724	10.8%	2,073,203	89.2%
		Sell offers	150,207	380,449	83,029	21.8%	297,420	78.2%
	Options	Buy bids	9,982	311,173	4,984	1.6%	306,189	98.4%
		Sell offers	3,364	23,216	6,602	28.4%	16,614	71.6%
2013/2014*	Obligations	Buy bids	2,981,219	20,739,786	3,284,056	15.8%	17,455,730	84.2%
		Sell offers	1,513,626	4,166,671	681,264	16.4%	3,485,407	83.6%
	Options	Buy bids	93,770	4,348,879	130,444	3.0%	4,218,435	97.0%
		Sell offers	188,618	1,314,005	472,571	36.0%	841,435	64.0%
2014/2015**	Obligations	Buy bids	1,375,085	9,531,039	875,401	9.2%	8,655,639	90.8%
		Sell offers	612,277	1,354,922	284,590	21.0%	1,070,331	79.0%
	Options	Buy bids	74,330	1,565,015	18,561	1.2%	1,546,454	98.8%
		Sell offers	12,432	76,180	22,891	30.0%	53,289	70.0%

* Shows Twelve Months for 2013/2014; ** Shows four months ended 30-Sep-14 for 2014/2015

Table 13-5 presents the buy-bid, bid and cleared volume of the Monthly Balance of Planning Period FTR Auction, and the effective periods for the volume. The average monthly cleared volume for January through September 2014 was 225,005.7 MW. The average monthly cleared volume for January through September 2013 was 235,328.3 MW.

Table 13-5 Monthly Balance of Planning Period FTR Auction buy-bid, bid and cleared volume (MW per period): January through September 2014

Monthly Auction	MW Type	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-14	Bid	955,235	415,803	335,298				385,720	2,092,055
	Cleared	171,036	42,816	21,423				30,002	265,277
Feb-14	Bid	960,803	349,289	340,651				328,949	1,979,691
	Cleared	158,160	30,891	23,446				33,096	245,593
Mar-14	Bid	1,021,453	362,479	380,157				153,936	1,918,025
	Cleared	184,026	38,011	30,016				9,616	261,670
Apr-14	Bid	1,161,109	398,878						1,559,987
	Cleared	178,584	41,758						220,341
May-14	Bid	934,844							934,844
	Cleared	138,209							138,209
Jun-14	Bid	1,021,130	430,585	413,652	240,150	401,266	393,290	357,024	3,257,096
	Cleared	106,450	21,444	21,044	9,429	23,422	24,475	18,036	224,301
Jul-14	Bid	1,017,318	449,630	238,447		339,946	328,868	315,032	2,689,241
	Cleared	95,712	22,531	9,957		19,194	23,706	21,054	192,154
Aug-14	Bid	1,003,256	318,153	254,595		281,430	351,485	304,697	2,513,616
	Cleared	115,107	22,373	13,502		18,769	26,993	24,053	220,798
Sep-14	Bid	936,374	392,098	380,817		170,507	384,798	371,506	2,636,101
	Cleared	118,620	31,642	30,339		11,318	34,109	30,682	256,709

Figure 13-4 shows cleared auction volumes as a percent of the total FTR cleared volume by calendar months for June 2004 through September 2014, 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 13-4 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through September 2014

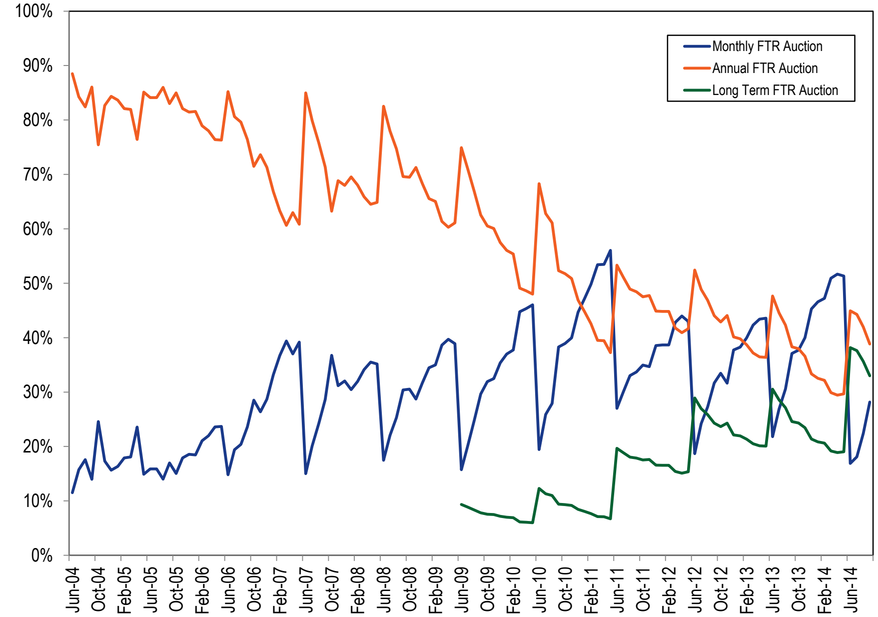


Table 13-6 provides the secondary bilateral FTR market volume for the entire 2013 to 2014 and 2014 to 2015 planning periods.

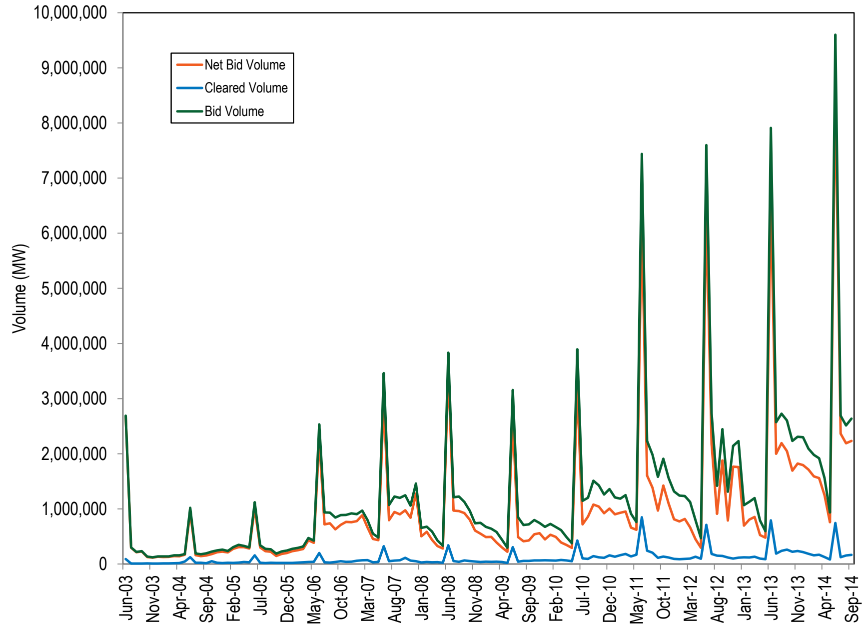
Table 13-6 Secondary bilateral FTR market volume: Planning periods 2013 to 2014 and 2014 to 2015[9]

Planning Period	Type	Class Type	Volume (MW)
2013/2014	Obligation	24-Hour	110
		On Peak	43,495
		Off Peak	36,012
		Total	79,617
	Option	24-Hour	0
		On Peak	9,724
		Off Peak	914
		Total	10,638
2014/2015	Obligation	24-Hour	69
		On Peak	1,397
		Off Peak	1,042
		Total	2,508
	Option	24-Hour	0
		On Peak	0
		Off Peak	0
		Total	0

Figure 13-5 shows the FTR bid, cleared and net bid volume from June 2003 through September 2014 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. In 2013 cleared volume increased, and there was a larger increase in 2014. The demand for FTRs has increased while availability of FTRs generally did not increase until 2011.

9 The 2013 to 2014 planning period covers bilateral FTRs that are effective for any time between June 1, 2013 through June 1, 2014, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

Figure 13-5 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through September 2014



Price

Table 13-7 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2014 through September 2014. For example, for the January 2014 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 September 2014 was $0.15 per MW, up from $0.09 per MW in the same time last year.

