Q2

State of the Market Report for PJM

January through June

Monitoring Analytics, LLC

Independent
Market Monitor
for PJM

8.13.2015

2015

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 *2015 Quarterly State of the Market Report for PJM: January through June.*[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: *2015 Quarterly State of the Market Report for PJM: January through June.*

Table of Contents

Figures

SECTION 8 Environmental and Renewable Energy Regulations 237

SECTION 9 Interchange Transactions 259

SECTION 10 Ancillary Service Markets 313

SECTION 12 Generation and Transmission Planning 397

SECTION 13 Financial Transmission and Auction Revenue Rights 423

Tables

SECTION 5 Capacity Market 181

SECTION 6 Demand Response 205

SECTION 7 Net Revenue 229

SECTION 8 Environmental and Renewable Energy Regulations 237

SECTION 9 Interchange Transactions 259

SECTION 10 Ancillary Service Markets 313

SECTION 11 Congestion and Marginal Losses 367

Introduction

2015 Q2 in Review

The results of the energy market, the results of the capacity market and the results of the regulation market were competitive in the first six months of 2015. The PJM markets work. The PJM markets bring customers the benefits of competition. The goal of competition is to provide customers wholesale power at the lowest possible price, but no lower.

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 and 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 short run marginal costs, although this was not always the case during the high demand hours in February 2015 and January 2014. This is evidence of generally competitive behavior, although the behavior of some participants during the high demand periods in 2014 and 2015 raises concerns about economic withholding. The performance of the PJM markets under high load 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.

Energy market prices decreased significantly from the first six months of 2014 as a combined result of lower fuel prices and lower demand. The load-weighted average real-time LMP was 39.5 percent lower in the first six months of 2015 than in the first six months of 2014, $42.30 per MWh versus $69.92 per MWh. If fuel costs in the first six months of 2015 had been the same as in the first six months of 2014, holding everything else constant, the real time load-weighted LMP in 2015 would have been 24.9 percent higher, $52.85 per MWh instead of the observed $42.30 per MWh, but still lower than in 2014.

The markup conduct of individual owners and units has an identifiable impact on market prices. In the Real-Time Energy Market, the adjusted markup component of LMP decreased from $4.61 in the first six months of 2014 to $2.42 in the first six months of 2015. The markup was also lower as a percent of LMP, 5.7 percent in the first six months of 2015 compared to 6.6 percent in the first six months of 2014. Although markups continued to be significant in the first six months of 2015, participant behavior was evaluated as competitive because marginal units generally made offers at, or close to, their short run marginal costs.

Total energy uplift charges decreased by $590.1 million or 71.0 percent in the first six months of 2015 compared to the first six months of 2014, from $831.5 million to $241.4 million.

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. Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Coal and natural gas prices and energy prices were lower in the first six months of 2015 than in the first six months of 2014. Net revenues from the energy market for all plant types were affected by the lower prices.

While net revenues were uniformly lower for new entrant units in the first six months of 2015 than in the first six months of 2014, net revenues for new entrant gas and coal units were generally higher in the first six months of 2015 than in the first six months of every other year since 2009. The comparison to the first six months of 2014 reflects the very high net revenues in January 2014. In the first six months of 2015, average energy market net revenues decreased by 24 percent for a new CT, 26 percent for a new CC, 58 percent for a new CP, 70 percent for a new DS, 45 percent for a new nuclear plant, 24 percent for a new wind installation, and 10 percent for a new solar installation.

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, coal 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.

These market design choices have substantial impacts. PJM has addressed 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 short run 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. Generators should have the ability to reflect gas cost changes in energy offers during the day in order to permit the energy market to reflect the current cost of gas. But offer changes should be based only on verifiable changes in gas cost and therefore not permit the exercise of market power. 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 has been a substantial decline in UTC activity beginning in September 2014, as a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges ultimately assigned to UTCs.[1] To date, there have not been negative impacts on market outcomes as a result of the reduction in cleared UTC MW and there have been some positive impacts. The MMU will continue to evaluate the market results and to report on them.

While it is difficult to predict all the ramifications of the Court's EPSA decision, and the Supreme Court's review of that decision, on jurisdiction over demand side resources, 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.[2] Demand response should be on

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 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. The decision calls into question the jurisdictional foundation for

the demand side of markets rather than on the supply side. Demand response does not need to be formally included in PJM markets. Customers would avoid paying for capacity by interrupting designated load when PJM indicates that it is a critical hour. Customers would pay for actual metered 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 metered 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. This approach would work regardless of the final decision in the EPSA case.

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

While the market performance in the first six months of 2015 was improved over the first six months of 2014, the underlying capacity market issues continued to have an effect, although they have been addressed for the future in the Capacity Performance filing. For example, uplift remained high in large part as a result of inflexible unit parameters which were based, in many cases, on inflexible gas supply arrangements, outages were high, performance incentives remain weak, prices in the capacity market remain well below replacement costs and there is no resolution of the disconnect between the incentives facing electric generating units and the incentives facing gas pipelines which is a barrier to the construction of new pipeline capacity.

all demand response programs currently subject to FERC oversight, and, in particular, those in the energy and capacity markets. 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).

PJM Market Summary Statistics

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

Table 1-1 PJM Market Summary Statistics, January through June, 2014 and 2015[3]

	2014 (Jan-Jun)	2015 (Jan-Jun)	Percent Change
Load	398,901 GWh	393,413 GWh	(1.4%)
Generation	407,279 GWh	396,177 GWh	(2.7%)
Net Actual Interchange	586 GWh	10,424 GWh	1,679%
Losses	9,066 GWh	7,470 GWh	(17.6%)
Regulation Requirement*	664 MW	533 MW	(19.7%)
RTO Primary Reserve Requirement	2,063 MW	2,175 MW	5.4%
Total Billing	$31.06 Billion	$23.40 Billion	(24.7%)
Peak	Jun 17, 2014 16:00	Feb 20, 2015 7:00	
Peak Load	141,673 MW	143,115 MW	1.0%
Load Factor	0.65	0.63	(2.4%)
Installed Capacity	As of 6/30/2014	As of 6/30/2015	
Installed Capacity	184,007 MW	176,741 MW	(3.9%)

* This is an hourly average stated in effective MW.

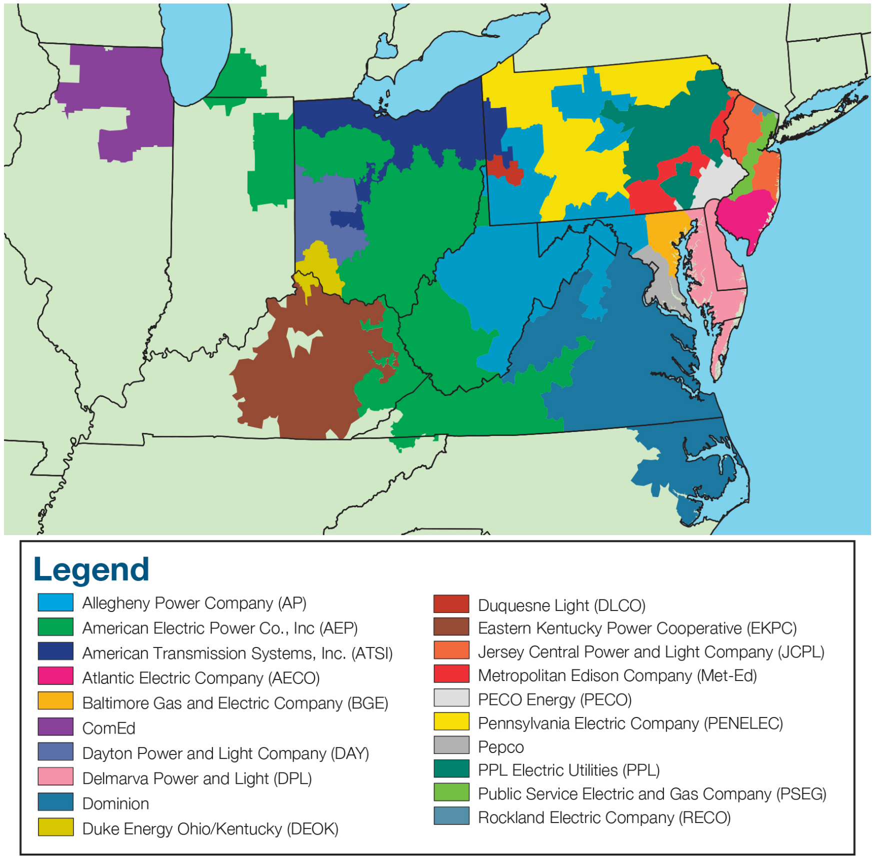
PJM Market Background

The PJM Interconnection, L.L.C. (PJM) operates a centrally dispatched, competitive wholesale electric power market that, as of June 30, 2015, had installed generating capacity of 176,741 megawatts (MW) and 944 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]

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.

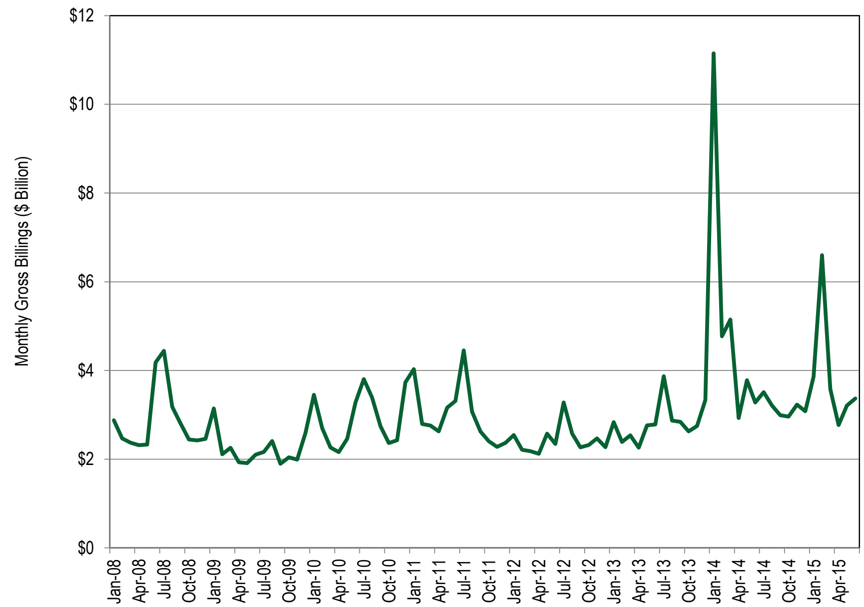
3 The load reported in this table is the accounting load plus net withdrawals at generator buses. The average hourly accounting load is reported in Section 3, "Energy Market."
4 See PJM's "Member List," which can be accessed at: <http://pjm.com/about-pjm/member-services/member-list.aspx>.
5 See PJM's "Who We Are," which can be accessed at: <http://pjm.com/about-pjm/who-we-are.aspx>.
6 See the *2014 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography" for maps showing the PJM footprint and its evolution prior to 2015.

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



In the first six months of 2015, PJM had total billings of $23.40 billion, down 25 percent from $31.06 billion in the first six months of 2014 (Figure 1-2).[7]

Figure 1-2 PJM reported monthly billings ($ Billions): 2008 through June, 2015



PJM operates the Day-Ahead Energy Market, the Real-Time Energy Market, the Reliability Pricing Model (RPM) Capacity Market, the Regulation Market, the Synchronized Reserve Markets, the Day - Ahead Scheduling Reserve (DASR) Market and the Long Term, Annual and Monthly Balance of Planning Period Auction Markets in Financial Transmission Rights (FTRs).

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

7 Monthly billing values are provided by PJM.

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 synchronized 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]

Conclusions

This report assesses the competitiveness of the markets managed by PJM in the first six months of 2015, 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 with 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 short run 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.

The MMU concludes for the first six months of 2015:

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 in the first six months

8 See also the *2014 State of the Market Report for PJM*, Volume II, Appendix B, "PJM Market Milestones."

9 Analysis of 2015 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 2015, see *2014 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

of 2015 was moderately concentrated. Average HHI was 1117 with a minimum of 916 and a maximum of 1468 in the first six months of 2015.

- 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, although high markups during periods of high demand did affect prices.
- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes. 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 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. If market-based offer caps are raised, or if generators are allowed to modify offers hourly, aggregate market power mitigation rules need to be developed.

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]

10 PJM. OATT Attachment M (PJM Market Monitoring Plan).
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.
12 In the 2008/2009 RPM Third Incremental Auction, 18 participants in the RTO market passed the TPS test.

- 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.

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**

- The Regulation Market structure was evaluated as not competitive for the year because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 98 percent of the hours in the first six months of 2015.
- Participant behavior in the Regulation Market was evaluated as competitive for the first six months of 2015 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. 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 Tier 2 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.

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.

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	Not Competitive	
Participant Behavior	Mixed	
Market Performance	Competitive	Mixed

- The Day-Ahead Scheduling Reserve Market structure was evaluated as not competitive because market participants failed the three pivotal supplier test in 52 hours in the first six months of 2015.
- 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; regular reports on market

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.

issues; such as RPM auction reports; reports responding to requests from regulators and other authorities; and ad hoc reports on specific topics. 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.

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…"[20,21,22] The MMU also monitors PJM for compliance with the rules, in addition to market participants.[23]

Another important component of the monitoring function is the review of inputs to mitigation. The actual or potential exercise of market power is addressed in part through *ex ante* mitigation rules incorporated in PJM's market clearing software for the energy market, the capacity market and the regulation market. If a market participant fails the TPS test in any of these markets its offer is set to the lower of its price based or cost based offer. This prevents the exercise of market power and ensures competitive pricing, provided that the cost based offer accurately reflects short run marginal cost. Cost based offers for the energy market and the regulation market are based on incremental costs as defined in the PJM Cost Development Guidelines (PJM Manual 15).[24] The MMU evaluates every offer in each capacity market (RPM) auction using data submitted to the MMU through web-based data input systems developed by the MMU.[25]

The MMU also reviews operational parameter limits included with unit offers, 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.[26,27,28,29]

The MMU reviews offers and inputs in order to evaluate whether those offers raise market power concerns.[30] Market participants, not the MMU, determine and take responsibility for offers that they submit and the market conduct that those offers represent.[31] 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.

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 The MMU has no prosecutorial or enforcement authority. The MMU notifies the FERC when it identifies a significant market problem or market violation. OATT Attachment M § IV.I.1. 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. *Id.* If the problem involves an existing or proposed law, rule or practice that exposes PJM markets to the risk that market power or market manipulation could compromise the integrity of the markets, the MMU explains the issue, as appropriate, to the FERC, state regulators, stakeholders or other authorities. The MMU may also participate as a party or provide information or testimony in regulatory or other proceedings.
23 OATT Attachment M § IV.C.
24 See OATT Attachment M–Appendix § II.A.
25 OATT Attachment M–Appendix § II.E.
26 OATT Attachment M–Appendix § II.B.
27 OATT Attachment M–Appendix § II.C.
28 OATT Attachment M–Appendix § IV.
29 OATT Attachment M–Appendix § VII.
30 OATT Attachment M § IV.
31 OATT § 12A.

PJM also reviews offers, but it does so in order to determine whether offers comply with the PJM tariff and manuals.[32] 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.

The PJM Markets monitored by the MMU include market related procurement processes conducted by PJM, such as for Black Start resources included in the PJM system restoration plan.[33,34] With the introduction of competitive transmission development policy in Order No. 1000, a competitive procurement process for including projects in PJM Regional Transmission Expansion Plan is now in place.[35]

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.[36] The MMU initiates and proposes changes to the design of such markets or the PJM Market Rules in stakeholder or regulatory proceedings.[37] 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.[38] 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.[39] The MMU may provide in its annual, quarterly and other reports "recommendations regarding any matter within its purview."[40]

32 OATT § 12A.
33 See OATT Attachment M–Appendix § II(p).
34 See OATT Attachment M–Appendix § III.
35 OA Schedule 6 § 1.5.
36 OATT Attachment M § IV.D.
37 *Id.*
38 *Id.*
39 *Id.*
40 OATT Attachment M § VI.A.

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,"[41] 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 *2015 Quarterly State of the Market Report for PJM: January through June*, the MMU makes four new recommendations.

New Recommendation from Section 3, Energy Market

- The MMU recommends that PJM remove non-specific fuel types such as "other" or "co-fire other" from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules. The MMU recommends that PJM require every market participant to make available at least one cost schedule with the same fuel-type and parameters as that of their offered price schedule. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendation from Section 6, Demand Response

- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate registrations that are no longer capable of responding to PJM dispatch directives, such as in the case of bankrupt and out of service facilities. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendation from Section 10, Ancillary Services

- The MMU recommends that a reason code be attached to every hour in which PJM dispatch adds additional DASR MW. The addition of such a code would make the reason explicit, increase transparency and facilitate

41 18 CFR § 35.28(g)(3)(ii)(A); see also OATT Attachment M § IV.D.

analysis of the use of PJM's ability to add DASR MW. (Priority: Medium. New recommendation. Status: not adopted.

New Recommendation from Section 12, Planning

- The MMU recommends that PJM enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. (Priority: Medium. New recommendation. Status: Not adopted.)

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 six months of 2014 and the first six months of 2015.

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 95.3 percent of the total price per MWh in the first six months of 2015.

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.[42]
- The Energy Uplift (Operating Reserves) component is the average price per MWh of day-ahead, balancing and synchronous condensing charges.[43]
- The Reactive component is the average cost per MWh of reactive supply and voltage control from generation and other sources.[44]
- The Regulation component is the average cost per MWh of regulation procured through the Regulation Market.[45]
- 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.[46]
- 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.[47]
- The Emergency Load Response component is the average cost per MWh of the PJM Emergency Load Response Program.[48]
- 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.[49]

42 OATT §§ 13.7, 14.5, 27A & 34.
43 OA Schedules 1 §§ 3.2.3 & 3.3.3.
44 OATT Schedule 2 and OA Schedule 1 § 3.2.3B. The line item in Table 1-8 includes all reactive services charges.
45 OA Schedules 1 §§ 3.2.2, 3.2.2A, 3.3.2, & 3.3.2A; OATT Schedule 3.
46 OATT Schedule 12.
47 Reliability Assurance Agreement Schedule 8.1.
48 OATT PJM Emergency Load Response Program.
49 OA Schedules 1 §§ 3.2.3A.01 & OATT Schedule 6.

- 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.[50]
- The Synchronized Reserve component is the average cost per MWh of synchronized reserve procured through the Synchronized Reserve Market.[51]
- The Black Start component is the average cost per MWh of black start service.[52]
- The RTO Startup and Expansion component is the average cost per MWh of charges to recover AEP, ComEd and DAY's integration expenses.[53]
- The NERC/RFC component is the average cost per MWh of NERC and RFC charges, plus any reconciliation charges.[54]
- The Economic Load Response component is the average cost per MWh of day ahead and real time economic load response program charges to LSEs.[55]
- The Transmission Facility Charges component is the average cost per MWh of Ramapo Phase Angle Regulators charges allocated to PJM Mid-Atlantic transmission owners.[56]
- The Non-Synchronized Reserve component is the average cost per MWh of non-synchronized reserve procured through the Non-Synchronized Reserve Market.[57]
- The Emergency Energy component is the average cost per MWh of emergency energy.[58]

50 OATT Schedule 1A.
51 OA Schedule 1 § 3.2.3A.01; PJM OATT Schedule 6.
52 OATT Schedule 6A. The line item in Table 1-8 includes all Energy Uplift (Operating Reserves) charges for Black Start.
53 OATT Attachments H-13, H-14 and H-15 and Schedule 13.
54 OATT Schedule 10-NERC and OATT Schedule 10-RFC.
55 OA Schedule 1 § 3.6.
56 OA Schedule 1 § 5.3b.
57 OA Schedule 1 § 3.2.3A.001.
58 OA Schedule 1 §3.2.6.

Table 1-8 Total price per MWh by category: January through June, 2014 and 2015

Category	Jan-Jun 2014 $/MWh	Jan-Jun 2014 Percent of Total	Jan-Jun 2015 $/MWh	Jan-Jun 2015 Percent of Total	Percent Change Totals
Load Weighted Energy	$69.92	78.6%	$42.30	68.7%	(39.5%)
Capacity	$8.56	9.6%	$9.65	15.7%	12.8%
Transmission Service Charges	$5.67	6.4%	$6.79	11.0%	19.8%
Energy Uplift (Operating Reserves)	$2.07	2.3%	$0.57	0.9%	(72.5%)
Transmission Enhancement Cost Recovery	$0.39	0.4%	$0.47	0.8%	19.2%
PJM Administrative Fees	$0.45	0.5%	$0.44	0.7%	(1.7%)
Reactive	$0.42	0.5%	$0.38	0.6%	(8.6%)
Regulation	$0.46	0.5%	$0.29	0.5%	(36.5%)
Capacity (FRR)	$0.10	0.1%	$0.25	0.4%	140.2%
Synchronized Reserves	$0.36	0.4%	$0.16	0.3%	(55.4%)
Transmission Owner (Schedule 1A)	$0.09	0.1%	$0.09	0.1%	5.5%
Day Ahead Scheduling Reserve (DASR)	$0.09	0.1%	$0.08	0.1%	(11.8%)
Black Start	$0.06	0.1%	$0.06	0.1%	(4.9%)
NERC/RFC	$0.02	0.0%	$0.03	0.0%	31.6%
Non-Synchronized Reserves	$0.03	0.0%	$0.02	0.0%	(29.3%)
Load Response	$0.03	0.0%	$0.02	0.0%	(29.1%)
RTO Startup and Expansion	$0.01	0.0%	$0.01	0.0%	(8.3%)
Emergency Load Response	$0.11	0.1%	$0.00	0.0%	NA
Emergency Energy	$0.07	0.1%	$0.00	0.0%	NA
Transmission Facility Charges	$0.00	0.0%	$0.00	0.0%	(100.0%)
Total	$88.90	100.0%	$61.61	100.0%	(30.7%)

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 11,851 MW, or 7.1 percent, in the first six months of 2015 from an average maximum of 167,891 MW to 156,040 MW. This decrease was a result of unit retirements between July 1, 2014, and June 30, 2015 and unit outages. In the first six months of 2015, 948.2 MW of new capacity were added to PJM. This new generation was offset by the deactivation of 105 units (9,770.5 MW) since January 1, 2015.

PJM average real-time generation in the first six months of 2015 decreased by 2.6 percent from the first six months of 2014, from 92,458 MW to 90,097 MW.

PJM average day-ahead supply in the first six months of 2015, including INCs and up-to congestion transactions, decreased by 30.5 percent from the first six months of 2014, from 165,620 MW to 115,148 MW.

- **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 six months of 2015, coal units provided 34.7 percent, nuclear units 28.6 percent and gas units 23.3 percent of total generation. Compared to the first six months of 2014, generation from coal units decreased 17.2 percent, generation from gas units increased 23.9 percent and generation from nuclear units increased 1.5 percent.
- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first six months of 2015, coal units were 56.12 percent of marginal resources and natural gas units were 32.85 percent of marginal resources. In the first six months of 2014, coal units were 48.59 percent and natural gas units were 42.02 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market in the first six months of 2015, up-to congestion transactions were 74.1 percent of marginal resources, INCs were 5.4 percent of marginal resources, DECs were 9.1 percent of marginal resources, and generation resources were 11.1 percent of marginal resources in the first six months of 2015.
- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM system peak load during the first six months of 2015 was 143,086 MW in the HE 0800 on February 20, 2015, which was 1,441 MW, or 1.0 percent, higher than the PJM peak load for the first six months of 2014, which was 141,673 MW in the HE 1700 on June 17, 2014.

  PJM average real-time load in the first six months of 2015 increased by 0.1 percent from the first six months of 2014, from 90,529 MW to 90,586 MW. PJM average day-ahead demand in the first six months of 2015, including DECs and up-to congestion transactions, decreased by 30.5 percent from the first six months of 2014, from 160,805 MW to 111,749 MW.
- **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 six months of 2015, 11.6 percent of real-time load was supplied by bilateral contracts, 30.8 percent by spot market purchases and 57.6 percent by self-supply. Compared with the first six months of 2014, reliance on bilateral contracts increased by 1.0 percent, reliance on spot market purchases increased by 4.1 percentage points and reliance on self-supply decreased by 5.1 percentage points.
- **Supply and Demand: Scarcity.** There were no shortage pricing events in the first six months of 2015.

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 six months of 2014 and 2015. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 0.7 percent in the first six months of 2014 to 0.5 percent in the first six months of 2015.

  In the first six months of 2015, 14 control zones experienced congestion resulting from one or more constraints binding for 50 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.

- **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 increased from 0.5 percent in the first six months of 2014 to 0.6 percent in the first six months of 2015. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0.4 percent in the first six months of 2014 to 0.5 percent in the first six months of 2015.

- **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 six months of 2015, 83.6 percent of marginal units had average dollar markups less than zero and had an average markup index less than or equal to zero. In the first six months of 2015, 7.9 percent of units had average dollar markups greater than or equal to $150. In the first six months of 2014, 11.3 percent of units had average dollar markups greater than or equal to $150.

  In the PJM Day-Ahead Energy Market in the first six months of 2015, 90.0 percent of marginal units had an average markup index less than or equal to zero. In the first six months of 2015, 4.0 percent of units had average dollar markups greater than or equal to $150. In the first six months of 2014, 3.8 percent of units had average dollar markups greater than or equal to $150.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** A new FMU rule became effective November 1, 2014, limiting the availability of FMU adders to units with net revenues less than unit going forward costs. The effects of the new rules were first observed in units eligible for an FMU or AU adder in December 2014, where the number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero in December 2014, and zero in the first six months of 2015.

- **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. The reduction in up-to congestion transactions (UTC) continued, following a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently 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 six months of 2015, 51.2 percent were offered as available for economic dispatch, 23.8 percent were offered as self scheduled, and 21.2 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 six months of 2015 were between $250 and $300 for one hour.

  PJM Real-Time Energy Market prices decreased in the first six months of 2015 compared to the first six months of 2014. The load-weighted average real-time LMP was 39.5 percent lower in the first six months of 2015 than in the first six months of 2014, $42.30 per MWh versus $69.92 per MWh.

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).

PJM Day-Ahead Energy Market prices decreased in the first six months of 2015 compared to the first six months of 2014. The load-weighted average day-ahead LMP was 38.8 percent lower in the first six months of 2015 than in the first six months of 2014, $43.26 per MWh versus $70.67 per MWh.[60]

- **Components of LMP.** In the PJM Real-Time Energy Market, for the first six months of 2015, 40.8 percent of the load-weighted LMP was the result of coal costs, 30.2 percent was the result of gas costs and 0.71 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market for the first six months of 2015, 30.6 percent of the load-weighted LMP was the result of the cost of coal, 15.6 percent was the result of the cost of gas, 5.3 percent was the result of the up-to congestion transactions, 20.4 percent was the result of DECs and 11.4 percent was the result of INCs.

- **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 in the first six months of 2015, the adjusted markup component of LMP was $2.42 per MWh or 5.7 percent of the PJM real-time, load-weighted average LMP. The month of February had the highest adjusted markup component, $6.44 per MWh, or 12.65 percent of the real-time load-weighted average LMP. In the first six months of 2014, the adjusted markup was $4.61 per MWh or 6.8 percent of the PJM real-time load-weighted average LMP.

  In the PJM Day-Ahead Energy Market, marginal INCs, DECs and UTCs have zero markups. In the first six months of 2015, the adjusted markup component of LMP resulting from generation resources was $0.64 per MWh or 1.5 percent of the PJM day-ahead load-weighted average LMP.

  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 the Day-Ahead and Real-Time Energy Markets, although the behavior of some participants during the high demand periods in the first quarter 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 -$1.38 per MWh in the first six months of 2014 and -$1.11 per MWh in the first six months of 2015. The difference between average day-ahead and real-time prices, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

Scarcity

- There were no shortage pricing events in the first six months of 2015.

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 that affect 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. Status: Adopted partially, Q4, 2014.)

  The MMU and PJM proposed, and on October 31, 2014, the Commission approved, a compromise that limited FMU adders to units with net revenues less than unit going forward costs or ACR.[61]

- 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. Status: Adopted in full, Q4, 2014.)

- The MMU recommends that PJM remove non-specific fuel types such as “other” or “co-fire other” from the list of fuel types available for market

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.”

61 149 FERC ¶ 61,091 (2014).

participants to identify the fuel type associated with their price and cost schedules. The MMU recommends that PJM require every market participant to make available at least one cost schedule with the same fuel-type and parameters as that of their offered price schedule. (Priority: Medium. New recommendation. Status: Not adopted.)

- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- The MMU recommends that generation owners be permitted to submit cost-based and price-based offers above the $1,000/MWh energy offer cap if both offer types are calculated in accordance with PJM's Cost Development Guidelines excluding the ten percent adder, subject to after the fact review by the MMU. Such offers should be allowed to set LMP. (Priority: Medium. First reported 2014. Status: Not adopted. Pending before FERC.)
- 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, 2010. Status: Not adopted.)

62 PJM. OATT Section: 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.
63 The general definition of a hub can be found in PJM. "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.

Section 3 Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first six months of 2015, 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 11,851 MW in the first six months of 2015 compared to the first six months of 2014, while peak load increased by 1,441 MW. Market concentration levels remained moderate although there is high concentration in the intermediate and peaking segments which adds to concerns about market power when market conditions are tight. The 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 although the market structure during high demand hours remains a concern.

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 in the first six months of 2015 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 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

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

required in PJM. Scarcity pricing for price signals that reflect market conditions during periods of scarcity is required in PJM. Scarcity pricing is also part of an appropriate incentive structure facing both load and generation owners in a working wholesale electric power market design. Scarcity pricing must be designed to ensure that market prices reflect actual market conditions, that scarcity pricing occurs with transparent triggers and prices and that there are strong incentives for competitive behavior and strong disincentives to exercise market power. Such administrative scarcity pricing is a key link between energy and capacity markets. The PJM Capacity Market is explicitly designed to provide revenue adequacy and the resultant reliability. Nonetheless, with a market design that includes a direct and explicit scarcity pricing revenue true up mechanism, scarcity pricing can be a mechanism to appropriately increase reliance on the energy market as a source of revenues and incentives in a competitive market without reliance on the exercise of market power. 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 the first quarter. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods in the first quarter 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 and provide a reason to use cost as the sole basis for hourly changes in offers or offers greater than $1,000 per MWh. The MMU concludes that the PJM energy market results were competitive in the first six months of 2015.

Overview: Section 4, "Energy Uplift"

Energy Uplift Results

- **Energy Uplift Charges.** Total energy uplift charges decreased by $590.1 million or 71.0 percent in the first six months of 2015 compared to the first six months of 2014, from $831.5 million to $241.4 million.
- **Energy Uplift Charges Categories:** The decrease of $590.1 million in the first six months of 2015 is comprised of a $6.3 million increase in day-ahead operating reserve charges, a $573.9 million decrease in balancing operating reserve charges, a $13.0 million decrease in reactive services charges, a $0.1 million decrease in synchronous condensing charges and a $9.3 million decrease in black start services charges.
- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.175 per MWh. The balancing operating reserve reliability rates averaged $0.060, $0.015 and $0.004 per MWh for the RTO, Eastern and Western regions. The balancing operating reserve deviation rates averaged $0.824, $0.097 and $0.049 per MWh for the RTO, Eastern and Western regions. The lost opportunity cost rate averaged $0.967 per MWh and the canceled resources rate averaged $0.002 per MWh.
- **Reactive Services Rates.** The DPL, ATSI and Dominion control zones had the three highest reactive local voltage support rates: $0.145, $0.110 and $0.049 per MWh. The reactive transfer interface support rate averaged $0.003 per MWh.
- **Energy Uplift Costs:** In the Eastern Region, a decrement bid paid an average of $1.858 per MWh, real-time load paid an average of $0.066 per MWh and deviations either from generators, load or interchange paid an average of $1.690 per MWh. In the Western Region, a decrement bid paid an average of $1.816 per MWh, real-time load paid an average of $0.057 per MWh and deviations either from generators, load or interchange paid an average of $1.649 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 30.7 percent of all day-ahead generator credits and 41.2 percent of all balancing generator credits. Combustion turbines and diesels received 87.8 percent of the lost opportunity cost credits. Coal units received 42.4 percent of all reactive services credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 33.9 percent of all credits. The top 10 organizations received 82.9 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 4664, balancing operating reserves HHI was 3691, lost opportunity cost HHI was 3338 and reactive services HHI was 8737.
- **Economic and Noneconomic Generation.** In the first six months of 2015, 87.8 percent of the day-ahead generation eligible for operating reserve credits was economic and 72.9 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In the first six months of 2015, 2.7 percent of the total day-ahead generation was scheduled as must run by PJM, of which 40.2 percent received energy uplift payments.

Geography of Charges and Credits

- In the first six months of 2015, 87.7 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 generation, 2.9 percent by transactions at hubs and aggregates and 9.4 percent by transactions at interfaces.

Energy Uplift Issues

- **Lost Opportunity Cost Credits.** In the first six months of 2015, lost opportunity cost credits decreased by $61.0 million compared to the first six months of 2014. In the first six months of 2015, resources in the top three control zones receiving lost opportunity cost credits, AEP, Dominion and PENELEC accounted for 51.2 percent of all lost opportunity cost credits, 48.0 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 59.8 percent of all day-ahead generation not committed in real time by PJM from those unit types and 68.3 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 were 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. PJM replaced all ALR units as black start resources as of April 2015. In the first six months of 2015, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $4.8 million, a decrease of $9.4 million compared to the first six months of 2014.
- **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 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 six months of 2015, the average rate paid by a DEC in the Eastern Region would have been $0.236 per MWh, which is $1.622 per MWh, or 87.3 percent, lower than the actual average rate paid.

Section 4 Recommendations

The MMU recognizes that many of the issues addressed in the recommendations are being discussed in PJM stakeholder processes. Until new rules are in place, the MMU's recommendations and the reported status of those recommendations are based on the existing market rules.

- 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. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the implementation of closed loop interface constraints be studied carefully sufficiently in advance to identify issues and that, if they are to be used, 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. (Priority: Medium. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM clearly identify and 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 to be made aware of the reasons for 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 2011. Status: Adopted partially.)
- 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 credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted. Stakeholder process.)
- 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. Status: Not adopted. Stakeholder process.)
- 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. Status: Not adopted. Stakeholder process.)
- 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. Status: Not adopted. Stakeholder process.)
  - 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. Status: Not adopted. Stakeholder process.)
  - 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. Status: Not adopted. Stakeholder process.)
  - The MMU recommends calculating LOC based on segments of hours not on an hourly basis in the calculation of credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that up-to congestion transactions be required to pay energy uplift charges. (Priority: High. First reported 2013. Status: Not adopted. Stakeholder process.)

- 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. Status: Not adopted. Stakeholder process.)
- The MMU recommends allocating the energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements. (Priority: Medium. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted. Stakeholder process.)
- 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. Status: Not adopted.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported Q1, 2014. Status: Not adopted. Stakeholder process.)

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. Energy uplift payments also result from units' operational parameters that may require PJM to schedule or commit resources during noneconomic hours. 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

68 The terms *PJM Region*, *RTO Region* and *RTO* are synonymous in the *2015 Quarterly State of the Market Report for PJM: January through June*, 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.

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 six months of 2015, PJM installed capacity decreased 6,985.5 MW or 3.8 percent, from 183,726 MW on January 1 to 176,740.5 MW on June 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity on June 30, 2015, 37.8 percent was coal; 33.6 percent was gas; 18.7 percent was nuclear; 3.9 percent was oil; 4.9 percent was hydroelectric; 0.5 percent was wind; 0.4 percent was solid waste; and 0.1 percent was solar.
- **Market Concentration.** In the first six months of 2015, no RPM Auctions were held as the Base Residual Auction for the 2018/2019 Delivery Year was delayed.[73]
- **Imports and Exports.** In the first six months of 2015, no RPM Auctions were held as the Base Residual Auction for the 2018/2019 Delivery Year was delayed.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 12,149.5 MW for June 1, 2015, as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2015/2016 Delivery Year (16,643.3 MW) less replacement capacity from sources other than Demand Resources and Energy Efficiency (4,493.8 MW).

73 151 FERC ¶ 61,067 (2015).

Market Conduct

- In the first six months of 2015, no RPM Auctions were held as the Base Residual Auction for the 2018/2019 Delivery Year was delayed.

Market Performance

- In the first six months of 2015, no RPM Auctions were held as the Base Residual Auction for the 2018/2019 Delivery Year was delayed.
- For the 2015/2016 Delivery Year, RPM annual charges to load were $9.6 billion.
- The Delivery Year weighted average capacity price was $126.40 per MW-day in 2014/2015 and $160.01 per MW-day in 2015/2016.

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for the first six months of 2015 was 7.7 percent, a decrease from 11.3 percent for the first six months of 2014.[74]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for 2015 was 82.5 percent, an increase from 80.2 percent for 2014.
- **Outages Deemed Outside Management Control (OMC).** In the first six months of 2015, 4.4 percent of forced outages were classified as OMC outages, and 0.1 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[75]

The MMU recognizes that PJM has proposed the Capacity Performance construct to replace some of the existing core market rules and to address fundamental

74 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 six months ending June 30, as downloaded from the PJM GADS database on July 24, 2015. 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.
75 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.

performance incentive issues. The MMU recognizes that the Capacity Performance construct addresses many of the MMU's recommendations. Until new rules are in place, the MMU's recommendations and the reported status of those recommendations are based on the existing capacity market rules. The status is reported as adopted if the recommendation was included in FERC's order approving PJM's Capacity Performance filing.[76]

- 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.[77,78] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- 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. Status: Adopted.)
- 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. Status: Adopted.)
- 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. Status: Not adopted.)

76 *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (June 9, 2015).
77 See also Comments of the Independent Market Monitor for PJM. Docket No. ER14-503-000 (December 20, 2013).
78 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).

- 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. Status: Not adopted.)
- 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 2010. Status: Not adopted.)
- The MMU recommends three changes with respect to capacity imports into PJM:
  - The MMU recommends that all capacity have firm transmission to the PJM border acquired prior to the offering in an RPM auction. (Priority: High. First reported 2014. Status: Adopted.)
  - The MMU recommends that all capacity imports be required to be pseudo tied prior to the relevant Delivery Year in order to ensure that imports are as close to full substitutes for internal, physical capacity resources as possible. (Priority: High. First reported 2014. Status: Adopted.)
  - The MMU recommends that all resources importing capacity into PJM accept a must offer requirement. (Priority: High. First reported 2014. Status: Adopted.)
- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[79,80] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that the rule requiring that relatively small proposed increases in the capability of a Generation Capacity Resource

79 See PJM Interconnection, L.L.C., Docket No. ER12-513 (December 1, 2011) ("Triennial Review").
80 See the *2012 State of the Market Report for PJM*, Volume II, Section 6, Net Revenue.

be treated as planned for purposes of mitigation and exempted from offer capping be removed. (Priority: Low. First reported 2013. Status: Not adopted.)

- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[81] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends two changes to the RPM solution methodology related to make-whole payments and the iterative reconfiguration of the VRR curve:
  - — The MMU recommends changing the RPM solution methodology to explicitly incorporate the cost of make-whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - — The MMU also recommends changing the RPM solution methodology to define variables for the nesting relationships in the BRA optimization model directly rather than employing the current iterative approach, in order to improve the efficiency and stability. (Priority: Medium. First reported 2014. Status: Not adopted.)
- 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. Status: Adopted.)
  - — 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. Status: Not adopted. Pending before FERC.)
  - — 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. Status: Adopted.)
  - — 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.[82] (Priority: Medium. First reported 2013. Status: Not adopted. Pending before FERC.)

81 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).

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 six months of 2015. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive in the first six months of 2015.

82 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).

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 2014 and 2015, the MMU prepared a number of RPM-related reports and testimony, shown in Table 5-2.

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.[88] 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. *EPSA v. FERC* is now subject to a stay pending the Supreme Court's review of the decision in its October 2015 term. The Supreme Court granted certiorari on May 4, 2015.

  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.[89]

  On March 31, 2015, the FERC rejected as premature certain tariff revisions filed by PJM on January 14, 2015, which had been intended to adapt the PJM demand response rules depending on the outcomes and timing of the outcomes on potential review of EPSA v. FERC and PJM's pending capacity performance proposal.[90]

- **Demand Response Activity.** Demand response includes the economic program and the emergency program. Emergency program revenue includes both capacity and energy revenue. The capacity market is still the primary source of revenue to participants in PJM demand response programs, including both capacity market revenue and the associated emergency energy revenue. In the first six months of 2015, capacity market revenue increased by $70.0 million, or 24.4 percent, from $287.4 million in the first six months of 2014 to $357.4 million in the first six months of 2015.[91] Emergency energy revenue decreased by $42.5 million, from $43.0 million in the first six months of 2014 to $0.5 million in the first six months of 2015. Economic program revenue is energy revenue only. Economic program credits decreased by $9.3 million, from $14.3 million in the first six months of 2014 to $5.0 million in the first six months of 2015, a 65.2 percent decrease.[92] Total revenue in the first six months of 2015 increased by 4.9 percent from $348.8 million in the first six months of 2014 to $365.9 million in the first six months of 2015. Not all DR activities in the first six months of 2015 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 paid by 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.[93]

- **Demand Response Market Concentration.** Economic demand response was highly concentrated in the first six months of 2014 and 2015. The HHI for economic demand response reductions increased from 7522 in the first six months of 2014 to 7852 in the first six months of 2015. Emergency demand response was moderately concentrated in the first six months of 2015. The HHI for emergency demand response registrations

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 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).
89 See FirstEnergy Service Company complaint, FERC Docket No. EL14-55-000, amending the complaint filed May 23, 2014.
90 150 FERC ¶ 61,251.
91 The total credits and MWh numbers for demand resources were calculated as of July 27, 2015 and may change as a result of continued PJM billing updates.
92 Economic credits are synonymous with revenue received for reductions under the economic load response program.
93 PJM: "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), p 70.

was 1760. In 2015, the four largest companies contributed 65.3 percent of all registered emergency demand response resources.