Table 13-7 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MW): January through September 2014

Monthly Auction	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-14	$0.11	$0.12	$0.08				$0.05	$0.09
Feb-14	$0.31	$0.22	$0.10				$0.13	$0.22
Mar-14	$0.19	$0.18	$0.17				$0.17	$0.19
Apr-14	$0.18	$0.20						$0.18
May-14	$0.17	$0.00						$0.17
Jun-14	$0.14	$0.26	$0.20	$0.22	$0.12	$0.15	$0.11	$0.15
Jul-14	$0.23	$0.31	$0.08		$0.06	$0.13	$0.06	$0.15
Aug-14	$0.11	$0.18	$0.18		$0.13	$0.18	$0.07	$0.13
Sep-14	$0.09	$0.19	$0.20		$0.03	$0.14	$0.10	$0.11
Oct-14	$0.00	$0.00	$0.00			$0.00	$0.00	$0.00
Nov-14	$0.00	$0.00	$0.00			$0.00	$0.00	$0.00
Dec-14	$0.00	$0.00	$0.00			$0.00	$0.00	$0.00

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 13-8 lists FTR profits by organization type and FTR direction for the period from January through September 2014. 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 which are very small and do not occur in every month. 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. Self-scheduled FTRs have zero cost. FTRs were profitable overall, with $780.4 million in profits for physical entities, of which $420.5 million was from self-scheduled FTRs, and $517.9 million for financial entities.

Table 13-8 FTR profits by organization type and FTR direction: January through September 2014

	FTR Direction				
Organization Type	Prevailing Flow	Self Scheduled Prevailing Flow	Counter Flow	Self Scheduled Counter Flow	All
Physical	$425,598,457	$420,544,503	($63,624,149)	($2,075,814)	$780,442,997
Financial	$509,775,154	NA	$8,122,420	NA	$517,897,574
Total	$935,373,611	$420,544,503	($55,501,729)	($2,075,814)	$1,298,340,572

Table 13-9 lists the monthly FTR profits in the first nine months of 2014 by organization type.

Table 13-9 Monthly FTR profits by organization type: January through September 2014

	Organization Type			
Month	Physical	Self Scheduled Physical FTRs	Financial	Total
Jan	$249,622,111	$180,379,965	$284,346,392	$714,348,467
Feb	$51,128,624	$39,339,259	$50,029,319	$140,497,202
Mar	$52,904,642	$80,420,488	$92,975,434	$226,300,564
Apr	$2,575,191	$13,269,781	$29,611,277	$45,456,249
May	$4,488,987	$14,781,066	$25,211,798	$44,481,851
Jun	$4,619,156	$26,825,465	$12,924,305	$44,368,926
Jul	$447,514	$25,801,674	$15,173,380	$41,422,568
Aug	($8,208,355)	$15,086,322	($355,132)	$6,522,834
Sep	$4,399,677	$22,564,671	$7,980,802	$34,945,149
Total	$361,977,548	$418,468,689	$517,897,574	$1,298,343,811

Revenue

Monthly Balance of Planning Period FTR Auction Revenue

Table 13-10 shows Monthly Balance of Planning Period FTR Auction revenue data by trade type, type and class type for January through September 2014. The Monthly Balance of Planning Period FTR Auction netted $4.2 million in revenue, with buyers paying $72.9 million and sellers receiving $68.6 million for the first four months of the 2014 to 2015 planning period. For the entire 2013 to 2014 planning period, the Monthly Balance of Planning Period FTR Auctions netted $29.8 million in revenue with buyers paying $206.9 million and sellers receiving $177.1 million.

Table 13-10 Monthly Balance of Planning Period FTR Auction revenue: January through September 2014

			Class Type			
Monthly Auction	Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-14	Obligations	Buy bids	$538,610	$6,544,992	$3,406,763	$10,490,364
		Sell offers	$255,974	$3,772,022	$2,170,525	$6,198,521
	Options	Buy bids	$0	$495,869	$277,203	$773,072
		Sell offers	$0	$2,607,255	$2,450,896	$5,058,152
Feb-14	Obligations	Buy bids	$772,337	$13,639,753	$8,949,253	$23,361,343
		Sell offers	$861,314	$8,562,236	$6,040,336	$15,463,885
	Options	Buy bids	$0	$530,102	$628,647	$1,158,749
		Sell offers	$7,752	$4,398,077	$3,362,318	$7,768,147
Mar-14	Obligations	Buy bids	$1,279,408	$9,929,162	$6,943,023	$18,151,593
		Sell offers	$674,564	$6,152,784	$3,794,533	$10,621,881
	Options	Buy bids	$0	$959,329	$699,358	$1,658,688
		Sell offers	$13,013	$3,653,094	$2,937,076	$6,603,182
Apr-14	Obligations	Buy bids	$1,730,553	$7,258,667	$5,042,410	$14,031,631
		Sell offers	$483,489	$4,812,099	$2,767,189	$8,062,776
	Options	Buy bids	$0	$476,073	$303,342	$779,415
		Sell offers	$0	$2,455,211	$2,261,171	$4,716,382
May-14	Obligations	Buy bids	$199,961	$4,707,719	$3,063,318	$7,970,998
		Sell offers	$1,103,488	$2,672,060	$1,874,957	$5,650,505
	Options	Buy bids	$0	$401,410	$428,029	$829,439
		Sell offers	$0	$1,649,823	$1,446,271	$3,096,093
Jun-14	Obligations	Buy bids	$1,370,874	$11,646,070	$6,989,461	$20,006,404
		Sell offers	$3,279,375	$7,756,077	$5,507,835	$16,543,287
	Options	Buy bids	$0	$429,965	$404,600	$834,565
		Sell offers	$11,621	$1,391,691	$959,140	$2,362,452
Jul-14	Obligations	Buy bids	$98,785	$10,783,323	$5,560,387	$16,442,495
		Sell offers	$1,788,888	$7,836,788	$4,505,301	$14,130,977
	Options	Buy bids	$0	$587,602	$464,945	$1,052,547
		Sell offers	$0	$1,124,620	$548,951	$1,673,571
Aug-14	Obligations	Buy bids	$774,786	$9,994,361	$5,509,790	$16,278,937
		Sell offers	$1,183,803	$8,364,852	$5,625,188	$15,173,844
	Options	Buy bids	$0	$555,704	$558,010	$1,113,713
		Sell offers	$0	$1,078,815	$545,358	$1,624,173
Sep-14	Obligations	Buy bids	$1,171,664	$8,893,384	$4,995,699	$15,060,747
		Sell offers	$1,740,200	$9,049,685	$4,842,638	$15,632,523
	Options	Buy bids	$0	$1,265,636	$814,664	$2,080,301
		Sell offers	$0	$902,256	$582,261	$1,484,517
2013/2014*	Obligations	Buy bids	$9,826,767	$101,822,004	$64,728,872	$176,377,643
		Sell offers	$10,784,494	$59,962,481	$41,025,433	$111,772,408
	Options	Buy bids	$161,270	$10,651,046	$7,972,402	$18,784,718
		Sell offers	$20,765	$39,700,666	$32,300,116	$72,021,546
	Total		$20,793,296	$212,136,196	$146,026,822	$378,956,314
2014/2015**	Obligations	Buy bids	$3,416,108	$41,317,138	$23,055,336	$67,788,582
		Sell offers	$7,992,266	$33,007,401	$20,480,962	$61,480,630
	Options	Buy bids	$0	$2,838,908	$2,242,219	$5,081,127
		Sell offers	$11,621	$4,497,382	$2,635,710	$7,144,713
	Total		($4,587,779)	$6,651,263	$2,180,883	$4,244,366

* Shows Twelve Months; ** Shows four months ended 30-Sep-2014 for 2014/2015

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 2014 to 2015 planning period. Figure 13-6 shows the ten largest positive and negative FTR target allocations, summed by sink, for the 2014 to 2015 planning period. The top 10 sinks that produced financial benefit accounted for 21.7 percent of total positive target allocations during the 2014 to 2015 planning period with the Western Hub accounting for 4.1 percent of all positive target allocations. The top 10 sinks that created liability accounted for 12.3 percent of total negative target allocations with the JCPL Zone accounting for 2.0 percent of all negative target allocations.