- **Locational Dispatch of Demand Resources.** Beginning with the 2014/2015 Delivery Year, demand resources are dispatchable for mandatory reduction on a subzonal basis, defined by zip codes, only if the subzone is defined at least one day before dispatched. More locational dispatch of demand resources in a nodal market improves market efficiency. The goal should be nodal dispatch of demand resources with no advance notice required.

Section 6 Recommendations

The MMU recognizes the substantial uncertainty related to the treatment of demand response in wholesale power markets which depends on Supreme Court review and on FERC treatment of PJM's Capacity Performance filing. The MMU recognizes that PJM has incorporated some of these recommendations in the Capacity Performance filing. The status of each recommendation reflects the status at June 30, 2015.

- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate registrations that are no longer capable of responding to PJM dispatch directives, such as in the case of bankrupt and out of service facilities. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, 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. Status: Not Adopted.[94] Pending before FERC.)
- The MMU recommends that, if demand response remains in the PJM market, 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 and not triggering the definition of an emergency. (Priority: High. First reported 2012. Status: Partially adopted.)
- The MMU recommends that, if demand response remains in the PJM market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[95] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that, if demand response remains in the PJM market, 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. Status: Not adopted. Pending before FERC.)
- The MMU recommends that, if demand response remains in the PJM market, the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Adopted in full, Q1, 2014.)
- The MMU recommends that, if demand response remains in the PJM market, demand resources be required to provide their nodal location on the electricity grid. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, measurement and verification methods for demand resources be further modified to more accurately reflect compliance. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, 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. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, PJM adopt the ISO-NE five-minute metering requirements in order to ensure that dispatchers have the necessary information for

94 PJM's Capacity Performance proposal includes this change. See "Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA")," Docket No. ER15-632-000 and "PJM Interconnection, L.L.C." Docket No. EL15-29-000.

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.

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. Status: Not adopted.)

- The MMU recommends that, if demand response remains in the PJM market, demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance. (Priority: Medium. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that, if demand response remains in the PJM market, demand resources whose load drop method is designated as "Other" explicitly record the method of load drop. (Priority: Low. First reported 2013. Status: Adopted in full, Q2, 2014.)
- The MMU recommends that, if demand response remains in the PJM market, load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends, as a preferred alternative to having PJM demand side programs, that demand response be on the demand side of the markets and that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion and that customer payments be determined only by metered load. (Priority: High. First reported 2014. Status: Not adopted. Pending before FERC.)

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 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

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 February 17, 2015) 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 should be required to offer in the Day-Ahead Energy 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.

In order to be a substitute for generation, any demand resource and its CSP, if any, should be required to notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate registrations that are no longer capable of responding to PJM dispatch directives, such as in the case of bankrupt and out of service facilities. Generation resources are required to inform PJM of any change in availability status, including outages and shutdown status.

As a preferred alternative, demand response would be on the demand side of the Capacity Market rather than on the supply side. Rather than complex demand response programs with their attendant complex and difficult to administer rules, customers would be able to avoid capacity and energy charges by not using capacity and energy at their discretion.

The long term appropriate end state for demand resources in the PJM markets should be comparable to the demand side of any market. Customers should use energy as they wish and that usage will determine the amount of capacity and energy for which each customer pays. There would be no counterfactual measurement and verification.

Under this approach, customers that wish to avoid capacity payments would reduce their load during expected high load hours. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these critical hours. Customers wishing to avoid high energy prices would reduce their load during high price hours. Customers would pay for what they actually use, as measured by meters, rather than relying on flawed measurement and verification methods. No M&V estimates are required. No promises of future reductions which can only be verified by M&V are required. To the extent that customers enter into contracts with CSPs or LSEs to manage their payments, M&V can be negotiated as part of a bilateral commercial contract between a customer and its CSP or LSE.

This approach provides more flexibility to customers to limit usage at their discretion. There is no requirement to be available year round or every hour of every day. There is no 30 minute notice requirement. There is no requirement to offer energy into the day-ahead market. All decisions about interrupting are up to the customers only and they may enter into bilateral commercial arrangements with CSPs at their sole discretion. Customers would pay for capacity and energy depending solely on metered load.

A transition to this end state should be defined in order to ensure that appropriate levels of demand side response are incorporated in PJM's load forecasts and thus in the demand curve in the capacity market for the next three years. That transition should be defined by the PRD rules, modified as suggested by the Market Monitor.

This approach would work under the current RPM design and this approach would work under the CP design. This approach is entirely consistent with any Supreme Court decision on *EPSA* as it does not require FERC to have jurisdiction over the demand side. This approach will allow the Commission to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets.

Overview: Section 7, "Net Revenue"

Net Revenue

- Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Coal and natural gas prices and energy prices were lower in the first six months of 2015 than in the first six months of 2014. Net revenues from the energy market for all plant types were affected by the lower prices.
- In the first six months of 2015, average energy market net revenues decreased by 24 percent for a new CT, 26 percent for a new CC, 58 percent for a new CP, 70 percent for a new DS, 45 percent for a new nuclear plant, 24 percent for a new wind installation, and 10 percent for a new solar installation. The comparison to the first six months of 2014 reflects the very high net revenues in January 2014.

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.

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.[98] 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 June 29, 2015, the U.S. Supreme Court remanded MATS to the D.C. Circuit Court and ordered the EPA to consider cost earlier in the process when making the decision whether to regulate power plants under MATS.[99]
- **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.[100]

  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

98 *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).
99 Michigan et al. v. EPA, Slip Op. No. 14-46.
100 CAA § 110(a)(2)(D)(i)(I).

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).[101,102]

In the same decision, the Supreme Court remanded "particularized as-applied challenge[s]" to the EPA's 2014 emissions budgets.[103] On July 28, 2015, on remand, the U.S. Court of Appeals for the District of Columbia Circuit invalidated the 2014 SO_2 budgets for a number of states, including PJM states Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and West Virginia.[104] The court directed the EPA to reconsider the 2015 emissions budgets for these states based on the actual amount of reduced emissions states in upwind states needed to bring each downwind state into attainment.[105] Under the invalidated approach, EPA calculated how much pollution each upwind state could eliminate if all of its sources applied pollution control at particular cost thresholds.[106] A new approach likely will significantly reduce the emission budgets for the indicated states. The court did not vacate the currently assigned budgets which remain effective until replaced.[107]

On November 21, 2014, EPA issued a rule tolling by three years CSAPR's original deadlines. Compliance with CSAPR's Phase 1 emissions budgets is now required in 2015 and 2016 and CSAPR's Phase 2 emissions in 2017 and beyond.[108]

- **National Emission Standards for Reciprocating Internal Combustion Engines.** On May 1, 2015, the U.S. Court of Appeals for the District of Columbia Circuit reversed the portion of the final rule exempting 100 hours of run time for certain stationary reciprocating internal combustion engines (RICE) participating in emergency demand response programs from the otherwise applicable emission standards.[109] The Court held that "EPA acted arbitrarily and capriciously when it modified the National Emissions Standards and the Performance Standards to allow backup generators to operate without emissions controls for up to 100 hours per year as part of an emergency demand-response program."[110] Specifically, the Court found that EPA failed to consider arguments concerning the rule's "impact on the efficiency and reliability of the energy grid," including arguments raised by the MMU.[111]

- **Greenhouse Gas Emissions Rule.** On August 3, 2015, the EPA issued a final rule for regulating CO_2 from certain existing power generation facilities titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.[112] Individual state plans must be submitted by September 6, 2016, while multistate plans are eligible for a two-year extension.

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.[113] 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.[114]

- **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").[115] MPS and CPS establish standards that are more stringent and

101 See EPA et al. v. EME Homer City Generation, L.P. et al., 134 S. Ct. 1584 (2014), *reversing* 696 F.3d 7 (D.C. Cir. 2012).
102 See EME Homer City Generation, L.P. v EPA et al., No. 11-1302.
103 134 S. Ct. at 1609.
104 EME Homer City Generation , L.P. v EPA et al., Slip Op. No. 11-1302 (July 28, 2015).
105 *Id.* at 11–12.
106 *Id.* at 11.
107 Emissions Budget Decision at 24–25.
108 *Rulemaking to Amend Dates in Federal Implementation Plans Addressing Interstate Transport of Ozone and Fine Particulate Matter*, EPA-HQ-OAR-2009-0491 (Nov. 21, 2014).
109 Delaware Department of Natural Resources and Environmental Control (DENREC) v. EPA, Slip Op. No. 13-1093; *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).
110 DENREC v. EPA at 3, 20–21.
111 *Id.* at 22, citing Comments of the Independent Market Monitor for PJM, EPA Docket No. EPA-HQ-OAR-2008-0708 (August 9, 2012) at 2.
112 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (June 18August 3, 20145), also known as the "Clean Power Plan."
113 N.J.A.C. § 7:27-19.
114 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).
115 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).

take effect earlier than comparable Federal regulations, such as the EPA MATS rule.

- **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 and facilitate trading of emissions allowances. Auction prices in 2015 for the 2015-2017 compliance period were $5.50 per ton. The clearing price is equivalent to a price of $6.06 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, 2015, 78.3 percent of coal steam MW had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions, while 99.5 percent of coal steam MW had some type of particulate control, and 92.8 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 retail suppliers' 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, 2015, 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. Ohio delayed a scheduled increase from 2.5 percent to 3.5 percent in its RPS standards from 2015 until 2017 and removed the 12.5 percent alternative energy requirement. Ohio currently has an ongoing Ohio Energy Mandates Study Committee that is discussing the costs and benefits of the RPS as outlined in Senate Bill 310.[116] West Virginia had a voluntary standard, but the state Legislature repealed their renewable portfolio standard on January 22, 2015.

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 could increase this impact if successful. Renewable energy credit markets are markets related to the production and purchase of wholesale power, but FERC has determined that RECs are not regulated under the Federal Power Act unless bundled with a wholesale sale of electric energy.[117]

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 and more generally provide an incentive to operate whenever possible. These subsidies affect the offer behavior and the operational behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

RECs clearly affect prices in the PJM wholesale power market. Some resources are not economic except for the ability to purchase or sell RECs. REC markets are not transparent. Data on REC 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.

116 See Ohio Senate Bill 310.
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.").

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 resources 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.

PJM markets could also provide a flexible mechanism for states to comply with the EPA's Clean Power Plan, for example by incorporating a carbon price in unit offers which would be reflected in PJM's economic dispatch. The imposition of specific environmental dispatch rules would, in contrast, pose a threat to economic dispatch and create very difficult market power monitoring and mitigation issues.

Overview: Section 9, "Interchange Transactions"

Interchange Transaction Activity

- **Aggregate Imports and Exports in the Real-Time Energy Market.** During the first six months of 2015, PJM was a net importer of energy in the Real-Time Energy Market in all months.[118] In the first six months of 2015, the real-time net interchange of 10,817.3 GWh was higher than net interchange of 489.5 GWh in the first six months of 2014.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first six months of 2015, PJM was a net exporter of energy in the Day-Ahead Energy Market in February, and a net importer in the remaining months. In the first six months of 2015, the total day-ahead net interchange of 2,864.9 GWh was higher than net interchange of -8,952.7 GWh in the first six months of 2014. The large difference in the day-ahead net interchange totals was a result of the reduction in up-to congestion transaction volumes.[119]
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first six months of 2015, gross imports in the Day-Ahead Energy Market were 78.2 percent of gross imports in the Real-Time Energy Market (123.6 percent in the first six months of 2014). In the first six months of 2015, gross exports in the Day-Ahead Energy Market were 110.0 percent of the gross exports in the Real-Time Energy Market (162.8 percent in the first six months of 2014).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, in the first six months of 2015, there were net scheduled exports at nine of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, in the first six months of 2015, there were net scheduled exports at 10 of PJM's 18 interface pricing points eligible for real-time transactions.[120]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, in the first six months of 2015, there were net scheduled exports at nine of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, in the first six months of 2015, there were net scheduled exports at 10 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, in the first six months of 2015, up-to congestion transactions were net exports at four of PJM's 19 interface pricing points eligible for day-ahead transactions.
- **Loop Flows.** In the first six months of 2015, net scheduled interchange was 10,817 GWh and net actual interchange was 10,424 GWh, a difference of 393 GWh. In the first six months of 2014, net scheduled interchange

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 On August 29, 2014, FERC issued an Order which created an obligation for UTCs to pay any uplift determined to be appropriate in the Commission review, effective September 8, 2014.

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

was 489 GWh and net actual interchange was 586 GWh, a difference of 96 GWh. This difference is inadvertent interchange.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first six months of 2015, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface in 55.5 percent of the hours.
- **PJM and New York ISO Interface Prices.** In the first six months of 2015, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/NYIS Interface and the NYISO/PJM proxy bus in 56.6 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first six months of 2015, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Neptune Interface and the NYISO Neptune Bus in 56.0 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first six months of 2015, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Linden Interface and the NYISO Linden Bus in 50.3 percent of the hours.
- **Hudson DC Line.** In the first six months of 2015, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Hudson Interface and the NYISO Hudson Bus in 39.1 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued 20 TLRs of level 3a or higher in the first six months of 2015, compared to three such TLRs issued in the first six months of 2014.
- **Up-To Congestion.** On August 29, 2014, FERC issued an Order which created an obligation for UTCs to pay any uplift determined to be appropriate in the Commission review, effective September 8, 2014.[121]

  The average number of up-to congestion bids decreased by 67.8 percent and the average cleared volume of up-to congestion bids decreased by 74.0 percent in the first six months of 2015, compared to the first six months in 2014 (Figure 9-13).
- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule in response to Order No. 764.[122,123] PJM and the MMU issued a statement indicating ongoing concern about market participants' scheduling behavior, and a commitment to address any scheduling behavior that raises operational or market manipulation concerns.[124]

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 2012. Status: Not adopted.)
- 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. First reported 2009. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1200 on the day prior, to

121 148 FERC ¶ 61,144 (2014).*Order Instituting Section 206 Proceeding and Establishing Procedures.*
122 *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).
123 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).
124 *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>.

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. First reported Q3 2014. Status: Not adopted.)

- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that remove 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 constraints, similar to any other constraint within an LMP market. (Priority: Medium. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- The MMU recommends that the validation method also require market participants to submit transactions on market paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted. Stakeholder process.)
- 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. Status: Not adopted.)
- The MMU recommends that PJM immediately provide the required 12-month notice to Duke Energy Progress (DEP) to unilaterally terminate the Joint Operating Agreement. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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. Status: Adopted partially, Q4 2013.)
- The MMU recommends that PJM implement additional business rules to remove the incentive to engage in sham scheduling activities using the PJM/IMO interface price. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM file revisions to the marginal loss surplus allocation method to fully comply with the February 24, 2009, Order. The MMU recommends that marginal loss surplus allocations be capped such that the marginal loss surplus credits cannot exceed the contributions made to the fixed costs of the transmission system for any reason. (Priority: Medium. First reported 2014. Status: Not adopted.)

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 was raised on January 8, 2015, to 2,175 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 in January through June 2015 was 2,248.8 MW. The actual demand for primary reserve in the MAD subzone in January through June 2015 was 1,708.2 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 counts as part of PJM's primary reserve requirement and is the capability of on-line resources following economic dispatch to ramp up in ten minutes from their current output in response to a synchronized reserve event.

- **Supply.** No offers are made for tier 1 synchronized reserve. The market solution calculates tier 1 synchronized reserve as available 10-minute ramp from the energy dispatch. In the first six months of 2015, there was an average hourly supply of 1,380.8 MW of tier 1 for the RTO synchronized reserve zone, and an average hourly supply of 1,204.2 MW of tier 1 in the Mid-Atlantic Dominion subzone.
- **Demand.** The default hourly required synchronized reserve requirement is 1,450 MW in the RTO Reserve Zone and 1,450 MW for the Mid-Atlantic Dominion Reserve subzone.
- **Tier 1 Synchronized Reserve Event Response.** Tier 1 synchronized reserve is paid when a synchronized reserve event occurs and it responds. The synchronized reserve 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.

  Of tier 1 synchronized reserve eligible for payment in Settlements, 60.5 percent actually responded during the eleven distinct synchronized reserve events in the first six months of 2015. PJM made changes to the way it calculated tier 1 MW for settlements beginning in July 2014. These changes improved the reported response rate by reducing the initial tier 1 estimate.
- **Issues.** The competitive price for tier 1 synchronized reserves is zero, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point. A tariff change included in the shortage pricing tariff changes (October 1, 2012) added the requirement

to pay tier 1 synchronized reserve 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 $26,576,359 to tier 1 resources in 2014, and $25,816,249 in the first six months of 2015.

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 be synchronized, that have an obligation to respond with corresponding penalties, 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 six months of 2015, 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.
- **Demand.** The default hourly required synchronized reserve requirement was 1,450 MW in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone.
- **Market Concentration.** In the first six months of 2015, the weighted average HHI for cleared tier 2 synchronized reserve in the Mid-Atlantic Dominion subzone was 5705 which is classified as highly concentrated. The MMU calculates that 27.1 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion subzone.

  In the first six months of 2015, the weighted average HHI for cleared tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was 4886 which is classified as highly concentrated. The MMU calculates that 38.2 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 six months of 2015.

Market Conduct

- **Offers.** Tier 2 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.

Market Performance

- **Price.** The weighted average price (includes all hours when a market was cleared including hours when the SRMCP was $0) for tier 2 synchronized reserve for all cleared hours in the Mid-Atlantic Dominion (MAD) subzone was $13.07 per MW in the first six months of 2015, a decrease of $2.11, 13.9 percent from the first six months of 2014.

  The weighted average price for tier 2 synchronized reserve for all cleared hours in the RTO Synchronized Reserve Zone was $16.76 per MW in the first six months of 2015, a decrease of $1.39 from the first six months of 2014.

Non-Synchronized Reserve Market

Non-synchronized reserve is part of primary reserve and includes the same two markets, the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone (MAD). Non-synchronized reserve is comprised of non-emergency energy resources not currently synchronized to the grid that can provide energy within ten minutes. Non-synchronized reserve is available to fill the primary reserve requirement above the synchronized reserve requirement.

Market Structure

- **Supply.** In the first six months of 2015, the supply of eligible non-synchronized reserve was 1,895.6 MW in MAD and 2,651.9 MW in the RTO. This supply was sufficient to cover the primary reserve requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone.
- **Demand.** Demand for non-synchronized reserve is the remaining primary reserve requirement after tier 1 synchronized reserve is estimated and tier 2 synchronized reserve (if any) is scheduled. In the RTO Zone, the market cleared an hourly average of 460.3 MW of non-synchronized reserve in the first six months of 2015. In the MAD subzone, the market cleared an hourly average of 434.9 MW of non-synchronized reserve.

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.** There are no offers for non-synchronized reserve. The non-synchronized reserve price is determined by the opportunity cost of the marginal non-synchronized reserve unit. The non-synchronized reserve weighted average price for all cleared hours in the RTO Reserve Zone was $1.40 per MW in the first six months of 2015 and in 80.0 percent of hours the market clearing price was $0. The non-synchronized reserve weighted average price for all cleared hours in the Mid-Atlantic Dominion (MAD) subzone was $1.68 and in 80.7 percent of hours the market clearing price was $0.

Secondary Reserve (Day-Ahead Scheduling Reserve)

PJM maintains a day-ahead, offer based market for 30-minute secondary reserve, designed to provide price signals to encourage resources to provide 30-minute reserve.[125] The DASR Market has no performance obligations.

Market Structure

- **Concentration.** In the first six months of 2015, 52 hours in the DASR Market would have failed the three pivotal supplier test. All 52 hours occurred during times when PJM Dispatch increased the DASR requirement.
- **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. In the first six months of 2015, the average available hourly DASR was 36,192 MW.
- **Demand.** The DASR requirement in 2015 is 5.93 percent of peak load forecast, down from 6.27 percent in 2014. The average DASR MW purchased was 4,454 MW per hour in the first six months of 2015.

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 June 30, 2015, 8.0 percent of resources offered DASR at levels above $5 per MW.
- **DR.** Demand resources are eligible to participate in the DASR Market. Six demand resources have entered offers for DASR.

Market Performance

- **Price.** The weighted average DASR market clearing price in January through March 2015 was $1.54 per MW. This is a decrease from $1.63 per MW in the first six months of 2014.

125 See PJM. "Manual 35, Definitions and Acronyms," Revision 23, (April 11, 2014), p. 22.

Regulation Market

The PJM Regulation Market is a single real-time market. Regulation is provided by generation resources and demand response resources that qualify to follow a regulation signal (RegA or RegD). PJM jointly optimizes regulation with synchronized reserve and energy to provide all three services at least cost. The PJM Regulation Market design includes three clearing price components: capability; performance; and lost opportunity cost. The marginal benefit factor and performance score translate a resource's capability (actual) MW into effective MW.

Market Structure

- **Supply.** In the first six months of 2015, the average hourly eligible supply of regulation was 1,237.2 actual MW (907.1 effective MW). This is a decrease of 98.4 actual MW (73.3 effective MW) from the same period of 2014, when the average hourly eligible supply of regulation was 1,335.6 actual MW (980.4 effective MW).
- **Demand.** The average hourly regulation demand was 655.6 actual MW (663.7 effective MW) in the first six months of 2015. This is a 17.9 actual MW (0 effective MW) decrease in the average hourly regulation demand of 673.5 actual MW (663.7 effective MW) from the same period of 2014.
- **Supply and Demand.** The ratio of offered and eligible regulation to regulation required averaged 1.79. This is a 9.84 percent decrease from the same period of 2014 when the ratio was 1.98.
- **Market Concentration.** In the first six months of 2015, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 1477 which is classified as moderately concentrated. In the first six months of 2015, the three pivotal supplier test was failed in 98 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-based offer along with cost parameters to verify the offer, and may optionally submit a price-based 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.[126] In the first six months of 2015, there were 265 resources following the RegA signal and 41 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $41.33 per MW of regulation in the first six months of 2015, a decrease of $20.76 per MW of regulation, or 33.4 percent, from the same period of 2014. The cost of regulation in the first six months of 2015 was $50.04 per MW of regulation, a decrease of $25.16 per MW of regulation, or 33.5 percent, from the same period of 2014. The decreases in regulation price and regulation cost resulted primarily from high prices and costs in the first six months of 2014, particularly in January.
- **RMCP Credits.** RegD resources continue to be incorrectly compensated relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment, pricing, and settlement processes. If the Regulation Market were functioning efficiently, RegD and RegA resources would be paid equally per effective MW.
- **Marginal Benefit Factor Function.** The marginal benefit factor measures the substitutability of RegD resources for RegA resources in satisfying the regulation requirement. The regulation market's effectiveness and efficiency depends on the marginal benefit factor function being properly defined based on the actual tradeoff between RegA and RegD MW in providing regulation. Current regulation performance indicates that the marginal benefit factor function used by PJM is incorrectly describing the operational relationship between RegA and RegD for purposes of providing regulation service.
- **Inconsistent accounting of RegD Effective MW.** The current market design does not correctly account for the amount of effective MW being provided by RegD. Rather than calculating the total effective MW contribution of RegD MW on the basis of the area under the marginal benefit function curve, the current regulation market optimization

126 See the *2014 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

assigns all RegD resources the lowest marginal benefit factor associated with last RegD MW at that price. This incorrect accounting of effective MW results in the purchase of more than the efficient level of regulation MW necessary to meet PJM's regulation requirement.

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.[127]

In the first six months of 2015, total black start charges were $25.0 million with $20.0 million in revenue requirement charges and $5.0 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 to units scheduled in the Day-Ahead Energy Market or committed in real time to provide black start service under the automatic load rejection (ALR) option or for black start testing. Black start zonal charges in the first six months of 2015 ranged from $0.04 per MW-day in the PPL Zone (total charges were $59,801) to $4.35 per MW-day in the BGE Zone (total charges were $5,246,763).

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 six months of 2015, total reactive service charges were $148.5 million, a 8.8 percent decrease from $162.9 million in the first six months of 2014. Revenue requirement charges decreased from $140.7 million to $139.3 million and operating reserve charges fell from $22.2 million to $9.2 million. Total charges in the first six months of 2015 ranged from $1,800 in the RECO Zone to $20.6 million in the AEP Zone. 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.

127 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. Status: Not adopted.)
- 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. Status: Not adopted. Stakeholder process.)
- The MMU recommends that no payments be made to tier 1 resources if they are deselected in the PJM market solution. (Priority: High. First reported Q3, 2014. Status: Adopted July 2014.)
- The MMU recommends that the tier 2 synchronized reserve must-offer provision of scarcity pricing be enforced. As of the end of December 31, 2014 compliance with the tier 2 must-offer provision was 99.5 percent. (Priority: Medium. First reported 2013. Status: Adopted partially.)
- 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 2012. Status: Not adopted.)
- The MMU recommends 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. Status: Not adopted.)

- 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. Status: Not adopted.)
- The MMU recommends that the three pivotal supplier test be incorporated in the DASR Market. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM dispatch adds additional DASR MW. The addition of such a code would make the reason explicit, increase transparency and facilitate analysis of the use of PJM's ability to add DASR MW. (Priority: Medium. New recommendation. Status: not adopted.)

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 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 in settlement. This failure to correctly incorporate marginal benefit factor into the current Regulation Market design has resulted in both underpayment and overpayment of RegD resources and in the over procurement of RegD resources in some hours. 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 synchronized reserve events has been an issue. Compliance with the synchronized reserve must-offer requirement has also been an issue.

The shortage pricing rule that requires market participants to pay tier 1 synchronized reserve the tier 2 synchronized reserve price when the nonsynchronized reserve price is greater than zero, is inefficient and results in a windfall payment to the holders of tier 1 synchronized reserve resources. Such tier 1 resources have no obligation to perform and pay no penalties if they do not perform. Such resources are not tier 2 resources, although they have the option to offer as tier 2, to take on tier 2 obligations and to be paid as tier 2. Application of this rule added $80.0 million to the cost of primary reserve in 2014.

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 decreased by $523.6 million or 36.3 percent, from $1,442.3 million in the first six months of 2014 to $918.6 million in the first six months of 2015.

- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $598.7 million or 35.4 percent, from $1,691.9 million in the first six months of 2014 to $1,093.2 million in the first six months of 2015.
- **Balancing Congestion.** Balancing congestion costs increased by $75.1 million or 30.1 percent, from -$249.7 million in the first six months of 2014 to -$174.6 million in the first six months of 2015.
- **Real-Time Congestion.** Real-time congestion costs decreased by $716.8 million or 43.0 percent, from $1,668.4 million in the first six months of 2014 to $951.6 million in the first six months of 2015.
- **Monthly Congestion.** In 2015, 46.8 percent ($429.8 million) of total congestion cost was incurred in February and 22.0 percent ($201.9 million) of total congestion cost was incurred in the months of January and March. Monthly total congestion costs in the first six months of 2015 ranged from $69.5 million in March to $429.8 million in February.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the 5004/5005 Interface, the Bedington - Black Oak Interface, the AEP - DOM Interface, the AP South Interface, and the Bergen - New Milford line.
- **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 six months of 2015. The number of congestion event hours in the Day-Ahead Energy Market was about five times higher than the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion frequency decreased by 57.9 percent from 228,169 congestion event hours in the first six months of 2014 to 95,960 congestion event hours in the first six months of 2015. The day-ahead congestion event hours decreased significantly after September 8, 2014. The reduction was the result of the reduction in UTC activity which was a result of FERC's UTC uplift refund notice, retroactive to September 8, 2014.

  Real-time congestion frequency increased by 2.7 percent from 16,722 congestion event hours in the first six months of 2014 to 17,169 congestion event hours in the first six months of 2015.
- **Congested Facilities.** Day-ahead, congestion-event hours decreased on all types of congestion facilities. Real-time, congestion-event hours increased on line and transformer facilities and decrease on flowgate and interface facilities.

  The 5004/5005 Interface was the largest contributor to congestion costs in the first six months of 2015. With $88.8 million in total congestion costs, it accounted for 9.7 percent of the total PJM congestion costs in the first six months of 2015.
- **Zonal Congestion.** AEP had the largest total congestion costs among all control zones in the first six months of 2015. AEP had $248.8 million in total congestion costs, comprised of -$352.0 million in total load congestion payments, -$621.0 million in total generation congestion credits and -$20.2 million in explicit congestion costs. The AEP - DOM Interface, the Joshua Falls transformer, the 5004/5005 Interface, the Bedington - Black Oak Interface and the Mahans Lane – Tidd line contributed $119.7 million, or 48.1 percent of the total AEP control zone congestion costs.
- **Ownership.** In the first six months of 2015, financial entities as a group were net recipients of congestion credits, and physical entities were net payers of congestion charges. Explicit costs are the primary source of congestion credits to financial entities. In the first six months of 2015, financial entities received $98.8 million in congestion credits, a decrease of $92.3 million or 48.3 percent compared to the first six months of 2014. In the first six months of 2015, physical entities paid $1,017.5 million in congestion charges, a decrease of $615.9 million or 37.7 percent compared to the first six months of 2014. UTCs are in the explicit cost category and comprise most of that category. The total explicit cost is equal to day-ahead explicit cost plus balancing explicit cost. In the first six months of 2015, the total explicit cost is -$107.0 million and 120.3

percent of the total explicit cost is comprised of congestion cost by UTCs, which is -$128.6 million.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $397.9 million or 39.5 percent, from $1,006.2 million in the first six months of 2014 to $608.3 million in the first six months of 2015. Total marginal loss costs decreased because of the distribution of high load and outages caused by cold weather in January 2014. The loss MW in PJM decreased 17.6 percent, from 9,065.7 GWh in the first six months of 2014 to 7,470.2 GWh in the first six months of 2015. The loss component of LMP remained constant, $0.02 in the first six months of 2014 and $0.02 in the first six months of 2015.
- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first six months of 2015 ranged from $52.0 million in April to $220.3 million in February.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by $469.6 million or 42.9 percent, from $1,095.0 million in the first six months of 2014 to $625.4 million in the first six months of 2015.
- **Balancing Marginal Loss Costs.** Balancing marginal loss costs increased by $71.7 million or 80.7 percent, from -$88.8 million in the first six months of 2014 to -$17.1 million in the first six months of 2015.
- **Marginal Loss Credits.** The marginal loss credits decreased in the first six months of 2015 by $118.3 million or 36.4 percent, from $325.0 million in the first six months of 2014, to $206.7 million in the first six months of 2015.

Energy Cost

- **Total Energy Costs.** Total energy costs increased by $279.5 million or 41.3 percent, from -$677.2 million in the first six months of 2014 to -$397.6 million in the first six months of 2015.
- **Day-Ahead Energy Costs.** Day-ahead energy costs increased by $479.4 million or 50.6 percent, from -$948.3 million in the first six months of 2014 to -$468.9 million in the first six months of 2015.
- **Balancing Energy Costs.** Balancing energy costs decreased by $207.8 million or 75.1 percent, from $276.6 million in the first six months of 2014 to $68.8 million in the first six months of 2015.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first six months of 2015 ranged from -$141.5 million in February to -$36.0 million in April.

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 to congestion. ARR and FTR revenues offset 88.3 percent of the total congestion costs including the Day-Ahead Energy Market and the balancing energy market in PJM for 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.

Overview: Section 12, “Planning”

Planned Generation and Retirements

- **Planned Generation.** As of June 30, 2015, 77,461.3 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 192,864.9 MW as of June 30, 2015. Of the capacity in queues, 8,242.9 MW, or 10.6 percent, are uprates and the rest are new generation. Wind projects account for 15,297.5 MW of nameplate capacity or 19.7 percent of the capacity in the queues. Combined-cycle projects account for 49,851.5 MW of capacity or 64.4 percent of the capacity in the queues.

- **Generation Retirements.** As shown in Table 12-6, 26,967.6 MW have been, or are planned to be, retired between 2011 and 2019. Of that, 3,203.3 MW are planned to retire after 2015. In the first two quarters of 2015, 9,717.0 MW were retired, of which 7,537.8 MW were coal units. The coal unit retirements were a result of the EPA's Mercury and Air Toxics Standards (MATS) and low gas prices.
- **Generation Mix.** A significant shift in the distribution of unit types within the PJM footprint continues as natural gas fired units enter the queue and steam units retire. While only 1,936.0 MW of coal fired steam capacity are currently in the queue, 53,050.5 MW of gas fired capacity are in the queue. The replacement of coal 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.[128] The process is complex and time consuming at least in part as a result 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. Excluding currently active projects and projects currently under construction, 2,182 projects, representing 262,424 MW, have completed the queue process since its inception. Of those, 566 projects, 32,622 MW, went into service. Of the projects that have completed the queue process, 87.6 percent of the MW that entered the queue withdrew at some point in the process. 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.

128 See PJM, OATT Parts IV & VI.

- 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 the backlog of incomplete 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 the parent company of the transmission owner or the interconnection requirements of a merchant transmission developer which is a competitor of the transmission owner. 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 as the transmission owner.

Regional Transmission Expansion Plan (RTEP)

- Artificial Island is an area in southern New Jersey that includes nuclear units at Salem and at Hope Creek in the PSEG zone. 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 staff announced on April 28, 2015, that they will recommend that the Board approve the Artificial Island project being designated to LS Power, PSEG, and PHI with a total cost estimate between $263M and $283M.[129]

Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects, which are intended to resolve multiple reliability criteria violations and congestion issues and which have substantial impacts on energy and capacity markets. The current backbone

129 See "Artificial Island Recommendations," at <http://www.pjm.com/~/media/committees-groups/committees/teac/20150428-ai/20150428-artificial-island-recommendations.ashx>

projects are Mount Storm-Doubs, Jacks Mountain, Susquehanna-Roseland, and Surry Skiffes Creek 500kV.

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When the reportable transmission facilities need to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outages according to rules in PJM's Manual 3 to decide if the outage is on time, late, or past its deadline.[130]

Section 12 Recommendations

The MMU recommends improvements to the planning process.

- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for 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. Status: Not adopted.)
- 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.[131] (Priority: Low. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not Adopted.)
- 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. Status: Partially adopted, 2014.)
- The MMU recommends that PJM enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and merchant transmission providers in the Regional Transmission Expansion Plan. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM reevaluate all transmission outage tickets as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)

130 PJM. "Manual 03: Transmission Operations," Revision 46 (December 1, 2014), Section 4.

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

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 transparent, robust and clearly defined mechanism to permit competition to build transmission projects, to ensure that competitors provide total project cost cap, 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, whether there is more risk associated with the generation or transmission alternatives, 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 for new generation investments 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.

The PJM rules for competitive transmission development through the Regional Transmission Expansion Plan should build upon Order No. 1000 to create real competition between incumbent transmission providers and merchant transmission providers. PJM should enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base. Because PJM now has the responsibility for planning the development of the grid under its RTEP process, property bought to facilitate future expansion should be a part of that process and be made available to all providers on equal terms.

The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR Auction bid submission dates and are late for the Day Ahead Energy Market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers.

Overview: Section 13, "FTR and ARRs"

Financial Transmission Rights

Market Structure

- **Supply.** Market participants can sell FTRs. In the 2015 to 2016 Annual FTR Auction, total participant FTR sell offers were 378,744 MW, up from 271,368 MW in the 2014 to 2015 planning period. In the Monthly Balance of Planning Period FTR Auctions for the 2014 to 2015 planning period, total participant FTR sell offers were 3,583,085 MW, down from 5,010,437 MW for the same period during the 2013 to 2014 planning period.
- **Demand.** The total FTR buy and self-scheduled bids from the 2015 to 2016 Annual FTR Auction decreased 24.7 percent from 3,270,331 MW, for the 2014 to 2015 planning period, to 2,461,662 MW. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the 2014 to 2015 planning period increased 1.0 percent from 25,088,655 MW for the same time period of the prior planning period, 25,346,226 MW.

- **Patterns of Ownership.** For the 2015 to 2016 Annual FTR Auction, financial entities purchased 56.3 percent of prevailing flow FTRs and 75.0 percent of counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 76.4 percent of prevailing flow and 80.1 percent of counter flow FTRs for January through June of 2015. Financial entities owned 69.9 percent of all prevailing and counter flow FTRs, including 61.7 percent of all prevailing flow FTRs and 83.2 percent of all counter flow FTRs during the period from January through June 2015.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the 2014 to 2015 planning period were $3.5 million for Increment Offers, Decrement Bids and UTC Transactions.
- **Credit Issues.** There were two collateral defaults and seven payment defaults for the first six months of 2015. The two collateral defaults totaled $710,300 and the seven payment defaults totaled $1,726,641. All of these default events were from Intergrid Mideast Group, LLC.

  PJM terminated Intergrid's membership as of April 23, 2015, and FERC approved PJM's termination as of June 23, 2015. Some of Intergrid's invoices were paid through Intergrid, a guarantor or cash collateral posted with PJM. Intergrid held FTRs at the time they were declared in default. PJM will liquidate Intergrid's FTR positions in accordance with Section 7.3.9 of the Operating Agreement.[132] The amount of revenue generated by these liquidated FTRs will impact the default allocation assessments that may be billed in accordance with Section 15.2.2 of the Operating Agreement.[133] PJM liquidated 500.8 MW of Intergrid's FTRs in the June Monthly Balance of Planning Period Auction for a net of $509,732 in revenue. PJM also liquidated 417.2 MW of Long Term FTRs for various planning periods for a net of $230,318 in cost. The net revenue result of Intergrid's FTR liquidation so far is $279,414.

132 *See* PJM OATT. Liquidation of Financial Transmission Rights in the Event of Member Default. § 7.3.9.
133 *See* PJM OATT. Default Allocation Assessment § 15.2.2.

Market Performance

- **Volume.** In the Annual FTR Auction for the 2015 to 2016 planning period, 378,328 (15.4 percent) of buy and self-scheduled bids cleared. In the 2014 to 2015 planning period Monthly Balance of Planning Period FTR Auctions 2,256,736 MW (8.9 percent) of FTR buy bids and 813,870 MW (22.7 percent) of FTR sell offers cleared.
- **Price.** The weighted-average buy-bid FTR price for the 2015 to 2016 Annual FTR Auction was $0.31 per MW, up from $0.29 per MW in the 2014 to 2015 planning period. The weighted-average buy-bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for the 2014 to 2015 planning period was $0.15, up from $0.17 per MW in the 2013 to 2014 planning period.
- **Revenue.** The 2015 to 2016 Annual FTR Auction generated $936.3 million in net revenue, up from $748.6 million from the 2014 to 2015 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $19.3 million in net revenue for all FTRs for the 2014 to 2015 planning period, down from $29.8 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 2014 to 2015 planning period. This high level of revenue adequacy was primarily due to actions taken by PJM to address prior low levels of revenue adequacy. PJM's actions included PJM's assumption of higher outage levels and PJM's decision to include additional constraints (closed loop interfaces) both of which reduced system capability in the FTR auction model. PJM's actions led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs.
- **ARR and FTR Offset.** ARRs and FTRs served as an effective, but not total, offset to congestion. ARR and FTR revenues offset 88.3 percent of the total congestion costs including the Day-Ahead Energy Market and the balancing energy market in PJM for 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. In 2015, FTRs were profitable overall, with $339.3 million in profits for physical entities, of which $229.1 million was from self-scheduled FTRs, and $191.0 million for financial entities.

Auction Revenue Rights

Market Structure

- **ARR Allocations.** PJM's actions to address prior low levels of revenue adequacy included PJM's assumption of higher outage levels and PJM's decision to include additional constraints (closed loop interfaces) both of which reduced system capability in the FTR auction model. PJM's actions led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs. ARR allocation quantities were significantly reduced from historic levels for both the 2014 to 2015 and 2015 to 2016 planning periods. 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. For the 2015 to 2016 planning period, Stage 1B and Stage 2 ARR allocations were reduced 79.7 percent from the 2013 to 2014 planning period.

- **Residual ARRs.** If ARR allocations are reduced as the result of a modeled transmission outage and the transmission outage ends during the relevant planning year, the result is that residual ARRs may be available. These residual ARRs are automatically assigned to eligible participants the month before the effective date. Residual ARRs are only available on paths prorated in Stage 1 of the annual ARR allocation, are only effective for single, whole months and cannot be self scheduled. Residual ARR clearing prices are based on monthly FTR auction clearing prices.

  In the 2014 to 2015 planning period planning period, PJM allocated a total of 22,532.9 MW of residual ARRs, up from 15,417.5 MW in the 2013 to 2014 planning period, with a total target allocation of $8.2 million for the 2014 to 2015 planning period, up from $4.7 million for the 2013 to 2014 planning period. This 46.2 percent increase in residual ARR volume was primarily a result of PJM's significant reductions in Annual ARR Stage 1B allocations. The assumed outages did not materialize resulting in more available ARRs which were distributed as residual ARRs.

- **ARR Reassignment for Retail Load Switching.** There were 64,086 MW of ARRs associated with $338,100 of revenue that were reassigned in the 2013 to 2014 planning period. There were 57,270 MW of ARRs associated with $506,000 of revenue that were reassigned for the 2014 to 2015 planning period.

Market Performance

- **Revenue Adequacy.** For the 2014 to 2015 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $735.3 million while PJM collected $767.9 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. The increase in ARR target allocations and auction revenue, despite decreased volume, is a result of increased prices resulting from the reduced allocation of Stage 1B and Stage 2 ARRs.

- **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 ARR holders across the Day-Ahead Energy Market and balancing energy market for the 2014 to 2015 planning period and for the 2013 to 2014 planning period. Individual participants may not have a 100 percent offset.

Section 13 Recommendations

- 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. Status: Not adopted.)

- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR marketplace participants. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM 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. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models. (Priority: Low. First reported 2013. Status: Adopted partially, 14/15 planning period.)
- The MMU recommends that PJM 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. Status: Adopted partially, 14/15 planning period.)
- The MMU recommends that PJM implement a seasonal ARR and FTR allocation system to better represent outages. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate overallocation requirement of ARRs in the Annual ARR Allocation process. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM 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. Status: Not adopted. (Pending before FERC.)
- 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. Status: Not adopted.)

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 repeatedly.[134] 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 adequacy 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 2014 to 2015 planning period, total day-ahead congestion was $1,624.0 million while total day-ahead plus balancing congestion was $1,390.2 million, compared to target allocations of $1,254.4 million in the same time period.

Clearing prices fell and cleared quantities increased from the 2010 to 2011 planning period through the 2013 to 2014 planning period. The market response to lower revenue adequacy was to reduce bid prices and to increase bid volumes and offer volumes.

PJM's actions to address prior low levels of revenue adequacy included PJM's assumption of higher outage levels and PJM's decision to include additional constraints (closed loop interfaces) both of which reduced system capability in the FTR auction model. PJM's actions led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs from the 2013 to 2014 planning period, and a corresponding reduction in the available quantity of FTRs, an increase in FTR prices and an increase in ARR target allocations. The market response to the reduced supply of FTRs was increased bid prices, increased clearing prices and reduced clearing quantities.

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

134 See "FirstEnergy Solutions Corp. Allegheny Energy Supply Company, LLC v PJM Interconnection, LLC," Docket No. EL13-47-000 (February 15, 2013).

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. For the 2014 to 2015 planning period the payout ratio was 100 percent. The MMU recommends that counter flow and prevailing flow FTRs be treated symmetrically with respect to the application of a payout ratio.

The overallocation of Stage 1A ARRs results in FTR overallocations on the same facilities. Stage 1A ARR overallocation is a source of revenue inadequacy and cross subsidy. While prorating the Stage 1A ARR allocations based on actual system capability would address the issue, Stage 1A ARRs cannot be prorated under current market rules.

The MMU recommends that Stage 1A allocations be prorated to match actual system capability and that PJM commit to building the transmission capability required to provide all defined Stage 1A allocations. If Stage 1A overallocations are addressed, Stage 1B and Stage 2 allocations would not need to be reduced as they were for the 2014 to 2015 and 2015 to 2016 planning periods.

The result of removing portfolio netting, applying a payout ratio to counter flow FTRs and eliminating Stage 1A ARR overallocation in the 2013 to 2014 planning period would have increased the payout ratio to 94.6 percent without reducing ARR allocations in Stage 1B and Stage 2.

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.

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.

The MMU is also tracking PJM's progress in addressing these recommendations. The MMU recognizes that part of the process of addressing recommendations may include discussions in the stakeholder process, FERC decisions and court decisions and those elements are included in the tracking. Each recommendation includes a status. The status categories are:

- **Adopted in full:** PJM has implemented the recommendation made by the MMU.
- **Adopted partially:** PJM has implemented part of the recommendation made by the MMU.
- **Not adopted:** PJM does not plan to implement the recommendation made by the MMU, or has not yet implemented any part of the recommendation made by the MMU. Where the subject of the recommendation is pending stakeholder or FERC action, that status is noted.

New Recommendations for Q2, 2015

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 *2015 Quarterly State of the Market Report for PJM: January through June*, the MMU makes four new recommendations.

New Recommendation from Section 3, Energy Market

- The MMU recommends that PJM remove non-specific fuel types such as "other" or "co-fire other" from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules. The MMU recommends that PJM require every market

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

participant to make available at least one cost schedule with the same fuel-type and parameters as that of their offered price schedule. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendation from Section 6, Demand Response

- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate registrations that are no longer capable of responding to PJM dispatch directives, such as in the case of bankrupt and out of service facilities. (Priority: Medium. New recommendation. Status: Not adopted.)

New Recommendation from Section 10, Ancillary Services

- The MMU recommends that a reason code be attached to every hour in which PJM dispatch adds additional DASR MW. The addition of such a code would make the reason explicit, increase transparency and facilitate analysis of the use of PJM's ability to add DASR MW. (Priority: Medium. New recommendation. Status: not adopted.

New Recommendation from Section 12, Planning

- The MMU recommends that PJM enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. (Priority: Medium. New recommendation. Status: Not adopted.)

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 that affect 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. Status: Adopted partially, Q4, 2014.)

  The MMU and PJM proposed, and on October 31, 2014, the Commission approved, a compromise that limited FMU adders to units with net revenues less than unit going forward costs or ACR.[7]

- 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. Status: Adopted in full, Q4, 2014.)
- The MMU recommends that PJM remove non-specific fuel types such as "other" or "co-fire other" from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules. The MMU recommends that PJM require every market participant to make available at least one cost schedule with the same fuel-type and parameters as that of their offered price schedule. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[8] (Priority: Medium. First reported 2012. Status: Not adopted.)
- 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. Status: Not adopted.)

7 149 FERC ¶ 61,091 (2014).
8 PJM. OATT Section: 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.

- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[9] 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.[10] (Priority: Low. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- The MMU recommends that generation owners be permitted to submit cost-based and price-based offers above the $1,000/MWh energy offer cap if both offer types are calculated in accordance with PJM's Cost Development Guidelines excluding the ten percent adder, subject to after the fact review by the MMU. Such offers should be allowed to set LMP. (Priority: Medium. First reported 2014. Status: Not adopted. Pending before FERC.)
- 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, 2010. Status: Not adopted.)

Section 4, Energy Uplift

The MMU recognizes that many of the issues addressed in the recommendations are being discussed in PJM stakeholder processes. Until new rules are in place, the MMU's recommendations and the reported status of those recommendations are based on the existing market rules.

- 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. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the implementation of closed loop interface constraints be studied carefully sufficiently in advance to identify issues and that, if they are to be used, 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.

9 The general definition of a hub can be found in PJM. "Manual 35: Definitions and Acronyms," Revision 23 (April 11, 2014).
10 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.

(Priority: Medium. First reported 2013. Status: Not adopted. Stakeholder process.)

- The MMU recommends that PJM clearly identify and 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 to be made aware of the reasons for 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 2011. Status: Adopted partially.)
- 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 credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted. Stakeholder process.)
- 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. Status: Not adopted. Stakeholder process.)
- 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. Status: Not adopted. Stakeholder process.)
- 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. Status: Not adopted. Stakeholder process.)
  - 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. Status: Not adopted. Stakeholder process.)
  - 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. Status: Not adopted. Stakeholder process.)
  - The MMU recommends calculating LOC based on segments of hours not on an hourly basis in the calculation of credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that up-to congestion transactions be required to pay energy uplift charges. (Priority: High. First reported 2013. Status: Not adopted. Stakeholder process.)
- 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. Status: Not adopted. Stakeholder process.)
- The MMU recommends allocating the energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements. (Priority: Medium. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted. Stakeholder process.)

- 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. Status: Not adopted.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported Q1, 2014. Status: Not adopted. Stakeholder process.)

Section 5, Capacity[11]

The MMU recognizes that PJM has proposed the Capacity Performance construct to replace some of the existing core market rules and to address fundamental performance incentive issues. The MMU recognizes that the Capacity Performance construct addresses many of the MMU's recommendations. Until new rules are in place, the MMU's recommendations and the reported status of those recommendations are based on the existing capacity market rules. The status is reported as adopted if the recommendation was included in FERC's order approving PJM's Capacity Performance filing.[12]

- 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.[13] [14] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- 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. Status: Adopted.)
- 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. Status: Adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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 2010. Status: Not adopted.)
- The MMU recommends three changes with respect to capacity imports into PJM:
  - The MMU recommends that all capacity have firm transmission to the PJM border acquired prior to the offering in an RPM auction. (Priority: High. First reported 2014. Status: Adopted.)
  - The MMU recommends that all capacity imports be required to be pseudo tied prior to the relevant Delivery Year in order to ensure that imports are as close to full substitutes for internal, physical capacity

11 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.
12 *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (June 9, 2015).
13 See also Comments of the Independent Market Monitor for PJM. Docket No. ER14-503-000 (December 20, 2013).
14 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).

resources as possible. (Priority: High. First reported 2014. Status: Adopted.)

- The MMU recommends that all resources importing capacity into PJM accept a must offer requirement. (Priority: High. First reported 2014. Status: Adopted.)

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[15,16] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that the rule requiring that relatively small proposed increases in the capability of a Generation Capacity Resource be treated as planned for purposes of mitigation and exempted from offer capping be removed. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[17] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends two changes to the RPM solution methodology related to make-whole payments and the iterative reconfiguration of the VRR curve:
  - The MMU recommends changing the RPM solution methodology to explicitly incorporate the cost of make-whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU also recommends changing the RPM solution methodology to define variables for the nesting relationships in the BRA optimization model directly rather than employing the current iterative approach, in order to improve the efficiency and stability. (Priority: Medium. First reported 2014. Status: Not adopted.)
- 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. Status: Adopted.)
  - 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. Status: Not adopted. Pending before FERC.)
  - 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. Status: Adopted.)
  - 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.[18] (Priority: Medium. First reported 2013. Status: Not adopted. Pending before FERC.)

15 See PJM Interconnection, L.L.C., Docket No. ER12-513 (December 1, 2011) ("Triennial Review").
16 See the *2012 State of the Market Report for PJM*, Volume II, Section 6, Net Revenue.
17 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).
18 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).

Section 6, Demand Response

The MMU recognizes the substantial uncertainty related to the treatment of demand response in wholesale power markets which depends on Supreme Court review and on FERC treatment of PJM's Capacity Performance filing. The MMU recognizes that PJM has incorporated some of these recommendations in the Capacity Performance filing. The status of each recommendation reflects the status at June 30, 2015.

- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate registrations that are no longer capable of responding to PJM dispatch directives, such as in the case of bankrupt and out of service facilities. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, 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. Status: Not Adopted.[19] Pending before FERC.)
- The MMU recommends that, if demand response remains in the PJM market, 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 and not triggering the definition of an emergency. (Priority: High. First reported 2012. Status: Partially adopted.)
- The MMU recommends that, if demand response remains in the PJM market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[20] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that, if demand response remains in the PJM market, 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.[21] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that, if demand response remains in the PJM market, the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Adopted in full, Q1, 2014.)
- The MMU recommends that, if demand response remains in the PJM market, demand resources be required to provide their nodal location on the electricity grid. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, measurement and verification methods for demand resources be further modified to more accurately reflect compliance. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, 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. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, 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.[22] (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance. (Priority: Medium. First reported 2013. Status: Not adopted. Pending before FERC.)

19 PJM's Capacity Performance proposal includes this change. See "Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA")," Docket No. ER15-632-000 and "PJM Interconnection, L.L.C." Docket No. EL15-29-000.

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

21 *Id* at 1.

22 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 February 17, 2015) 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, if demand response remains in the PJM market, demand resources whose load drop method is designated as "Other" explicitly record the method of load drop. (Priority: Low. First reported 2013. Status: Adopted in full, Q2, 2014.)
- The MMU recommends that, if demand response remains in the PJM market, load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends, as a preferred alternative to having PJM demand side programs, that demand response be on the demand side of the markets and that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion and that customer payments be determined only by metered load. (Priority: High. First reported 2014. Status: Not adopted. Pending before FERC.)

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 2012. Status: Not adopted.)
- 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. First reported 2009. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1200 on the 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. First reported Q3 2014. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that remove 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 constraints, similar to any other constraint within an LMP market. (Priority: Medium. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- The MMU recommends that the validation method also require market participants to submit transactions on market paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)

- 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. Status: Not adopted. Stakeholder process.)
- 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. Status: Not adopted.)
- The MMU recommends that PJM immediately provide the required 12-month notice to Duke Energy Progress (DEP) to unilaterally terminate the Joint Operating Agreement. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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. Status: Adopted partially, Q4 2013.)
- The MMU recommends that PJM implement additional business rules to remove the incentive to engage in sham scheduling activities using the PJM/IMO interface price. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM file revisions to the marginal loss surplus allocation method to fully comply with the February 24, 2009, Order. The MMU recommends that marginal loss surplus allocations be capped such that the marginal loss surplus credits cannot exceed the contributions made to the fixed costs of the transmission system for any reason. (Priority: Medium. First reported 2014. Status: Not adopted.)

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. Status: Not adopted.)
- 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. Status: Not adopted. Stakeholder process.)
- The MMU recommends that no payments be made to tier 1 resources if they are deselected in the PJM market solution. (Priority: High. First reported Q3, 2014. Status: Adopted July 2014.)
- The MMU recommends that the tier 2 synchronized reserve must-offer provision of scarcity pricing be enforced. As of the end of December 31, 2014 compliance with the tier 2 must-offer provision was 99.5 percent. (Priority: Medium. First reported 2013. Status: Adopted partially.)
- 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 2012. Status: Not adopted.)
- The MMU recommends 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- The MMU recommends that the three pivotal supplier test be incorporated in the DASR Market. (Priority: Low. First reported 2009. Status: Not adopted.)

- The MMU recommends that a reason code be attached to every hour in which PJM dispatch adds additional DASR MW. The addition of such a code would make the reason explicit, increase transparency and facilitate analysis of the use of PJM's ability to add DASR MW. (Priority: Medium. New recommendation. Status: not adopted.)

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, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for 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. Status: Not adopted.)
- 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.[23] (Priority: Low. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not Adopted.)
- 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. Status: Partially adopted, 2014.)
- The MMU recommends that PJM enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and merchant transmission providers in the Regional Transmission Expansion Plan. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM reevaluate all transmission outage tickets as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)

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

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. Status: Not adopted.)
- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR marketplace participants. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM 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. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models. (Priority: Low. First reported 2013. Status: Adopted partially, 14/15 planning period.)
- The MMU recommends that PJM 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. Status: Adopted partially, 14/15 planning period.)
- The MMU recommends that PJM implement a seasonal ARR and FTR allocation system to better represent outages. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate overallocation requirement of ARRs in the Annual ARR Allocation process. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM 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. Status: Not adopted. (Pending before FERC.)
- 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. Status: Not adopted.)

Energy Market

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

The Market Monitoring Unit (MMU) analyzed measures of market structure, participant conduct and market performance for the first six months of 2015, including market size, concentration, residual supply index, and price.[1] The MMU concludes that the PJM energy market results were competitive in the first six months of 2015.

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 in the first six months of 2015 was moderately concentrated. Average HHI was 1117 with a minimum of 916 and a maximum of 1468 in the first six months of 2015.
- 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, although high markups during periods of high demand did affect prices.
- Market design was evaluated as effective because the analysis shows that the PJM Energy Market resulted in competitive market outcomes. 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 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 basis for competitive outcomes) and on limiting market power mitigation to

1 Analysis of 2015 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 *2014 State of the Market Report for PJM*, Appendix A, "PJM Geography."

2 PJM. OATT Attachment M (PJM Market Monitoring Plan).

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. If market-based offer caps are raised, or if generators are allowed to modify offers hourly, aggregate market power mitigation rules need to be developed.

Overview

Market Structure

- **Supply.** Supply includes physical generation and imports and virtual transactions. Average offered real-time generation decreased by 11,851 MW, or 7.1 percent, in the first six months of 2015 from an average maximum of 167,891 MW to 156,040 MW. This decrease was a result of unit retirements between July 1, 2014, and June 30, 2015 and unit outages. In the first six months of 2015, 948.2 MW of new capacity were added to PJM. This new generation was offset by the deactivation of 105 units (9,770.5 MW) since January 1, 2015.

  PJM average real-time generation in the first six months of 2015 decreased by 2.6 percent from the first six months of 2014, from 92,458 MW to 90,097 MW.

  PJM average day-ahead supply in the first six months of 2015, including INCs and up-to congestion transactions, decreased by 30.5 percent from the first six months of 2014, from 165,620 MW to 115,148 MW.

- **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 six months of 2015, coal units provided 34.7 percent, nuclear units 28.6 percent and gas units 23.3 percent of total generation. Compared to the first six months of 2014, generation from coal units decreased 17.2 percent, generation from gas units increased 23.9 percent and generation from nuclear units increased 1.5 percent.

- **Marginal Resources.** In the PJM Real-Time Energy Market, in the first six months of 2015, coal units were 56.12 percent of marginal resources and natural gas units were 32.85 percent of marginal resources. In the first six months of 2014, coal units were 48.59 percent and natural gas units were 42.02 percent of the marginal resources.

  In the PJM Day-Ahead Energy Market in the first six months of 2015, up-to congestion transactions were 74.1 percent of marginal resources, INCs were 5.4 percent of marginal resources, DECs were 9.1 percent of marginal resources, and generation resources were 11.1 percent of marginal resources in the first six months of 2015.

- **Demand.** Demand includes physical load and exports and virtual transactions. The PJM system peak load during the first six months of 2015 was 143,086 MW in the HE 0800 on February 20, 2015, which was 1,441 MW, or 1.0 percent, higher than the PJM peak load for the first six months of 2014, which was 141,673 MW in the HE 1700 on June 17, 2014.

  PJM average real-time load in the first six months of 2015 increased by 0.1 percent from the first six months of 2014, from 90,529 MW to 90,586 MW. PJM average day-ahead demand in the first six months of 2015, including DECs and up-to congestion transactions, decreased by 30.5 percent from the first six months of 2014, from 160,805 MW to 111,749 MW.

- **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 six months of 2015, 11.6

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.

percent of real-time load was supplied by bilateral contracts, 30.8 percent by spot market purchases and 57.6 percent by self-supply. Compared with the first six months of 2014, reliance on bilateral contracts increased by 1.0 percent, reliance on spot market purchases increased by 4.1 percentage points and reliance on self-supply decreased by 5.1 percentage points.

- **Supply and Demand: Scarcity.** There were no shortage pricing events in the first six months of 2015.

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 six months of 2014 and 2015. In the Real-Time Energy Market, for units committed to provide energy for local constraint relief, offer-capped unit hours decreased from 0.7 percent in the first six months of 2014 to 0.5 percent in the first six months of 2015.

  In the first six months of 2015, 14 control zones experienced congestion resulting from one or more constraints binding for 50 or more hours. The analysis of the application of the TPS test to local markets demonstrates that it is working successfully to offer cap pivotal owners when the market structure is noncompetitive and to ensure that owners are not subject to offer capping when the market structure is competitive.

- **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 increased from 0.5 percent in the first six months of 2014 to 0.6 percent in the first six months of 2015. In the Real-Time Energy Market, for units committed for reliability reasons, offer-capped unit hours increased from 0.4 percent in the first six months of 2014 to 0.5 percent in the first six months of 2015.

- **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 six months of 2015, 83.6 percent of marginal units had average dollar markups less than zero and had an average markup index less than or equal to zero. In the first six months of 2015, 7.9 percent of units had average dollar markups greater than or equal to $150. In the first six months of 2014, 11.3 percent of units had average dollar markups greater than or equal to $150.

  In the PJM Day-Ahead Energy Market in the first six months of 2015, 90.0 percent of marginal units had an average markup index less than or equal to zero. In the first six months of 2015, 4.0 percent of units had average dollar markups greater than or equal to $150. In the first six months of 2014, 3.8 percent of units had average dollar markups greater than or equal to $150.

- **Frequently Mitigated Units (FMU) and Associated Units (AU).** A new FMU rule became effective November 1, 2014, limiting the availability of FMU adders to units with net revenues less than unit going forward costs. The effects of the new rules were first observed in units eligible for an FMU or AU adder in December 2014, where the number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero in December 2014, and zero in the first six months of 2015.

- **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. The reduction in up-to congestion transactions (UTC) continued, following a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[4]

- **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

4 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).

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 six months of 2015, 51.2 percent were offered as available for economic dispatch, 23.8 percent were offered as self scheduled, and 21.2 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 six months of 2015 were between $250 and $300 for one hour.

  PJM Real-Time Energy Market prices decreased in the first six months of 2015 compared to the first six months of 2014. The load-weighted average real-time LMP was 39.5 percent lower in the first six months of 2015 than in the first six months of 2014, $42.30 per MWh versus $69.92 per MWh.

  PJM Day-Ahead Energy Market prices decreased in the first six months of 2015 compared to the first six months of 2014. The load-weighted average day-ahead LMP was 38.8 percent lower in the first six months of 2015 than in the first six months of 2014, $43.26 per MWh versus $70.67 per MWh.[5]

- **Components of LMP.** In the PJM Real-Time Energy Market, for the first six months of 2015, 40.8 percent of the load-weighted LMP was the result of coal costs, 30.2 percent was the result of gas costs and 0.71 percent was the result of the cost of emission allowances.

  In the PJM Day-Ahead Energy Market for the first six months of 2015, 30.6 percent of the load-weighted LMP was the result of the cost of coal, 15.6 percent was the result of the cost of gas, 5.3 percent was the result of the up-to congestion transactions, 20.4 percent was the result of DECs and 11.4 percent was the result of INCs.

- **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 in the first six months of 2015, the adjusted markup component of LMP was $2.42 per MWh or 5.7 percent of the PJM real-time, load-weighted average LMP. The month of February had the highest adjusted markup component, $6.44 per MWh, or 12.65 percent of the real-time load-weighted average LMP. In the first six months of 2014, the adjusted markup was $4.61 per MWh or 6.8 percent of the PJM real-time load-weighted average LMP.

  In the PJM Day-Ahead Energy Market, marginal INCs, DECs and UTCs have zero markups. In the first six months of 2015, the adjusted markup component of LMP resulting from generation resources was $0.64 per MWh or 1.5 percent of the PJM day-ahead load-weighted average LMP.

  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 the Day-Ahead and Real-Time Energy Markets, although the behavior of some participants during the high demand periods in the first quarter 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 -$1.38 per MWh in the first six months of 2014 and -$1.11 per MWh in the first six months of 2015. The difference between average day-ahead and real-time prices, by itself, is not a measure of the competitiveness or effectiveness of the Day-Ahead Energy Market.

5 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."

Scarcity

- There were no shortage pricing events in the first six months of 2015.

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 that affect 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. Status: Adopted partially, Q4, 2014.)

  The MMU and PJM proposed, and on October 31, 2014, the Commission approved, a compromise that limited FMU adders to units with net revenues less than unit going forward costs or ACR.[6]

- 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. Status: Adopted in full, Q4, 2014.)
- The MMU recommends that PJM remove non-specific fuel types such as “other” or “co-fire other” from the list of fuel types available for market participants to identify the fuel type associated with their price and cost schedules. The MMU recommends that PJM require every market participant to make available at least one cost schedule with the same fuel-type and parameters as that of their offered price schedule. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that the definition of maximum emergency status in the tariff apply at all times rather than just during maximum emergency events.[7] (Priority: Medium. First reported 2012. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- There is currently no PJM documentation in the tariff or manuals explaining how hubs are created and how their definitions are changed.[8] 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.[9] (Priority: Low. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted.)

6 149 FERC ¶ 61,091 (2014).
7 PJM. OATT Section: 6A.1.3 Maximum Emergency, (February 25, 2014), p. 1740, 1795.
8 The general definition of a hub can be found in PJM. “Manual 35: Definitions and Acronyms,” Revision 23 (April 11, 2014).
9 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 identify and collect data on available behind the meter generation resources, including nodal location information and relevant operating parameters. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that generation owners be permitted to submit cost-based and price-based offers above the $1,000/MWh energy offer cap if both offer types are calculated in accordance with PJM's Cost Development Guidelines excluding the ten percent adder, subject to after the fact review by the MMU. Such offers should be allowed to set LMP. (Priority: Medium. First reported 2014. Status: Not adopted. Pending before FERC.)
- 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, 2010. Status: Not adopted.)

Conclusion

The MMU analyzed key elements of PJM energy market structure, participant conduct and market performance in the first six months of 2015, 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 11,851 MW in the first six months of 2015 compared to the first six months of 2014, while peak load increased by 1,441 MW. Market concentration levels remained moderate although there is high concentration in the intermediate and peaking segments which adds to concerns about market power when market conditions are tight. The 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 although the market structure during high demand hours remains a concern.

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 in the first six months of 2015 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.[10] 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

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

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 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 the first quarter. This is evidence of generally competitive behavior and competitive market outcomes, although the behavior of some participants during the high demand periods in the first quarter 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 and provide a reason to use cost as the sole basis for hourly changes in offers or offers greater than $1,000 per MWh. The MMU concludes that the PJM energy market results were competitive in the first six months of 2015.

Market Structure

Market Concentration

Analyses of supply curve segments of the PJM energy market in the first six months of 2015 indicates moderate concentration in the base load segment, but high concentration in the intermediate and peaking segments.[11] High concentration levels, particularly in the peaking segment, increase the probability that a generation owner will be pivotal during high demand periods.

When transmission constraints exist, local markets are created with ownership that is typically significantly more concentrated than the overall energy market. PJM offer-capping rules that limit the exercise of local market power were generally effective in preventing the exercise of market power in these areas during the first six months of 2015.

11 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.

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.[12]

PJM HHI Results

Calculations for hourly HHI indicate that by the FERC standards, the PJM energy market during the first six months of 2015 was moderately concentrated (Table 3-2).

Table 3-2 PJM hourly Energy Market HHI: January through June 2014 and 2015[13]

	Hourly Market HHI (Jan - Jun, 2014)	Hourly Market HHI (Jan - Jun, 2015)
Average	1138	1117
Minimum	891	916
Maximum	1407	1468
Highest market share (One hour)	29%	30%
Average of the highest hourly market share	21%	21%
# Hours	4,343	4,343
# 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 six months of 2014 and 2015.

Table 3-3 PJM hourly Energy Market HHI (By supply segment): January through June 2014 and 2015

	Jan - Jun, 2014			Jan - Jun, 2015		
	Minimum	Average	Maximum	Minimum	Average	Maximum
Base	1029	1174	1454	1021	1148	1489
Intermediate	727	1719	5693	693	2016	8147
Peak	713	6119	10000	802	6080	10000

Figure 3-1 shows the number of units in the baseload, intermediate and peaking segments by fuel source in the first six months of 2015.

12 77 FERC ¶ 61,263, pp. 64-70 (1996), "*Inquiry Concerning the Commission's Merger Policy under the Federal Power Act: Policy Statement.*"

13 This analysis includes all hours in 2014 and 2015, regardless of congestion.

Figure 3-1 Fuel source distribution in unit segments: January through June 2015

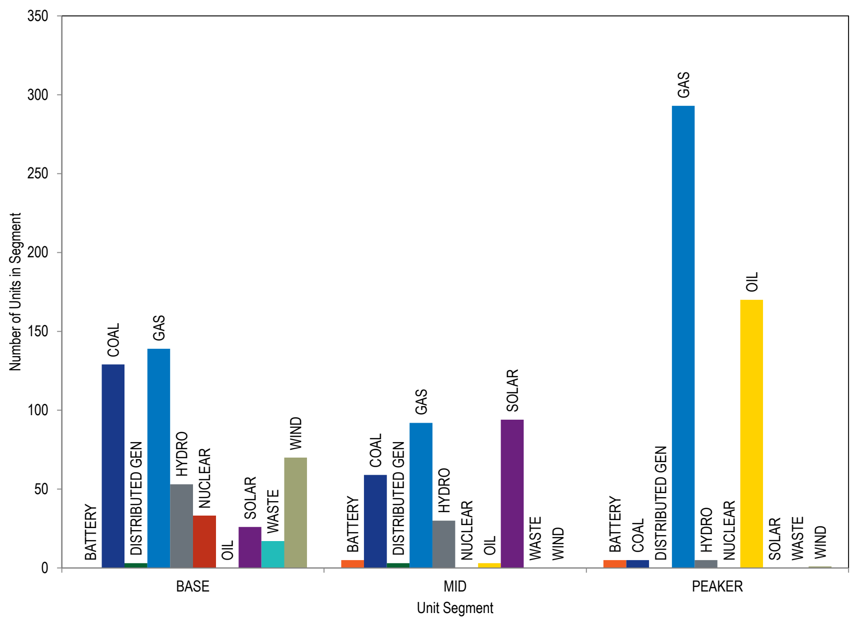
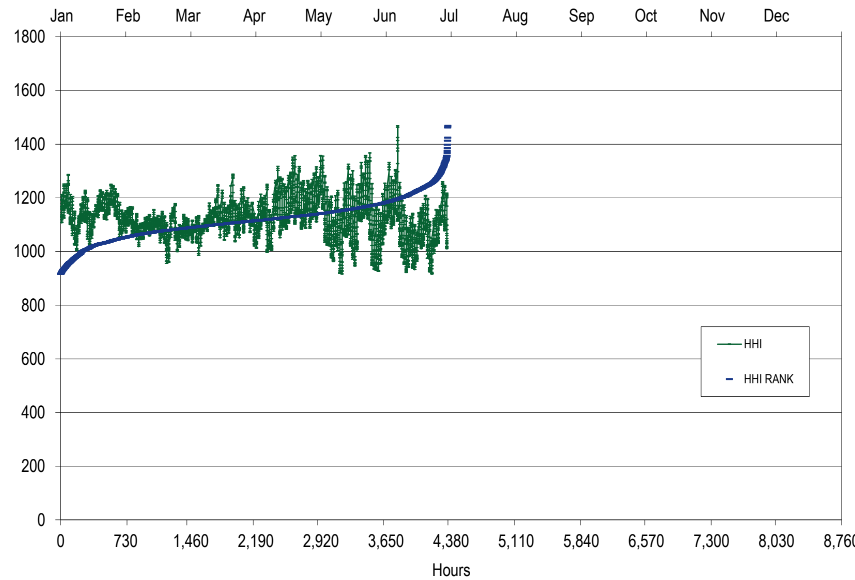


Figure 3-2 presents the hourly HHI values in chronological order and an HHI duration curve for the first six months of 2015.

Figure 3-2 PJM hourly Energy Market HHI: January through June 2015



Ownership of Marginal Resources

Table 3-4 shows the contribution to real-time, load-weighted LMP by individual marginal resource owner.[14] The contribution of each marginal resource to price at each load bus is calculated for each five-minute interval of 2015, and summed by the parent company that offers the marginal resource into the Real-Time Energy Market. The results show that in the first six months of 2015, the offers of one company contributed 17.8 percent of the real-time, load-weighted PJM system LMP and that the offers of the top four companies contributed 54.7 percent of the real-time, load-weighted, average PJM system LMP. During the first six months of 2014, the offers of one company contributed 18.2 percent of the real time, load-weighted PJM system LMP and offers of the top four companies contributed 53.7 percent of the real-time, load-weighted, average PJM system LMP.

14 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 June 2014 and 2015

2014 (Jan-Jun)		2015 (Jan-Jun)	
Company	Percent of Price	Company	Percent of Price
1	18.2%	1	17.8%
2	14.6%	2	15.6%
3	12.1%	3	11.4%
4	8.8%	4	9.9%
5	7.6%	5	8.3%
6	6.6%	6	8.2%
7	6.2%	7	5.3%
8	4.8%	8	5.0%
9	3.8%	9	2.8%
Other (58 companies)	17.3%	Other (57 companies)	15.7%

Table 3-5 shows the contribution to day-ahead, load-weighted LMP by individual marginal resource owners.[15] 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 (10.5 percent), in the first six months of 2014 also had the largest impact (16.5 percent) in the first six months of 2015.

Table 3-5 Marginal resource contribution to PJM day-ahead, load-weighted LMP (By parent company): January through June of 2014 and 2015

2014 (Jan - Jun)		2015 (Jan - Jun)	
Company	Percent of Price	Company	Percent of Price
1	10.5%	1	16.5%
2	7.3%	2	10.7%
3	7.0%	3	7.6%
4	6.2%	4	5.8%
5	6.1%	5	5.2%
6	5.7%	6	5.1%
7	4.3%	7	4.7%
8	3.8%	8	4.5%
9	3.3%	9	3.5%
Other (133 companies)	45.9%	Other (136 companies)	36.4%

15 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 six months of 2014, coal units were 56.12 percent and natural gas units were 32.85 percent of marginal resources. In the first six months of 2014, coal units were 48.59 percent and natural gas units were 42.02 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.[16] In the first six months of 2015, 68.81 percent of the wind marginal units had negative offer prices, 24.47 percent had zero offer prices and 3.73 percent had positive offer prices.

16 Prior to April 1, 2015, for the generation units that are capable of using multiple fuel types, PJM did 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.

Table 3-6 Type of fuel used (By real-time marginal units): January through June 2014 and 2015

Type/Fuel	2014 (Jan - Jun)	2015 (Jan - Jun)
Coal	48.59%	56.12%
Gas	42.02%	32.85%
Oil	3.64%	7.37%
Wind	5.10%	3.11%
Other	0.42%	0.43%
Municipal Waste	0.05%	0.06%
Uranium	0.09%	0.05%
Emergency DR	0.08%	0.00%

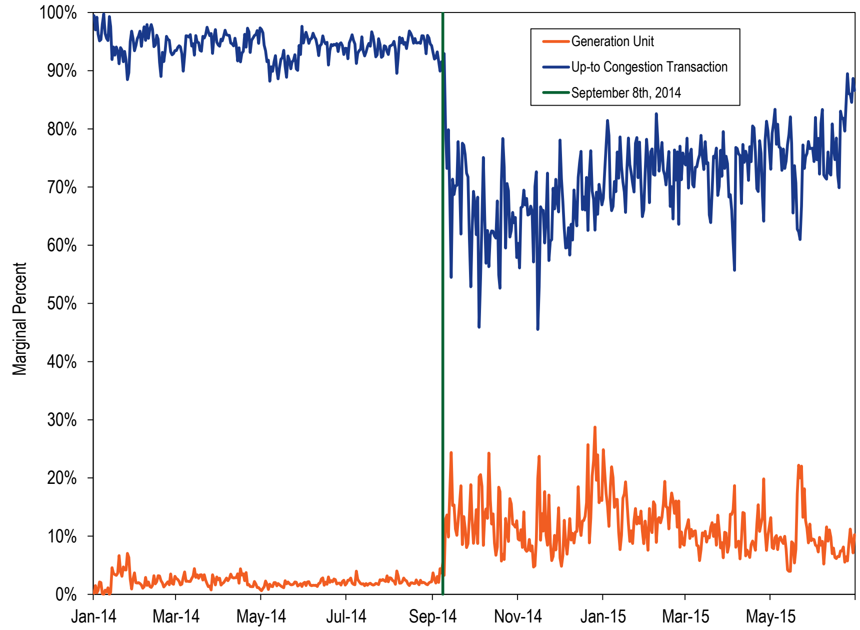
Table 3-7 shows the type and fuel type where relevant, of marginal resources in the Day-Ahead Energy Market. In the first six months of 2015, up-to congestion transactions were 74.06 percent of the total marginal resources. Up-to congestion transactions were 94.15 percent of the total marginal resources in the first six months of 2014.

Table 3-7 Day-ahead marginal resources by type/fuel: January through June of 2014 and 2015

Type/Fuel	2014 (Jan - Jun)	2015 (Jan - Jun)
Up-to Congestion Transaction	94.15%	74.06%
DEC	2.07%	9.11%
INC	1.38%	5.35%
Coal	1.19%	7.09%
Gas	0.94%	3.29%
Wind	0.11%	0.18%
Dispatchable Transaction	0.10%	0.38%
Oil	0.02%	0.42%
Other	0.02%	0.05%
Price Sensitive Demand	0.01%	0.04%
Import	0.01%	0.00%
Municipal Waste	0.00%	0.01%
Total	100.00%	100.00%

Figure 3-3 shows, for the Day-Ahead Market in 2014 through June of 2015, 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 that date.[17] The percentage of marginal up-to congestion transaction decreased and that of generation units increased.

Figure 3-3 Day-ahead marginal up-to congestion transaction and generation units: 2014 through June of 2015



Supply

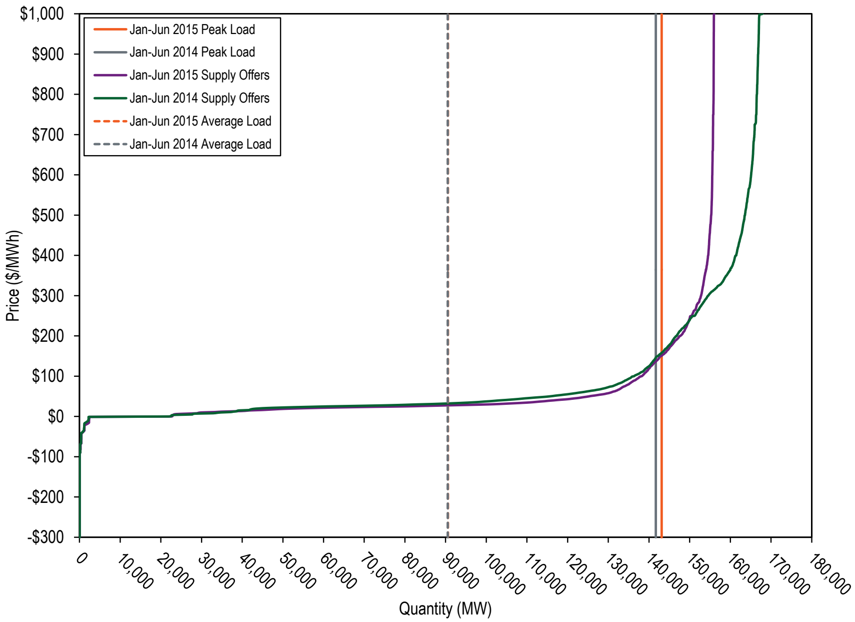
Supply includes physical generation and imports and virtual transactions.

Figure 3-4 shows the average PJM aggregate real-time generation supply curves by offer price, peak load and average load for January through June of 2014 and 2015. Total average PJM aggregate real-time generation supply decreased by 11,851 MW, or 7.1 percent, in the first six months of 2015 from an average maximum of 167,891 MW to 156,040 MW in the first six months

17 See 18 CFR § 385.213 (2014).

of 2015. This decrease was a result of unit retirements between July 1, 2014, and June 30, 2015 and unit outages.

Figure 3-4 Average PJM aggregate real-time generation supply curves by offer price: January through June of 2014 and 2015



Energy Production by Fuel Source

In the first six months of 2015, generation from coal units decreased 16.3 percent and generation from natural gas units increased 29.2 percent compared to the first six months of 2014 (Table 3-8).[18]

Table 3-8 PJM generation (By fuel source (GWh)): January through June of 2014 and 2015[19]

		Jan-Jun 2014		Jan-Jun 2015		Change in
		GWh	Percent	GWh	Percent	Output
Coal		186,497.4	45.8%	156,026.8	39.4%	(16.3%)
	Standard Coal	184,552.9	45.3%	154,324.2	39.0%	(16.4%)
	Waste Coal	1,944.5	0.5%	1,702.6	0.4%	(12.4%)
Nuclear		134,954.5	33.1%	136,978.9	34.6%	1.5%
Gas		65,564.7	16.1%	84,695.5	21.4%	29.2%
	Natural Gas	63,810.4	15.7%	82,781.3	20.9%	29.7%
	Landfill Gas	1,183.3	0.3%	1,237.3	0.3%	4.6%
	Biomass Gas	571.0	0.1%	676.9	0.2%	18.5%
Hydroelectric		8,241.9	2.0%	6,585.4	1.7%	(20.1%)
	Pumped Storage	3,451.6	0.8%	2,696.9	0.7%	(21.9%)
	Run of River	4,790.3	1.2%	3,888.5	1.0%	(18.8%)
Wind		8,678.0	2.1%	8,760.8	2.2%	1.0%
Waste		2,334.9	0.6%	2,252.8	0.6%	(3.5%)
	Solid Waste	2,027.2	0.5%	1,988.8	0.5%	(1.9%)
	Miscellaneous	307.7	0.1%	264.1	0.1%	(14.2%)
Oil		809.0	0.2%	597.5	0.2%	(26.1%)
	Heavy Oil	340.8	0.1%	408.6	0.1%	19.9%
	Light Oil	374.3	0.1%	140.6	0.0%	(62.4%)
	Diesel	70.4	0.0%	46.6	0.0%	(33.8%)
	Kerosene	23.5	0.0%	1.7	0.0%	(92.7%)
	Jet Oil	0.0	0.0%	0.0	0.0%	NA
Solar, Net Energy Metering		201.4	0.0%	262.1	0.0%	30.1%
Battery		5.4	0.0%	2.7	0.0%	(50.1%)
Total		407,287.2	100.0%	396,162.5	100.0%	(2.7%)

18 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.