Figure 13-6 Ten largest positive and negative FTR target allocations summed by sink: 2014 to 2015 planning period through September

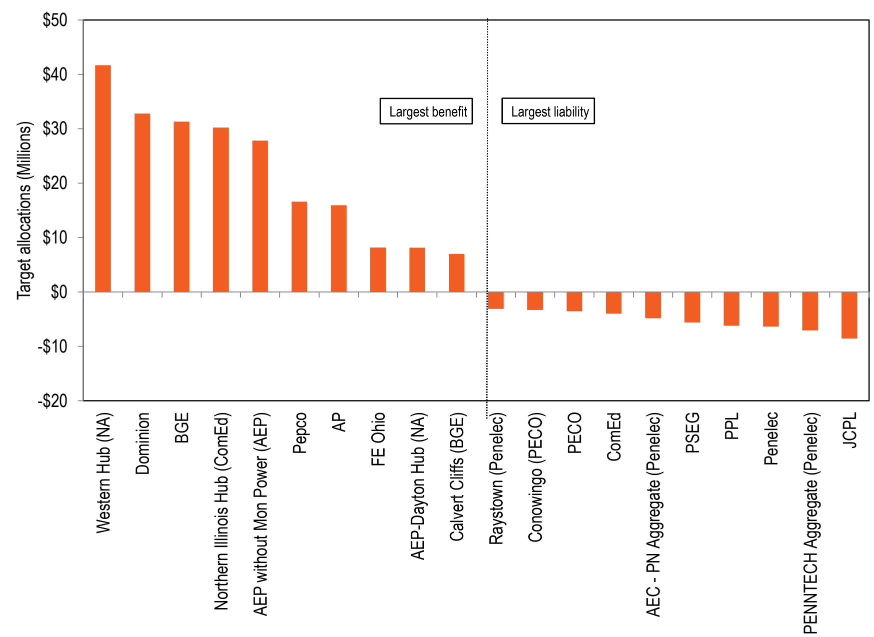
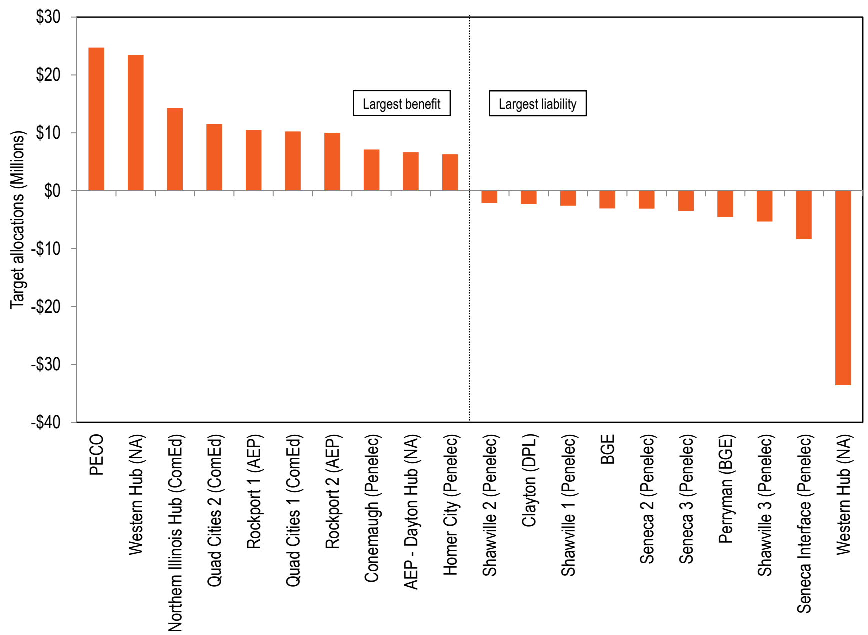


Figure 13-7 shows the ten largest positive and negative FTR target allocations, summed by source, for the 2014 to 2015 planning period. The top 10 sources with a positive target allocation accounted for 12.3 percent of total positive target allocations with the PECO Zone accounting for 2.4 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 16.0 percent of all negative target allocations, with the Western Hub accounting for 7.9 percent.

Figure 13-7 Ten largest positive and negative FTR target allocations summed by source: 2014 to 2015 planning period through September



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.[10] 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 ARR and FTR revenues to total congestion on the system as a measure of the extent to which ARRs and FTRs offset the actual, total congestion across all paths paid by market participants, regardless of the availability of ARRs or 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. Since the 2011 to 2012 planning period, FTRs were not fully

10 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."

funded and thus an uplift charge was collected. In June 2014, there was $2.9 million in excess congestion revenue, to be used to fund months later in the planning period that may have a revenue shortfall.

FTR revenues are primarily comprised of hourly congestion revenue, from the day-ahead and balancing markets.[11] FTR revenues also include ARR excess, which is the difference between ARR target allocations and FTR auction revenues, and negative FTR target allocations, which is an income for the FTR market from FTRs with a negative target allocation. Competing use revenues are based on the Unscheduled Transmission Service Agreement between the New York Independent System Operator (NYISO) and PJM. This agreement sets forth the terms and conditions under which compensation is provided for transmission service in connection with transactions not scheduled directly or otherwise prearranged between NYISO and PJM. Congestion revenues appearing in Table 13-11 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates (M2M flowgates) in MISO and NYISO whose operating limits are respected by PJM.[12]

In the first nine months of 2014, the market to market operations resulted in NYISO, 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. The Firm Flow Entitlement (FFE) represents the amount of historic flow that each RTO had created on each reciprocally coordinated flowgate (RCF) used in the market to market settlement process. The FFE establishes the amount of market flow that each RTO is permitted to create on the RCF before incurring redispatch costs during the market to market process. If the non-monitoring RTO's real-time market flow is greater than their FFE plus the approved MW adjustment from day-ahead coordination, then the non-monitoring RTO will pay the monitoring RTO based on the difference between their market flow and their FFE. If the non-monitoring RTO's real-time market flow is less than their FFE plus the approved MW adjustment from day-ahead coordination, then the monitoring RTO will pay the non-monitoring RTO for congestion relief provided by the non-monitoring RTO based on the difference between the non-monitoring RTO's market flow and their FFE.

For the 2013 to 2014 planning period, PJM paid MISO and NYISO a combined $44.3 million for redispatch on the designated M2M flowgates, and for the first four months of the 2014 to 2015 planning period PJM has paid MISO and NYISO a combined $6.4 million. The timing of the addition of new M2M flowgates may reduce FTR funding levels. MISO's ability to add flowgates dynamically throughout the planning period, which were not modeled in any previous PJM FTR auction, may result in oversold FTRs in PJM, and as a direct consequence, reduce FTR funding.

FTRs were paid at 100 percent of the target allocation level for the 2014 to 2015 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $351.2 million of FTR revenues during the first four months of the 2014 to 2015 planning period, and $1,819.5 million during the 2013 to 2014 planning period. Congestion in January 2014 was extremely high due to cold weather events, resulting in target allocations and congestion revenues that were unusually high for 2014. For the first four months of the 2014 to 2015 planning period, the top sink and top source with the highest positive FTR target allocations were the Western Hub and PECO zone. The top sink with the largest negative FTR target allocation was the JCPL zone and the top source with the largest negative FTR target allocation was the Western Hub.

One of the main causes of the 2014 to 2015 planning period revenue adequacy was PJM's more conservative treatment of transmission outages in the FTR Auction model, designed to reduce revenue inadequacy, which resulted in a reduction of ARR allocation quantities. For the 2014 to 2015 planning period, Stage 1B and Stage 2 ARR allocations were reduced 84.9 percent and 99.1 percent from the 2013 to 2014 planning period.

Table 13-11 presents the PJM FTR revenue detail for the 2013 to 2014 planning period and the 2014 to 2015 planning period.

11 When hourly congestion revenues are negative, it is defined as a net negative congestion hour.

12 See "Joint Operating Agreement between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008), Section 6.1 <http://www.pjm.com/~/Media/documents/agreements/joa-complete.ashx>. (Accessed March 13, 2012)

Table 13-11 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2013 to 2014 and 2014 to 2015

Accounting Element		
ARR information	**2013/2014**	**2014/2015**
ARR target allocations	$520.0	$258.4
FTR auction revenue	$593.9	$260.2
ARR excess	$71.7	$3.9
FTR targets		
Positive target allocations	$2,625.8	$353.4
Negative target allocations	($126.4)	($58.6)
FTR target allocations	$2,499.4	$294.8
Adjustments:		
Adjustments to FTR target allocations	($1.2)	$0.1
Total FTR targets	$2,498.2	$294.8
FTR revenues		
ARR excess	$71.7	$3.9
Competing uses	$0.0	$0.0
Congestion		
Net Negative Congestion (enter as negative)	($55.0)	($4.7)
Hourly congestion revenue	$1,837.9	$358.3
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($44.3)	($6.4)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	$0.0	$0.0
Adjustments:		
Excess revenues carried forward into future months	$0.0	$124.8
Excess revenues distributed back to previous months	$0.0	$0.0
Other adjustments to FTR revenues	$0.0	$0.0
Total FTR revenues		
Excess revenues distributed to other months	$0.0	$0.0
Net Negative Congestion charged to DA Operating Reserves	$9.2	$0.0
Excess revenues distributed to CEPSW for end-of-year distribution	$0.0	$0.0
Excess revenues distributed to FTR holders	$0.0	$0.0
Total FTR congestion credits	$1,819.5	$351.2
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$1,819.5	$351.2
Remaining deficiency	$678.7	($56.4)

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, the unallocated congestion charges are included in day-ahead operating reserve charges so that the total congestion for the month is not less than 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 in three months, 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 13-12 shows the monthly unallocated congestion charges made to day-ahead operating reserves for the 2012 to 2013 planning period through the 2014 to 2015 planning period. Months with no unallocated congestion are excluded from the table.[13]

Table 13-12 Unallocated congestion charges: Planning period 2012 to 2013 through 2014 to 2015

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
Sep-13	$6,411,602
2012/2013	$12,133,668
2013/2014	$9,240,262

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 13-13 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.