19 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 June 2015

		Jan	Feb	Mar	Apr	May	Jun	Total
Coal		32,666.4	33,315.4	25,902.0	18,265.1	21,619.0	24,258.9	156,026.8
	Standard Coal	32,309.5	32,992.8	25,589.6	18,068.7	21,363.2	24,000.4	154,324.2
	Waste Coal	356.8	322.6	312.4	196.4	255.8	258.5	1,702.6
Nuclear		25,881.8	21,994.5	22,290.8	20,346.7	22,641.7	23,823.5	136,978.9
Gas		13,916.1	13,271.0	14,467.2	12,119.3	14,292.4	16,629.6	84,695.5
	Natural Gas	13,567.7	12,957.9	14,155.0	11,840.9	13,978.2	16,281.5	82,781.3
	Landfill Gas	218.1	192.1	212.7	203.7	214.7	196.1	1,237.3
	Biomass Gas	130.4	121.0	99.5	74.7	99.5	151.9	676.9
Hydroelectric		954.0	763.3	1,152.5	1,379.8	1,025.2	1,310.5	6,585.4
	Pumped Storage	398.8	388.7	344.7	331.4	504.2	729.1	2,696.9
	Run of River	555.2	374.6	807.7	1,048.4	521.1	581.5	3,888.5
Wind		1,683.6	1,526.6	1,724.1	1,657.3	1,213.9	955.2	8,760.8
Waste		400.9	324.0	357.1	378.6	384.8	407.5	2,252.8
	Solid Waste	347.8	279.7	308.0	335.4	347.2	370.7	1,988.8
	Miscellaneous	53.1	44.3	49.1	43.2	37.5	36.8	264.1
Oil		81.0	408.6	13.1	5.3	43.8	45.7	597.5
	Heavy Oil	64.3	315.0	0.0	0.0	0.0	29.3	408.6
	Light Oil	13.7	58.8	10.4	5.2	40.0	12.6	140.6
	Diesel	2.9	33.4	2.5	0.2	3.8	3.8	46.6
	Kerosene	0.1	1.4	0.2	0.0	0.0	0.0	1.7
	Jet Oil	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar, Net Energy Metering		23.3	32.1	38.7	53.1	61.9	53.0	262.1
Battery		0.4	0.4	0.5	0.4	0.5	0.6	2.7
Total		75,607.5	71,635.8	65,945.9	54,205.5	61,283.2	67,484.5	396,162.5

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 11,851 MW, or 7.1 percent, in the first six months of 2015 from an average maximum of 167,891 MW to 156,040 MW in the first six months of 2015.[20] This decrease was a result of unit retirements between July 1, 2014, and June 30, 2015 and unit outages. In the first six months of 2015, 948.2 MW of new capacity were added to PJM. This new generation was offset by the deactivation of 105 units (9,770.5 MW) since January 1, 2015.

PJM average real-time generation in the first six months of 2015 decreased by 2.6 percent from the first six months of 2014, from 92,458 MW to 90,097 MW.[21]

PJM average real-time supply including imports decreased by 1.7 percent in the first six months of 2015 from the first six months of 2014, from 106,879 MW to 105,027 MW.

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.

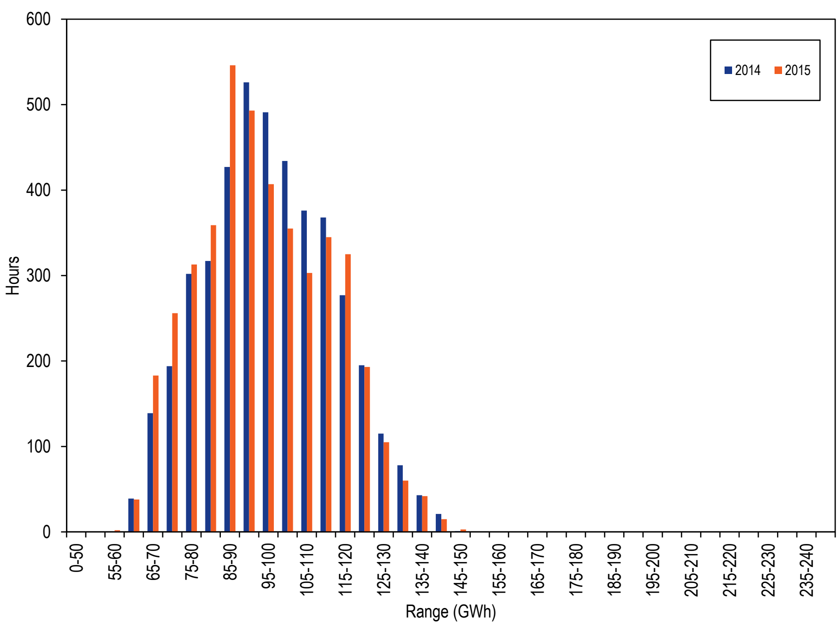
20 Calculated values shown in Section 3, "Energy Market," are based on unrounded, underlying data and may differ from calculations based on the rounded values shown in tables.
21 Generation data are the net MWh injections and withdrawals MWh at every generation bus in PJM.

- **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 Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Supply Duration

Figure 3-5 shows the hourly distribution of PJM real-time generation plus imports for the first six months of 2014 and 2015.

Figure 3-5 Distribution of PJM real-time generation plus imports: January through June of 2014 and 2015[22]



PJM Real-Time, Average Supply

Table 3-10 presents summary real-time supply statistics for each year for the first six months of the 16-year period from 2000 through 2015.[23]

Table 3-10 PJM real-time average hourly generation and real-time average hourly generation plus average hourly imports: January through June of 2000 through 2015

	PJM Real-Time Supply (MWh)				Year-to-Year Change			
	Generation		Generation Plus Imports		Generation		Generation Plus Imports	
	Generation	Standard Deviation	Supply	Standard Deviation	Generation	Standard Deviation	Supply	Standard Deviation
2000	31,523	5,560	34,190	6,329	NA	NA	NA	NA
2001	29,428	4,679	32,412	4,813	(6.6%)	(15.8%)	(5.2%)	(24.0%)
2002	30,967	5,770	34,730	6,238	5.2%	23.3%	7.2%	29.6%
2003	36,034	6,008	39,644	6,021	16.4%	4.1%	14.1%	(3.5%)
2004	41,430	9,435	45,597	9,699	15.0%	57.0%	15.0%	61.1%
2005	74,365	12,661	79,693	13,242	79.5%	34.2%	74.8%	36.5%
2006	80,249	11,011	84,819	11,574	7.9%	(13.0%)	6.4%	(12.6%)
2007	83,478	12,105	88,150	13,192	4.0%	9.9%	3.9%	14.0%
2008	83,294	12,458	88,824	12,778	(0.2%)	2.9%	0.8%	(3.1%)
2009	77,508	12,961	82,928	13,580	(6.9%)	4.0%	(6.6%)	6.3%
2010	80,702	13,968	85,575	14,455	4.1%	7.8%	3.2%	6.4%
2011	81,483	13,677	86,268	14,428	1.0%	(2.1%)	0.8%	(0.2%)
2012	86,310	13,695	91,526	14,279	5.9%	0.1%	6.1%	(1.0%)
2013	87,974	13,528	93,166	14,277	1.9%	(1.2%)	1.8%	(0.0%)
2014	92,458	15,722	98,186	16,710	5.1%	16.2%	5.4%	17.0%
2015	90,097	16,028	96,626	17,168	(2.6%)	1.9%	(1.6%)	2.7%

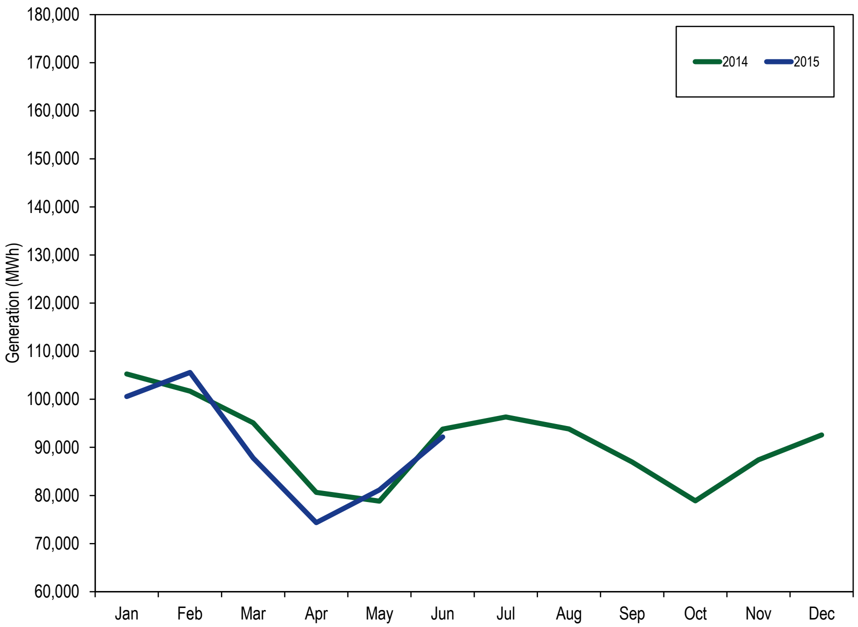
22 Each range on the horizontal axis excludes the start value and includes the end value.

23 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 3-6 compares the real-time, monthly average hourly generation in the first six months of 2014 and 2015.

Figure 3-6 PJM real-time average monthly hourly generation: January 2014 through June 2015



Day-Ahead Supply

PJM average day-ahead supply in the first six months of 2015, including INCs and up-to congestion transactions, decreased by 30.5 percent from the first six months of 2014, from 165,620 MW to 115,148 MW.

PJM average day-ahead supply in the first six months of 2015, including INCs, up-to congestion transactions, and imports, decreased by 30.0 percent from the first six months of 2014, from 167,939 MW to 117,612 MW. The reduction in PJM day-ahead supply was a result of a sharp decrease in in UTCs beginning in September 2014 based on a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[24]

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

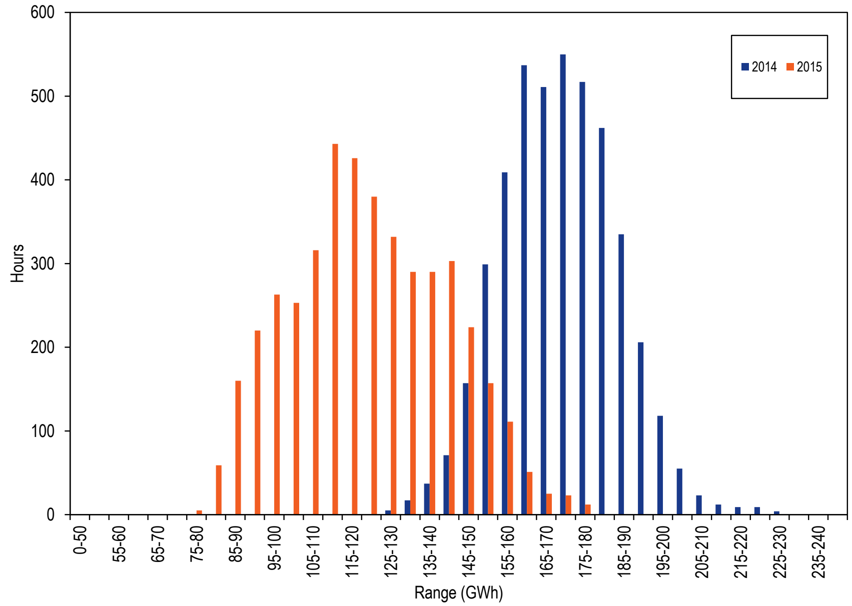
- **Self-Scheduled Generation Offer.** Offer to supply a fixed block of MWh, as a price taker, from a unit that may also have a dispatchable component above the minimum.
- **Dispatchable Generation Offer.** Offer to supply a schedule of MWh and corresponding offer prices from a unit.
- **Increment Offer (INC).** Financial offer to supply MWh and corresponding offer prices. INCs can be submitted by any market participant.
- **Up-to Congestion Transaction (UTC).** 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 3-7 shows the hourly distribution of PJM day-ahead supply, including increment offers, up-to congestion transactions, and imports for the first six months of 2014 and 2015.

24 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 3-7 Distribution of PJM day-ahead supply plus imports: January through June of 2014 and 2015[25]



PJM Day-Ahead, Average Supply

Table 3-11 presents summary day-ahead supply statistics for the first six months of each year of the 16-year period from 2000 through 2015.[26]

Table 3-11 PJM day-ahead average hourly supply and day-ahead average hourly supply plus average hourly imports: January through June 2000 through 2015

	PJM Day-Ahead Supply (MWh)				Year-to-Year Change			
	Supply		Supply Plus Imports		Supply		Supply Plus Imports	
	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation	Supply	Standard Deviation
2000	29,474	5,648	29,645	5,766	NA	NA	NA	NA
2001	26,796	4,305	27,540	4,382	(9.1%)	(23.8%)	(7.1%)	(24.0%)
2002	25,840	10,011	26,398	10,021	(3.6%)	132.5%	(4.1%)	128.7%
2003	36,420	7,000	36,994	7,023	40.9%	(30.1%)	40.1%	(29.9%)
2004	50,089	10,108	50,836	10,171	37.5%	44.4%	37.4%	44.8%
2005	87,855	14,365	89,382	14,395	75.4%	42.1%	75.8%	41.5%
2006	95,562	12,620	97,796	12,615	8.8%	(12.1%)	9.4%	(12.4%)
2007	106,470	14,522	108,815	14,772	11.4%	15.1%	11.3%	17.1%
2008	104,705	14,124	107,169	14,190	(1.7%)	(2.7%)	(1.5%)	(3.9%)
2009	97,607	16,283	100,076	16,342	(6.8%)	15.3%	(6.6%)	15.2%
2010	102,626	18,206	105,463	18,378	5.1%	11.8%	5.4%	12.5%
2011	108,143	16,666	110,656	16,926	5.4%	(8.5%)	4.9%	(7.9%)
2012	132,326	15,710	134,747	15,841	22.4%	(5.7%)	21.8%	(6.4%)
2013	148,381	15,606	150,554	15,830	12.1%	(0.7%)	11.7%	(0.1%)
2014	165,620	13,930	167,939	14,119	11.6%	(10.7%)	11.5%	(10.8%)
2015	115,148	18,849	117,612	18,994	(30.5%)	35.3%	(30.0%)	34.5%

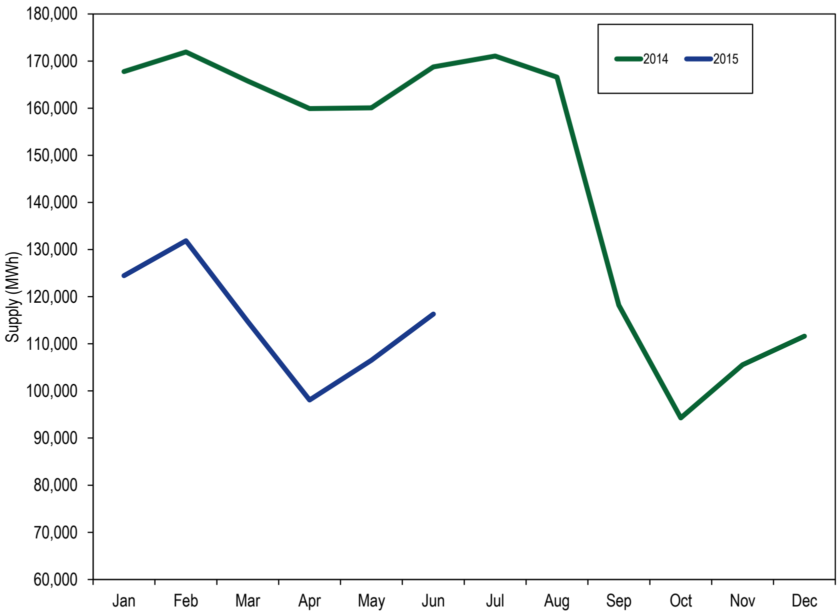
25 Each range on the horizontal axis excludes the start value and includes the end value.

26 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.

PJM Day-Ahead, Monthly Average Supply

Figure 3-8 compares the day-ahead, monthly average hourly supply, including increment offers and up-to congestion transactions, in the first six months of 2014 and 2015. The reduction in PJM day-ahead supply was a result of a sharp decrease in in UTCs beginning in September 2014 based on a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[27]

Figure 3-8 PJM day-ahead monthly average hourly supply: January 2014 through June 2015



Real-Time and Day-Ahead Supply

Table 3-12 presents summary statistics for the first six months of 2014 and 2015, 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 six months of 2015 up-to congestion transactions were 14.8 percent of the total day-ahead supply compared to 39.9 percent in the first six months of 2014.

27 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 June 2014 and 2015

		Day Ahead					Real Time		Day Ahead Less Real Time	
(Jan-Mar)		Generation	INC Offers	Up-to Congestion	Imports	Total Supply	Generation	Total Supply	Total Supply	Total Generation
Average	2014	95,332	3,240	67,048	2,319	167,939	92,458	98,186	69,753	2,874
	2015	93,011	4,713	17,425	2,464	117,612	90,097	96,626	20,986	2,914
Median	2014	94,879	3,121	67,141	2,286	167,849	91,635	97,154	70,695	3,244
	2015	92,017	4,650	17,190	2,469	116,585	88,510	94,831	21,754	3,507
Standard Deviation	2014	16,262	857	10,018	385	14,119	15,722	16,710	(2,591)	540
	2015	17,290	694	3,592	426	18,994	16,028	17,168	1,826	1,262
Peak Average	2014	104,620	3,633	66,773	2,441	177,466	100,878	107,222	70,243	3,741
	2015	101,910	4,863	18,426	2,602	127,801	97,640	104,825	22,976	4,270
Peak Median	2014	103,967	3,548	67,716	2,375	176,835	100,317	106,500	70,334	3,650
	2015	101,652	4,837	18,037	2,613	126,568	96,767	103,701	22,867	4,885
Peak Standard Deviation	2014	13,288	828	9,565	366	10,818	13,101	13,952	(3,134)	188
	2015	14,167	651	3,604	423	15,794	13,896	14,767	1,027	271
Off-Peak Average	2014	87,165	2,894	67,291	2,213	159,563	85,054	90,240	69,322	2,111
	2015	84,951	4,577	16,518	2,338	108,384	83,265	89,200	19,184	1,685
Off-Peak Median	2014	86,694	2,798	66,558	2,220	159,087	84,042	89,083	70,004	2,652
	2015	83,297	4,490	16,244	2,306	105,973	81,495	86,632	19,340	1,802
Off-Peak Standard Deviation	2014	14,115	723	10,397	370	11,035	14,018	14,789	(3,754)	96
	2015	15,852	704	3,331	388	16,807	14,716	15,755	1,052	1,136

Figure 3-9 shows the average hourly cleared volumes of day-ahead supply and real-time supply for January through June of 2015. 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 3-9 Day-ahead and real-time supply (Average hourly volumes): January through June 2015

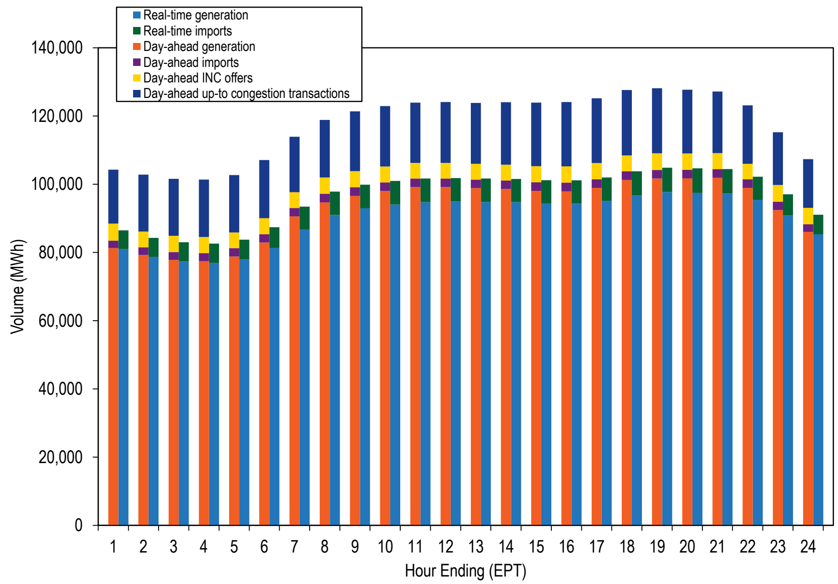


Figure 3-10 shows the difference between the day-ahead and real-time average daily supply in January 2014 through June 2015.

Figure 3-10 Difference between day-ahead and real-time supply (Average daily volumes): January 2014 through June 2015

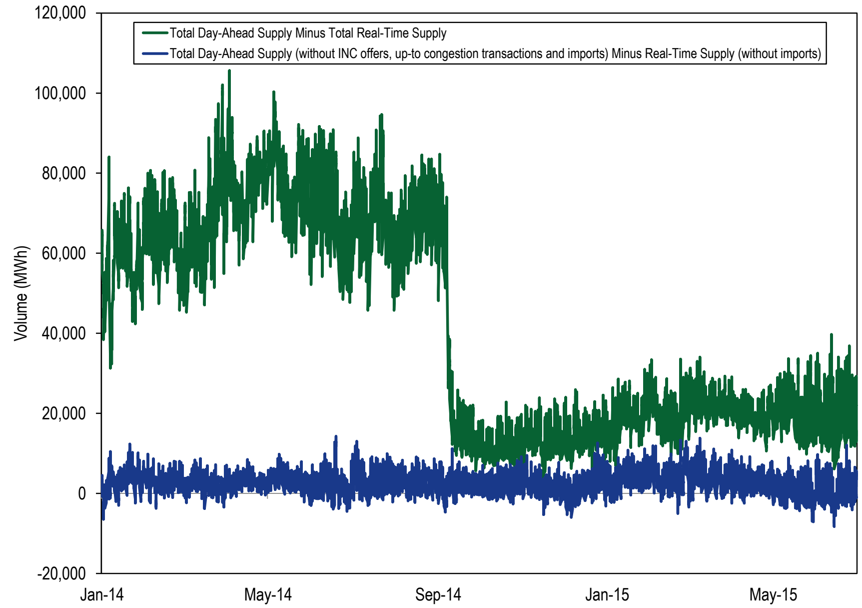
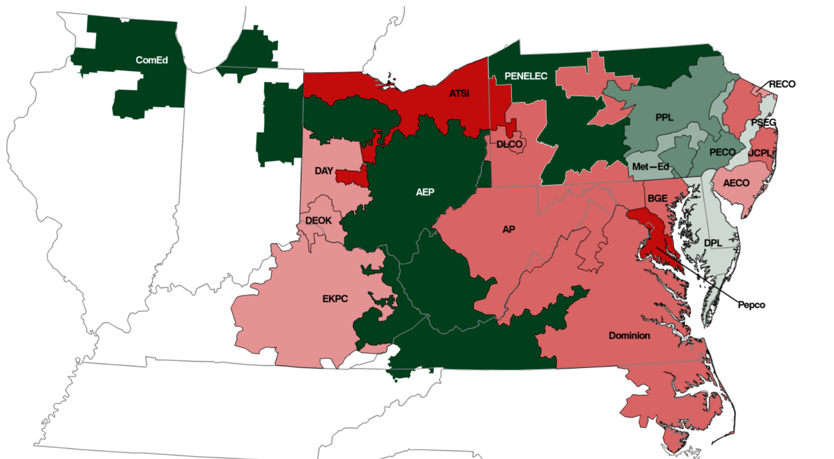


Figure 3-11 shows the difference between the PJM real-time generation and real-time load by zone in the first six months of 2015. Table 3-13 shows the difference between the PJM real-time generation and real-time load by zone in the first six months of 2014 and 2015. Figure 3-11 is color coded on a scale 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 3-11 Map of PJM real-time generation less real-time load by zone: January through June 2015[28]



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	(2,270)	ComEd	15,509	DPL	(5,713)	PENELEC	13,045
AEP	7,843	DAY	(2,177)	EKPC	(1,918)	Pepco	(10,346)
AP	(4,272)	DEOK	(4,054)	JCPL	(5,059)	PPL	4,752
ATSI	(10,611)	DLCO	1,200	Met-Ed	3,470	PSEG	1,671
BGE	(5,370)	Dominion	(5,867)	PECO	8,775	RECO	(731)

28 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.aspx> (Accessed on 7/14/2015)

Table 3-13 PJM real-time generation less real-time load by zone (GWh): January through June 2014 and 2015

Zonal Generation and Load (GWh)						
	(Jan-Jun) 2014			(Jan-Jun) 2015		
Zone	Generation	Load	Net	Generation	Load	Net
AECO	1,392.9	4,952.0	(3,559.1)	2,836.0	5,105.9	(2,269.9)
AEP	79,566.2	65,576.1	13,990.0	73,030.8	65,187.9	7,842.9
AP	22,057.4	24,691.8	(2,634.4)	20,898.6	25,170.3	(4,271.7)
ATSI	26,162.3	34,171.4	(8,009.2)	23,158.8	33,769.7	(10,610.9)
BGE	11,110.2	16,193.1	(5,082.9)	11,084.5	16,454.9	(5,370.4)
ComEd	62,191.7	48,784.7	13,406.9	62,304.6	46,795.9	15,508.8
DAY	7,109.6	8,599.0	(1,489.4)	6,356.2	8,533.2	(2,177.1)
DEOK	9,079.3	13,578.2	(4,498.9)	9,437.7	13,491.7	(4,054.0)
DLCO	41,837.2	48,093.9	(6,256.8)	43,431.8	49,298.9	(5,867.0)
Dominion	3,453.4	9,243.4	(5,790.0)	3,827.6	9,540.9	(5,713.3)
DPL	8,371.5	7,285.6	1,085.9	8,295.3	7,095.3	1,200.0
EKPC	5,696.2	6,645.9	(949.7)	4,529.2	6,447.5	(1,918.3)
JCPL	5,950.4	11,107.4	(5,157.0)	6,253.7	11,312.5	(5,058.8)
Met-Ed	10,308.8	7,673.6	2,635.2	11,241.4	7,771.3	3,470.1
PECO	29,247.1	19,819.1	9,427.9	29,003.8	20,228.4	8,775.3
PENELEC	24,080.3	8,806.4	15,273.9	21,850.0	8,804.8	13,045.3
Pepco	6,958.7	15,339.9	(8,381.2)	5,128.6	15,475.1	(10,346.5)
PPL	25,990.2	21,007.3	4,982.9	25,840.0	21,087.7	4,752.4
PSEG	20,982.1	20,881.3	100.8	22,781.3	21,110.3	1,671.0
RECO	0.0	717.2	(717.2)	0.0	731.0	(731.0)

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 six months of 2015 was 143,115 MW in the HE 0800 on February 20, 2015, which was 1,441 MW, or

1.0 percent, higher than the peak load for the first six months of 2014, which was 141,673 MW in the HE 17 on June 17, 2014.

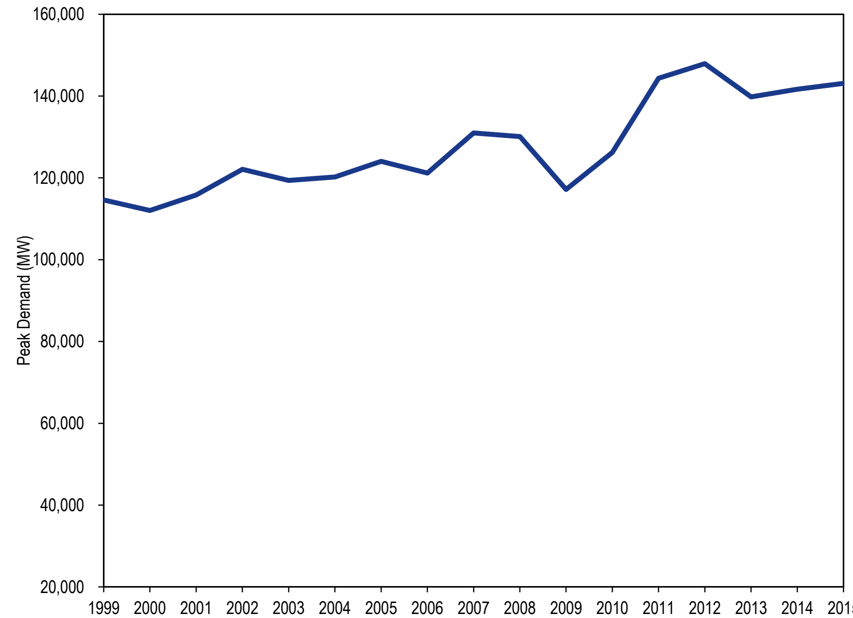
Table 3-14 shows the peak loads for the first six months of 1999 through 2015.

Table 3-14 Actual PJM footprint peak loads: January through June 1999 to 2015[29]

(Jan - Jun)	Date	Hour Ending (EPT)	PJM Load (MW)	Annual Change (MW)	Annual Change (Percent)
1999	Tue, June 08	17	114,607	NA	NA
2000	Mon, June 26	16	112,028	(2,579)	(2.3%)
2001	Thu, June 28	17	115,808	3,780	3.4%
2002	Mon, June 24	17	122,105	6,297	5.4%
2003	Wed, June 25	17	119,378	(2,727)	(2.2%)
2004	Wed, June 09	17	120,218	840	0.7%
2005	Tue, June 28	16	124,052	3,833	3.2%
2006	Tue, May 30	17	121,165	(2,887)	(2.3%)
2007	Wed, June 27	16	130,971	9,806	8.1%
2008	Mon, June 09	17	130,100	(871)	(0.7%)
2009	Fri, January 16	19	117,169	(12,930)	(9.9%)
2010	Wed, June 23	17	126,188	9,019	7.7%
2011	Wed, June 08	17	144,350	18,162	14.4%
2012	Wed, June 20	18	147,913	3,563	2.5%
2013	Tue, June 25	16	139,779	(8,134)	(5.5%)
2014	Tue, June 17	17	141,673	1,895	1.4%
2015	Fri, February 20	8	143,115	1,441	1.0%

Figure 3-12 shows the peak loads for the first six months of 1999 through 2015.

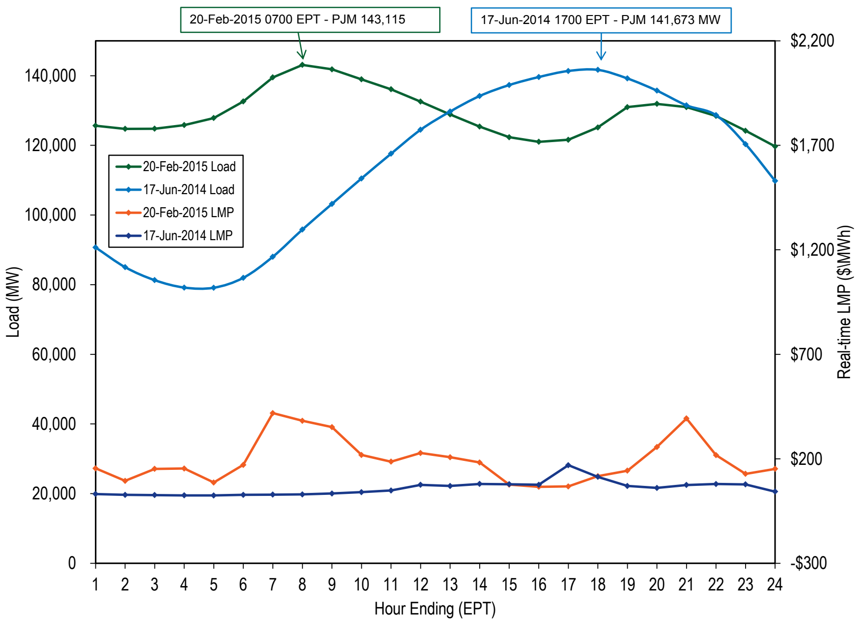
Figure 3-12 PJM footprint calendar year peak loads: January through June 1999 to 2015



29 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 3-13 compares the peak load days during the first six months of 2014 and 2015. The average hourly real-time LMP peaked at $418.74 on February 20, 2015 and peaked at $169.33 on June 17, 2014.

Figure 3-13 PJM peak-load comparison: Friday, February 20, 2015, and Tuesday, June 17, 2014



Real-Time Demand

PJM average real-time load in the first six months of 2015 increased by 0.1 percent from the first six months of 2014, from 90,529 MW to 90,586 MW.[30]

PJM average real-time demand in the first six months of 2015 decreased 1.5 percent from the first six months of 2014, from 96,189 MW to 94,782 MW.

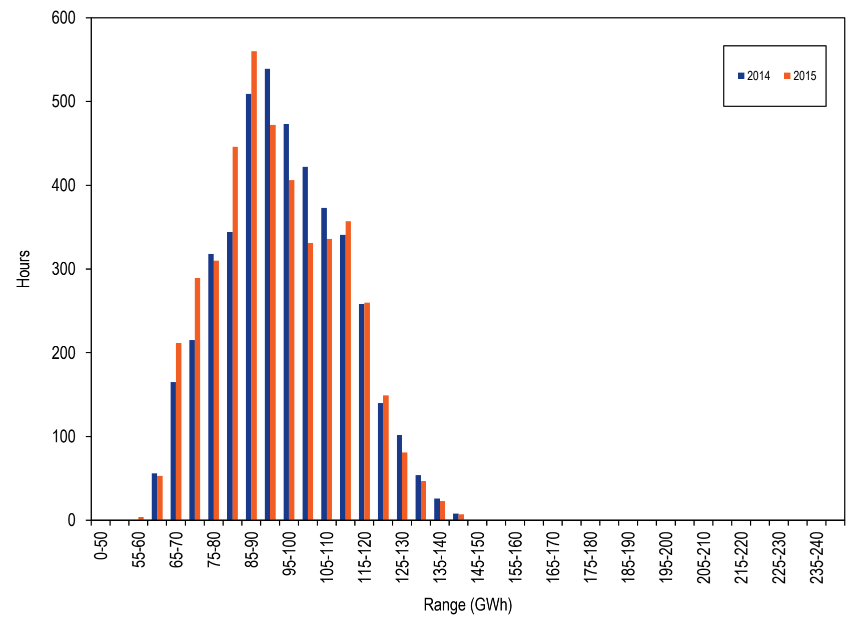
In the PJM Real-Time Energy Market, there are two types of demand:

- **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 Tag, and must pass the neighboring balancing authority checkout process.

PJM Real-Time Demand Duration

Figure 3-14 shows the hourly distribution of PJM real-time load plus exports for the first six months of 2014 and 2015.[31]

Figure 3-14 Distribution of PJM real-time accounting load plus exports: January through June 2014 and 2015[32]



30 Load data are the net MWh injections and withdrawals MWh at every load bus in PJM.

31 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>.

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

PJM Real-Time, Average Load

Table 3-15 presents summary real-time demand statistics for the first six months during the 18-year period 1998 to 2054. 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.[33]

Table 3-15 PJM real-time average hourly load and real-time average hourly load plus average hourly exports: January through June of 1998 through 2015[34]

	PJM Real-Time Demand (MWh)				Year-to-Year Change			
	Load		Load Plus Exports		Load		Load Plus Exports	
	Load	Standard Deviation	Demand	Standard Deviation	Load	Standard Deviation	Demand	Standard Deviation
1998	27,662	4,703	27,662	4,703	NA	NA	NA	NA
1999	28,714	5,113	28,714	5,113	3.8%	8.7%	3.8%	8.7%
2000	29,649	5,382	29,902	5,511	3.3%	5.3%	4.1%	7.8%
2001	30,180	5,274	32,041	5,103	1.8%	(2.0%)	7.2%	(7.4%)
2002	32,678	6,457	33,969	6,557	8.3%	22.4%	6.0%	28.5%
2003	36,727	6,428	38,775	6,554	12.4%	(0.4%)	14.1%	(0.0%)
2004	41,787	8,999	44,808	10,033	13.8%	40.0%	15.6%	53.1%
2005	71,939	13,603	78,745	13,798	72.2%	51.2%	75.7%	37.5%
2006	77,232	12,003	83,606	12,377	7.4%	(11.8%)	6.2%	(10.3%)
2007	81,110	13,499	86,557	13,819	5.0%	12.5%	3.5%	11.6%
2008	78,685	12,819	85,819	13,242	(3.0%)	(5.0%)	(0.9%)	(4.2%)
2009	75,991	12,899	81,062	13,253	(3.4%)	0.6%	(5.5%)	0.1%
2010	78,106	13,643	83,758	14,227	2.8%	5.8%	3.3%	7.3%
2011	78,823	13,931	84,288	14,046	0.9%	2.1%	0.6%	(1.3%)
2012	84,946	13,941	89,638	13,848	7.8%	0.1%	6.3%	(1.4%)
2013	86,897	13,871	91,199	13,848	2.3%	(0.5%)	1.7%	0.0%
2014	90,529	16,266	96,189	16,147	4.2%	17.3%	5.5%	16.6%
2015	90,586	16,192	94,782	16,589	0.1%	(0.5%)	(1.5%)	2.7%

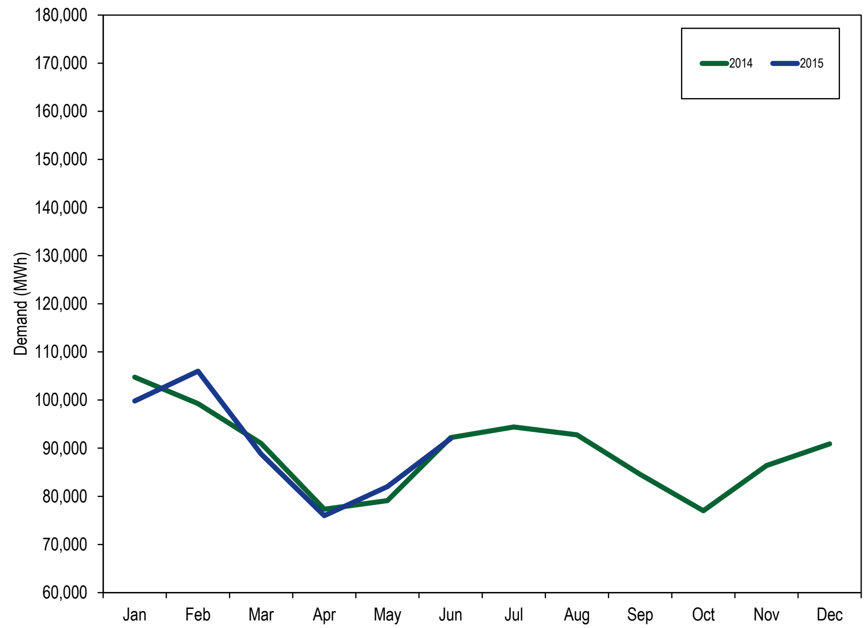
33 Accounting load is used here because PJM uses accounting load in the settlement process, which determines how much load customers pay for. In addition, the use of accounting load with losses before June 1, and without losses after June 1, 2007, is consistent with PJM's calculation of LMP, which excludes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

34 Export data 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 3-15 compares the real-time, monthly average hourly loads in the first six months of 2014 and 2015.

Figure 3-15 PJM real-time monthly average hourly load: January 2014 through June 2015



PJM real-time load is significantly affected by temperature. Figure 3-16 and Table 3-16 compare the PJM monthly heating and cooling degree days in the first six months of 2015 with those in the first six months of 2014.[35] Heating

35 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). PJM uses 60 degrees F for a heating degree day as stated in Manual 19.
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 hourly 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.

degree days decreased 1.8 percent and cooling degree days increased 10.8 percent from the first six months of 2014 to the first six months of 2015.

Figure 3-16 PJM heating and cooling degree days: January 2014 through June 2015

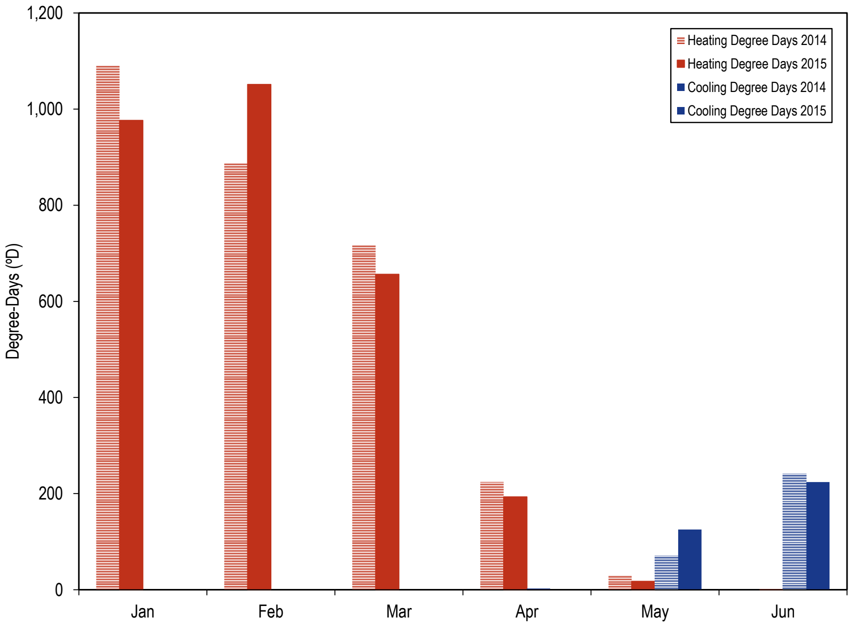


Table 3-16 PJM heating and cooling degree days: January 2014 through June 2015

	2014		2015		Percent Change	
	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days	Heating Degree Days	Cooling Degree Days
Jan	1,090	0	977	0	(10.4%)	0.0%
Feb	887	0	1,051	0	18.5%	0.0%
Mar	716	0	656	0	(8.4%)	0.0%
Apr	224	2	193	0	(13.8%)	0.0%
May	30	71	18	125	(40.3%)	75.8%
Jun	0	242	1	224	0.0%	(7.3%)
Jul	0	277				
Aug	0	256				
Sep	3	113				
Oct	133	4				
Nov	583	0				
Dec	690	0				
Total	4,358	966	2,896	349	(1.7%)	10.8%

Day-Ahead Demand

PJM average day-ahead demand in the first six months of 2015, including DECs and up-to congestion transactions, decreased by 30.5 percent from the first six months of 2014, from 160,805 MW to 111,749 MW.

PJM average day-ahead demand in the first six months of 2015, including DECs, up-to congestion transactions, and exports, decreased by 30.0 percent from the first six month of 2014, from 164,740 MW to 115,294 MW.