13 See Section 4, "Energy Uplift" at "Energy Uplift Charges" for the impact of Unallocated Congestion Charges on Operating Reserve rates.

The total row in Table 13-13 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 13-13 Monthly FTR accounting summary (Dollars (Millions)): Planning period 2013 to 2014 and 2014 to 2015

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-13	$61.3	$81.9	74.7%	$64.1	78.2%	($17.8)
Jul-13	$113.5	$128.3	88.3%	$113.5	88.5%	($14.7)
Aug-13	$43.1	$45.8	94.0%	$43.1	94.0%	($2.7)
Sep-13	$60.3	$116.0	52.0%	$66.7	57.5%	($49.3)
Oct-13	$47.4	$63.9	74.0%	$47.4	74.1%	($16.6)
Nov-13	$44.7	$66.9	66.9%	$44.7	66.9%	($22.1)
Dec-13	$85.0	$115.9	73.3%	$85.0	73.3%	($31.0)
Jan-14	$815.8	$1,044.0	78.1%	$815.8	78.1%	($228.2)
Feb-14	$167.7	$243.2	68.9%	$167.7	68.9%	($75.5)
Mar-14	$245.5	$367.0	66.8%	$245.5	66.8%	($121.8)
Apr-14	$60.9	$112.2	54.2%	$60.9	54.3%	($51.3)
May-14	$65.2	$113.2	57.6%	$65.2	57.6%	($48.0)
Summary for Planning Period 2013 to 2014						
Total	$1,810.3	$2,498.3		$1,819.5	72.8%	($678.8)
Jun-14	$89.0	$86.1	100.0%	$89.0	100.0%	$2.9
Jul-14	$104.0	$84.4	100.0%	$104.0	100.0%	$19.5
Aug-14	$69.5	$49.2	100.0%	$69.5	100.0%	$20.3
Sep-14	$88.7	$75.0	100.0%	$88.7	100.0%	$13.7
Summary for Planning Period 2014 to 2015						
Total	$351.2	$294.7		$351.2	100.0%	$56.4

Figure 13-8 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through September 2014. The months with payout ratios above 100 percent have excess congestion revenue and the months with payout ratios under 100 percent are revenue inadequate. Figure 13-8 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 2014 to 2015 planning period may change if excess revenue is collected in the remainder of the planning period.

Figure 13-8 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through September 2014

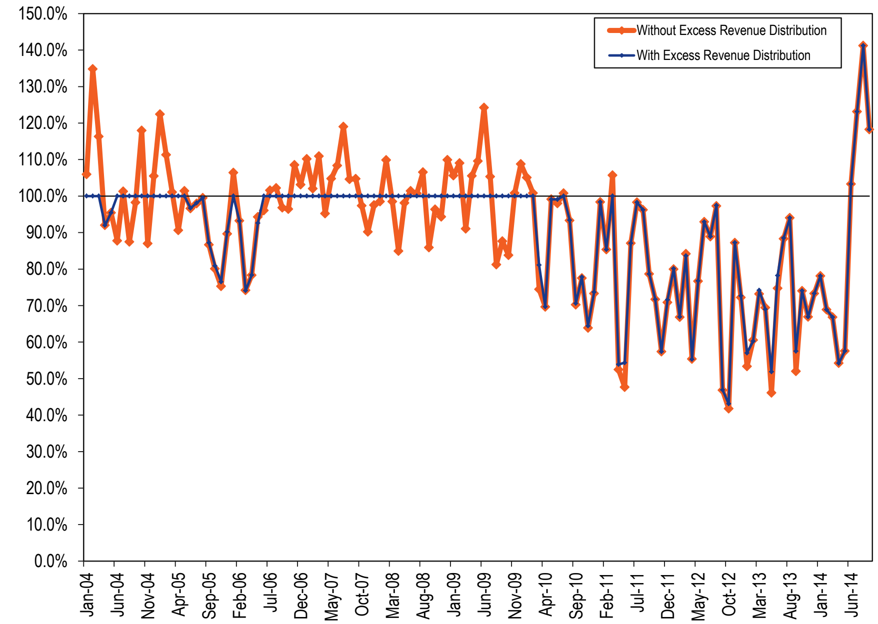


Table 13-14 shows the FTR payout ratio by planning period from the 2003 to 2004 planning period forward. Planning period 2013 to 2014 includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves. For June through September 2014, there was excess congestion revenue to pay target allocations resulting in a reported payout ratio of 119.1 percent for the planning period.

Table 13-14 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	72.8%
2014/2015	100.0%

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 13-15 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 13-15 End of planning period FTR uplift charge example

Participant	Net Target Allocation	Total Monthly Payment	Monthly Deficiency	Uplift Charge	Net Payout	Payout Change	Monthly Payout Ratio	EOPP Payout Ratio
1	$10.00	$8.00	$2.00	$3.13	$6.88	$(1.13)	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	$0.31	66.7%	68.8%
4	$3.00	$1.00	$2.00	$0.94	$2.06	$1.06	33.3%	68.8%
5	$4.00	$3.00	$1.00	$1.25	$2.75	$(0.25)	75.0%	68.8%
Total	$28.00	$22.00	$10.00	$10.00	$18.00	$0.00		

Revenue Adequacy Issues and Solutions

PJM Reported Payout Ratio

The payout ratios shown in Table 13-16 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 is included with congestion revenue when funding FTRs with net positive target allocations.[14] 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 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 13-16 shows the PJM reported and actual monthly payout ratios for 2014. In April 2014, the PJM reported payout ratio is 1.1 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. On a monthly basis, this provides a slightly understated payout ratio. In June 2014, there was an excess of FTR revenues, so total funding was actually over 100 percent. Additional revenue will be distributed to future months of the planning period to cover any shortfall.

Table 13-16 PJM Reported and Actual Monthly Payout Ratios: Calendar year 2014

	Reported Monthly Payout Ratio	Actual Monthly Payout Ratio
Jan-14	78.1%	78.9%
Feb-14	69.0%	70.7%
Mar-14	66.8%	68.1%
Apr-14	54.2%	55.3%
May-14	57.6%	62.0%
Jun-14	100.0%	100.0%
Jul-14	100.0%	100.0%
Aug-14	100.0%	100.0%
Sep-14	100.0%	100.0%

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.

14 See PJM. "Manual 28: Operating Agreement Accounting," Revision 63 (December 19, 2013), p. 50.

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. But all FTRs with positive target allocations should be treated in exactly the same way, 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.

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 method 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 13-17 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 target allocation 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. In this example, the actual monthly payout ratio is 41.7 percent. If portfolio netting were eliminated, the actual monthly payout ratio would rise to 61.1 percent.

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 13-17 Example of FTR payouts from portfolio netting and without portfolio netting

Participant	Positive Target Allocation	Negative Target Allocation	Percent Negative Target Allocation	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 13-18 shows the total value for the 2013 to 2014 planning period 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 2013 to 2014 planning period would have been 87.5 percent instead of the reported 72.8.

Table 13-18 Monthly positive and negative target allocations and payout ratios with and without hourly netting: Planning period 2013 to 2014 and 2014 to 2015

	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)
Jan-14	$1,081,718,330	($37,626,711)	$2,042,537,214	($998,445,595)	$815,789,461	78.1%	78.9%
Feb-14	$257,630,277	($14,286,013)	$581,660,982	($338,316,718)	$167,731,282	69.0%	70.7%
Mar-14	$381,568,930	($14,281,323)	$823,861,546	($456,573,940)	$245,465,062	66.9%	68.2%
Apr-14	$115,047,446	($2,753,503)	$255,732,814	($143,428,606)	$60,894,528	54.3%	55.4%
May-14	$126,329,939	($13,141,697)	$362,871,684	($249,683,438)	$65,163,098	57.6%	62.0%
Jun-14	$100,523,323	($14,425,640)	$218,239,158	($132,125,293)	$88,974,913	100.0%	100.0%
Jul-14	$97,073,106	($12,614,842)	$215,524,070	($131,065,807)	$103,981,118	100.0%	100.0%
Aug-14	$62,474,287	($13,237,305)	$162,748,254	($131,174,370)	$69,520,938	100.0%	100.0%
Sep-14	$93,351,901	($18,359,780)	$221,683,347	($149,589,001)	$88,683,326	100.0%	100.0%
2013/2014 Total	$2,625,369,880	($126,385,125)	$5,442,171,151	($2,942,754,444)	$1,819,508,754	72.8%	87.5%
2014/2015 Total	$353,422,616	($58,637,567)	$818,194,829	($543,954,471)	$351,160,295	100.0%	100.0%

Counter Flow FTRs and Revenues

The current rules create an asymmetry between the treatment of counter flow and prevailing flow FTRs. The payout to the holders of counter flow FTRs is not affected when the payout ratio is less than 100 percent. There is no reason for that asymmetric treatment.

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.

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.

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, parallel to the decreased payments to prevailing flow FTRs. The adjusted payout ratio would evenly divide funding between 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.

Table 13-19 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 an actual payout ratio of 87.5 percent. In the example, the profit is shown with and without the counter flow adjustment. As the example shows, the profit of a counter flow FTR does not change when there is a payout ratio less than 100 percent, while the profit of a prevailing flow FTR is reduced. Applying the payout ratio to counter flow FTRs distributes the funding penalty evenly to both prevailing and counter flow FTR holders.

Table 13-19 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)

Table 13-20 shows the monthly positive, negative and total target allocations.[15] Table 13-20 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 $188.4 million (27.8 percent of difference between revenues and total target allocations) in revenue available to fund positive target allocations for the 2013 to 2014 planning period. This change would not result in additional revenue for the first four months of the 2014 to 2015 planning period because counter flow FTRs are treated in the same way as prevailing flow FTRs when there is congestion revenue sufficiency.

15 Reported payout ratio may differ between Table 13-29 and Table 13-31 due to rounding differences when netting target allocations and considering each FTR individually.

Table 13-20 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
Jan-14	2,042,537,213.90	(998,445,595.01)	$1,044,091,619	$815,789,461	78.1%	$1,814,235,056	91.9%	$1,874,258,807
Feb-14	581,660,982.15	(338,316,718.47)	$243,344,264	$167,731,282	68.9%	$506,048,000	95.6%	$528,451,343
Mar-14	823,861,545.64	(456,573,939.94)	$367,287,606	$245,465,062	66.8%	$702,039,002	98.1%	$736,678,623
Apr-14	255,732,814.32	(143,428,606.41)	$112,304,208	$60,894,528	54.2%	$204,323,135	87.3%	$218,931,616
May-14	362,871,684.13	(249,683,438.50)	$113,188,246	$65,163,098	57.6%	$314,846,537	92.5%	$329,096,401
Jun-14	218,239,157.67	(132,125,293.49)	$86,113,864	$88,974,913	100.0%	$221,100,206	100.0%	$221,100,206
Jul-14	215,524,070.28	(131,065,806.70)	$84,458,264	$103,981,118	100.0%	$235,046,924	100.0%	$235,046,924
Aug-14	158,672,445.33	(109,435,463.69)	$49,236,982	$69,520,938	100.0%	$178,956,402	100.0%	$178,956,402
Sep-14	230,425,061.55	(155,432,941.15)	$74,992,120	$88,683,326	100.0%	$244,116,267	100.0%	$244,116,267
Total 2013/2014	$5,442,171,151	($2,942,754,444)	$2,499,416,707	$1,819,508,754	72.8%	$4,762,263,198	91.0%	$4,950,708,852
Total 2014/2015	$822,860,735	(528,059,505.03)	$294,801,230	$351,160,295	100.0%	$879,219,800	100.0%	$879,219,800

* Reported payout ratios may vary due to rounding differences when netting

The result of removing portfolio netting and applying a payout ratio to counter flow FTRs would increase the calculated payout ratio for the 2013 to 2014 planning period from the reported 72.8 percent to 91.0 percent.

Figure 13-9 shows the FTR surplus, collected day-ahead, balancing and total congestion payments from January 2005 through September 2014. August and September 2014 had positive total balancing congestion of $0.03 million and $4.4 million.

Figure 13-9 FTR surplus and the collected Day-Ahead, Balancing and Total congestion: January 2005 through September 2014

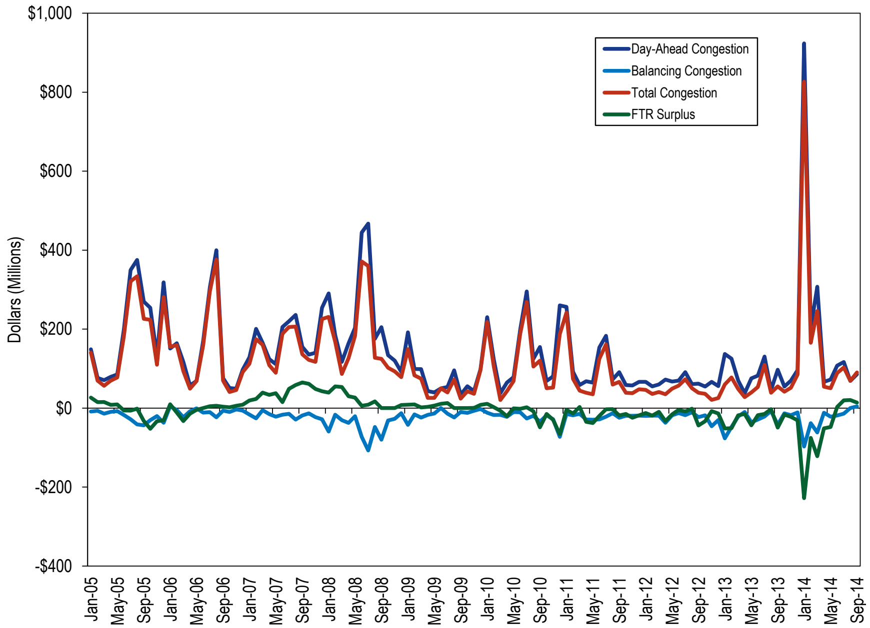
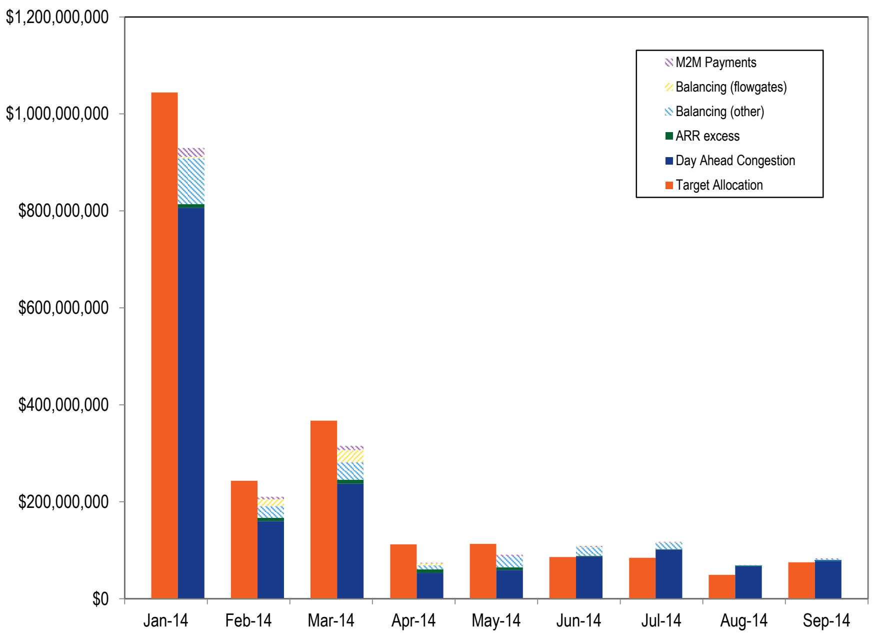


Figure 13-10 shows the relationship among monthly target allocations, balancing congestion, M2M payments and day-ahead congestion. Revenues to fund FTR target allocations are represented by solid fill, and offsets are represented by stripes. When the height of the stacked solid segments exceeds the height of the target allocations, the month is revenue adequate. For example, June was revenue adequate. The revenue shortfalls in the months from January through May are consistent with the over selling of FTRs. In January 2014, cold weather events resulted in high levels of congestion and therefore target allocations. In the first four months of the 2014 to 2015 planning period, day-ahead congestion exceeded target allocations and offsets were small, resulting in payout ratios over 100 percent.