The reduction in PJM day-ahead demand was a result of a substantial decrease in in UTCs beginning in September 2014 based on a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[36]

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

36 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).

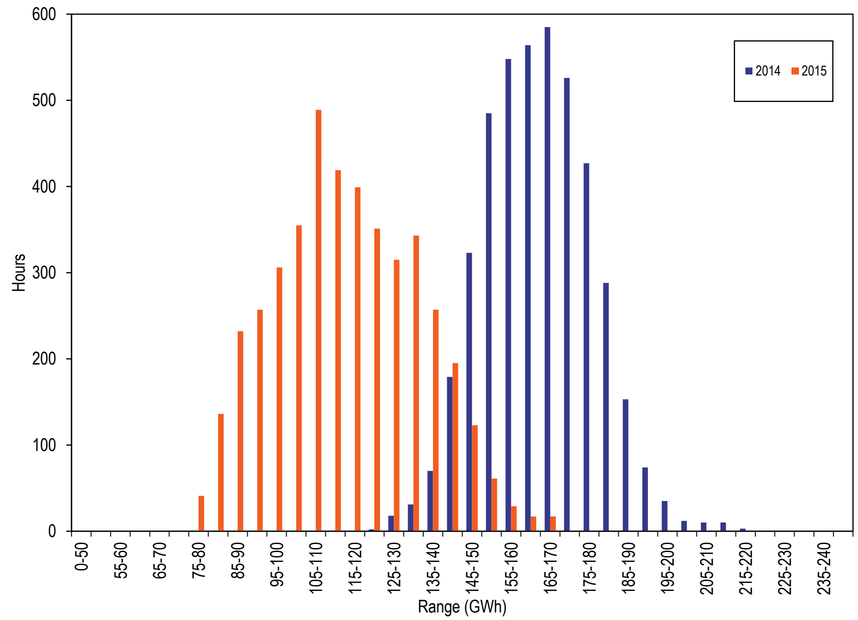
- **Fixed-Demand Bid.** Bid to purchase a defined MWh level of energy, regardless of LMP.
- **Price-Sensitive Bid.** Bid to purchase a defined MWh level of energy only up to a specified LMP, above which the load bid is zero.
- **Decrement Bid (DEC).** Financial bid to purchase a defined MWh level of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

PJM Day-Ahead Demand Duration

Figure 3-17 shows the hourly distribution of PJM day-ahead demand, including decrement bids, up-to congestion transactions, and exports for the first six months of 2014 and 2015.

Figure 3-17 Distribution of PJM day-ahead demand plus exports: January through June of 2014 and 2015[37]



37 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 six months of each year of the 16-year period 2000 to 2015.[38]

Table 3-17 PJM day-ahead average demand and day-ahead average hourly demand plus average hourly exports: January through June 2000 through 2015

	PJM Day-Ahead Demand (MWh)				Year-to-Year Change			
	Demand		Demand Plus Exports		Demand		Demand Plus Exports	
	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation	Demand	Standard Deviation
2000	35,448	8,138	35,623	7,982	NA	NA	NA	NA
2001	32,425	6,014	33,075	5,857	(8.5%)	(26.1%)	(7.2%)	(26.6%)
2002	37,561	8,293	37,607	8,311	15.8%	37.9%	13.7%	41.9%
2003	44,391	7,717	44,503	7,704	18.2%	(6.9%)	18.3%	(7.3%)
2004	50,161	10,304	50,596	10,557	13.0%	33.5%	13.7%	37.0%
2005	86,890	14,677	89,388	14,827	73.2%	42.4%	76.7%	40.4%
2006	94,470	12,925	97,460	13,303	8.7%	(11.9%)	9.0%	(10.3%)
2007	104,737	15,019	107,647	15,269	10.9%	16.2%	10.5%	14.8%
2008	100,948	14,255	104,499	14,461	(3.6%)	(5.1%)	(2.9%)	(5.3%)
2009	95,130	15,878	98,001	15,972	(5.8%)	11.4%	(6.2%)	10.4%
2010	99,691	18,097	103,573	18,366	4.8%	14.0%	5.7%	15.0%
2011	105,071	16,452	108,756	16,578	5.4%	(9.1%)	5.0%	(9.7%)
2012	129,881	15,268	133,046	15,436	23.6%	(7.2%)	22.3%	(6.9%)
2013	145,280	15,552	148,414	15,588	11.9%	1.9%	11.6%	1.0%
2014	160,805	13,872	164,740	13,800	10.7%	(10.8%)	11.0%	(11.5%)
2015	111,749	18,074	115,294	18,468	(30.5%)	30.3%	(30.0%)	33.8%

PJM Day-Ahead, Monthly Average Demand

Figure 3-18 compares the day-ahead, monthly average hourly demand, including decrement bids and up-to congestion transactions, in the first six months of 2014 and 2015. The reduction in PJM day-ahead demand was a result of a sharp decrease in in UTCs beginning in September 2014 based on a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[39]

Figure 3-18 PJM day-ahead monthly average hourly demand: January 2014 through June 2015

Real-Time and Day-Ahead Demand

Table 3-18 presents summary statistics for the first six months of 2014 and 2015 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.

38 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.

39 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 3-18 Cleared day-ahead and real-time demand (MWh): January through June 2014 and 2015

		Day Ahead						Real Time		Day Ahead Less Real Time	
	Year	Fixed Demand	Price Sensitive	DEC Bids	Up-to Congestion	Exports	Total Demand	Load	Total Demand	Total Demand	Total Load
Average	2014	86,321	1,270	6,165	67,048	3,935	164,740	90,529	96,189	68,551	21,978
	2015	86,891	3,133	4,300	17,425	3,545	115,294	90,586	94,782	20,512	70,074
Median	2014	84,903	1,257	5,961	67,141	3,823	164,502	89,103	95,269	69,232	19,871
	2015	85,670	3,238	4,079	17,190	3,398	114,177	88,946	93,024	21,153	67,793
Standard Deviation	2014	15,391	173	1,270	10,018	1,081	13,800	16,266	16,147	(2,348)	18,614
	2015	15,378	655	1,279	3,592	1,036	18,468	16,192	16,589	1,878	14,314
Peak Average	2014	95,297	1,351	6,756	66,773	3,886	174,063	99,513	104,987	69,076	30,437
	2015	95,165	3,387	4,613	18,426	3,622	125,213	98,598	102,752	22,461	76,137
Peak Median	2014	94,153	1,354	6,569	67,716	3,811	173,368	98,350	104,292	69,076	29,274
	2015	94,032	3,482	4,386	18,037	3,431	123,990	97,538	101,752	22,238	75,301
Peak Standard Deviation	2014	12,781	162	1,235	9,565	1,082	10,643	13,664	13,478	(2,835)	16,499
	2015	12,762	626	1,216	3,604	1,098	15,420	13,713	14,270	1,150	12,563
Off-Peak Average	2014	78,428	1,200	5,646	67,291	3,978	156,543	82,629	88,453	68,090	14,540
	2015	79,398	2,903	4,016	16,518	3,474	106,310	83,329	87,564	18,746	64,583
Off-Peak Median	2014	77,333	1,191	5,473	66,558	3,837	156,189	81,095	87,373	68,816	12,279
	2015	77,498	2,951	3,771	16,244	3,345	104,000	81,294	85,179	18,821	62,473
Off-Peak Standard Deviation	2014	12,979	149	1,055	10,397	1,078	10,708	14,132	14,228	(3,520)	17,652
	2015	13,604	592	1,269	3,331	970	16,273	14,785	15,181	1,093	13,692

Figure 3-19 shows the average hourly cleared volumes of day-ahead demand and real-time demand for January through June of 2015. 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 3-19 Day-ahead and real-time demand (Average hourly volumes): January through June 2015

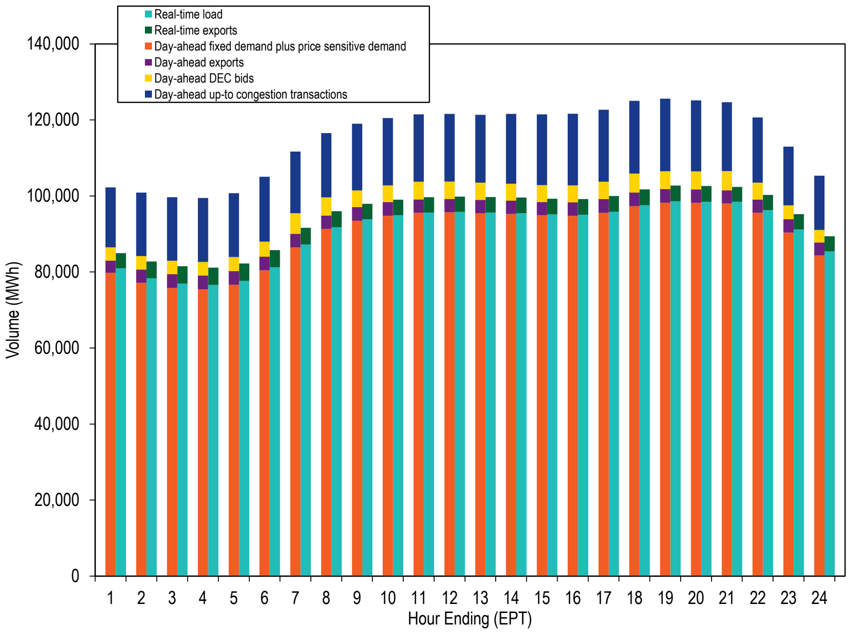
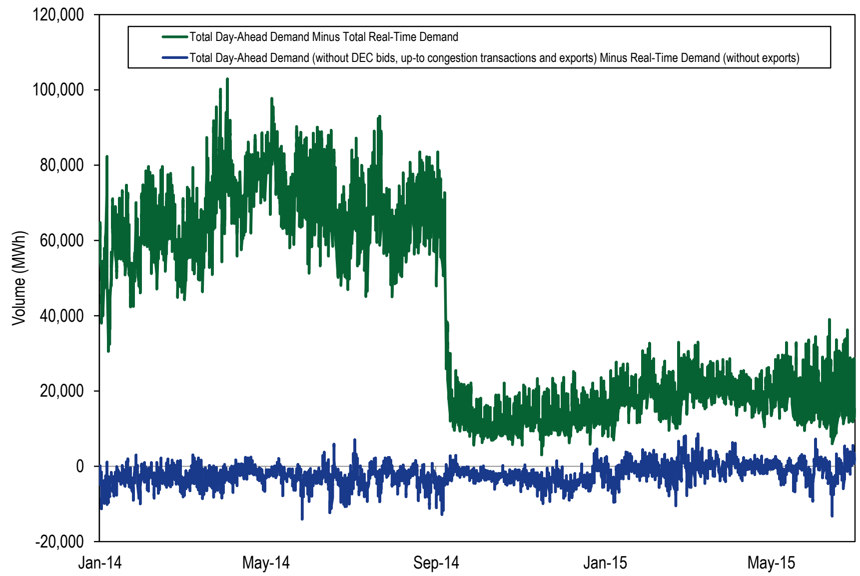


Figure 3-20 shows the difference between the day-ahead and real-time average daily demand in the first six months of 2014 and 2015. The substantial decrease in UTC MW in September, which resulted in a corresponding decrease in day-ahead demand, was a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[40]

Figure 3-20 Difference between day-ahead and real-time demand (Average daily volumes): January 2014 through June 2015



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).

40 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).

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 January 2014 through June 2015 based on parent company. In the first six months of 2015, 11.6 percent of real-time load was supplied by bilateral contracts, 30.8 percent by spot market purchase and 57.6 percent by self-supply. Compared with the first six months of 2014, reliance on bilateral contracts increased by 1.0 percentage points, reliance on spot supply increased by 4.1 percentage points and reliance on self-supply decreased by 5.1 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: January 2014 through June 2015

	2014			2015			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	9.5%	27.9%	62.6%	13.4%	23.2%	63.5%	3.9%	(4.7%)	0.9%
Feb	9.2%	27.3%	63.5%	12.8%	23.1%	64.1%	3.7%	(4.2%)	0.6%
Mar	9.7%	27.2%	63.0%	12.3%	25.9%	61.8%	2.5%	(1.3%)	(1.2%)
Apr	9.1%	29.7%	61.2%	11.4%	37.8%	50.8%	2.3%	8.1%	(10.4%)
May	9.7%	28.8%	61.5%	10.1%	37.3%	52.6%	0.4%	8.5%	(8.9%)
Jun	10.6%	29.0%	60.4%	9.9%	37.4%	52.6%	(0.7%)	8.5%	(7.8%)
Jul	11.2%	25.7%	63.1%						
Aug	11.2%	25.4%	63.4%						
Sep	11.2%	25.6%	63.2%						
Oct	11.5%	25.1%	63.4%						
Nov	11.8%	24.9%	63.4%						
Dec	12.9%	23.4%	63.7%						
Annual	10.6%	26.7%	62.7%	11.6%	30.8%	57.6%	1.0%	4.1%	(5.1%)

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 January 2014 through June 2015, based on parent companies. In the first six months of 2015, 10.3 percent of day-ahead demand was supplied by bilateral contracts, 25.7 percent by spot market purchases, and 63.9 percent by self-supply. Compared with the first six months of 2014, reliance on bilateral contracts increased by 0.8 percentage points, reliance on spot supply decreased by 0.5 percentage points, and reliance on self-supply decreased by 0.3 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: January 2014 through June 2015

	2014			2015			Difference in Percentage Points		
	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply	Bilateral Contract	Spot	Self-Supply
Jan	11.0%	28.9%	60.1%	11.1%	23.1%	65.8%	0.1%	0.1%	0.1%
Feb	8.4%	26.5%	65.1%	10.5%	23.2%	66.2%	0.1%	0.1%	0.1%
Mar	8.6%	27.8%	63.6%	10.1%	26.2%	63.7%	0.1%	0.1%	0.1%
Apr	7.9%	29.8%	62.3%	10.5%	27.9%	61.6%	0.1%	0.1%	0.1%
May	8.1%	29.1%	62.9%	9.7%	26.3%	64.0%	0.1%	0.1%	0.1%
Jun	9.4%	26.2%	64.4%	9.9%	29.0%	61.1%	0.1%	0.1%	0.1%
Jul	9.6%	25.2%	65.2%						
Aug	9.7%	24.6%	65.7%						
Sep	9.4%	25.1%	65.6%						
Oct	9.6%	24.5%	65.9%						
Nov	10.7%	24.3%	65.0%						
Dec	11.3%	23.2%	65.5%						
Annual	9.5%	26.2%	64.2%	10.3%	25.7%	63.9%	0.8%	(0.5%)	(0.3%)

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.

Table 3-21 Offer-capping statistics – energy only: January through June, 2011 to 2015

	Real Time		Day Ahead	
(Jan-Jun)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2011	0.7%	0.3%	0.0%	0.0%
2012	1.0%	0.5%	0.1%	0.1%
2013	0.3%	0.1%	0.1%	0.0%
2014	0.7%	0.3%	0.2%	0.1%
2015	0.5%	0.2%	0.2%	0.2%

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 increased in the first six months from 2011 through 2013. Before 2011, the units that ran to provide black start service and reactive support were generally economic in the energy market. From 2011 through 2013, the percentage of hours when these units were not economic (and were therefore committed on their cost schedule for reliability reasons) increased. This trend reversed in the first six months of 2014 and 2015 because higher LMPs (in the first three months) resulted in the increased economic dispatch of black start and reactive service resources. PJM also created closed loop interfaces to, in some cases, model reactive constraints with a corresponding impact on LMP, which contributed to the reduction in units offer capped for reliability.

Table 3-22 Offer-capping statistics for energy and reliability: January through June, 2011 to 2015

	Real Time		Day Ahead	
(Jan-Jun)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2011	0.7%	0.3%	0.0%	0.0%
2012	1.4%	0.8%	0.1%	0.1%
2013	2.6%	2.1%	3.0%	2.0%
2014	1.1%	0.7%	0.7%	0.5%
2015	1.0%	1.0%	0.8%	0.9%

Table 3-23 shows the offer capping percentages for units committed to provide black start service and reactive support. The data in Table 3-23 is the difference between the offer cap percentages shown in Table 3-22 and Table 3-21.

Table 3-23 Offer-capping statistics for reliability: January through June, 2011 to 2015

	Real Time		Day Ahead	
(Jan-Jun)	Unit Hours Capped	MW Capped	Unit Hours Capped	MW Capped
2011	0.0%	0.0%	0.0%	0.0%
2012	0.4%	0.3%	0.0%	0.0%
2013	2.3%	2.0%	2.9%	2.0%
2014	0.4%	0.4%	0.5%	0.4%
2015	0.5%	0.7%	0.6%	0.7%

Table 3-24 presents data on the frequency with which units were offer capped in the first six months of 2014 and 2015, for failing the TPS test to provide energy for constraint relief in the Real-Time Energy Market.

Table 3-24 Real-time offer-capped unit statistics: January through June, 2014 and 2015

		Offer-Capped Hours					
Run Hours Offer-Capped, Percent Greater Than Or Equal To:	(Jan - Jun)	Hours ≥ 500	Hours ≥ 400 and < 500	Hours ≥ 300 and < 400	Hours ≥ 200 and < 300	Hours ≥ 100 and < 200	Hours ≥ 1 and < 100
90%	2015	0	1	0	0	0	9
	2014	0	0	0	0	0	1
80% and < 90%	2015	0	0	0	1	0	10
	2014	0	0	1	0	1	2
75% and < 80%	2015	0	0	0	0	1	3
	2014	0	0	1	1	1	2
70% and < 75%	2015	0	0	0	0	1	3
	2014	0	0	0	0	1	1
60% and < 70%	2015	0	0	0	0	0	9
	2014	1	0	0	0	10	6
50% and < 60%	2015	0	0	0	0	0	8
	2014	0	0	0	0	2	15
25% and < 50%	2015	0	0	2	1	0	30
	2014	0	0	4	7	10	51
10% and < 25%	2015	0	0	1	3	3	38
	2014	0	0	0	0	1	36

Table 3-24 shows that nine units were offer capped for 90 percent or more of their run hours in the first six months of 2015 compared to one unit in the first six months of 2014.

Offer Capping for Local Market Power

In the first six months of 2015, the AEP, AP, ATSI, BGE, ComEd, DEOK, DLCO, Dominion, DPL, JCPL, MetEd, PECO, PENELEC, and PSEG control zones experienced congestion resulting from one or more constraints binding for 50 or more hours or resulting from an interface constraint. The AECO, DAY, EKPC, Pepco, PPL, and RECO control zones did not have constraints binding for 50 or more hours in the first six months of 2015. Table 3-25 shows that AEP, AP, BGE, ComEd, and PSEG were the control zones experienced congestion resulting from one or more constraints binding for 50 or more hours or resulting from an interface constraint that was binding for one or more hours in every year in January through June of 2009 through 2015.

Table 3-25 Numbers of hours when control zones experienced congestion resulting from one or more constraints binding for 50 or more hours or from an interface constraint: January through June, 2009 through 2015

	2009 (Jan - Jun)	2010 (Jan - Jun)	2011 (Jan - Jun)	2012 (Jan - Jun)	2013 (Jan - Jun)	2014 (Jan - Jun)	2015 (Jan - Jun)
AECO	149	69	88	NA	NA	NA	NA
AEP	932	355	1,228	322	811	1,773	1,902
AP	598	1,292	1,117	173	51	170	451
ATSI	101	NA	NA	1	70	403	464
BGE	90	154	184	1,556	316	1,142	3,079
ComEd	576	1,406	153	845	1,678	1,729	1,727
DEOK	NA	NA	NA	58	NA	NA	69
DLCO	156	342	NA	209	NA	281	747
Dominion	310	589	824	200	NA	52	1,422
DPL	NA	NA	NA	126	142	560	1,199
EKPC	NA	NA	NA	NA	NA	65	NA
JCPL	NA	NA	NA	NA	NA	NA	79
Met-Ed	NA	NA	NA	123	NA	NA	182
PECO	59	NA	130	53	256	944	485
PENELEC	55	NA	NA	NA	NA	1,441	1,385
Pepco	NA	NA	59	203	85	39	NA
PPL	176	NA	52	146	261	147	NA
PSEG	438	479	605	316	1,462	2,023	2,591

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 in the first six months of 2015.[41] 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.

41 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 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 3-26 Three pivotal supplier test details for interface constraints: January through June, 2015

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	385	477	15	2	13
	Off Peak	424	574	15	2	13
AEP - DOM	Peak	436	297	8	0	8
	Off Peak	254	278	7	0	7
AP South	Peak	341	423	11	2	10
	Off Peak	276	438	11	1	10
Bedington - Black Oak	Peak	177	234	14	2	12
	Off Peak	175	220	13	2	10
Central	Peak	945	918	14	2	12
	Off Peak	667	754	13	3	10
Eastern	Peak	837	740	13	0	13
	Off Peak	897	763	12	4	9
Western	Peak	617	633	13	1	12
	Off Peak	476	508	12	1	11

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 3-27 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.

Table 3-27 Summary of three pivotal supplier tests applied for interface constraints: January through June, 2015

Constraint	Period	Total Tests Applied	Total Tests that Could Have Resulted in Offer Capping	Percent Total Tests that Could Have Resulted in Offer Capping	Total Tests Resulted in Offer Capping	Percent Total Tests Resulted in Offer Capping	Tests Resulted in Offer Capping as Percent of Tests that Could Have Resulted in Offer Capping
5004/5005 Interface	Peak	1,817	58	3%	38	2%	66%
	Off Peak	1,801	107	6%	59	3%	55%
AEP - DOM	Peak	148	21	14%	18	12%	86%
	Off Peak	106	11	10%	4	4%	36%
AP South	Peak	118	6	5%	3	3%	50%
	Off Peak	65	10	15%	2	3%	20%
Bedington - Black Oak	Peak	1,535	55	4%	27	2%	49%
	Off Peak	960	32	3%	12	1%	38%
Central	Peak	198	3	2%	3	2%	100%
	Off Peak	102	1	1%	0	0%	0%
Eastern	Peak	86	3	3%	3	3%	100%
	Off Peak	14	0	0%	0	0%	0%
Western	Peak	429	9	2%	5	1%	56%
	Off Peak	116	0	0%	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.[42] 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 3-28 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 six months of 2015, 83.6 percent of marginal units had average dollar markups less than zero. The data show that some marginal units did have substantial markups. Using the unadjusted cost offers, the highest markup in the first six months of 2015 was $792.21 while the highest markup in the first six months of 2014 was $922.26. The unit with the highest markup in the first six months of 2015 was marginal for at least one interval on March 6, 2015. The unit with highest markup in the first three months of 2014 was marginal for at least one interval on January 6, 2014.

42 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 3-28 Average, real-time marginal unit markup index (By offer price category): January through June 2014 and 2015

	2014 (Jan - Jun)			2015 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.16)	($2.20)	11.7%	(0.05)	($2.60)	35.2%
$25 to $50	(0.01)	($1.08)	58.1%	(0.03)	($1.30)	48.4%
$50 to $75	0.04	$1.12	10.4%	0.06	$3.27	4.0%
$75 to $100	0.08	$5.93	3.3%	0.10	$7.35	1.6%
$100 to $125	0.06	$6.12	3.6%	0.09	$9.02	1.5%
$125 to $150	0.10	$12.94	1.6%	0.06	$6.97	1.4%
>= $150	0.09	$23.49	11.3%	0.05	$12.11	7.9%

Day-Ahead Markup

Table 3-29 shows the average markup index of marginal units in the Day-Ahead Energy Market, by offer price category. In the first six months of 2015, 90.0 percent of marginal units had average dollar markups less than zero and an average markup index less than or equal to 0.00. The data show that some marginal units in the first six months of 2014 did have substantial markups. The average markup index decreased significantly, for example, from 0.14 in the first six months of 2014, to -0.01 in the first six months of 2015 in the offer price category from $100 to $125.

Table 3-29 Average day-ahead marginal unit markup index (By offer price category): January through June of 2014 and 2015

	2014 (Jan - Jun)			2015 (Jan - Jun)		
Offer Price Category	Average Markup Index	Average Dollar Markup	Frequency	Average Markup Index	Average Dollar Markup	Frequency
< $25	(0.09)	($2.42)	8.2%	(0.00)	($1.44)	34.4%
$25 to $50	(0.02)	($1.27)	68.2%	(0.01)	($0.52)	53.2%
$50 to $75	0.03	$1.48	13.9%	0.10	$5.81	3.3%
$75 to $100	0.06	$4.09	2.3%	0.04	$2.58	1.6%
$100 to $125	0.14	$15.42	1.7%	(0.01)	($3.25)	1.2%
$125 to $150	0.02	($2.02)	1.7%	0.00	($2.90)	1.2%
>= $150	0.07	$14.43	3.8%	0.02	$3.45	4.0%

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 FMU adder was filed with FERC in 2005, and approved effective February 2006.[43] 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 on the elimination of FMU adders that maintains the ability of certain generating units to qualify for FMU adders but limits FMU adders to units with net revenues less than unit going forward costs or ACR. PJM submitted the joint MMU/PJM proposal to the Commission pursuant to section 206 of the Federal Power Act. On October 31, 2014, the Commission conditionally approved the filing and the new rule became effective November 1, 2014.

43 110 FERC ¶ 61,053 (2005).

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 10 percent of their cost-based offer or $30 per MWh. Units capped for 80 percent or more of their run hours are entitled to an adder of either 10 percent of their cost-based offer or $40 per MWh. These categories are designated Tier 1, Tier 2 and Tier 3.

In addition to being offer capped for the designated percent of run hours, in order to qualify for the FMU adder, a generating unit's Projected PJM Market Revenues plus the unit's PJM capacity market revenues on a rolling 12-month basis, divided by the unit's MW of installed capacity (in $/MW-year) must be less than its accepted unit specific Avoidable Cost Rate (in $/MW-year) (excluding APIR and ARPIR), or its default Avoidable Cost Rate (in $/MW-year) if no unit-specific Avoidable Cost Rate is accepted for the BRAs for the Delivery Years included in the rolling 12-month period, determined pursuant to Sections 6.7 and 6.8 of Attachment DD of the Tariff. (The relevant Avoidable Cost Rate is the weighted average of the Avoidable Cost Rates for each Delivery Year included in the rolling 12-month period, weighted by month.) No portion of the unit may be included in a FRR Capacity Plan or be receiving compensation under Part V of the PJM Tariff and the unit must be internal to the PJM Region and subject only to PJM dispatch.[44]

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.[45] 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.

The new rules for determining the qualification of a unit as a FMU or AU became effective November 1, 2014. 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.[46] The effects of the new rules were first observed in units eligible for an FMU or AU adder in December, 2014, where the number of units that were eligible for an FMU or AU adder declined from an average of 70 units during the first 11 months of 2014, to zero in December 2014 (See Table 3-31).

Table 3-30 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 2014 and January through June, 2015.[47] In the first six months of 2015, no units qualified as an FMU or AU.

Table 3-30 Frequently mitigated units and associated units by total months eligible: 2014 and January through June, 2015

Months Adder-Eligible	2014	2015
1	21	8
2	9	13
3	0	2
4	3	2
5	5	0
6	15	0
7	1	
8	6	
9	8	
10	5	
11	35	
12	4	
Total	112	25

44 PJM. OA, Schedule 1 § 6.4.2.

45 An associated unit (AU) must belong to the same design class (where a design class includes generation that is the same size and utilizes the same technology, without regard to manufacturer) and uses the identical primary fuel as the FMU.

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

47 The data on FMUs and AUs reported in the *2015 Quarterly State of the Market Report for PJM: January through March*, reflected an incorrect calculation by the MMU. In fact, there should have been zero FMUs and AUs since the implementation of the new FMU rules effective for December 2014.

Figure 3-21 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 Jun 30, 2015, there were 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 months. Two units qualified in 106 of the 114 possible months, and 74 of the 351 units (21.1 percent) qualified for an adder in more than half of the possible months.

Figure 3-21 Frequently mitigated units and associated units total months eligible: February, 2006 through June, 2015

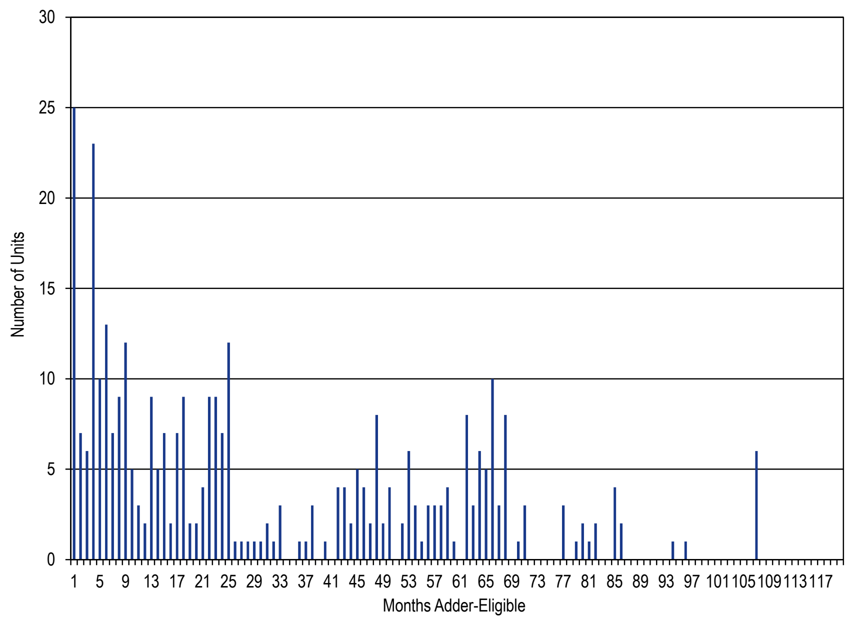


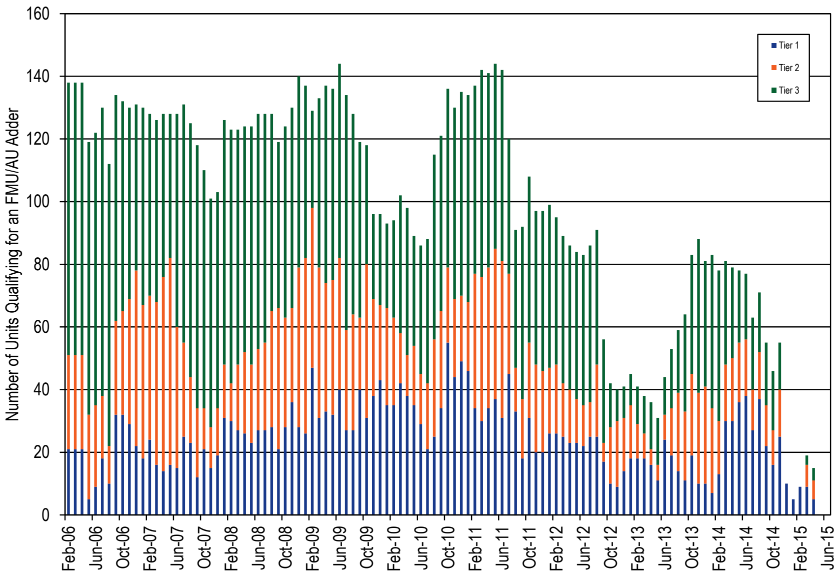
Table 3-31 shows, by month, the number of FMUs and AUs in 2014 and January through June, 2015. For example, in November 2014, there were 25 FMUs and AUs in Tier 1, 15 FMUs and AUs in Tier 2, and 15 FMUs and AUs in Tier 3. In the first six months of 2015, no units qualified as an FMU or AU.

Table 3-31 Number of frequently mitigated units and associated units (By month): January 2014 through June 2015

	2014				2015			
	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder	Tier 1	Tier 2	Tier 3	Total Eligible for Any Adder
January	7	27	49	83	5	0	0	5
February	13	17	48	78	9	0	0	9
March	30	18	33	81	9	7	3	19
April	30	20	29	79	5	6	4	15
May	36	19	23	78	0	0	0	0
June	38	18	21	77	0	0	0	0
July	27	13	23	63				
August	37	15	19	71				
September	22	13	20	55				
October	16	11	19	46				
November	25	15	15	55				
December	10	0	0	10				

Figure 3-22 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 continued to affect the number of FMU eligible units through November of 2014. The reduction in the total number of units qualifying for an FMU or AU adder starting in December 2014 was the result of the revised rules for FMUs.

Figure 3-22 Frequently mitigated units and associated units (By month): February 2006 through June 2015



An error in the Market Monitoring Unit's (MMU) monthly calculation used to determine unit eligibility for the Frequently Mitigated Unit (FMU) adder under the new FMU rules resulted in a number of generators permitted to use an adder when no units should have been permitted to use an adder. This occurred for the period from December 1, 2014, the first day that the new FMU rules had an effect, to April 22, 2015. The affected generators were immediately directed to cease using FMU adders when the issue was discovered. The MMU has evaluated the impact of the incorrect FMU status on the markets and found that there was no impact on the day-ahead market outcomes. In the four months where the units were incorrectly allowed to use FMU adders, a total of four five-minute intervals in the real-time market were affected. The impact on hourly PJM system-wide load-weighted real-time LMP ranged between $0.19 and $0.58 per MWh for the three hours affected. There was no impact on the monthly PJM system-wide load-weighted real-time LMP.

Virtual Offers and Bids

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

Any market participant in the PJM Day-Ahead Energy Market can use increment offers, decrement bids, 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.[48] 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.

Figure 3-23 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 2015.

48 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 3-23 PJM day-ahead aggregate supply curves: 2015 example day

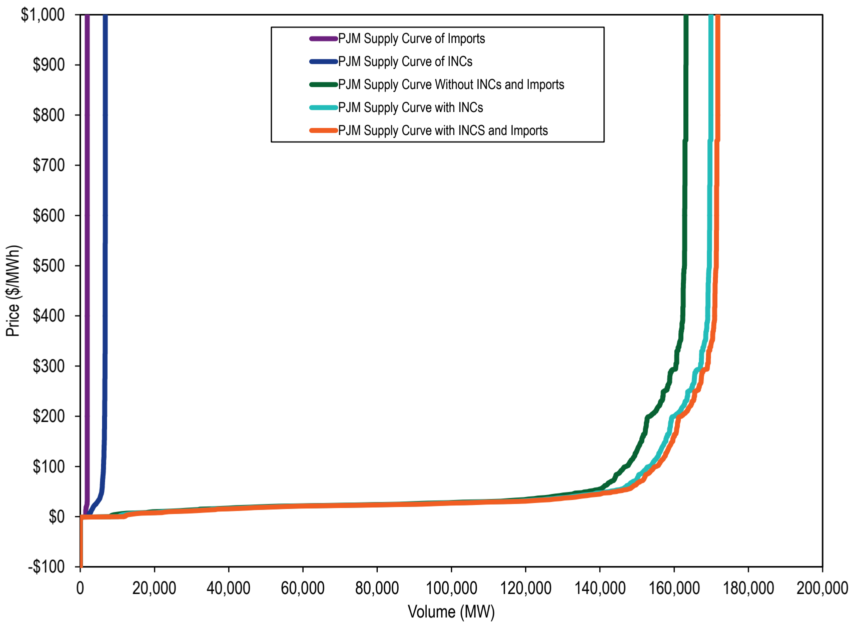


Table 3-32 shows the average hourly number of increment offers and decrement bids and the average hourly MW January 2014 through June 2015. In the first six months of 2015, the average hourly submitted and cleared increment offer MW increased 51.2 and 42.1 percent, and the average hourly submitted and cleared decrement bid MW decreased 17.1 and 28.4 percent, compared to the first six months of 2014.

Table 3-32 Hourly average number of cleared and submitted INCs, DECs by month: January 2014 through June 2015

		Increment Offers				Decrement Bids			
		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
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	2,961	3,889	66	179	6,744	9,452	97	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	Oct	3,477	5,826	91	470	6,806	9,991	136	510
2014	Nov	4,210	7,151	134	553	7,193	11,028	166	637
2014	Dec	3,992	7,021	102	525	7,210	10,260	139	490
2014	Annual	3,494	5,279	78	310	6,596	9,278	125	393
2015	Jan	4,350	6,447	78	398	5,153	7,320	76	295
2015	Feb	4,754	7,109	116	578	4,511	7,445	72	409
2015	Mar	4,973	8,689	142	760	4,305	8,894	101	648
2015	Apr	4,511	6,351	187	558	3,453	6,990	84	451
2015	May	5,089	7,459	181	656	4,171	6,823	94	404
2015	June	4,592	7,043	143	697	4,196	6,696	89	410
2015	Annual	4,713	7,190	141	608	4,300	7,366	86	436

The reduction in up-to congestion transactions (UTC) continued, following a FERC order setting September 8, 2014, as the effective date for any uplift charges subsequently assigned to UTCs.[49] Table 3-33 shows the average hourly number of up-to congestion transactions and the average hourly MW for January 2014 through June 2015. In the first six months of 2015, the average hourly up-to congestion submitted MW decreased 70.1 percent and cleared MW decreased 74.0 percent, compared to the first six months of 2014, as a result of the decreases after September 8.

49 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 3-33 Hourly average of cleared and submitted up-to congestion bids by month: January 2014 through June 2015

		Up-to Congestion			
		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
2014	Jan	55,969	199,708	2,436	7,056
2014	Feb	64,123	229,256	3,262	9,020
2014	Mar	66,003	243,469	3,527	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	Oct	9,298	30,502	512	1,289
2014	Nov	11,890	36,600	661	1,633
2014	Dec	12,952	37,177	770	1,770
2014	Annual	49,511	166,537	2,269	6,315
2015	Jan	15,903	46,626	806	2,132
2015	Feb	17,255	57,318	892	2,695
2015	Mar	18,406	72,995	979	2,912
2015	Apr	16,300	73,446	811	2,734
2015	May	18,929	81,358	941	3,219
2015	Jun	17,714	81,452	896	3,220
2015	Annual	17,421	68,947	888	2,818

Table 3-34 shows the average hourly number of import and export transactions and the average hourly MW for January 2014 through June 2015. In the first six months of 2015, the average hourly submitted and cleared import transaction MW increased 8.4 and 6.2 percent, and the average hourly submitted and cleared export transaction MW decreased 15.6 and 13.0 percent, compared to the first six months of 2014.

Table 3-34 Hourly average number of cleared and submitted import and export transactions by month: January 2014 through June 2015

		Imports				Exports			
		Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume	Average Cleared MW	Average Submitted MW	Average Cleared Volume	Average Submitted Volume
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	Oct	1,714	1,721	11	11	3,506	3,525	20	21
2014	Nov	2,087	2,097	13	13	3,491	3,528	21	21
2014	Dec	2,373	2,498	12	13	3,939	3,959	21	22
2014	Annual	2,221	2,276	12	13	3,740	3,823	22	22
2015	Jan	2,579	2,716	15	17	4,473	4,559	26	26
2015	Feb	2,588	2,726	17	19	4,383	4,469	23	25
2015	Mar	2,484	2,668	16	18	3,268	3,302	16	17
2015	Apr	2,531	2,638	18	21	2,624	2,626	13	13
2015	May	2,339	2,482	18	20	2,612	2,623	17	17
2015	Jun	2,269	2,349	14	16	2,895	2,906	14	14
2015	Annual	2,464	2,595	16	18	3,366	3,404	18	19

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 June of 2015

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	14.3%	0.5%	71.9%	6.9%	6.3%	0.1%
Feb	13.1%	0.4%	73.1%	7.6%	5.6%	0.1%
Mar	10.1%	0.7%	73.2%	10.6%	5.3%	0.0%
Apr	10.4%	0.3%	73.2%	10.8%	5.3%	0.0%
May	10.2%	0.1%	75.2%	9.2%	5.3%	0.0%
Jun	8.0%	0.1%	78.2%	9.5%	4.1%	0.0%
Annual	11.1%	0.4%	74.1%	9.1%	5.4%	0.0%

Figure 3-24 shows the monthly volume of bid and cleared INC, DEC and up-to congestion bids by month for the period from January 2005 through June 2015. Figure 3-25 shows the daily volume of bid and cleared INC, DEC and up-to congestion bids for the period for January 2014 through June 2015 in order to show the drop off in UTC volumes compared to volumes in the last 15 months.