Figure 13-10 FTR target allocation compared to sources of positive and negative congestion revenue



Auction Revenue Rights

ARRs are financial instruments that entitle the holder to receive revenues or to pay charges based on nodal price differences determined in the Annual FTR Auction.[16] These price differences are based on the bid prices of participants in the Annual FTR Auction. 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.

ARRs are available only as obligations (not options) and only as the 24-hour product. ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to the product of the ARR MW and the price difference between sink and source from the Annual FTR Auction. An ARR value can be positive or negative depending on the price difference between sink and source, with a negative difference resulting in a liability for the holder. The ARR target allocation represents the revenue that an ARR holder should receive. ARR credits can be positive or negative and can range from zero to the ARR target allocation. If the combined net revenues from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions are greater than the sum of all ARR target allocations, ARRs are fully funded. If these revenues are less than the sum of all ARR target allocations, available revenue is proportionally allocated among all ARR holders.

When a new control zone is integrated into PJM, firm transmission customers in that control zone may choose to receive either an FTR allocation or an ARR allocation before the start of the Annual FTR Auction for two consecutive planning periods following their integration date. After the transition period, such participants receive ARRs from the annual allocation process and are not eligible for directly allocated FTRs. Network Service Users and Firm Transmission Customers cannot choose to receive both an FTR allocation and an ARR allocation. This selection applies to the participant's entire portfolio of ARRs that sink into the new control zone. During this transitional period,

16 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces the most net revenue.

the directly allocated FTRs are reallocated, as load shifts between LSEs within the transmission zone.

Incremental ARRs (IARRs) are allocated to customers that have been assigned cost responsibility for certain upgrades included in the PJM's Regional Transmission Expansion Plan (RTEP). These customers as defined in Schedule 12 of the Tariff are network service customers and/or merchant transmission facility owners that are assigned the cost responsibility for upgrades included in the PJM RTEP. PJM calculates IARRs for each Regionally Assigned Facility and allocates the IARRs, if any are created by the upgrade, to eligible customers based on their percentage of cost responsibility. The customers may choose to decline the IARR allocation during the annual ARR allocation process.[17] Each network service customer within a zone is allocated a share of the IARRs in the zone based on their share of the network service peak load of the zone.

Market Structure

ARRs have been available to network service and firm, point-to-point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003 to 2004 planning period. The initial allocation covered the Mid-Atlantic Region and the AP Control Zone. For the 2006 to 2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the AEP, DAY, DLCO and Dominion control zones. For the 2007 to 2008 and subsequent planning periods through the 2014 to 2015 planning period, all eligible market participants were allocated ARRs.

Supply and Demand

ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of ARRs that are feasible.

17 PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), pp. 31 and "IARRs for RTEP Upgrades Allocated for 2011/2012 Planning Period," <http://www.pjm.com/~/media/markets-ops/ftr/annual-arr-allocation/2011-2012/iarrs-rtep-upgrades-allocated-for-2011-12-planning-period.ashx>.

ARR Allocation

For the 2007 to 2008 planning period, the annual ARR allocation process was revised to include Long Term ARRs that would be in effect for 10 consecutive planning periods.[18] Long Term ARRs can give LSEs the ability to offset their congestion costs on a long-term basis. Long Term ARR holders can self schedule their Long Term ARRs as FTRs for any planning period during the 10 planning period timeline.

Each March, PJM allocates ARRs to eligible customers in a three-stage process:

- **Stage 1A.** In the first stage of the allocation, network transmission service customers can obtain Long Term ARRs, up to their share of the zonal base load, after taking into account generation resources that historically have served load in each control zone and up to 50 percent of their historical nonzone network load. Nonzone network load is load that is located outside of the PJM footprint. Firm, point-to-point transmission service customers can obtain Long Term ARRs, based on up to 50 percent of the MW of long-term, firm, point-to-point transmission service provided between the receipt and delivery points for the historical reference year. Stage 1A ARRs cannot be prorated. If Stage 1A ARRs are found to be infeasible, transmission system upgrades must be undertaken to maintain feasibility.19
- **Stage 1B.** ARRs unallocated in Stage 1A are available in the Stage 1B allocation for the following planning period. Network transmission service customers can obtain ARRs, up to their share of the zonal peak load, based on generation resources that historically have served load in each control zone and up to 100 percent of their transmission responsibility for nonzone network load. Firm, point-to-point transmission service customers can obtain ARRs based on the MW of long-term, firm, point-to-point service provided between the receipt and delivery points for the historical reference year. These long-term point-to-point service agreements must also remain in effect for the planning period covered by the allocation.

18 See the *2006 State of the Market Report* (March 8, 2007) for the rules of the annual ARR allocation process for the 2006 to 2007 and prior planning periods.

19 See PJM. "Manual 6: Financial Transmission Rights" Revision 15 (October 10, 2013), p. 22.

- **Stage 2.** Stage 2 of the annual ARR allocation is a three-step procedure, with one-third of the remaining system capability allocated in each step of the process. Network transmission service customers can obtain ARRs from any hub, control zone, generator bus or interface pricing point to any part of their aggregate load in the control zone or load aggregation zone for which an ARR was not allocated in Stage 1A or Stage 1B. Firm, point-to-point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

Prior to the start of the Stage 2 annual ARR allocation process, ARR holders can relinquish any portion of their ARRs resulting from the Stage 1A or Stage 1B allocation process, provided that all remaining outstanding ARRs are simultaneously feasible following the return of such ARRs.[20] Participants may seek additional ARRs in the Stage 2 allocation.

Effective for the 2015 to 2016 planning period, when residual zone pricing will be introduced, an ARR will default to sinking at the load settlement point, but the ARR holder may elect to sink their ARR at the physical zone instead.[21]

ARRs can also be traded between LSEs, but these trades must be made before the first round of the Annual FTR Auction. Traded ARRs are effective for the full 12-month planning period.

When ARRs are allocated, all ARRs must be simultaneously feasible to ensure that the physical transmission system can support the approved set of ARRs. In making simultaneous feasibility determinations, PJM utilizes a power flow model of security-constrained dispatch that takes into account generation and transmission facility outages and is based on assumptions about the configuration and availability of transmission capability during the planning period.[22] This simultaneous feasibility requirement is necessary to ensure that there are sufficient revenues from congestion charges to satisfy all resulting ARR obligations. If the requested set of ARRs is not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints, except Stage 1A ARRs:

Equation 13-1 Calculation of prorated ARRs

Individual prorated MW = (Constraint capability) X (Individual requested MW / Total requested MW) X (1 / MW effect on line).[23]

The effect of an ARR request on a binding constraint is measured using the ARR's power flow distribution factor. An ARR's distribution factor is the percent of each requested MW of ARR that would have a power flow on the binding constraint. The PJM methodology prorates ARR requests in proportion to their MW value and the impact on the binding constraint. PJM's method results in the prorating only of ARRs that cause the greatest flows on the binding constraint. Were all ARR requests prorated equally, regardless of their proportional impact on the binding constraints, the result would be a significant reduction in market participants' ARRs.

Revenue Adequacy and Stage 1B ARR Allocations

For the first four months of the 2014 to 2015 planning period, revenue adequacy was over 100 percent. The last time there were four months of consecutive funding of 100 percent or more was in the 2009 to 2010 planning period.

One of the main causes of the 2014 to 2015 planning period revenue adequacy was PJM's more conservative treatment of transmission outages in the FTR Auction model, designed to reduce revenue inadequacy, which resulted in a reduction of ARR allocation quantities. For the 2014 to 2015 planning period, Stage 1B and Stage 2 ARR allocations were reduced 84.9 percent and 88.1 percent from the 2013 to 2014 planning period.

PJM's more conservative approach is reflected in the increase in the outages, the increase in down rated constrained facilities and the inclusion of closed loop interfaces as thermal limits in the ARR and FTR auction model. While

20 PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), pp. 21.

21 *See* "Residual Zone Pricing," PJM Presentation to the Members Committee (February 23, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mc/20120223/20120223-item-03-residual-zone-pricing-presentation.ashx> The introduction of residual zone pricing, while approved by PJM members, depends on a FERC order.

22 PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), pp. 55-56.

23 See the *MMU Technical Reference for PJM Markets*, at "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining this calculation in greater detail.

the more conservative approach to outages in the Annual FTR Auction reduces revenue inadequacy, which was caused in part by Stage 1A ARR over allocations, it does not address the Stage 1A ARR over allocation issue directly and it resulted in decreased Stage 1B ARR allocations through proration, decreased Stage 2 ARR allocations through proration and decreased FTR capability. Stage 1A ARRs were not affected by the more conservative treatment of outages because they may not be prorated.

Figure 13-11 shows the historic allocations for Stage 1B and Stage 2 ARRs from the 2011 to 2012 to 2014 to 2015 planning periods. There was an 84.9 percent decrease in Stage 1B ARRs allocated and an 88.1 percent decrease in total Stage 2 ARR allocations from the 2013 to 2014 planning period to the 2014 to 2015 planning period.

Figure 13-11 Historic Stage 1B and Stage 2 ARR Allocations from the 2011 to 2012 through 2014 to 2015 planning periods

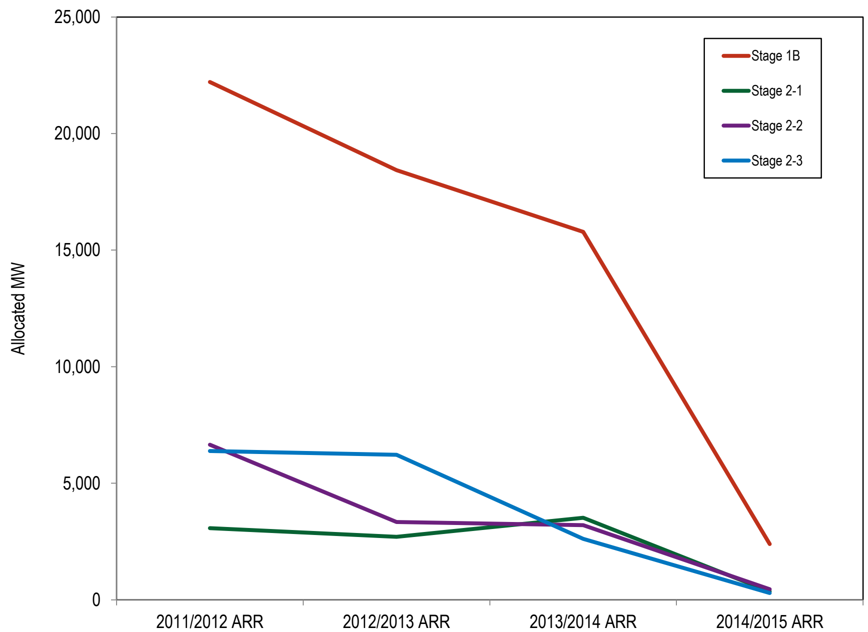


Table 13-21 shows the ARR allocations for the 2011 to 2012 through 2014 to 2015 planning periods. Stage 1A allocations cannot be prorated and have been slowly increasing. Stage 1B and Stage 2 allocations can be prorated. Stage 1B and Stage 2 allocations were steadily declining over the 2011 to 2012 through 2013 to 2014 planning periods, but were very significantly reduced in the 2014 to 2015 planning period as a result of PJM's modified approach to outage modeling designed to increase revenue adequacy.

Table 13-21 Historic Stage 1B and Stage 2 ARR Allocations from the 2011 to 2012 through 2014 to 2015 planning periods

Stage	2011/2012 ARR	2012/2013 ARR	2013/2014 ARR	2014/2015 ARR
Stage 1A	64,159.9	67,299.6	67,861.4	68,837.7
Stage 1B	22,208.3	18,431.7	15,782.0	2,389.6
Stage 2-1	3,072.5	2,700.6	3,519.2	360.9
Stage 2-2	6,652.6	3,334.3	3,200.0	455.9
Stage 2-3	6,382.6	6,218.7	2,611.8	291.2
Total Stage 2	16,107.7	12,253.6	9,331.0	1,108.0

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.[24] 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

24 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p. 28.

this may result in lower value of the ARRs for the receiving LSE compared to the total value held by the original ARR holder.

There were 64,086 MW of ARRs associated with approximately $382,100 of revenue that were reassigned in the 2013 to 2014 planning period. There were 30,323 MW of ARRs associated with approximately $302,600 of revenue that were reassigned for the first four months of the 2014 to 2015 planning period.

Table 13-22 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2013 and September 2014.

Table 13-22 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2013, through September 30, 2014

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
	2013/2014	2014/2015	2013/2014	2014/2015
Control Zone	(12 months)	(4 months)*	(12 months)	(4 months)*
AECO	971	287	$3.8	$1.6
AEP	8,006	1,084	$25.6	$17.9
AP	2,618	1,319	$51.4	$33.9
ATSI	6,792	4,788	$8.9	$39.4
BGE	3,672	1,908	$42.2	$22.6
ComEd	9,664	5,609	$104.9	$74.0
DAY	1,100	317	$2.1	$2.3
DEOK	7,568	2,452	$9.8	$5.1
DLCO	5,248	3,645	$11.5	$6.6
DPL	2,740	1,634	$25.0	$21.4
Dominion	5	0	$0.1	$0.0
EKPC	NA	0	NA	$0.0
JCPL	1,519	792	$5.7	$5.7
Met-Ed	1,043	399	$7.6	$4.1
PECO	2,883	677	$21.8	$10.2
PENELEC	1,265	365	$11.8	$5.2
PPL	3,197	1,964	$13.3	$14.1
PSEG	2,441	1,010	$24.6	$25.2
Pepco	3,134	2,043	$11.8	$13.2
RECO	222	31	$0.1	$0.0
Total	64,086	30,323	$382.1	$302.6

* Through 30-September-2014

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.

Effective August 1, 2012, as ordered by the 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 13-23 shows the residual ARRs automatically allocated to eligible participants, along with the target allocations from the effective month.

Table 13-23 Residual ARR allocation volume and target allocation

Month	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
Jan-14	2,809.3	1,760.3	62.7%	$273,006
Feb-14	2,076.9	1,564.0	75.3%	$480,688
Mar-14	11,733.8	1,203.1	10.3%	$1,030,177
Apr-14	4,156.2	2,723.5	65.5%	$284,042
May-14	1,542.7	389.6	25.3%	$333,749
Jun-14	7,870.1	2,901.1	36.9%	$1,386,108
Jul-14	5,849.0	2,768.0	47.3%	$2,076,393
Aug-14	7,191.8	2,406.2	33.5%	$1,450,787
Sep-14	3,896.0	1,751.1	44.9%	$195,876
Total	47,125.8	17,466.9	37.1%	$7,510,825

Market Performance

Revenue

ARRs are allocated to qualifying customers rather than sold, so 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 $568.8 million in credits from the FTR auctions during the 2013 to 2014 planning period. During the 2013 to 2014 planning period, ARR holders received $506.2 million in ARR credits.

Table 13-24 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 2012 to 2013 planning period and the 2013 to 2014 planning periods.