Figure 3-24 Monthly bid and cleared INCs, DECs, and UTCs (MW): January 2005 through June 2015

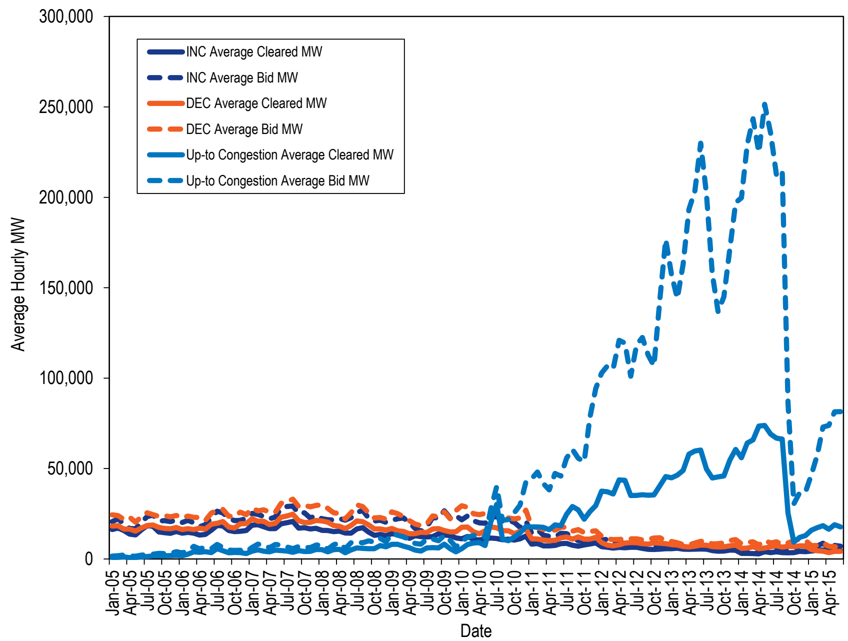
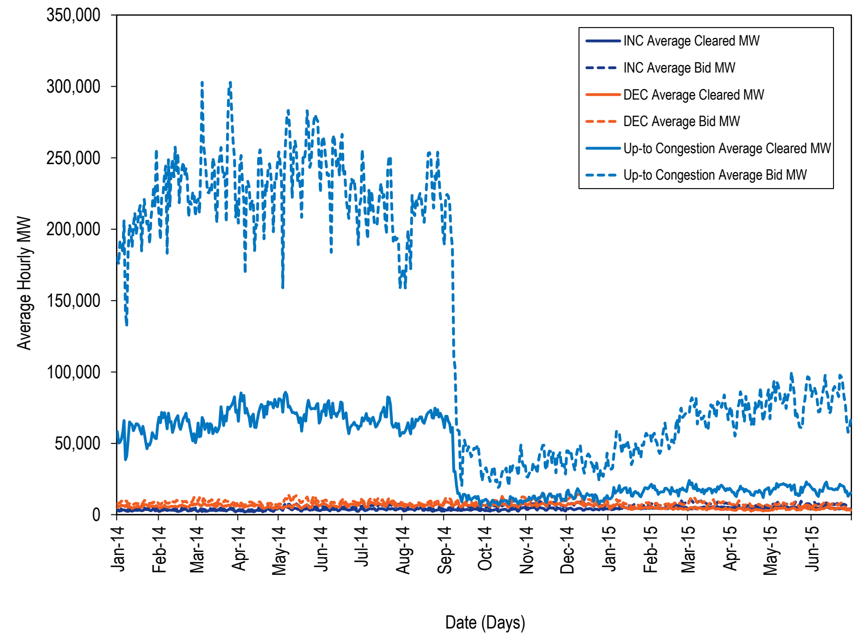


Figure 3-25 Daily bid and cleared INCs, DECs, and UTCs (MW): January 2014 through June 2015



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 six months of 2014 and 2015, the total increment offers and decrement bids by whether the parent organization is financial or physical.

Table 3-36 PJM INC and DEC bids by type of parent organization (MW): January through June 2014 and 2015

	2014 (Jan-Jun)		2015 (Jan-Jun)	
Category	Total Virtual Bids MW	Percent	Total Virtual Bids MW	Percent
Financial	20,768,062	35.6%	26,591,256	42.1%
Physical	37,611,273	64.4%	36,518,285	57.9%
Total	58,379,334	100.0%	63,109,541	100.0%

Table 3-37 shows, for the first six months of 2014 and 2015, the total up-to congestion transactions by the type of parent organization.

Table 3-37 PJM up-to congestion transactions by type of parent organization (MW): January through June 2014 and 2015

	2014 (Jan-Jun)		2015 (Jan-Jun)	
Category	Total Up-to Congestion MW	Percent	Total Up-to Congestion MW	Percent
Financial	276,055,889	94.8%	62,960,182	83.6%
Physical	15,264,864	5.2%	12,381,797	16.4%
Total	291,320,753	100.0%	75,341,978	100.0%

Table 3-38 shows for the first six months of 2014 and 2015, the total import and export transactions by whether the parent organization is financial or physical.

Table 3-38 PJM import and export transactions by type of parent organization (MW): January through June 2014 and 2015

	2014 (Jan-Jun)		2015 (Jan-Jun)	
Category	Total Import and Export MW	Percent	Total Import and Export MW	Percent
Financial	9,353,076	34.4%	10,531,899	40.4%
Physical	17,809,239	65.6%	15,561,730	59.6%
Total	27,162,315	100.0%	26,093,629	100.0%

Table 3-39 shows increment offers and decrement bids bid by top ten locations for the first six months of 2014 and 2015.

Table 3-39 PJM virtual offers and bids by top ten locations (MW): January through June 2014 and 2015

2014 (Jan-Jun)					2015 (Jan-Jun)				
Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW	Aggregate/Bus Name	Aggregate/Bus Type	INC MW	DEC MW	Total MW
WESTERN HUB	HUB	5,392,588	6,060,329	11,452,917	WESTERN HUB	HUB	9,644,293	11,368,368	21,012,662
MISO	INTERFACE	293,286	4,007,374	4,300,660	SOUTHIMP	INTERFACE	4,116,718	0	4,116,718
PPL	ZONE	95,332	3,305,357	3,400,689	IMO	INTERFACE	2,553,011	36,819	2,589,830
SOUTHIMP	INTERFACE	3,336,133	0	3,336,133	N ILLINOIS HUB	HUB	446,003	1,625,506	2,071,509
PECO	ZONE	94,450	2,718,399	2,812,848	NYIS	INTERFACE	1,036,204	201,609	1,237,813
IMO	INTERFACE	2,226,609	137,034	2,363,643	LINDENVFT	INTERFACE	200,100	560,299	760,399
AEP-DAYTON HUB	HUB	990,986	1,206,700	2,197,686	MISO	INTERFACE	225,653	484,675	710,328
N ILLINOIS HUB	HUB	490,521	1,438,357	1,928,878	BGE	ZONE	81,842	578,517	660,359
BGE	ZONE	6,905	1,492,146	1,499,051	BOCGASE2138 KV T1	LOAD	113,791	526,349	640,140
NYIS	INTERFACE	458,402	357,044	815,446	AEP-DAYTON HUB	HUB	260,402	360,024	620,427
Top ten total		13,385,210	20,722,740	34,107,950			18,678,019	15,742,166	34,420,185
PJM total		19,489,604	38,889,730	58,379,334			31,223,368	31,988,489	63,211,856
Top ten total as percent of PJM total		68.7%	53.3%	58.4%			59.8%	49.2%	54.5%

Table 3-40 shows up-to congestion transactions by import bids for the top ten locations for the first six months of 2014 and 2015.[50]

Table 3-40 PJM cleared up-to congestion import bids by top ten source and sink pairs (MW): January through June 2014 and 2015

2014 (Jan-Jun)				
Imports				
Source	Source Type	Sink	Sink Type	MW
SOUTHEAST	INTERFACE	EDANVILL T1	AGGREGATE	668,476
HUDSONTP	INTERFACE	LEONIA 230 T-2	AGGREGATE	559,234
MISO	INTERFACE	COOK	EHVAGG	464,744
OVEC	INTERFACE	BIG SANDY CT1	AGGREGATE	424,626
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	370,916
NEPTUNE	INTERFACE	SOUTHRIV 230	AGGREGATE	323,460
MISO	INTERFACE	AEP-DAYTON HUB	HUB	311,956
OVEC	INTERFACE	DEOK	ZONE	285,971
HUDSONTP	INTERFACE	LEONIA 230 T-1	AGGREGATE	283,077
SOUTHEAST	INTERFACE	CLOVER	EHVAGG	271,791
Top ten total				3,964,249
PJM total				18,515,599
Top ten total as percent of PJM total				21.4%
2015 (Jan-Jun)				
Imports				
Source	Source Type	Sink	Sink Type	MW
SOUTHIMP	INTERFACE	NAGELAEP	EHVAGG	1,374,846
OVEC	INTERFACE	AEP-DAYTON HUB	HUB	325,363
SOUTHIMP	INTERFACE	WOLF HILLS 1-5	AGGREGATE	299,757
SOUTHEAST	INTERFACE	HALIFXDP TX1	AGGREGATE	241,852
NORTHWEST	INTERFACE	N ILLINOIS HUB	HUB	232,246
NORTHWEST	INTERFACE	COMED	ZONE	213,288
SOUTHEAST	INTERFACE	NAGELAEP	EHVAGG	206,945
MISO	INTERFACE	21 KINCA ATR24304	AGGREGATE	188,052
SOUTHWEST	INTERFACE	NAGELAEP	EHVAGG	187,521
SOUTHEAST	INTERFACE	DOM	ZONE	153,981
Top ten total				3,423,851
PJM total				10,714,345
Top ten total as percent of PJM total				32.0%

Table 3-41 shows up-to congestion transactions by export bids for the top ten locations for the first six months of 2014 and 2015.

Table 3-41 PJM cleared up-to congestion export bids by top ten source and sink pairs (MW): January through June 2014 and 2015

2014 (Jan-Jun)				
Exports				
Source	Source Type	Sink	Sink Type	MW
JEFFERSON	EHVAGG	OVEC	INTERFACE	1,218,831
TANNERS CRK 4	AGGREGATE	SOUTHWEST	INTERFACE	1,203,791
TANNERS CRK 4	AGGREGATE	OVEC	INTERFACE	508,887
21 KINCA ATR24304	AGGREGATE	SOUTHWEST	INTERFACE	493,537
ROCKPORT	EHVAGG	OVEC	INTERFACE	406,763
LINDEN A	AGGREGATE	LINDENVFT	INTERFACE	383,555
STUART 1	AGGREGATE	OVEC	INTERFACE	322,069
JEFFERSON	EHVAGG	SOUTHWEST	INTERFACE	321,205
BECKJORD 6	AGGREGATE	OVEC	INTERFACE	320,470
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	311,767
Top ten total				5,490,874
PJM total				20,675,487
Top ten total as percent of PJM total				26.6%
2015 (Jan-Jun)				
Exports				
Source	Source Type	Sink	Sink Type	MW
FOWLER RIDGE II WF	AGGREGATE	SOUTHWEST	INTERFACE	222,312
ROCKPORT	EHVAGG	SOUTHWEST	INTERFACE	139,271
21 KINCA ATR24304	AGGREGATE	NIPSCO	INTERFACE	102,611
COMED	ZONE	NIPSCO	INTERFACE	94,998
MARION	AGGREGATE	HUDSONTP	INTERFACE	85,614
SULLIVAN-AEP	EHVAGG	OVEC	INTERFACE	83,097
FOWLER RIDGE II WF	AGGREGATE	OVEC	INTERFACE	78,238
KAMMER 2	AGGREGATE	NIPSCO	INTERFACE	75,128
ROCKPORT	EHVAGG	OVEC	INTERFACE	70,132
RECO	ZONE	HUDSONTP	INTERFACE	67,428
Top ten total				1,018,829
PJM total				3,957,549
Top ten total as percent of PJM total				25.7%

50 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 six months of 2014 and 2015.

Table 3-42 PJM cleared up-to congestion wheel bids by top ten source and sink pairs (MW): January through June 2014 and 2015

2014 (Jan-Jun)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
NORTHWEST	INTERFACE	MISO	INTERFACE	677,437
OVEC	INTERFACE	SOUTHEXP	INTERFACE	293,822
MISO	INTERFACE	NORTHWEST	INTERFACE	204,572
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	176,441
NORTHWEST	INTERFACE	NIPSCO	INTERFACE	80,739
IMO	INTERFACE	NYIS	INTERFACE	71,240
MISO	INTERFACE	SOUTHEXP	INTERFACE	60,208
OVEC	INTERFACE	SOUTHWEST	INTERFACE	59,451
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	57,579
MISO	INTERFACE	NIPSCO	INTERFACE	54,605
Top ten total				1,736,095
PJM total				2,181,474
Top ten total as percent of PJM total				79.6%
2015 (Jan-Jun)				
Wheels				
Source	Source Type	Sink	Sink Type	MW
MISO	INTERFACE	NORTHWEST	INTERFACE	164,983
MISO	INTERFACE	NIPSCO	INTERFACE	102,566
NORTHWEST	INTERFACE	MISO	INTERFACE	97,019
IMO	INTERFACE	NYIS	INTERFACE	66,275
NYIS	INTERFACE	IMO	INTERFACE	48,713
SOUTHWEST	INTERFACE	IMO	INTERFACE	32,383
SOUTHWEST	INTERFACE	SOUTHEXP	INTERFACE	28,262
NIPSCO	INTERFACE	IMO	INTERFACE	25,694
SOUTHEAST	INTERFACE	SOUTHEXP	INTERFACE	17,129
NYIS	INTERFACE	HUDSONTP	INTERFACE	13,525
Top ten total				596,548
PJM total				707,302
Top ten total as percent of PJM total				84.3%

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. The top ten internal up-to congestion transaction locations were 10.7 percent of the PJM total internal up-to congestion transactions in the first six months of 2015.

Table 3-43 shows up-to congestion transactions by internal bids for the top ten locations for the first six months of 2014 and 2015.

Table 3-43 PJM cleared up-to congestion internal bids by top ten source and sink pairs (MW): January through June 2014 and 2015

2014 (Jan-Jun)				
Internal				
Source	Source Type	Sink	Sink Type	MW
MOUNTAINEER	EHVAGG	GAVIN	EHVAGG	4,015,383
VERNON BK 4	AGGREGATE	AEC - JC	AGGREGATE	2,941,605
MOUNTAINEER	EHVAGG	FLATLICK	EHVAGG	2,876,108
DAY	ZONE	BUCKEYE - DPL	AGGREGATE	2,851,509
ATSI GEN HUB	HUB	ATSI	ZONE	2,505,841
FE GEN	AGGREGATE	ATSI	ZONE	2,293,233
WESTERN HUB	HUB	AEP-DAYTON HUB	HUB	1,803,219
DUMONT	EHVAGG	COOK	EHVAGG	1,604,519
JEFFERSON	EHVAGG	COOK	EHVAGG	1,542,406
SUNBURY 1-3	AGGREGATE	CITIZENS	AGGREGATE	1,444,519
Top ten total				23,878,343
PJM total				249,948,193
Top ten total as percent of PJM total				9.6%
2015 (Jan-Jun)				
Internal				
Source	Source Type	Sink	Sink Type	MW
BERGEN 2CC	AGGREGATE	LEONIA 230 T-1	AGGREGATE	1,288,307
BYRON 1	AGGREGATE	ROCKFORD	AGGREGATE	848,984
JEFFERSON	EHVAGG	COOK	EHVAGG	773,981
ROCKPORT	EHVAGG	JEFFERSON	EHVAGG	673,877
ATSI GEN HUB	HUB	ATSI	ZONE	595,816
VALLEY	EHVAGG	DOOMS	EHVAGG	474,637
RONCO	EHVAGG	HATFIELD	EHVAGG	465,256
BERGEN 2CC	AGGREGATE	LEONIA 230 T-2	AGGREGATE	448,254
167 PLANO	EHVAGG	112 WILTON	EHVAGG	425,084
ALBURTIS	EHVAGG	PPL	ZONE	413,348
Top ten total				6,407,544
PJM total				59,962,987
Top ten total as percent of PJM total				10.7%

Table 3-44 shows the number of source-sink pairs that were offered and cleared monthly in January of 2013 through June 2015. 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 January 2013 and continuing through the first eight 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. 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.[51]

51 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 3-44 Number of PJM offered and cleared source and sink pairs: January 2013 through June 2015

		Daily Number of Source-Sink Pairs			
Year	Month	Average Offered	Max Offered	Average Cleared	Max Cleared
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	Oct	2,871	4,092	1,972	2,506
2014	Nov	2,463	3,988	1,812	3,163
2014	Dec	2,803	3,672	2,197	2,786
2014	Annual	5,996	14,065	3,620	8,069
2015	Jan	3,337	5,422	2,263	3,270
2015	Feb	4,600	7,041	2,775	4,147
2015	Mar	4,061	5,799	2,625	3,244
2015	Apr	3,777	6,967	2,343	3,378
2015	May	4,025	5,513	2,587	3,587
2015	Jun	3,852	5,967	2,781	3,748
2015	Annual	3,933	7,041	3,933	4,147

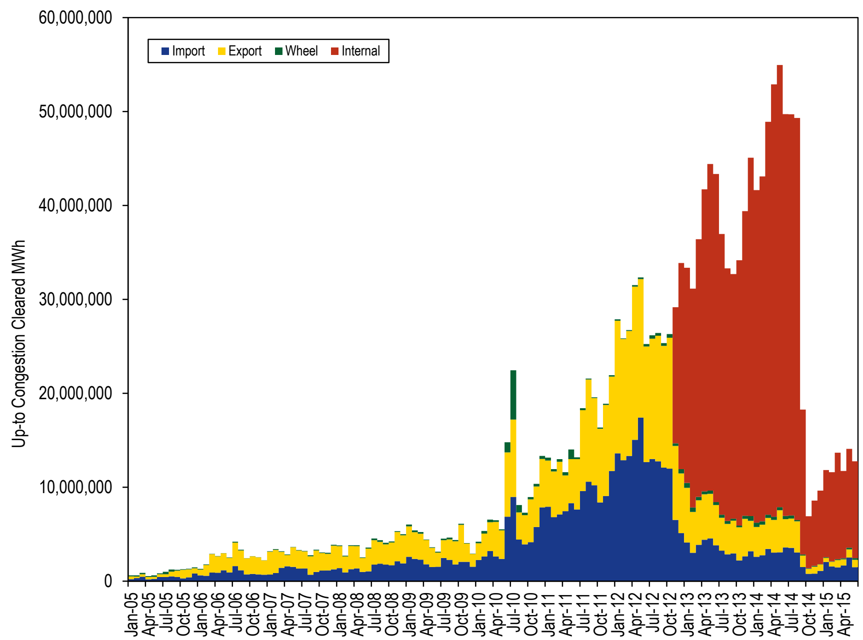
Table 3-45 and Figure 3-26 show total cleared up-to congestion transactions by type for the first six months of 2014 and 2015. Internal up-to congestion transactions in the first six months of 2015 were 79.6 percent of all up-to congestion transactions compared to 85.8 percent in the first six months of 2014.

Table 3-45 PJM cleared up-to congestion transactions by type (MW): January through June 2014 and 2015

	2014 (Jan-Jun)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	3,964,249	5,490,874	1,736,095	23,878,343	35,069,561
PJM total (MW)	18,515,599	20,675,487	2,181,474	249,948,193	291,320,753
Top ten total as percent of PJM total	21.4%	26.6%	79.6%	9.6%	12.0%
PJM total as percent of all up-to congestion transactions	6.4%	7.1%	0.7%	85.8%	100.0%
	2015 (Jan-Jun)				
	Cleared Up-to Congestion Bids				
	Import	Export	Wheel	Internal	Total
Top ten total (MW)	3,423,851	1,018,829	596,548	6,407,544	11,446,772
PJM total (MW)	10,714,345	3,957,549	707,302	59,962,987	75,342,184
Top ten total as percent of PJM total	32.0%	25.7%	84.3%	10.7%	15.2%
PJM total as percent of all up-to congestion transactions	14.2%	5.3%	0.9%	79.6%	100.0%

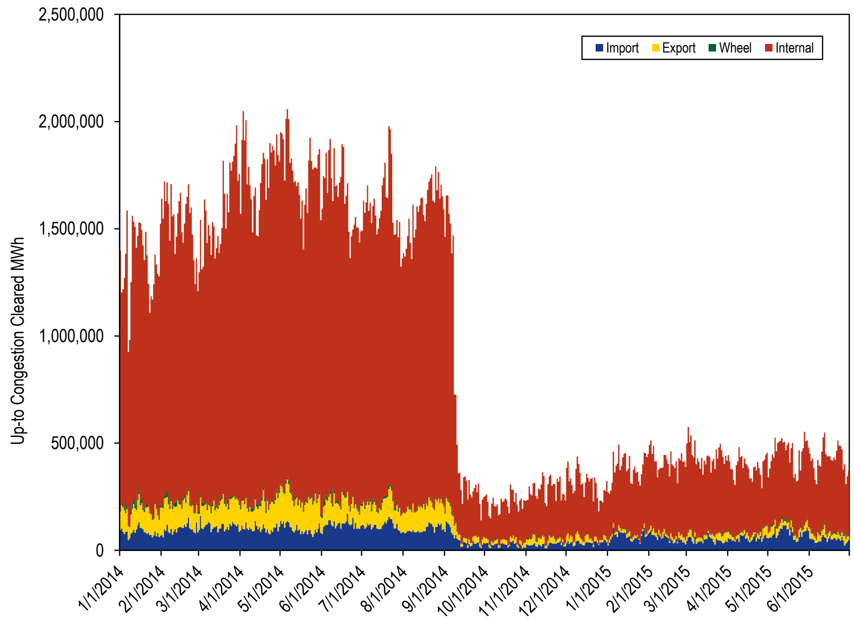
Figure 3-26 shows the initial increase and continued increase in internal up-to congestion transactions by month following the November 1, 2012 rule change permitting such transactions, until September 8, 2014. There was a sharp decrease in UTCs in September as a result of a FERC order setting September 8, 2014, as the effective date for any uplift charges assigned to UTCs.[52] Figure 3-27 shows the daily cleared up-to congestion MW by transaction type for the period from January 2014 through June 2015 in order to show the drop off in UTC volumes compared to volumes in the last 18 months.

Figure 3-26 PJM monthly cleared up-to congestion transactions by type (MW): January 2005 through June 2015



52 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 3-27 PJM daily cleared up-to congestion transaction by type (MW): January 2014 through June 2015



Generator Offers

Generator offers are categorized as dispatchable (Table 3-46) or self scheduled (Table 3-47).[53] 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 six months of 2015. For example, 72.4 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, 81.0 percent of all CC MW offers were dispatchable, including the 5.1 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, 45.2 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 six months of 2015, 51.2 percent were offered as available for economic dispatch.

Table 3-46 Distribution of MW for dispatchable unit offer prices: January through June 2015

	Dispatchable (Range)							
Unit Type	($200) - $0	$0 - $200	$200 - $400	$400 - $600	$600 - $800	$800 - $1,000	Emergency	Total
CC	0.3%	72.4%	1.9%	0.5%	0.8%	0.0%	5.1%	81.0%
CT	0.2%	70.7%	15.7%	1.7%	1.3%	0.1%	9.2%	98.9%
Diesel	6.2%	24.0%	21.5%	7.1%	1.8%	0.7%	12.4%	73.7%
Fuel Cell	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	7.5%	0.0%	0.0%	0.0%	0.0%	0.0%	7.5%
Pumped Storage	13.4%	38.2%	0.0%	0.0%	0.0%	0.0%	15.7%	67.3%
Run of River	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Solar	7.3%	7.0%	0.0%	0.0%	0.0%	0.0%	2.1%	16.4%
Steam	0.0%	45.1%	1.7%	0.1%	0.0%	0.0%	2.2%	49.2%
Transaction	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Wind	50.7%	12.1%	0.0%	0.0%	0.0%	0.0%	0.6%	63.3%
All Dispatchable Offers	1.2%	45.2%	3.9%	0.5%	0.4%	0.0%	3.8%	55.0%

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

53 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.

self-scheduled and dispatchable units, for the first six months of 2015. For example, 15.9 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, 19.0 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 0.7 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 22.6 percent of all offers and self-scheduled and dispatchable units accounted for 20.2 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 six months of 2015, 23.8 percent were offered as self scheduled and 21.2 percent were offered as self scheduled and dispatchable.

Table 3-47 Distribution of MW for self scheduled offer prices: January through June 2015

	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	1.3%	0.4%	0.2%	15.9%	0.2%	0.1%	0.2%	0.0%	0.7%	19.0%
CT	0.5%	0.1%	0.0%	0.4%	0.0%	0.0%	0.0%	0.1%	0.0%	1.1%
Diesel	24.8%	1.1%	0.0%	0.2%	0.1%	0.0%	0.0%	0.0%	0.1%	26.3%
Fuel Cell	65.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	34.8%	100.0%
Nuclear	91.0%	1.0%	0.0%	0.4%	0.0%	0.0%	0.0%	0.0%	0.0%	92.5%
Pumped Storage	16.7%	8.2%	3.5%	0.0%	0.0%	0.0%	0.0%	0.0%	4.2%	32.7%
Run of River	62.6%	9.1%	5.1%	15.2%	0.0%	0.0%	0.0%	5.1%	2.7%	99.8%
Solar	61.9%	21.2%	0.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	83.6%
Steam	5.6%	1.4%	0.2%	41.6%	0.2%	0.0%	0.0%	0.0%	1.7%	50.8%
Transaction	5.6%	1.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	92.5%	100.0%
Wind	3.5%	2.2%	27.8%	3.3%	0.0%	0.0%	0.0%	0.0%	0.0%	36.7%
All Self-Scheduled Offers	22.6%	1.2%	0.7%	19.2%	0.1%	0.0%	0.0%	0.1%	1.0%	45.0%

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.[54]

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

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

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 3-28.

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.[55]

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 markup component of the load-weighted LMP by fuel type and unit type using unadjusted and adjusted offers. The adjusted markup component of LMP decreased from $4.61 in the first six months of 2014 to $2.42 in the first six months of 2015. The adjusted markup contribution of coal units in the first six months of 2015 was $0.79. Although the price of natural gas was substantially lower in the first six months of 2015 compared to that in 2014, the adjusted markup component of all gas-fired units in the first six months of 2015 was $1.22, a decrease of $0.23 from the first six months of 2014. Coal units accounted for 72.4 percent of the decreased markup component of LMP in the first six months of 2015. The markup

55 See PJM. "Manual 15: Cost Development Guidelines," Revision: 25 (July 28, 2014).

component of wind units was $0.02. If a price-based offer is negative, but less negative than a cost-based offer, the markup is positive. In the first six months of 2015, among the wind units that were marginal, 3.73 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 June 2014 and 2015[56]

		2014 (Jan - Jun)		2015 (Jan - Jun)	
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	$1.19	$2.38	($0.95)	$0.79
Gas	CC	$0.89	$0.89	$1.25	$1.25
Gas	CT	$0.40	$0.40	($0.03)	($0.03)
Gas	Diesel	$0.17	$0.17	$0.01	$0.01
Gas	Steam	($0.01)	($0.01)	($0.01)	($0.01)
Municipal Waste	Steam	$0.30	$0.30	$0.17	$0.17
Oil	CC	$0.18	$0.18	$0.09	$0.09
Oil	CT	$0.18	$0.18	$0.06	$0.06
Oil	Diesel	$0.00	$0.00	$0.01	$0.01
Oil	Steam	$0.09	$0.09	$0.04	$0.04
Other	Steam	$0.00	$0.00	$0.03	$0.03
Uranium	Steam	$0.01	$0.01	$0.00	$0.00
Wind	Wind	$0.02	$0.02	$0.02	$0.02
Total		$3.43	$4.61	$0.67	$2.42

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 six months of 2015, when using unadjusted cost offers, $0.67 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. Using adjusted cost-offers, $2.42 per MWh of the PJM real-time load-weighted average LMP was attributable to markup. In the first six months of 2015, the peak markup component was highest in February, $4.79 per MWh using unadjusted cost offers and $6.64 per MWh using adjusted cost offers. This corresponds to 8.85 percent and 12.27 percent of the real time load-weighted average LMP in February.

56 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.

Table 3-49 Monthly markup components of real-time load-weighted LMP (Unadjusted): January through June 2014 and 2015

	2014			2015		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$5.44	$3.91	$6.92	($1.42)	($2.55)	($0.31)
Feb	$3.02	$0.88	$5.08	$4.62	$4.46	$4.79
Mar	$7.11	$3.24	$11.17	$2.34	$2.82	$1.86
Apr	($0.43)	($2.16)	$1.07	$0.95	($0.69)	$2.39
May	$1.74	($1.27)	$4.62	($2.13)	($4.17)	$0.03
Jun	$2.43	($0.08)	$4.60	($0.53)	($1.43)	$0.21
Total	$3.42	$1.02	$5.69	$0.67	($0.14)	$1.45

Table 3-50 Monthly markup components of real-time load-weighted LMP (Adjusted): January through June 2014 and 2015

	2014			2015		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
Jan	$6.83	$5.48	$8.12	$0.61	($0.53)	$1.72
Feb	$3.94	$1.97	$5.84	$6.44	$6.26	$6.64
Mar	$8.21	$4.59	$12.02	$4.21	$4.69	$3.74
Apr	$0.86	($0.45)	$2.00	$2.59	$0.72	$4.23
May	$2.87	$0.09	$5.54	($0.71)	($3.00)	$1.72
Jun	$3.69	$1.46	$5.62	$1.09	($0.16)	$2.10
Total	$4.61	$2.45	$6.65	$2.42	$1.48	$3.32

Hourly Markup Component of Real-Time Prices

Figure 3-28 shows markup contribution to the hourly load-weighted LMP using unadjusted cost offers for the first six months of 2015 and the first six months of 2014. Figure 3-29 shows markup contribution to the hourly load-weighted LMP using adjusted cost offers for the first six months of 2015 and the first six months of 2014. In 2014, high markups were seen during the polar vortex events in January and early March. In contrast, January 2015 had very low markups. Most high markup hours in 2015 were observed in February and March.

Figure 3-28 Markup Contribution to real-time hourly load-weighted LMP (Unadjusted): January through June 2014 and 2015

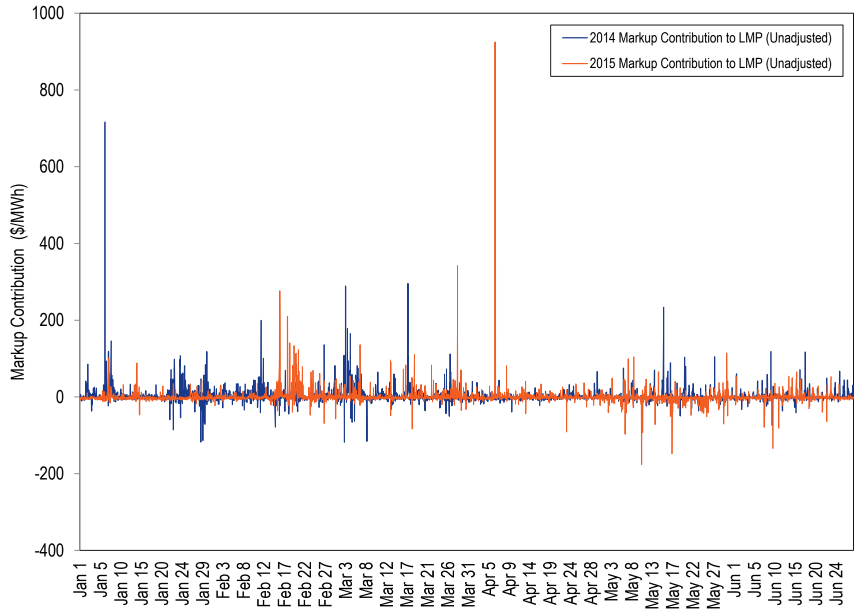
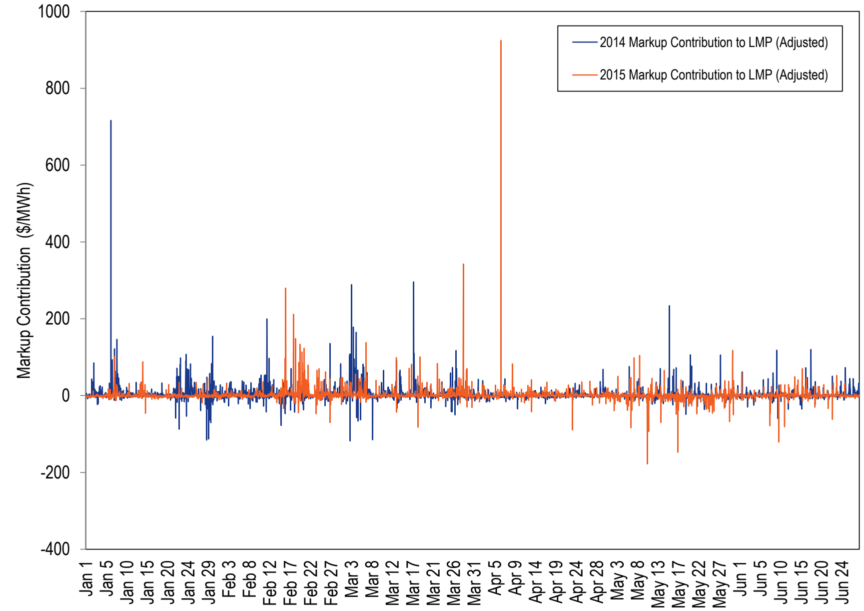


Figure 3-29 Markup Contribution to real-time hourly load-weighted LMP (Adjusted): January through June 2014 and 2015



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 six months of 2014 and 2015 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 six months of 2015 was in the DPL Zone, -$1.82 per MWh, while the highest was in the BGE Control Zone, $2.60 per MWh. The smallest zonal on peak average markup was in the PPL Control Zone, -$0.64 per MWh, while the highest was in the Pepco Control Zone, $3.31 per MWh.

Table 3-51 Average real-time zonal markup component (Unadjusted): January through June 2014 and 2015

	2014 (Jan - Jun)			2015 (Jan - Jun)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$3.37	$0.83	$5.81	($0.41)	($1.56)	$0.67
AEP	$2.94	$0.60	$5.22	($0.21)	($0.77)	$0.29
APS	$2.82	$0.86	$4.70	$0.41	($0.40)	$1.12
ATSI	$2.41	$0.28	$4.43	$0.16	($0.90)	$1.13
BGE	$5.10	$2.15	$7.89	$2.60	$2.21	$2.96
ComEd	$2.49	$0.50	$4.35	($0.60)	($1.67)	$0.33
DAY	$2.60	$0.28	$4.75	$0.60	($0.68)	$1.78
DEOK	$2.55	$0.15	$4.83	$0.45	($1.05)	$1.85
DLCO	$2.34	$0.73	$3.85	$0.04	($1.29)	$1.25
DPL	$3.88	$1.35	$6.30	($1.82)	($3.52)	($0.31)
Dominion	$5.35	$2.34	$8.19	$1.48	$0.88	$2.04
EKPC	$3.08	$0.69	$5.47	$0.10	($0.83)	$1.01
JCPL	$2.81	$0.65	$4.76	($0.57)	($1.19)	($0.02)
Met-Ed	$3.03	$1.10	$4.81	($0.54)	($1.14)	$0.01
PECO	$3.33	$0.86	$5.65	($0.76)	($1.15)	($0.39)
PENELEC	$3.28	$0.84	$5.56	$0.12	($0.79)	$0.95
PPL	$3.84	$1.22	$6.30	($0.85)	($1.09)	($0.64)
PSEG	$4.04	$1.46	$6.40	($0.57)	($1.27)	$0.05
Pepco	$4.93	$2.14	$7.48	$2.24	$1.04	$3.31
RECO	$4.26	$1.77	$6.41	$0.21	($1.15)	$1.33

Table 3-52 Average real-time zonal markup component (Adjusted): January through June 2014 and 2015

	2014 (Jan - Jun)			2015 (Jan - Jun)		
	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component	Markup Component (All Hours)	Off Peak Markup Component	Peak Markup Component
AECO	$4.52	$2.19	$6.77	$0.71	($0.47)	$1.82
AEP	$4.18	$2.13	$6.16	$1.59	$0.75	$2.34
APS	$3.99	$2.28	$5.65	$2.24	$1.17	$3.19
ATSI	$3.63	$1.78	$5.38	$1.97	$0.73	$3.10
BGE	$6.32	$3.63	$8.87	$5.15	$4.40	$5.85
ComEd	$3.68	$1.94	$5.31	$0.86	($0.46)	$2.00
DAY	$3.86	$1.83	$5.74	$2.43	$0.90	$3.82
DEOK	$3.77	$1.64	$5.78	$2.20	$0.49	$3.79
DLCO	$3.67	$2.32	$4.93	$1.82	$0.35	$3.16
DPL	$5.03	$2.69	$7.26	($0.87)	($2.72)	$0.75
Dominion	$6.45	$3.65	$9.11	$3.57	$2.70	$4.38
EKPC	$4.31	$2.18	$6.43	$1.91	$0.83	$2.99
JCPL	$3.96	$2.01	$5.73	$0.61	($0.05)	$1.19
Met-Ed	$4.17	$2.46	$5.75	$0.66	($0.02)	$1.28
PECO	$4.48	$2.21	$6.61	$0.41	($0.01)	$0.80
PENELEC	$4.49	$2.25	$6.57	$1.71	$0.66	$2.67
PPL	$5.00	$2.58	$7.27	$0.24	($0.06)	$0.51
PSEG	$5.16	$2.77	$7.35	$0.65	($0.13)	$1.34
Pepco	$6.12	$3.58	$8.44	$4.58	$2.94	$6.02
RECO	$5.45	$3.10	$7.47	$1.67	$0.25	$2.85

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 June 2014 and 2015

	2014 (Jan - Jun)		2015 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$0.60	51.4%	$0.46	69.3%
$25 to $50	($0.29)	25.2%	($0.45)	26.7%
$50 to $75	$0.33	10.2%	$0.35	2.6%
$75 to $100	$0.34	3.7%	$0.19	0.8%
$100 to $125	$0.18	2.0%	$0.01	0.3%
$125 to $150	$0.30	1.6%	$0.04	0.1%
>= $150	$2.01	5.8%	$0.07	0.2%

Table 3-54 Average real-time markup component (By price category, adjusted): January through June 2014 and 2015

	2014 (Jan - Jun)		2015 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	$1.18	51.4%	$1.68	69.3%
$25 to $50	$0.11	25.2%	$0.04	26.7%
$50 to $75	$0.41	10.2%	$0.38	2.6%
$75 to $100	$0.39	3.7%	$0.19	0.8%
$100 to $125	$0.19	2.0%	$0.02	0.3%
$125 to $150	$0.31	1.6%	$0.05	0.1%
>= $150	$2.08	5.8%	$0.07	0.2%

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 74.1 percent of marginal resources in the first six months of 2015. INCs were marginal for 5.4 percent of marginal resources and DECs were marginal for 9.1 percent of marginal resources in the first six months of 2015. 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.[57] 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 11.1 percent of marginal resources in the first six months of 2015. The markup component of LMP for marginal generating resources decreased in coal-fired steam units and oil-fired CT units. The markup component of LMP for coal units decreased from $1.49 in the first six months of 2014 to $0.39 in the first six months of 2015. The markup component of LMP for gas-fired CCs increased from -$0.46 in the first six months of 2014 to -$0.13 in the first six months of 2015.

Table 3-55 Markup component of the annual PJM day-ahead, load-weighted, average LMP by primary fuel type and unit type: January through June of 2014 and 2015

		2014 (Jan - Jun)		2015 (Jan - Jun)	
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	$0.36	$1.49	($1.03)	$0.39
Gas	CC	($0.46)	($0.46)	($0.13)	($0.13)
Gas	CT	$0.05	$0.05	$0.07	$0.07
Gas	Diesel	$0.00	$0.00	$0.01	$0.01
Gas	Steam	($0.05)	($0.05)	$0.06	$0.06
Import	Steam	$0.00	$0.01	$0.00	$0.00
Municipal Waste	Steam	($0.00)	($0.00)	($0.00)	($0.00)
Oil	CC	$0.04	$0.04	$0.06	$0.06
Oil	CT	$0.06	$0.08	$0.03	$0.03
Oil	Steam	$0.03	$0.03	$0.13	$0.13
Other	Steam	($0.01)	($0.01)	$0.00	$0.00
Wind	Wind	$0.00	$0.00	$0.03	$0.03
Total		$0.01	$1.17	($0.78)	$0.64

57 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. In the first six months of 2015, when using adjusted cost-offers, $0.64 per MWh of the PJM day-ahead load-weighted average LMP was attributable to markup. In the first six months of 2015, the peak markup component was highest in February, $4.26 per MWh using adjusted cost offers. Using adjusted cost-offers, the markup component in the first six months of 2015 decreased in every month except February from the first six months of 2014. The markup component decreased from $1.80 to -$0.26 in January.

Table 3-56 Monthly markup components of day-ahead (Unadjusted), load-weighted LMP: January through June of 2014 and 2015

	2014 (Jan - Jun)			2015 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	$1.03	$2.85	($0.88)	($1.96)	($1.25)	($2.64)
Feb	$0.34	$2.07	($1.47)	$1.39	$3.18	($0.26)
Mar	$0.14	($0.27)	$0.53	($0.43)	$0.49	($1.37)
Apr	($0.88)	$0.42	($2.37)	($0.76)	($0.02)	($1.63)
May	($0.99)	$0.07	($2.10)	($2.14)	($3.29)	($1.04)
Jun	$0.03	$1.30	($1.45)	($0.87)	($0.83)	($0.92)
Annual	$0.01	$1.16	($1.21)	($0.78)	($0.25)	($1.32)

Table 3-57 Monthly markup components of day-ahead (Adjusted), load-weighted LMP: January through June of 2014 and 2015

	2014 (Jan - Jun)			2015 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
Jan	$1.80	$3.42	$0.09	($0.26)	$0.23	($0.74)
Feb	$1.44	$2.86	($0.05)	$2.72	$4.26	$1.30
Mar	$1.34	$0.64	$2.01	$1.02	$1.79	$0.22
Apr	$0.51	$1.34	($0.45)	$0.50	$1.02	($0.11)
May	$0.24	$0.85	($0.39)	($0.66)	($1.62)	$0.26
Jun	$1.38	$2.31	$0.29	$0.37	$0.40	$0.34
Annual	$1.17	$1.98	$0.30	$0.64	$1.06	$0.22

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 decreased in all zones from the first six months of 2014 to the first six months of 2015. The smallest zonal all hours average markup component using adjusted offers for the first six months of 2015 was in the DEOK Zone, $0.28 per MWh, while the highest was in the RECO Control Zone, $0.92 per MWh. The smallest zonal on peak average markup was in the Dominion Control Zone, $0.53 per MWh, while the highest was in the PPL Control Zone, $1.46 per MWh.