Table 13-24 Projected ARR revenue adequacy (Dollars (Millions)): Planning periods 2012 to 2013 and 2013 to 2014

	2013/2014	2014/2015
Total FTR auction net revenue	$568.8	$752.9
Annual FTR Auction net revenue	$558.4	$748.6
Monthly Balance of Planning Period FTR Auction net revenue*	$10.4	$4.2
ARR target allocations	$506.2	$732.2
ARR credits	$506.2	$732.2
Surplus auction revenue	$62.6	$20.6
ARR payout ratio	100%	100%
FTR payout ratio*	72.8%	100.0%

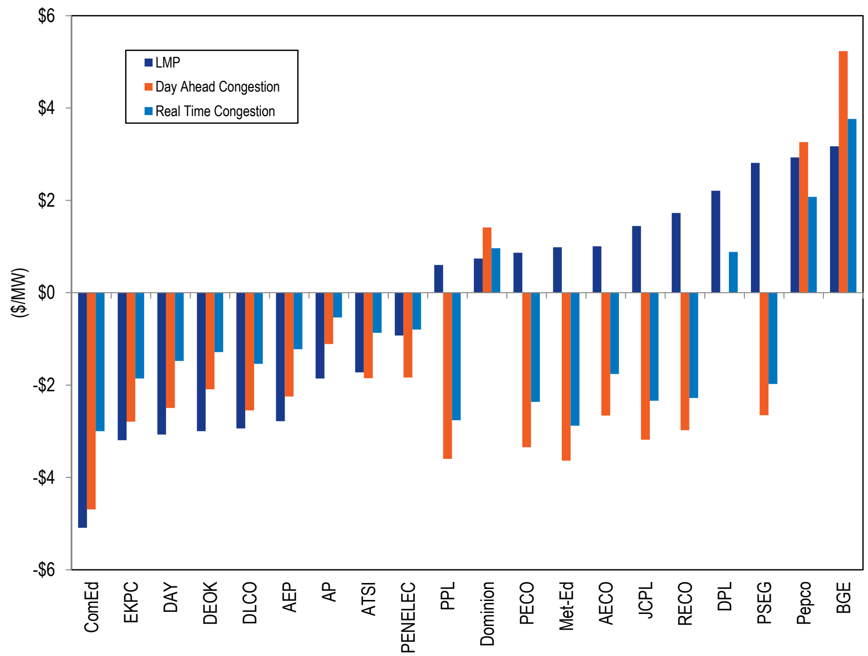
* Shows twelve months for 2013/2014 and four months for 2014/2015.

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 13-12 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone for the first four months of the 2014 to 2015 planning period. The day-ahead and real-time congestion are based on the difference between zonal congestion prices and Western Hub congestion prices.

Figure 13-12 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: 2014 to 2015 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 2013 to 2014 planning period, the total revenues received by the holders of all ARRs and FTRs offset 98.2 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 13-25. ARRs and self-scheduled FTRs that sink at an aggregate are assigned to a control zone if applicable.[25] 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 100 percent of the target allocation for the first four months of the 2014 to 2015 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.

ARRs served as an effective offset against congestion. The total revenues received by ARR holders, including self-scheduled FTRs, offset 100 percent of the total congestion costs experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market for the first four months of the 2014 to 2015 planning period and for the 2013 to 2014 planning period.

The Congestion column shows the amount of congestion in each control zone from the Day-Ahead Energy Market and the balancing energy market and includes only the congestion costs incurred by the organizations that hold ARRs or self-scheduled FTRs. The last column shows the difference between the total revenue and the congestion for each ARR control zone sink.

25 For Table 13-42 through Table 13-44, aggregates are separated into their individual bus components and each bus is assigned to a control zone. The "External" Control Zone includes all aggregate sinks that are external to PJM or buses that cannot otherwise be assigned to a specific control zone.

Table 13-25 ARR and self-scheduled FTR congestion offset (in millions) by control zone: 2014 to 2015 planning period[26]

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Offset
AECO	$5.4	$0.1	$5.4	($1.3)	$6.7	>100%
AEP	$42.5	$31.3	$73.9	$2.1	$71.7	>100%
APS	$33.6	$12.4	$46.0	$2.5	$43.6	>100%
ATSI	$15.3	$6.1	$21.4	$2.5	$18.9	>100%
BGE	$36.3	$2.0	$38.3	$7.0	$31.3	>100%
ComEd	$99.9	$0.0	$99.9	$17.0	$82.9	>100%
DAY	$3.0	$0.0	$3.0	($0.4)	$3.4	>100%
DEOK	$2.8	$2.0	$4.8	($0.4)	$5.2	>100%
DLCO	$1.4	$0.0	$1.4	$0.5	$1.0	>100%
Dominion	$3.5	$32.4	$35.9	$2.9	$33.0	>100%
DPL	$29.8	$0.7	$30.5	$0.9	$29.6	>100%
EKPC	($0.1)	($0.3)	($0.5)	($0.2)	($0.2)	0.0%
External	$1.9	$0.3	$2.2	$1.4	$0.8	>100%
JCPL	$15.4	($0.0)	$15.4	($2.1)	$17.6	>100%
Met-Ed	$11.3	($0.0)	$11.2	($0.3)	$11.5	>100%
PECO	$25.9	$0.0	$25.9	$9.5	$16.4	>100%
PENELEC	$16.1	$0.6	$16.7	$1.1	$15.6	>100%
Pepco	$29.2	$1.5	$30.6	$12.3	$18.3	>100%
PPL	$13.6	($0.0)	$13.5	($4.5)	$18.0	>100%
PSEG	$91.7	$0.8	$92.5	$7.5	$85.1	>100%
RECO	$0.0	$0.0	$0.0	($0.1)	$0.1	>100%
Total	$478.4	$93.3	$571.7	$57.8	$513.9	>100%

Effectiveness of ARRs and FTRs as an Offset to Congestion

Table 13-26 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 first four months of the 2014 to 2015 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 the FTR MW and congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are the product of the FTR target allocations and the FTR payout ratio. The FTR payout ratio was 100 percent of the target allocation for the first four months of the 2014 to 2015 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.[27] The last column shows the difference between the total ARR and FTR offset and the congestion cost for each control zone.

26 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.

27 The total zonal congestion numbers were calculated as of October 22, 2014 and may change as a result of continued PJM billing updates.

Table 13-26 ARR and FTR congestion offset (in millions) by control zone: 2014 to 2014 planning period

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
AECO	$5.4	$1.5	$7.9	($1.1)	$0.3	($1.4)	0.0%
AEP	$124.4	$55.6	$131.9	$48.1	$62.5	($14.4)	77.0%
APS	$65.1	$13.0	$40.5	$37.7	$27.9	$9.7	>100%
ATSI	$38.2	$16.9	$46.0	$9.1	$7.5	$1.6	>100%
BGE	$38.8	$60.4	$49.6	$49.6	$37.0	$12.6	>100%
ComEd	$110.1	$36.0	$77.0	$69.1	$58.4	$10.7	>100%
DAY	$3.0	$2.2	$2.5	$2.8	$1.2	$1.6	>100%
DEOK	$4.0	$7.5	$5.6	$6.0	$3.7	$2.3	>100%
DLCO	$1.5	($0.0)	($4.5)	$6.0	$0.9	$5.1	>100%
Dominion	$108.2	$41.2	$113.8	$35.6	$41.6	($6.0)	85.6%
DPL	$30.7	$19.7	$33.7	$16.7	$19.1	($2.4)	87.2%
EKPC	($0.0)	($0.2)	$2.0	($2.2)	($1.7)	($0.5)	0.0%
External	$2.4	$1.4	$1.8	$2.1	$1.7	$0.4	>100%
JCPL	$15.5	($6.9)	$26.2	($17.6)	($2.2)	($15.4)	0.0%
MetEd	$11.4	($1.7)	$13.5	($3.8)	$8.1	($11.9)	0.0%
PECO	$26.1	($1.3)	$15.8	$9.1	$24.0	($15.0)	37.8%
PENELEC	$21.8	$22.1	$46.6	($2.7)	$9.1	($11.8)	0.0%
Pepco	$34.3	$38.5	$78.0	($5.2)	$37.5	($42.7)	0.0%
PPL	$13.8	($14.3)	$8.2	($8.7)	$1.9	($10.6)	0.0%
PSEG	$104.7	$11.8	$87.5	$29.0	$13.8	$15.2	>100%
RECO	$0.0	($0.3)	($3.6)	$3.2	($0.5)	$3.7	>100%
Total	$759.5	$303.2	$779.9	$282.8	$351.8	($69.0)	80.4%

Table 13-27 shows the total offset due to ARRs and FTRs for the entire 2013 to 2014 and the first four months of the 2014 to 2015 planning periods. ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 80.4 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the first four months of the 2014 to 2015 planning period. In the 2013 to 2014 planning period, total ARR and FTR revenues offset 98.2 percent of the congestion costs.

Table 13-27 ARR and FTR congestion hedging (in millions): Planning periods 2013 to 2014 and 2014 to 2015[28]

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Offset	Congestion	Total Offset - Congestion Difference	Percent Offset
2013/2014	$522.3	$1,814.9	$598.8	$1,738.3	$1,771.0	($32.7)	98.2%
2014/2015*	$759.5	$303.2	$779.9	$282.8	$351.8	($69.0)	80.4%

* Shows first four months through September 30, 2014

28 The FTR credits do not include after-the-fact adjustments. For the 2013 to 2014 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.