Table 3-58 Day-ahead, average, zonal markup component (Unadjusted): January through June of 2014 and 2015

	2014 (Jan - Jun)			2015 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	$0.14	$1.33	($1.12)	($0.73)	($0.62)	($0.84)
AEP	($0.03)	$1.09	($1.20)	($1.19)	($0.80)	($1.59)
AP	($0.09)	$1.16	($1.39)	($0.71)	($0.22)	($1.21)
ATSI	($0.09)	$1.05	($1.31)	($0.88)	($0.00)	($1.81)
BGE	$0.11	$1.35	($1.22)	($0.76)	($0.19)	($1.35)
ComEd	$0.02	$0.94	($0.98)	($0.74)	$0.14	($1.67)
DAY	($0.03)	$1.06	($1.22)	($1.16)	($0.27)	($2.11)
DEOK	($0.04)	$1.01	($1.14)	($1.23)	($0.59)	($1.88)
DLCO	($0.10)	$0.90	($1.18)	($0.76)	$0.38	($1.97)
Dominion	($0.11)	$1.10	($1.39)	($0.96)	($1.04)	($0.89)
DPL	$0.24	$1.45	($1.04)	($0.39)	$0.04	($0.83)
EKPC	$0.16	$1.25	($0.92)	($0.95)	($0.22)	($1.65)
JCPL	$0.12	$1.28	($1.19)	($0.47)	($0.07)	($0.91)
Met-Ed	$0.21	$1.45	($1.12)	($0.40)	$0.07	($0.90)
PECO	$0.26	$1.53	($1.11)	($0.38)	$0.06	($0.84)
PENELEC	($0.04)	$1.17	($1.38)	($0.41)	$0.39	($1.21)
Pepco	$0.12	$1.35	($1.25)	($0.61)	($0.06)	($1.17)
PPL	$0.10	$1.35	($1.23)	($0.32)	$0.32	($0.97)
PSEG	$0.18	$1.41	($1.20)	($0.41)	$0.01	($0.87)
RECO	$0.18	$1.41	($1.26)	($0.24)	$0.36	($0.93)

Table 3-59 Day-ahead, average, zonal markup component (Adjusted): January through June of 2014 and 2015

	2014 (Jan - Jun)			2015 (Jan - Jun)		
	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component	Markup Component (All Hours)	Peak Markup Component	Off-Peak Markup Component
AECO	$1.28	$2.15	$0.36	$0.66	$0.84	$0.47
AEP	$1.15	$1.92	$0.34	$0.46	$0.86	$0.06
AP	$1.06	$1.96	$0.12	$0.65	$0.96	$0.34
ATSI	$1.09	$1.87	$0.25	$0.61	$1.29	($0.11)
BGE	$1.30	$2.17	$0.36	$0.61	$0.90	$0.31
ComEd	$1.20	$1.79	$0.56	$0.71	$1.41	($0.04)
DAY	$1.17	$1.92	$0.36	$0.37	$1.09	($0.38)
DEOK	$1.13	$1.84	$0.40	$0.28	$0.80	($0.24)
DLCO	$1.04	$1.67	$0.36	$0.60	$1.44	($0.28)
Dominion	$1.03	$1.91	$0.10	$0.59	$0.53	$0.65
DPL	$1.37	$2.26	$0.42	$0.79	$1.11	$0.47
EKPC	$1.28	$2.03	$0.54	$0.54	$1.11	($0.01)
JCPL	$1.28	$2.17	$0.28	$0.74	$1.03	$0.41
Met-Ed	$1.35	$2.28	$0.33	$0.79	$1.14	$0.41
PECO	$1.38	$2.34	$0.35	$0.78	$1.10	$0.44
PENELEC	$1.10	$2.02	$0.10	$0.84	$1.41	$0.27
Pepco	$1.29	$2.18	$0.29	$0.79	$1.16	$0.40
PPL	$1.22	$2.17	$0.19	$0.91	$1.46	$0.33
PSEG	$1.25	$2.21	$0.18	$0.79	$1.13	$0.42
RECO	$1.21	$2.20	$0.06	$0.92	$1.39	$0.37

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 Average, day-ahead markup (By LMP category, unadjusted): January through June of 2014 and 2015

	2014 (Jan - Jun)		2015 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($2.75)	2.6%	($1.75)	17.9%
$25 to $50	($1.65)	64.1%	($1.11)	66.0%
$50 to $75	$1.07	19.6%	($1.77)	7.7%
$75 to $100	($1.08)	4.5%	($1.56)	4.1%
$100 to $125	($7.11)	1.7%	$1.14	2.1%
$125 to $150	$5.66	1.4%	$9.11	0.9%
>= $150	$10.47	6.0%	$13.21	1.3%

Table 3-61 Average, day-ahead markup (By LMP category, adjusted): January through June 2014 and 2015

	2014 (Jan - Jun)		2015 (Jan - Jun)	
LMP Category	Average Markup Component	Frequency	Average Markup Component	Frequency
< $25	($0.85)	2.6%	($0.36)	17.9%
$25 to $50	$0.21	64.1%	$0.58	66.0%
$50 to $75	$2.26	19.6%	($0.28)	7.7%
$75 to $100	($0.54)	4.5%	($0.95)	4.1%
$100 to $125	($6.43)	1.7%	$1.77	2.1%
$125 to $150	$6.32	1.4%	$9.28	0.9%
>= $150	$11.45	6.0%	$13.45	1.3%

Prices

The conduct of individual market entities within a market structure is reflected in market prices. 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 39.5 percent and 38.8 percent lower in the first six months of 2015 than in the first six months of 2014 as a result of lower fuel costs and lower demand in the first six months of 2015. Coal and natural gas prices decreased in 2015. Comparing fuel prices in 2015 to 2014, the price of Northern Appalachian coal was 16.6 percent lower; the price of Central Appalachian coal was 23.1 percent lower; the price of Powder River Basin coal was 11.9 percent lower; the price of eastern natural gas was 45.2 percent lower; and the price of western natural gas was 55.1 percent lower.

PJM real-time energy market prices decreased in the first six months of 2015 compared to the first six months of 2014. The average LMP was 61.7 percent lower in the first six months of 2015 than in the first six months of 2014, $38.87 per MWh versus $62.14 per MWh. The load-weighted average LMP was 63.4 percent lower in the first six months of 2015 than in the first six months of 2014, $42.30 per MWh versus $69.92 per MWh.

The fuel-cost adjusted, load-weighted, average LMP in the first six months of 2015 was 24.9 percent higher than the load-weighted, average LMP for the first six months of 2015. If fuel costs in the first six months of 2015 had been the same as in the first six months of 2014, holding everything else constant, the load-weighted LMP would have been higher, $52.85 per MWh instead of the observed $42.30 per MWh.

PJM day-ahead energy market prices decreased in the first six months of 2015 compared to the first six months of 2014. The average LMP was 58.9 percent lower in the first six months of 2015 than in the first six months of 2014, $39.98 per MWh versus $63.52 per MWh. The day-ahead load-weighted average LMP was 59.6 percent lower in the first six months of 2015 than in the first six months of 2014, $43.26 per MWh versus $70.67 per MWh.[58]

58 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."

Real-Time LMP

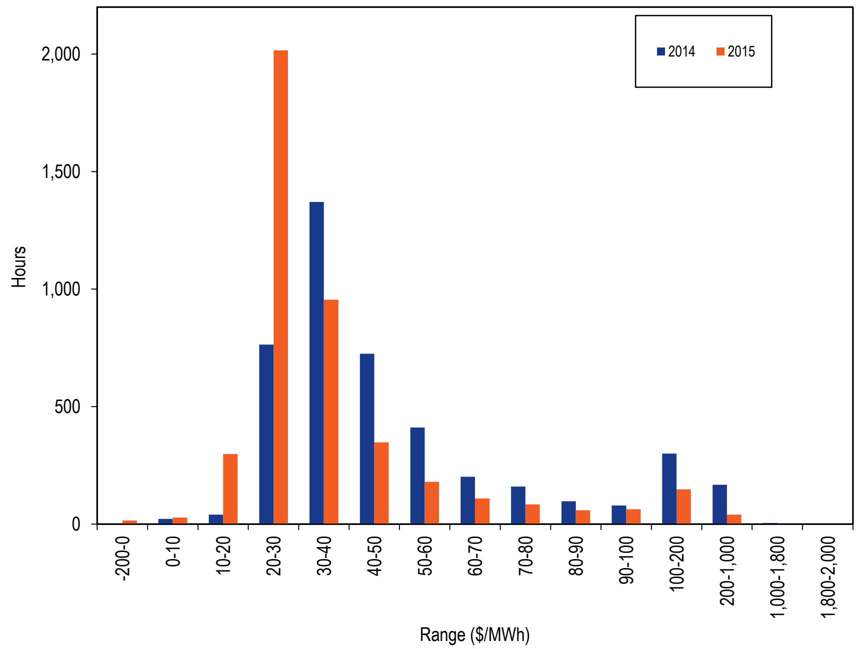
Real-time average LMP is the hourly average LMP for the PJM Real-Time Energy Market.[59]

Real-Time Average LMP

PJM Real-Time Average LMP Duration

Figure 3-30 shows the hourly distribution of PJM real-time average LMP for the first six months of 2014 and 2015. In the first six months of 2014, there were six hour in January in which PJM real-time average LMP was greater than $1,000 and one hour in which the real-time LMP was greater than $1,800.

Figure 3-30 Average LMP for the PJM Real-Time Energy Market: January through June 2014 and 2015[60]



59 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>.

60 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 six months of each year of the 18 year period 1998 to 2015.[61]

Table 3-62 PJM real-time, average LMP (Dollars per MWh): January through June of 1998 through 2015

	Real-Time LMP			Year-to-Year Change		
(Jan-Jun)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$20.13	$15.90	$15.59	NA	NA	NA
1999	$22.94	$17.84	$41.16	14.0%	12.2%	164.0%
2000	$25.38	$18.03	$25.65	10.6%	1.1%	(37.7%)
2001	$33.10	$25.69	$21.11	30.4%	42.5%	(17.7%)
2002	$24.10	$19.64	$13.21	(27.2%)	(23.6%)	(37.4%)
2003	$41.31	$33.74	$27.81	71.4%	71.8%	110.6%
2004	$44.99	$40.75	$22.97	8.9%	20.8%	(17.4%)
2005	$45.71	$39.80	$23.51	1.6%	(2.3%)	2.3%
2006	$49.36	$43.46	$25.26	8.0%	9.2%	7.5%
2007	$55.03	$48.05	$31.42	11.5%	10.6%	24.4%
2008	$70.19	$59.53	$41.77	27.6%	23.9%	33.0%
2009	$40.12	$35.42	$19.30	(42.8%)	(40.5%)	(53.8%)
2010	$43.27	$37.11	$22.20	7.9%	4.8%	15.0%
2011	$45.51	$37.40	$32.52	5.2%	0.8%	46.5%
2012	$29.74	$28.32	$16.10	(34.6%)	(24.3%)	(50.5%)
2013	$36.56	$32.79	$17.18	22.9%	15.8%	6.7%
2014	$62.14	$39.69	$88.87	69.9%	21.0%	417.4%
2015	$38.87	$29.04	$34.04	(37.4%)	(26.8%)	(61.7%)

Real-Time, Load-Weighted, Average LMP

Higher demand (load) generally results in higher prices, all else constant. As a result, load-weighted, average prices are generally higher than average prices. Load-weighted LMP reflects the average LMP paid for actual MWh consumed during a year. Load-weighted, average LMP is the average of PJM hourly LMP, each weighted by the PJM total hourly load. The real-time, load-weighted, average LMP decreased by 39.5 percent compared to the first six months of 2014.

61 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.

PJM Real-Time, Load-Weighted, Average LMP

Table 3-63 shows the PJM real-time, load-weighted, average LMP for the first six months of each year of the 18 year period 1998 to 2015.

Table 3-63 PJM real-time, load-weighted, average LMP (Dollars per MWh): January through June of 1998 through 2015

	Real-Time, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Jun)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
1998	$21.66	$16.80	$18.39	NA	NA	NA
1999	$25.34	$18.59	$52.06	17.0%	10.7%	183.1%
2000	$27.76	$18.91	$29.69	9.5%	1.7%	(43.0%)
2001	$35.27	$27.88	$22.12	27.0%	47.4%	(25.5%)
2002	$25.93	$20.67	$14.62	(26.5%)	(25.9%)	(33.9%)
2003	$44.43	$37.98	$28.55	71.4%	83.8%	95.2%
2004	$47.62	$43.96	$23.30	7.2%	15.8%	(18.4%)
2005	$48.67	$42.30	$24.81	2.2%	(3.8%)	6.5%
2006	$51.83	$45.79	$26.54	6.5%	8.3%	7.0%
2007	$58.32	$52.52	$32.39	12.5%	14.7%	22.1%
2008	$74.77	$64.26	$44.25	28.2%	22.4%	36.6%
2009	$42.48	$36.95	$20.61	(43.2%)	(42.5%)	(53.4%)
2010	$45.75	$38.78	$23.60	7.7%	5.0%	14.5%
2011	$48.47	$38.63	$37.59	5.9%	(0.4%)	59.3%
2012	$31.21	$28.98	$17.69	(35.6%)	(25.0%)	(52.9%)
2013	$37.96	$33.58	$18.54	21.6%	15.9%	4.8%
2014	$69.92	$42.61	$103.35	84.2%	26.9%	457.6%
2015	$42.30	$30.34	$37.85	(39.5%)	(28.8%)	(63.4%)

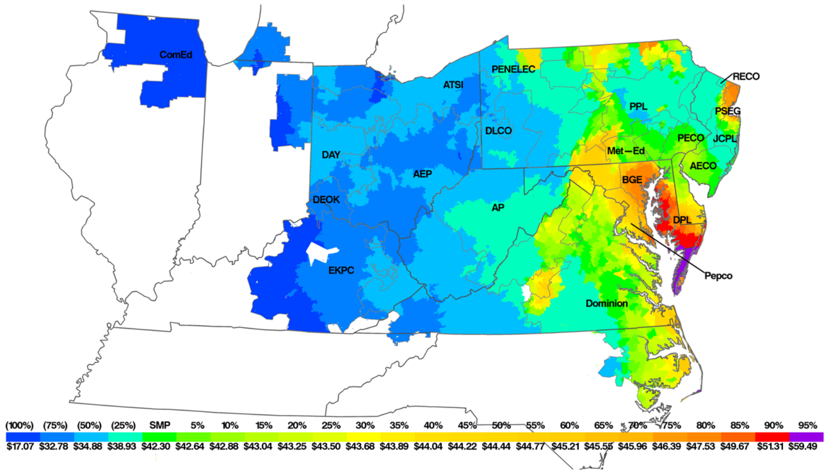
Table 3-64 shows zonal real-time, and real-time, load-weighted, average LMP for the first six months of 2014 and 2015.

Table 3-64 Zone real-time and real-time, load-weighted, average LMP (Dollars per MWh): January through June of 2014 and 2015

	Real-Time Average LMP			Real-Time, Load-Weighted, Average LMP		
Zone	2014 (Jan-Jun) Average	2015 (Jan-Jun) Average	Percent Change	2014 (Jan-Jun) Average	2015 (Jan-Jun) Average	Percent Change
AECO	$68.78	$41.58	(39.5%)	$76.31	$45.10	(40.9%)
AEP	$54.16	$35.25	(34.9%)	$59.99	$37.76	(37.1%)
AP	$60.95	$40.67	(33.3%)	$69.31	$44.73	(35.5%)
ATSI	$56.42	$35.82	(36.5%)	$60.96	$37.75	(38.1%)
BGE	$77.75	$48.89	(37.1%)	$92.61	$54.57	(41.1%)
ComEd	$47.30	$29.91	(36.8%)	$50.82	$31.54	(37.9%)
Day	$53.38	$35.45	(33.6%)	$58.75	$37.79	(35.7%)
DEOK	$50.79	$34.15	(32.8%)	$55.90	$36.50	(34.7%)
DLCO	$50.21	$33.23	(33.8%)	$53.86	$34.87	(35.3%)
Dominion	$72.42	$43.48	(40.0%)	$86.92	$49.19	(43.4%)
DPL	$50.21	$33.23	(33.8%)	$88.47	$52.35	(40.8%)
EKPC	$50.98	$32.82	(35.6%)	$60.73	$36.36	(40.1%)
JCPL	$68.98	$41.20	(40.3%)	$77.00	$45.14	(41.4%)
Met-Ed	$67.18	$41.09	(38.8%)	$77.14	$45.80	(40.6%)
PECO	$67.93	$40.41	(40.5%)	$77.01	$44.65	(42.0%)
PENELEC	$61.27	$40.07	(34.6%)	$67.58	$43.29	(35.9%)
Pepco	$77.00	$45.42	(41.0%)	$90.86	$50.34	(44.6%)
PPL	$67.23	$40.68	(39.5%)	$78.54	$46.08	(41.3%)
PSEG	$73.40	$44.83	(38.9%)	$80.35	$48.14	(40.1%)
RECO	$71.85	$45.63	(36.5%)	$77.97	$48.24	(38.1%)
PJM	$62.14	$38.87	(37.4%)	$69.92	$42.30	(39.5%)

Figure 3-31 is a contour map of the real-time, load-weighted, average LMP in the first six months of 2015. Green represents the system marginal price (SMP) for each year with each color to the right of green including five percent of the pricing nodes above SMP and each color to the left of green including 25 percent of pricing nodes below SMP. Prices in Eastern MAAC were all higher, on average, than the SMP for the first six months of 2015.

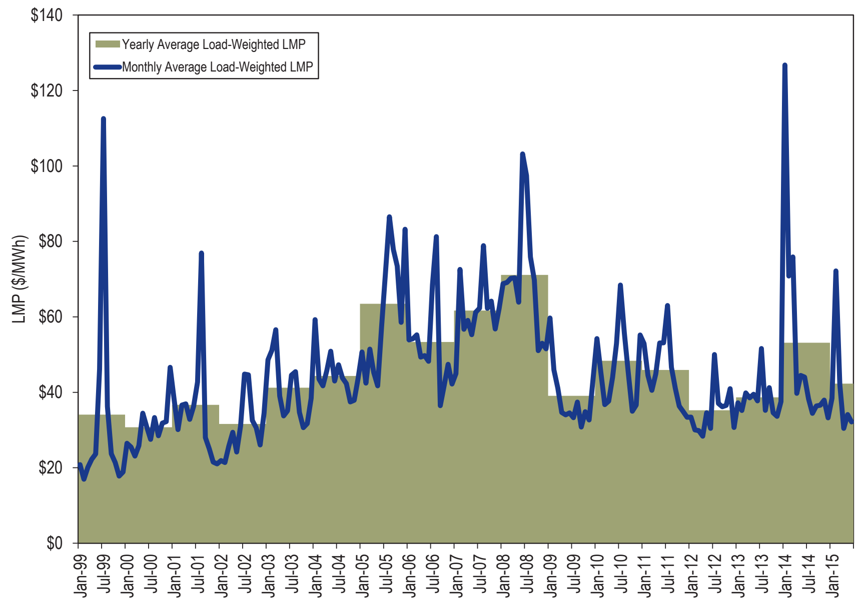
Figure 3-31 PJM real-time, load-weighted, average LMP: January through June 2015



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

Figure 3-32 shows the PJM real-time monthly and annual load-weighted LMP for the first six months from 1999 through 2015.

Figure 3-32 PJM real-time, monthly and annual, load-weighted, average LMP: January 1999 through June 2015



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. Coal and natural gas prices decreased in 2015. Comparing fuel prices in 2015 to 2014, the price of Northern Appalachian coal was 16.6 percent lower; the price of Central Appalachian coal was 23.1 percent lower; the price of Powder River Basin coal was 11.9 percent lower; the price of eastern natural gas was 45.2 percent lower; and the price of western natural gas was 55.1 percent lower. Figure 3-33 shows monthly average spot fuel prices.[62]

Figure 3-33 Spot average fuel price comparison with fuel delivery charges: 2012 through June, 2015 ($/MMBtu)

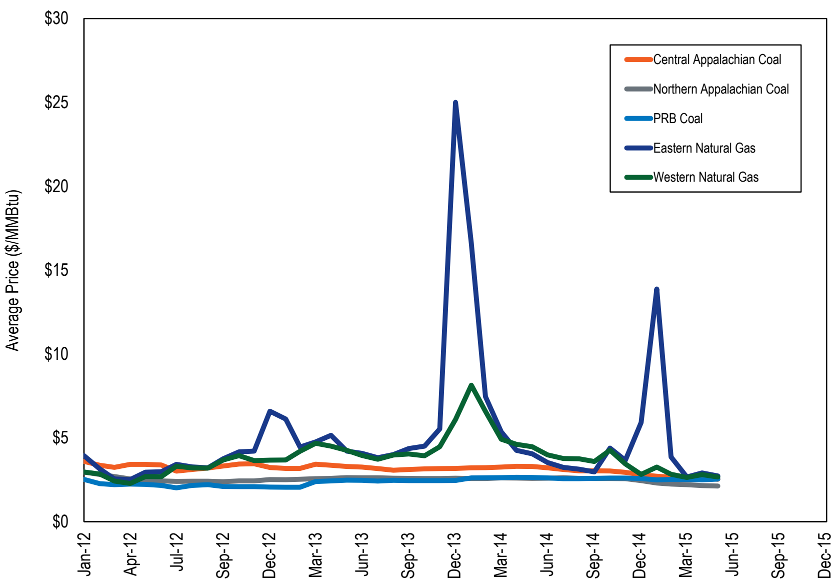


Table 3-65 compares the first six months of 2015 PJM real time fuel-cost adjusted, load-weighted, average LMP to the first six months of 2015 load-weighted, average LMP. The real time fuel-cost adjusted, load-weighted, average LMP for the first six months of 2015 was 24.9 percent higher than the real time load-weighted, average LMP for the first six months of 2015. The real-time, fuel-cost adjusted, load-weighted, average LMP for the first six months of 2015 was 24.4 percent lower than the real time load-weighted LMP for the first six months of 2014. If fuel costs in the first six months of 2015 had been the same as in the first six months of 2014, holding everything else constant, the real time load-weighted LMP in 2015 would have been higher, $52.85 per MWh instead of the observed $42.30 per MWh.

Table 3-65 PJM real-time annual, fuel-cost adjusted, load-weighted average LMP (Dollars per MWh): six months over six months

	2015 Load-Weighted LMP	2015 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$42.30	$52.85	24.9%
	2014 Load-Weighted LMP	2015 Fuel-Cost-Adjusted, Load-Weighted LMP	Change
Average	$69.92	$52.85	(24.4%)
	2014 Load-Weighted LMP	2015 Load-Weighted LMP	Change
Average	$69.92	$42.30	(39.5%)

Table 3-66 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 six months of 2015. Table 3-66 shows that lower coal, natural gas and oil prices explain almost all of the fuel-cost related decrease in the real time annual load-weighted average LMP in the first six months of 2015. Unlike oil and natural gas, there was no substantial change in the price of coal from the first six months of 2014 to the first six months of 2015. However, coal units' offer prices were generally lower in the first six months of 2015 compared to their offers in the first six months of 2014, particularly the high offer prices during the cold weather days in January and March of 2014.

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

Fuel Type	Share of Change in Fuel Cost Adjusted, Load Weighted LMP	Percent
Coal	($2.44)	23.1%
Gas	($6.94)	65.8%
Municipal Waste	($0.00)	0.0%
Oil	($1.12)	10.6%
Other	($0.04)	0.4%
Uranium	$0.00	(0.0%)
Wind	($0.00)	0.0%
Total	($10.55)	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.[63] 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.[64] 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 3-67, including markup using unadjusted cost offers.[65] Table 3-67 shows that for the first six months of 2015, 40.8 percent of the load-weighted LMP was the result of coal costs, 30.2 percent was the result of gas costs and 0.71 percent was the result of the cost of emission allowances. Markup was $0.67 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 six months of 2015, nearly nine 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 six months of 2015 and 2014.

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

64 PJM triggered shortage pricing on January 6, 2014 following a RTO-wide voltage reduction action. PJM triggered shortage pricing on January 7, 2014, due to RTO-wide shortage of synchronized reserve.

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

Table 3-67 Components of PJM real-time (Unadjusted), six month, load-weighted, average LMP: January through June 2014 and 2015

	2014 (Jan - Jun)		2015 (Jan - Jun)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Coal	$17.39	24.9%	$17.27	40.8%	16.0%
Gas	$26.93	38.5%	$12.78	30.2%	(8.3%)
Ten Percent Adder	$4.54	6.5%	$3.53	8.3%	1.9%
VOM	$2.79	4.0%	$2.66	6.3%	2.3%
Oil	$5.32	7.6%	$2.30	5.4%	(2.2%)
Ancillary Service Redispatch Cost	$0.76	1.1%	$1.27	3.0%	1.9%
LPA Rounding Difference	($0.11)	(0.2%)	$0.80	1.9%	2.1%
Markup	$3.42	4.9%	$0.67	1.6%	(3.3%)
NA	$2.73	3.9%	$0.67	1.6%	(2.3%)
Increase Generation Adder	$1.23	1.8%	$0.36	0.9%	(0.9%)
CO_2 Cost	$0.20	0.3%	$0.26	0.6%	0.3%
Other	$0.03	0.0%	$0.06	0.1%	0.1%
NO_x Cost	$0.13	0.2%	$0.03	0.1%	(0.1%)
SO_2 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%
FMU Adder	$1.01	1.5%	$0.00	0.0%	(1.4%)
Emergency DR Adder	$3.63	5.2%	$0.00	0.0%	(5.2%)
Scarcity Adder	$0.20	0.3%	$0.00	0.0%	(0.3%)
Constraint Violation Adder	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Uranium	($0.02)	(0.0%)	($0.00)	(0.0%)	0.0%
Wind	($0.02)	(0.0%)	($0.06)	(0.1%)	(0.1%)
Decrease Generation Adder	($0.26)	(0.4%)	($0.08)	(0.2%)	0.2%
LPA-SCED Differential	($0.01)	(0.0%)	($0.10)	(0.2%)	(0.2%)
Municipal Waste	$0.03	0.0%	($0.15)	(0.4%)	(0.4%)
Total	$69.92	100.0%	$42.30	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 3-67 and Table 3-71) markup is simply the difference between the price offer and the cost offer. In the second approach, (Table 3-68 and Table 3-72) the 10 percent markup is removed from the cost offers of coal units.

The components of LMP are shown in Table 3-68, including markup using adjusted cost offers.

Table 3-68 Components of PJM real-time (Adjusted), six month, load-weighted, average LMP: January through June 2014 and 2015

	2014 (Jan - Jun)		2015 (Jan - Jun)		Change
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Percent
Coal	$17.39	24.9%	$17.27	40.8%	16.0%
Gas	$26.93	38.5%	$12.78	30.2%	(8.3%)
VOM	$2.79	4.0%	$2.66	6.3%	2.3%
Markup	$4.61	6.6%	$2.42	5.7%	(0.9%)
Oil	$5.32	7.6%	$2.30	5.4%	(2.2%)
Ten Percent Adder	$3.35	4.8%	$1.78	4.2%	(0.6%)
Ancillary Service Redispatch Cost	$0.76	1.1%	$1.27	3.0%	1.9%
LPA Rounding Difference	($0.11)	(0.2%)	$0.80	1.9%	2.1%
NA	$2.73	3.9%	$0.67	1.6%	(2.3%)
Increase Generation Adder	$1.23	1.8%	$0.36	0.9%	(0.9%)
CO_2 Cost	$0.20	0.3%	$0.26	0.6%	0.3%
Other	$0.03	0.0%	$0.06	0.1%	0.1%
NO_x Cost	$0.13	0.2%	$0.03	0.1%	(0.1%)
SO_2 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%
FMU Adder	$1.01	1.5%	$0.00	0.0%	(1.4%)
Emergency DR Adder	$3.63	5.2%	$0.00	0.0%	(5.2%)
Scarcity Adder	$0.20	0.3%	$0.00	0.0%	(0.3%)
Constraint Violation Adder	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Uranium	($0.02)	(0.0%)	($0.00)	(0.0%)	0.0%
Wind	($0.02)	(0.0%)	($0.06)	(0.1%)	(0.1%)
Decrease Generation Adder	($0.26)	(0.4%)	($0.08)	(0.2%)	0.2%
LPA-SCED Differential	($0.01)	(0.0%)	($0.10)	(0.2%)	(0.2%)
Municipal Waste	$0.03	0.0%	($0.15)	(0.4%)	(0.4%)
Total	$69.92	100.0%	$42.30	100.0%	0.0%

Day-Ahead LMP

Day-ahead average LMP is the hourly average LMP for the PJM Day-Ahead Energy Market.[66]

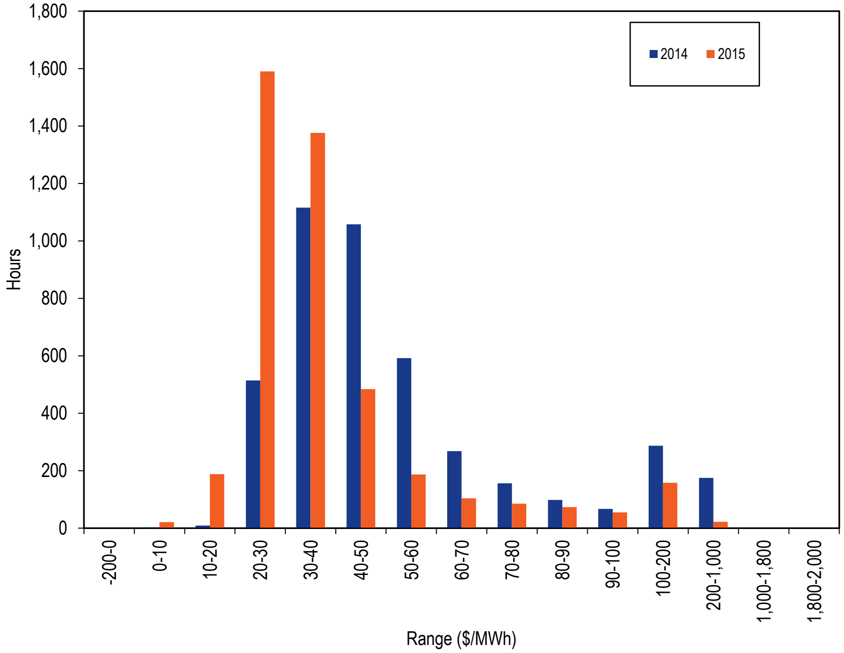
Day-Ahead Average LMP

PJM Day-Ahead Average LMP Duration

Figure 3-34 shows the hourly distribution of PJM day-ahead average LMP for the first six months of 2014 and 2015.

66 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 3-34 Average LMP for the PJM Day-Ahead Energy Market: January through June 2014 and 2015



PJM Day-Ahead, Average LMP

Table 3-69 shows the PJM day-ahead, average LMP for the first six months of each year of the 15-year period 2001 to 2015.

Table 3-69 PJM day-ahead, average LMP (Dollars per MWh): January through June of 2001 through 2015

	Day-Ahead LMP			Year-to-Year Change		
(Jan-Jun)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$35.02	$31.34	$17.43	NA	NA	NA
2002	$24.76	$21.28	$12.49	(29.3%)	(32.1%)	(28.4%)
2003	$42.83	$39.18	$23.52	73.0%	84.1%	88.3%
2004	$44.02	$43.14	$18.33	2.8%	10.1%	(22.0%)
2005	$45.63	$42.51	$18.35	3.7%	(1.5%)	0.1%
2006	$48.33	$47.07	$16.02	5.9%	10.7%	(12.7%)
2007	$53.03	$51.08	$22.91	9.7%	8.5%	43.0%
2008	$70.12	$66.09	$31.98	32.2%	29.4%	39.6%
2009	$40.01	$37.46	$15.38	(42.9%)	(43.3%)	(51.9%)
2010	$43.81	$40.64	$15.66	9.5%	8.5%	1.8%
2011	$44.75	$40.85	$19.53	2.1%	0.5%	24.8%
2012	$30.44	$29.64	$11.77	(32.0%)	(27.4%)	(39.8%)
2013	$37.11	$35.19	$10.42	21.9%	18.7%	(11.4%)
2014	$63.52	$44.42	$69.93	71.2%	26.2%	571.1%
2015	$39.98	$31.93	$28.76	(37.1%)	(28.1%)	(58.9%)

Day-Ahead, Load-Weighted, Average LMP

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

PJM Day-Ahead, Load-Weighted, Average LMP

Table 3-70 shows the PJM day-ahead, load-weighted, average LMP for the first six months of each year of the 15-year period 2001 to 2015.

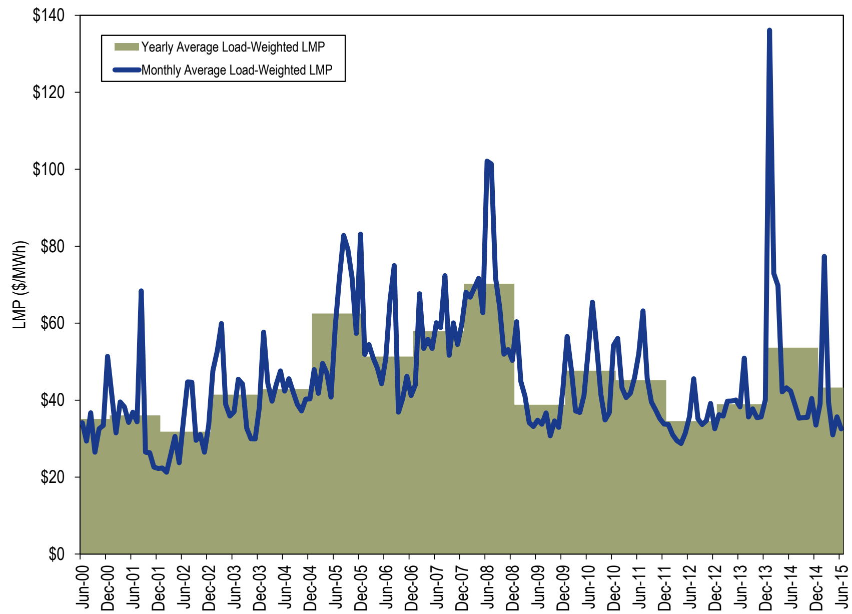
Table 3-70 PJM day-ahead, load-weighted, average LMP (Dollars per MWh): January through June 2001 through 2015

	Day-Ahead, Load-Weighted, Average LMP			Year-to-Year Change		
(Jan-Jun)	Average	Median	Standard Deviation	Average	Median	Standard Deviation
2001	$37.08	$33.91	$18.11	NA	NA	NA
2002	$26.88	$23.00	$14.36	(27.5%)	(32.2%)	(20.7%)
2003	$45.62	$42.01	$23.96	69.8%	82.6%	66.8%
2004	$46.12	$45.45	$18.62	1.1%	8.2%	(22.3%)
2005	$48.12	$44.88	$19.24	4.3%	(1.3%)	3.3%
2006	$50.21	$48.67	$16.23	4.3%	8.5%	(15.7%)
2007	$55.70	$54.26	$23.47	10.9%	11.5%	44.7%
2008	$73.71	$69.33	$33.95	32.3%	27.8%	44.7%
2009	$42.21	$38.83	$16.16	(42.7%)	(44.0%)	(52.4%)
2010	$46.12	$42.50	$16.54	9.3%	9.5%	2.3%
2011	$47.12	$42.58	$22.34	2.2%	0.2%	35.1%
2012	$31.84	$30.35	$13.94	(32.4%)	(28.7%)	(37.6%)
2013	$38.23	$36.19	$11.03	20.1%	19.3%	(20.8%)
2014	$70.67	$47.04	$79.85	84.8%	30.0%	623.8%
2015	$43.26	$33.45	$32.23	(38.8%)	(28.9%)	(59.6%)

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

Figure 3-35 shows the PJM day-ahead, monthly and annual, load-weighted LMP from June 2000 through June 2015.[67]

Figure 3-35 Day-ahead, monthly and annual, load-weighted, average LMP: June 2000 through June 2015



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

67 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.

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.[68] 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 3-71, including markup using unadjusted cost offers.

Table 3-71 shows the components of the PJM day-ahead, annual, load-weighted average LMP. In the first six months of 2015, 30.6 percent of the load-weighted LMP was the result of coal cost, 15.6 percent of the load-weighted LMP was the result of gas cost, 5.3 percent was the result of the up-to congestion transaction cost, 20.4 percent was the result of DEC bid cost and 11.4 percent was the result of INC bid cost. The contribution of up-to congestion transactions decreased on September 8, 2014, as a result of the FERC's UTC uplift refund notice which became effective on that date.[69]

Table 3-71 Components of PJM day-ahead, (unadjusted) six month, load-weighted, average LMP (Dollars per MWh): January through June of 2014 and 2015

	2014 (Jan - Jun)		2015 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$9.84	13.9%	$13.22	30.6%	16.6%
DEC	$10.77	15.2%	$8.83	20.4%	5.2%
Gas	$16.45	23.3%	$6.76	15.6%	(7.7%)
INC	$9.96	14.1%	$4.91	11.4%	(2.7%)
Ten Percent Cost Adder	$2.96	4.2%	$2.34	5.4%	1.2%
Up-to Congestion Transaction	$11.31	16.0%	$2.30	5.3%	(10.7%)
VOM	$1.43	2.0%	$1.72	4.0%	2.0%
Dispatchable Transaction	$4.06	5.7%	$1.55	3.6%	(2.1%)
Oil	$1.54	2.2%	$1.50	3.5%	1.3%
DASR LOC Adder	($0.06)	(0.1%)	$0.29	0.7%	0.8%
DASR Offer Adder	$0.10	0.1%	$0.23	0.5%	0.4%
CO_2	$0.14	0.2%	$0.14	0.3%	0.1%
Price Sensitive Demand	$1.57	2.2%	$0.06	0.1%	(2.1%)
NO_x	$0.08	0.1%	$0.01	0.0%	(0.1%)
Municipal Waste	$0.02	0.0%	$0.01	0.0%	(0.0%)
SO_2	$0.01	0.0%	$0.01	0.0%	0.0%
Constrained Off	$0.01	0.0%	($0.00)	(0.0%)	(0.0%)
Other	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Wind	$0.00	0.0%	($0.02)	(0.0%)	(0.1%)
Markup	$0.01	0.0%	($0.78)	(1.8%)	(1.8%)
Import	$0.12	0.2%	$0.00	0.0%	(0.2%)
FMU Adder	$0.52	0.7%	$0.00	0.0%	(0.7%)
NA	($0.15)	(0.2%)	$0.16	0.4%	0.6%
Total	$70.67	100.0%	$43.26	100.0%	(0.0%)

68 New Jersey withdrew from RGGI, effective January 1, 2012.
69 See 18 CFR § 385.213 (2014).

Table 3-72 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 3-72 Components of PJM day-ahead, (adjusted) six month, load-weighted, average LMP (Dollars per MWh): January through June of 2014 and 2015

	2014 (Jan - Jun)		2015 (Jan - Jun)		
Element	Contribution to LMP	Percent	Contribution to LMP	Percent	Change Percent
Coal	$9.80	13.9%	$13.22	30.6%	16.7%
DEC	$10.77	15.2%	$8.83	20.4%	5.2%
Gas	$16.45	23.3%	$6.76	15.6%	(7.7%)
INC	$9.96	14.1%	$4.91	11.4%	(2.7%)
Up-to Congestion Transaction	$11.31	16.0%	$2.30	5.3%	(10.7%)
VOM	$1.42	2.0%	$1.72	4.0%	2.0%
Dispatchable Transaction	$4.06	5.7%	$1.55	3.6%	(2.1%)
Oil	$1.54	2.2%	$1.50	3.5%	1.3%
Ten Percent Cost Adder	$1.85	2.6%	$0.91	2.1%	(0.5%)
Markup	$1.17	1.7%	$0.64	1.5%	(0.2%)
DASR LOC Adder	($0.06)	(0.1%)	$0.29	0.7%	0.8%
DASR Offer Adder	$0.10	0.1%	$0.23	0.5%	0.4%
CO_2	$0.14	0.2%	$0.14	0.3%	0.1%
Price Sensitive Demand	$1.57	2.2%	$0.06	0.1%	(2.1%)
NO_x	$0.08	0.1%	$0.01	0.0%	(0.1%)
Municipal Waste	$0.02	0.0%	$0.01	0.0%	(0.0%)
SO_2	$0.01	0.0%	$0.01	0.0%	0.0%
Constrained Off	$0.01	0.0%	($0.00)	(0.0%)	(0.0%)
Other	$0.00	0.0%	($0.00)	(0.0%)	(0.0%)
Wind	$0.00	0.0%	($0.02)	(0.0%)	(0.1%)
Import	$0.12	0.2%	$0.00	0.0%	(0.2%)
FMU Adder	$0.52	0.7%	$0.00	0.0%	(0.7%)
NA	($0.15)	(0.2%)	$0.17	0.4%	0.6%
Total	$70.67	100.0%	$43.26	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 3-73 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 six months of 2014 and 2015. In the first six months of 2015, 51.7 percent of all cleared UTC transactions were net profitable, with 66.8 percent of the source side profitable and 34.6 percent of the sink side profitable.

Table 3-73 Cleared UTC profitability by source and sink point: January through June 2014 and 2015[70]

(Jan-Jun)	Cleared UTCs	Profitable UTCs	UTC Profitable at Source Bus	UTC Profitable at Sink Bus	Profitable UTC	Profitable Source	Profitable Sink
2014	13,216,571	7,322,948	9,090,125	4,265,202	55.4%	68.8%	32.3%
2015	3,837,460	1,985,380	2,564,982	1,326,587	51.7%	66.8%	34.6%

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 3-37).

Table 3-74 shows that the difference between the average real-time price and the average day-ahead price was -$1.38 per MWh in the first six months of 2014, and -$1.11 per MWh in the first six months of 2015. The difference between average peak real-time price and the average peak day-ahead price was -$1.92 per MWh in the first six months of 2014 and -$3.29 per MWh in the first six months of 2015.

70 Calculations exclude PJM administrative charges.

Table 3-74 Day-ahead and real-time average LMP (Dollars per MWh): January through June, 2014 and 2015[71]

	2014 (Jan-Jun)				2015 (Jan-Jun)			
	Day Ahead	Real Time	Difference	Percent of Real Time	Day Ahead	Real Time	Difference	Percent of Real Time
Average	$63.52	$62.14	($1.38)	(2.2%)	$39.98	$38.87	($1.11)	(2.8%)
Median	$44.42	$39.69	($4.72)	(11.9%)	$31.93	$29.04	($2.90)	(10.0%)
Standard deviation	$69.93	$88.87	$18.94	21.3%	$28.76	$34.04	$5.29	15.5%
Peak average	$79.77	$77.85	($1.92)	(2.5%)	$47.35	$44.07	($3.29)	(7.5%)
Peak median	$52.96	$48.52	($4.43)	(9.1%)	$36.58	$32.83	($3.75)	(11.4%)
Peak standard deviation	$86.69	$111.61	$24.91	22.3%	$33.49	$34.20	$0.71	2.1%
Off peak average	$49.22	$48.32	($0.90)	(1.9%)	$33.58	$34.37	$0.78	2.3%
Off peak median	$36.52	$33.05	($3.47)	(10.5%)	$27.14	$25.87	($1.27)	(4.9%)
Off peak standard deviation	$46.33	$59.03	$12.70	21.5%	$22.01	$33.27	$11.26	33.8%

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 3-75 shows the difference between the Real-Time and the Day-Ahead Energy Market prices for January through June in each year of the 15-year period 2001 to 2015.

Table 3-75 Day-ahead and real-time average LMP (Dollars per MWh): January through June 2001 through 2015

(Jan-Jun)	Day Ahead	Real Time	Difference	Percent of Real Time
2001	$35.02	$33.10	($1.92)	(5.5%)
2002	$24.76	$24.10	($0.66)	(2.7%)
2003	$42.83	$41.31	($1.53)	(3.6%)
2004	$44.02	$44.99	$0.97	2.2%
2005	$45.63	$45.71	$0.07	0.2%
2006	$48.33	$49.36	$1.03	2.1%
2007	$53.03	$55.03	$2.00	3.8%
2008	$70.12	$70.19	$0.08	0.1%
2009	$40.01	$40.12	$0.11	0.3%
2010	$43.81	$43.27	($0.54)	(1.2%)
2011	$44.75	$45.51	$0.76	1.7%
2012	$30.44	$29.74	($0.69)	(2.3%)
2013	$37.11	$36.56	($0.55)	(1.5%)
2014	$63.52	$62.14	($1.38)	(2.2%)
2015	$39.98	$38.87	($1.11)	(2.8%)

Table 3-76 provides frequency distributions of the differences between PJM real-time hourly LMP and PJM day-ahead hourly LMP for January through June of 2007 through 2015.

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

Table 3-76 Frequency distribution by hours of PJM real-time LMP minus day-ahead LMP (Dollars per MWh): January through June of 2007 through 2015

(Jan-Jun)	2007		2008		2009		2010		2011		2012		2013		2014		2015	
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	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%	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	0.05%	0	0.00%
($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	0.12%	0	0.00%
($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	0.14%	0	0.00%
($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	0.28%	0	0.00%
($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	0.39%	0	0.00%
($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	0.51%	0	0.00%
($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	0.64%	0	0.00%
($250) to ($200)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%	0	0.00%	14	0.97%	1	0.02%
($200) to ($150)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	0	0.00%	3	0.09%	0	0.00%	14	1.29%	4	0.12%
($150) to ($100)	0	0.00%	0	0.00%	0	0.00%	0	0.00%	1	0.02%	4	0.18%	0	0.00%	45	2.33%	12	0.39%
($100) to ($50)	17	0.39%	62	1.42%	3	0.07%	6	0.14%	27	0.64%	8	0.37%	0	0.00%	89	4.37%	50	1.54%
($50) to $0	2,365	54.85%	2,578	60.45%	2,541	58.58%	2,890	66.68%	2,773	64.49%	2,940	67.69%	3,018	69.49%	2,837	69.70%	3,020	71.08%
$0 to $50	1,832	97.03%	1,505	94.92%	1,772	99.38%	1,366	98.13%	1,414	97.05%	1,377	99.22%	1,281	98.99%	1,144	96.04%	1,146	97.47%
$50 to $100	118	99.75%	195	99.38%	25	99.95%	69	99.72%	105	99.47%	25	99.79%	34	99.77%	82	97.93%	74	99.17%
$100 to $150	7	99.91%	23	99.91%	2	100.00%	5	99.84%	16	99.84%	5	99.91%	4	99.86%	36	98.76%	28	99.82%
$150 to $200	0	99.91%	2	99.95%	0	100.00%	7	100.00%	2	99.88%	2	99.95%	5	99.98%	17	99.15%	6	99.95%
$200 to $250	1	99.93%	1	99.98%	0	100.00%	0	100.00%	2	99.93%	0	99.95%	0	99.98%	9	99.36%	1	99.98%
$250 to $300	1	99.95%	0	99.98%	0	100.00%	0	100.00%	0	99.93%	1	99.98%	1	100.00%	8	99.54%	1	100.00%
$300 to $350	2	100.00%	1	100.00%	0	100.00%	0	100.00%	0	99.93%	1	100.00%	0	100.00%	3	99.61%	0	100.00%
$350 to $400	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.93%	0	100.00%	0	100.00%	3	99.68%	0	100.00%
$400 to $450	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.93%	0	100.00%	0	100.00%	2	99.72%	0	100.00%
$450 to $500	0	100.00%	0	100.00%	0	100.00%	0	100.00%	0	99.93%	0	100.00%	0	100.00%	0	99.72%	0	100.00%
$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	99.88%	0	100.00%
$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	99.88%	0	100.00%
$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	99.91%	0	100.00%
>= $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%	0	100.00%

Figure 3-36 shows the hourly differences between day-ahead and real-time hourly LMP in the first six months of 2015.

Figure 3-36 Real-time hourly LMP minus day-ahead hourly LMP: January through June 2015

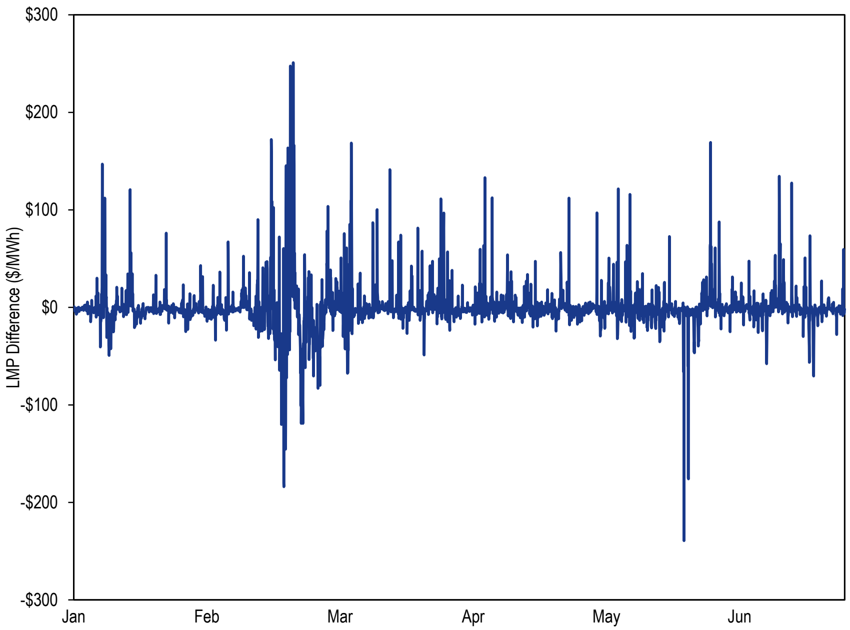


Figure 3-37 shows the monthly average differences between the day-ahead and real-time LMP in the first six months of 2015.

Figure 3-37 Monthly average of real-time minus day-ahead LMP: January through June 2015

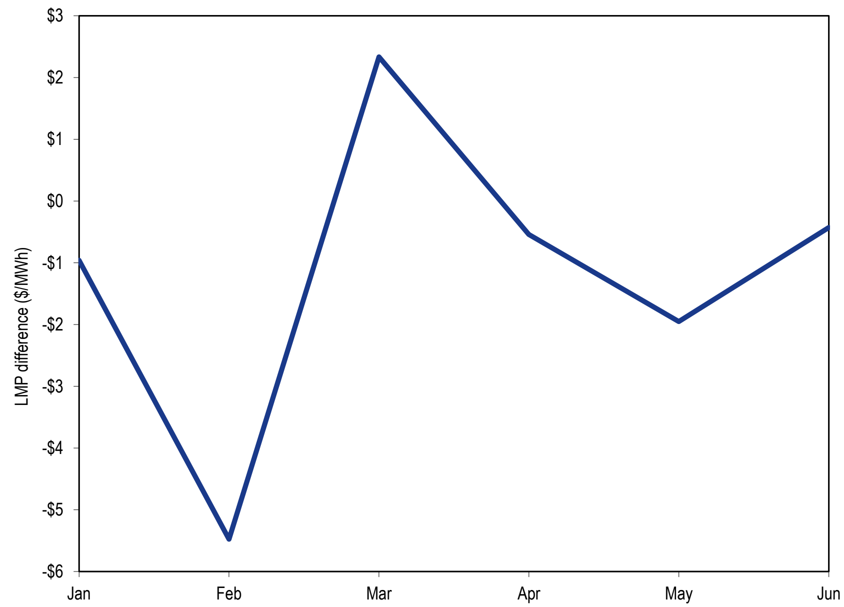
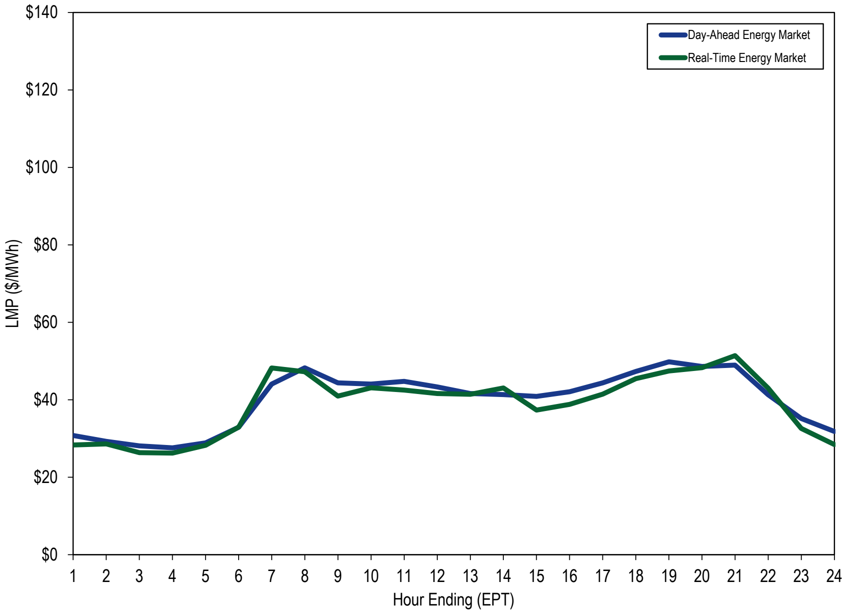


Figure 3-38 shows day-ahead and real-time LMP on an average hourly basis for the first six months of 2015.

Figure 3-38 PJM system hourly average LMP: January through June 2015



Scarcity

PJM's Energy Market experienced no shortage pricing events in the first six months of 2015 compared to two days in the first six months of 2014. Table 3-77 shows a summary of the number of days emergency alerts, warnings and actions were declared in PJM in the first six months of 2014 and 2015.

Table 3-77 Summary of emergency events declared: January through June, 2014 and 2015

	Number of days events declared	
Event Type	Jan - Jun, 2014	Jan - Jun, 2015
Cold Weather Alert	25	26
Hot Weather Alert	3	9
Maximum Emergency Generation Alert	6	0
Primary Reserve Alert	2	0
Voltage Reduction Alert	2	0
Primary Reserve Warning	1	0
Voltage Reduction Warning	4	0
Pre Emergency Mandatory Load Management Reduction Action	0	2
Emergency Load Management Long Lead Time	6	2
Emergency Load Management Short Lead Time	6	2
Maximum Emergency Action	8	1
Emergency Energy Bids Requested	3	0
Voltage Reduction Action	1	0
Shortage Pricing	2	0
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 26 days in the first six months of 2015 compared to 25 days in the first six months of 2014.[72] 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 nine days in the first six months of 2015 compared to three days in the first six months of 2014.[73] The purpose of a hot weather alert is to prepare personnel and facilities for expected extreme hot

72 See PJM. "Manual 13: Emergency Operations," Revision 57 (January 1, 2015), Section 3.3 Cold Weather Alert, p. 46.
73 See PJM. "Manual 13: Emergency Operations," Revision 57 (January 1, 2015), Section 3.4 Hot Weather Alert, p. 50.

and humid weather conditions, generally when temperatures are forecast to exceed 90 degrees Fahrenheit with high humidity.

PJM did not declare any maximum emergency generation alerts in the first six months of 2015 compared to six days in the first six months of 2014. 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.[74] 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 did not declare any primary reserve alert in the first six months of 2015 compared to two days in the first six 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 did not declare any voltage reduction alert in the first six months of 2015, compared to two days the first six 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 did not declare any primary reserve warning in the first six months of 2015, compared to one day in the first six 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 did not declare any voltage reduction warning and reduction of non-critical plant load in the first six months of 2015 compared to four days in the first six months of 2014. 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 on two days in the first six months of 2015 compared to six days in all or parts of the PJM service territory in the first six months of 2014. 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). Starting in June 2014, PJM combined the long lead and short lead emergency load management action procedures into Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time). PJM dispatch declares NERC Energy Emergency Alert level 2 (EEA2) concurrent with Emergency Mandatory load Management Reductions. PJM also added a Pre-Emergency Mandatory Load Management Reduction Action (30, 60 or 120 minute lead time) step to request load reductions before declaring emergency load management reductions. PJM declared Pre-Emergency Mandatory Load Management Reduction Action on two days in the first six months of 2015.

PJM declared maximum emergency generation action on one day in the first six months of 2015 compared to eight days in the first six months of 2014. 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.

PJM did not request any bids for emergency energy purchases in the first six months of 2015 compared to three days in the first six months of 2014.

74 See PJM. "Manual 13: Emergency Operations," Revision 57 (January 1, 2015), Section 2.3.1 Advance Notice Emergency Procedures: Alerts, p. 16.

PJM did not declare any voltage reduction action in the first three months of 2015 compared to one day (January 6) in the first six 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 eleven synchronized reserve events in the first six months of 2015 compared to 24 in the first six months of 2014.[75] Synchronized reserve events may occur at any time of the year due to sudden loss of generation or transmission facilities and do not necessarily coincide with capacity emergency conditions such as maximum generation emergency events or emergency load management events.

Table 3-78 provides a description of PJM declared emergency procedures.

Table 3-78 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 that 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 requirement and that voltage reduction may be required.
Pre-Emergency Mandatory Load Management Reduction Action (30, 60 or 120-minute)	To request any site registered in the PJM demand response program as a demand resource (DR) that needs 30, 60 or 120 minute lead time to provide load relief. This is declared prior to or with out PJM dispatch issuing a NERC Energy Emergency Alert Level 2 (EEA2).
Emergency Mandatory Load Management Reduction Action (30, 60 or 120-minute)	To request any site registered in the PJM demand response program as a demand resource (DR) that needs 30, 60 or 120 minute lead time to provide load relief. A NERC EEA2 is declared concurrent with the issuance of Emergency Mandatory Load Management Reductions.
Maximum Emergency 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 Action	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.

Table 3-79 shows when emergency alerts and warnings were declared and when emergency actions were implemented in the first six months of 2015.

75 See *2015 Quarterly State of the Market Report for PJM: January through June*, Section 10: Ancillary Service Markets for details on the spinning events.

Table 3-79 PJM declared emergency alerts, warnings and actions: January through June, 2015

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	Pre-Emergency Mandatory Load Management Reduction	Maximum Emergency Generation Action	Emergency Mandatory Load Management Reduction	Voltage Reduction	Manual Load Dump Warning	Load Shed Directive
1/5/2015	ComEd												
1/6/2015	ComEd												
1/7/2015	PJM Western Region												
1/8/2015	PJM												
1/9/2015	PJM Western Region												
1/10/2015	PJM Western Region												
1/14/2015	PJM Western Region												
1/15/2015	PJM Western Region												
2/2/2015	PJM												
2/3/2015	PJM												
2/5/2015	ComEd,DLCO,ATSI												
2/6/2015	Mid-Atlantic												
2/13/2015	DLCO,AP,ATSI												
2/14/2015	PJM Western Region												
2/15/2015	Mid-Atlantic,PJM Western Region												
2/16/2015	PJM												
2/17/2015	Mid-Atlantic												
2/18/2015	PJM Western Region												
2/19/2015	PJM												
2/20/2015	PJM												
2/21/2015												AEP	
2/23/2015	PJM Western Region												
2/24/2015	PJM												
2/26/2015	DLCO,ATSI												
2/27/2015	PJM Western Region												
3/5/2015	ComEd												
3/6/2015	PJM Western Region												
4/21/2015								Penelec	Penelec	Penelec			
4/22/2015								Penelec		Penelec			
5/26/2015		Mid-Atlantic,PJM Southern Region											
5/27/2015		Mid-Atlantic,PJM Southern Region											AEP (Milton, WV)
6/11/2015		Mid-Atlantic,PJM Southern Region											
6/12/2015		Mid-Atlantic,PJM Southern Region											
6/13/2015		Mid-Atlantic,PJM Southern Region											
6/16/2015		PJM Southern Region											
6/21/2015		PJM Southern Region											
6/22/2015		Mid-Atlantic,PJM Southern Region											
6/23/2015		Mid-Atlantic,PJM Southern Region											AECO

Scarcity and Scarcity Pricing

In electricity markets, scarcity means that demand, including reserve requirements, is nearing the limits of the available capacity of the system. Under the PJM rules that were in place through September 30, 2012, high prices, or scarcity pricing, resulted from high offers by individual generation owners for specific units when the system was close to its available capacity. But this was not an efficient way to manage scarcity pricing and made it difficult to distinguish between market power and scarcity pricing.

On October 1, 2012, PJM introduced a new administrative scarcity pricing regime. Under the current PJM market rules, shortage pricing conditions are triggered when there is a shortage of synchronized or primary reserves in the RTO or in the Mid-Atlantic and Dominion (MAD) subzone. In times of reserve shortage, the value of reserves is included as a penalty factor in the optimization and in the price of energy.[76] Shortage pricing is also triggered when PJM issues a voltage reduction action or a manual load dump action for a reserve zone or a reserve sub-zone. When shortage pricing is triggered, the primary reserve penalty factor and the synchronized reserve penalty factor are incorporated in the calculation of the synchronized and non-synchronized reserve market clearing prices and the locational marginal price.

In the first six months of 2015, there were no shortage pricing events triggered in PJM compared to two days in the first six months of 2014

PJM Cold Weather Operations 2015

Natural gas supply and prices

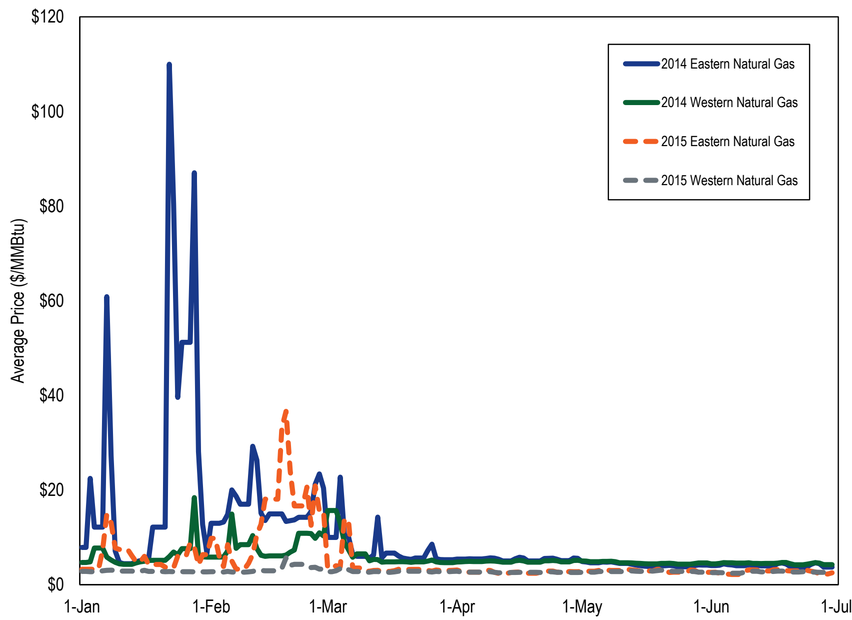
As of January 1, 2015, gas fired generation was 30.7 percent (56,364.5 MW) of the total installed PJM capacity (183,724.1MW).[77] The extreme cold weather conditions and the associated high demand for natural gas led to supply constraints on the gas transmission system which resulted in natural gas price volatility and interruptions to customers without firm transportation. Figure 3-39 shows the average daily price of delivered natural gas for eastern and western parts of PJM service territory in the first six months of 2014 and 2015.

During the first three months of 2014 and 2015, a number of interstate gas pipelines that supply fuel for generators in the PJM service territory issued notices for lack of non-firm gas availability. These notices include warnings of operational flow orders (OFO) and actual OFOs. OFOs may restrict the provision of gas to 24 hour ratable takes which means that hourly nominations must be the same for each of the 24 hours in the day, with penalties for deviating from the nominated quantities. Pipelines may also enforce strict balancing constraints which limit the ability of gas users (without no-notice service) to deviate from the 24 hour ratable take and which limit the ability of users to have access to unused gas.

The extreme conditions illustrate the shortcomings of a gas pipeline system that relies on individual pipelines to manage the balancing of supply and demand. Pipeline operators use restrictive and inflexible rules to manage the balance of supply and demand. The experience of pipelines and electric generators in these extreme conditions also suggests the potential benefits of creating an ISO/RTO structure to coordinate the supply of gas across pipelines and with the electric RTOs, or the inclusion of gas coordination under existing electric ISO/RTOs.

76 See PJM OATT, 2.2 (d) General, (February 25, 2014), pp. 1815, 1819.
77 *2015 Quarterly State of the Market Report for PJM: January through June*, Section 5: Capacity Market, at Installed Capacity.

Figure 3-39 Average daily delivered price for natural gas: January through June, 2014 and 2015 ($/MMBtu)



Parameter Limited Schedules

All capacity resources in PJM are required to submit at least one cost based offer. All cost based offers are parameter limited in accordance with the Parameter Limited Schedule (PLS) matrix or to the level of a prior approved exception.[78] All capacity resources that choose to offer price based schedules are required to make available at least one price based parameter limited schedule. This schedule is to be used by PJM for committing generation resources when a maximum emergency generation alert is declared.

During the extreme cold weather conditions in the first three months of 2015, a number of gas fired generators requested temporary exceptions to parameter limits for their parameter limited schedules due to restrictions imposed by natural gas pipelines. The parameters that were affected because of gas pipeline restrictions include minimum run time (MRT) and turn down ratio (TDR, ratio of economic maximum MW to economic minimum MW). When pipelines issue critical notices and enforce ratable take requirements, generators may be forced to nominate an equal amount of gas for each hour in a 24 hour period, with penalties for deviating from the nominated quantity. This led to requests for 24 hour minimum run times and turn down ratios close to 1, to avoid deviations from the hourly nominated quantity.

Key parameters like startup and notification time were not limited by the PLS matrix through the first six months of 2015. Some resource owners notified PJM that they needed extended notification times based on the claimed necessity for generation owners to nominate gas prior to gas nomination cycle deadlines.

78 See PJM, OATT, § 6.6 Minimum Generator Operating Parameters - Parameter-Limited Schedules, (September 10, 2014), pp. 1937- 1940.

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 decreased by $590.1 million or 71.0 percent in the first six months of 2015 compared to the first six months of 2014, from $831.5 million to $241.4 million.
- **Energy Uplift Charges Categories:** The decrease of $590.1 million in the first six months of 2015 is comprised of a $6.3 million increase in day-ahead operating reserve charges, a $573.9 million decrease in balancing operating reserve charges, a $13.0 million decrease in reactive services charges, a $0.1 million decrease in synchronous condensing charges and a $9.3 million decrease in black start services charges.
- **Operating Reserve Rates.** The day-ahead operating reserve rate averaged $0.175 per MWh. The balancing operating reserve reliability rates averaged $0.060, $0.015 and $0.004 per MWh for the RTO, Eastern and Western regions. The balancing operating reserve deviation rates averaged $0.824, $0.097 and $0.049 per MWh for the RTO, Eastern and Western regions. The lost opportunity cost rate averaged $0.967 per MWh and the canceled resources rate averaged $0.002 per MWh.
- **Reactive Services Rates.** The DPL, ATSI and Dominion control zones had the three highest reactive local voltage support rates: $0.145, $0.110 and $0.049 per MWh. The reactive transfer interface support rate averaged $0.003 per MWh.
- **Energy Uplift Costs:** In the Eastern Region, a decrement bid paid an average of $1.858 per MWh, real-time load paid an average of $0.066 per MWh and deviations either from generators, load or interchange paid an average of $1.690 per MWh. In the Western Region, a decrement bid paid an average of $1.816 per MWh, real-time load paid an average of $0.057 per MWh and deviations either from generators, load or interchange paid an average of $1.649 per MWh.

Characteristics of Credits

- **Types of units.** Combined cycles received 30.7 percent of all day-ahead generator credits and 41.2 percent of all balancing generator credits. Combustion turbines and diesels received 87.8 percent of the lost opportunity cost credits. Coal units received 42.4 percent of all reactive services credits.
- **Concentration of Energy Uplift Credits.** The top 10 units receiving energy uplift credits received 33.9 percent of all credits. The top 10 organizations received 82.9 percent of all credits. Concentration indexes for energy uplift categories classify them as highly concentrated. Day-ahead operating reserves HHI was 4664, balancing operating reserves HHI was 3691, lost opportunity cost HHI was 3338 and reactive services HHI was 8737.
- **Economic and Noneconomic Generation.** In the first six months of 2015, 87.8 percent of the day-ahead generation eligible for operating reserve credits was economic and 72.9 percent of the real-time generation eligible for operating reserve credits was economic.
- **Day-Ahead Unit Commitment for Reliability.** In the first six months of 2015, 2.7 percent of the total day-ahead generation was scheduled as must run by PJM, of which 40.2 percent received energy uplift payments.

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.

Geography of Charges and Credits

- In the first six months of 2015, 87.7 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 generation, 2.9 percent by transactions at hubs and aggregates and 9.4 percent by transactions at interfaces.

Energy Uplift Issues

- **Lost Opportunity Cost Credits.** In the first six months of 2015, lost opportunity cost credits decreased by $61.0 million compared to the first six months of 2014. In the first six months of 2015, resources in the top three control zones receiving lost opportunity cost credits, AEP, Dominion and PENELEC accounted for 51.2 percent of all lost opportunity cost credits, 48.0 percent of all day-ahead generation from pool-scheduled combustion turbines and diesels, 59.8 percent of all day-ahead generation not committed in real time by PJM from those unit types and 68.3 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 were 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. PJM replaced all ALR units as black start resources as of April 2015. In the first six months of 2015, the cost of the noneconomic operation of ALR units in the AEP Control Zone was $4.8 million, a decrease of $9.4 million compared to the first six months of 2014.
- **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 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 six months of 2015, the average rate paid by a DEC in the Eastern Region would have been $0.236 per MWh, which is $1.622 per MWh, or 87.3 percent, lower than the actual average rate paid.

Recommendations

The MMU recognizes that many of the issues addressed in the recommendations are being discussed in PJM stakeholder processes. Until new rules are in place, the MMU's recommendations and the reported status of those recommendations are based on the existing market rules.

- 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. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that the implementation of closed loop interface constraints be studied carefully sufficiently in advance to identify issues and that, if they are to be used, 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. (Priority: Medium. First reported 2013. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM clearly identify and 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 to be made aware of the reasons for 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 2011. Status: Adopted partially.)

- 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 credits by unit in the PJM region. (Priority: High. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted. Stakeholder process.)
- 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. Status: Not adopted. Stakeholder process.)
- 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. Status: Not adopted. Stakeholder process.)
- 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. Status: Not adopted. Stakeholder process.)
  - 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. Status: Not adopted. Stakeholder process.)
  - 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. Status: Not adopted. Stakeholder process.)
  - The MMU recommends calculating LOC based on segments of hours not on an hourly basis in the calculation of credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that up-to congestion transactions be required to pay energy uplift charges. (Priority: High. First reported 2013. Status: Not adopted. Stakeholder process.)
- 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. Status: Not adopted. Stakeholder process.)
- The MMU recommends allocating the energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends reallocating the operating reserve credits paid to units supporting the Con Edison – PJM Transmission Service Agreements. (Priority: Medium. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted. Stakeholder process.)
- 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. Status: Not adopted.)
- The MMU recommends enhancing the current energy uplift allocation rules to reflect the elimination of day-ahead operating reserves, the timing of commitment decisions and the commitment reasons. (Priority: High. First reported Q1, 2014. Status: Not adopted. Stakeholder process.)

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. Energy uplift payments also result from units' operational parameters that may require PJM to schedule or commit resources during noneconomic hours. 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

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>.

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.

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				
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 decreased by 71.0 percent in the first six months of 2015, compared to the first six months of 2014, to a total of $241.4 million. Table 4-3 shows total energy uplift charges in the first six months of 2014 and 2015.[5]

Table 4-3 Total energy uplift charges: January through June 2014 and 2015

	Jan - Jun 2014 Charges (Millions)	Jan - Jun 2015 Charges (Millions)	Change	Percent Change
Total Energy Uplift	$831.5	$241.4	($590.1)	(71.0%)
Energy Uplift as a Percent of Total PJM Billing	2.7%	1.0%	(1.6%)	(61.4%)

Total energy uplift charges decreased by $590.1 million or 71.0 percent in the first six months of 2015 compared to the first six months of 2014. Table 4-4 compares energy uplift charges by category for the first six months of 2014 and 2015. The decrease of $590.1 million in 2015 is comprised of an increase of $6.3 million in day-ahead operating reserve charges, a decrease of $573.9 million in balancing operating reserve charges, a decrease of $13.0 million in reactive services charges, a decrease of $0.1 million in synchronous condensing charges and a decrease of $9.3 million in black start services charges.

The decrease in total energy uplift charges was mainly a result of PJM not committing units for conservative operations in advance of the Day-Ahead Energy Market in the 2015 winter, compared to the 2014 winter. PJM still relied on some units committed for congestion in advance of the Day-Ahead Energy Market and during the reliability analysis after the Day-Ahead Energy Market closed, but the impact of these commitments on uplift in the first six months of 2015 was significantly lower than in the first six months of 2014.

5 Table 4-3 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 14, 2015.

Table 4-4 Energy uplift charges by category: January through June 2014 and 2015

Category	Jan - Jun 2014 Charges (Millions)	Jan - Jun 2015 Charges (Millions)	Change (Millions)	Percent Change
Day-Ahead Operating Reserves	$66.8	$73.1	$6.3	9.4%
Balancing Operating Reserves	$728.0	$154.1	($573.9)	(78.8%)
Reactive Services	$22.2	$9.2	($13.0)	(58.5%)
Synchronous Condensing	$0.1	$0.0	($0.1)	(100.0%)
Black Start Services	$14.3	$5.0	($9.3)	(65.1%)
Total	$831.5	$241.4	($590.1)	(71.0%)

The decrease in energy uplift charges in the first six months of 2015 was primarily a result of decreases in January. Total energy uplift charges decreased by $564.5 million in January 2015, compared to January 2014, while energy uplift charges decreased by $25.6 million in February through June 2015, compared to February through June 2014. Table 4-5 compares monthly energy uplift charges by category for 2014 and 2015.

Table 4-5 Monthly energy uplift charges: 2014 and January through June 2015

	2014 Charges (Millions)						2015 Charges (Millions)					
	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total	Day-Ahead	Balancing	Reactive Services	Synchronous Condensing	Black Start Services	Total
Jan	$35.8	$565.7	$3.8	$0.1	$4.0	$609.4	$16.8	$24.6	$1.8	$0.0	$1.7	$44.9
Feb	$9.5	$56.1	$1.0	$0.0	$0.9	$67.5	$31.4	$71.7	$2.4	$0.0	$1.1	$106.6
Mar	$5.7	$59.6	$2.7	$0.0	$2.6	$70.6	$7.0	$24.9	$2.1	$0.0	$1.9	$35.9
Apr	$4.2	$9.7	$5.3	$0.0	$2.8	$22.0	$3.1	$8.4	$1.7	$0.0	$0.1	$13.4
May	$6.4	$21.0	$5.3	$0.0	$1.8	$34.6	$5.7	$15.5	$0.7	$0.0	$0.2	$22.2
Jun	$5.3	$15.9	$4.2	$0.0	$2.1	$27.4	$9.1	$8.9	$0.5	$0.0	$0.0	$18.5
Jul	$6.7	$11.5	$2.9	$0.0	$4.4	$25.5						
Aug	$5.8	$9.9	$1.0	$0.0	$4.1	$20.8						
Sep	$8.0	$12.5	$1.3	$0.0	$3.9	$25.6						
Oct	$9.5	$9.8	$0.8	$0.0	$2.6	$22.8						
Nov	$5.6	$10.1	$0.5	$0.0	$1.4	$17.6						
Dec	$9.0	$9.2	$0.7	$0.0	$2.2	$21.0						
Total (Jan - Jun)	$66.8	$728.0	$22.2	$0.1	$14.3	$831.5	$73.1	$154.1	$9.2	$0.0	$5.0	$241.4
Share (Jan - Jun)	8.0%	87.6%	2.7%	0.0%	1.7%	100.0%	30.3%	63.8%	3.8%	0.0%	2.1%	100.0%
Total	$111.4	$791.0	$29.5	$0.1	$32.9	$964.8	$73.1	$154.1	$9.2	$0.0	$5.0	$241.4
Share	11.5%	82.0%	3.1%	0.0%	3.4%	100.0%	30.3%	63.8%	3.8%	0.0%	2.1%	100.0%

Table 4-6 Day-ahead operating reserve charges: January through June 2014 and 2015

Type	Jan - Jun 2014 Charges (Millions)	Jan - Jun 2015 Charges (Millions)	Change (Millions)	Jan - Jun 2014 Share	Jan - Jun 2015 Share
Day-Ahead Operating Reserve Charges	$66.8	$73.0	$6.1	100.0%	99.8%
Day-Ahead Operating Reserve Charges for Load Response	$0.0	$0.2	$0.2	0.0%	0.2%
Unallocated Congestion Charges	$0.0	$0.0	$0.0	0.0%	0.0%
Total	$66.8	$73.1	$6.3	100.0%	100.0%

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 $6.3 million or 9.4 percent in the first six months of 2015 compared to the first six months of 2014. This increase was primarily the result of higher uplift payments to units scheduled as must run by PJM. Units are typically scheduled as must run by PJM in the Day-Ahead Energy Market when the day-ahead model does not reflect certain real-time conditions or requirements (for example, reactive or ALR black start) or when units have parameters that extend beyond the 24 hour day ahead model.

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 decreased by $573.9 million in the first six months of 2015 compared to the first six months of 2014. This decrease was a result of high balancing operating reserve charges in January 2014. Balancing operating reserve charges decreased by $541.0 million in January 2015 compared to January 2014.

6 See PJM. 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 4-7 Balancing operating reserve charges: January through June 2014 and 2015

Type	Jan - Jun 2014 Charges (Millions)	Jan - Jun 2015 Charges (Millions)	Change (Millions)	Jan - Jun 2014 Share	Jan - Jun 2015 Share
Balancing Operating Reserve Reliability Charges	$437.2	$28.0	($409.3)	60.1%	18.2%
Balancing Operating Reserve Deviation Charges	$289.5	$125.9	($163.5)	39.8%	81.8%
Balancing Operating Reserve Charges for Load Response	$0.0	$0.0	($0.0)	0.0%	0.0%
Balancing Local Constraint Charges	$1.3	$0.1	($1.1)	0.2%	0.1%
Total	$728.0	$154.1	($573.9)	100.0%	100.0%

Table 4-8 Balancing operating reserve deviation charges: January through June 2014 and 2015

Charge Attributable To	Jan - Jun 2014 Charges (Millions)	Jan - Jun 2015 Charges (Millions)	Change (Millions)	Jan - Jun 2014 Share	Jan - Jun 2015 Share
Make Whole Payments to Generators and Imports	$161.8	$60.5	($101.3)	55.9%	48.1%
Energy Lost Opportunity Cost	$126.2	$65.3	($61.0)	43.6%	51.8%
Canceled Resources	$1.4	$0.2	($1.2)	0.5%	0.1%
Total	$289.5	$125.9	($163.5)	100.0%	100.0%

Table 4-9 Additional energy uplift charges: January through June 2014 and 2015

Type	Jan - Jun 2014 Charges (Millions)	Jan - Jun 2015 Charges (Millions)	Change (Millions)	Jan - Jun 2014 Share	Jan - Jun 2015 Share
Reactive Services Charges	$22.2	$9.2	($13.0)	60.6%	64.8%
Synchronous Condensing Charges	$0.1	$0.0	($0.1)	0.3%	0.0%
Black Start Services Charges	$14.3	$5.0	($9.3)	39.1%	35.2%
Total	$36.6	$14.2	($22.4)	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 six months of 2015, 48.1 percent of balancing operating reserve deviation charges were for make whole credits paid to generators and import transactions, a decrease of 7.9 percentage points compared to the share in the first six months of 2014.

Table 4-9 shows reactive services, synchronous condensing and black start services charges. Reactive services charges decreased by $13.0 million in the first six months of 2015 compared to the first six months of 2014. Black start services charges decreased by $9.3 million in the first six months of 2015 compared to the first six months of 2014 as a result of the replacement of black start units under the ALR (automatic load rejection) option in the second quarter of 2015.

Table 4-10 and Table 4-11 show the amount and percentages of regional balancing charges in the first six months of 2014 and 2015. 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 demand deviations. The regional balancing charges allocation table does not include charges attributed for resources controlling local constraints.

In the first six months of 2015, regional balancing operating reserve charges decreased by $572.8 million compared to the first six months of 2014. Balancing operating reserve reliability charges decreased by $409.3 million or 93.6 percent and balancing operating reserve deviation charges decreased by $163.5 million or 56.5 percent.

Table 4-10 Regional balancing charges allocation (Millions): January through June 2014

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$420.8	57.9%	$5.7	0.8%	$3.2	0.4%	$429.7	59.1%
	Real-Time Exports	$7.2	1.0%	$0.2	0.0%	$0.1	0.0%	$7.5	1.0%
	Total	$428.1	58.9%	$5.9	0.8%	$3.2	0.4%	$437.2	60.2%
Deviation Charges	Demand	$143.1	19.7%	$11.1	1.5%	$3.3	0.5%	$157.5	21.7%
	Supply	$40.4	5.6%	$3.3	0.5%	$0.7	0.1%	$44.4	6.1%
	Generator	$80.9	11.1%	$4.7	0.6%	$1.9	0.3%	$87.6	12.0%
	Total	$264.5	36.4%	$19.1	2.6%	$5.9	0.8%	$289.5	39.8%
Total Regional Balancing Charges		$692.6	95.3%	$25.0	3.4%	$9.2	1.3%	$726.7	100%

Table 4-11 Regional balancing charges allocation (Millions): January through June 2015

Charge	Allocation	RTO		East		West		Total	
Reliability Charges	Real-Time Load	$23.8	15.4%	$2.7	1.8%	$0.8	0.5%	$27.4	17.8%
	Real-Time Exports	$0.5	0.3%	$0.1	0.1%	$0.0	0.0%	$0.6	0.4%
	Total	$24.3	15.8%	$2.8	1.8%	$0.9	0.6%	$28.0	18.2%
Deviation Charges	Demand	$68.7	44.7%	$1.9	1.3%	$0.9	0.6%	$71.6	46.5%
	Supply	$20.8	13.5%	$0.6	0.4%	$0.3	0.2%	$21.7	14.1%
	Generator	$31.5	20.4%	$0.8	0.5%	$0.3	0.2%	$32.6	21.2%
	Total	$121.0	78.6%	$3.3	2.2%	$1.6	1.0%	$125.9	81.8%
Total Regional Balancing Charges		$145.3	94.4%	$6.2	4.0%	$2.4	1.6%	$153.9	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 4-12 for how these charges are allocated.[8]

Figure 4-1 shows the daily day-ahead operating reserve rate for 2014 and the first six months of 2015. The average rate in the first six months of 2015 was $0.175 per MWh, $0.015 per MWh higher than the average in the first six months of 2014. The highest rate occurred on February 16, when the rate reached $1.600 per MWh, $0.088 per MWh lower than the $1.689 per MWh reached in the first six months of 2014, on January 22. 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 2014 and in the first six months of 2015.

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.

Figure 4-1 Daily day-ahead operating reserve rate ($/MWh): 2014 and 2015

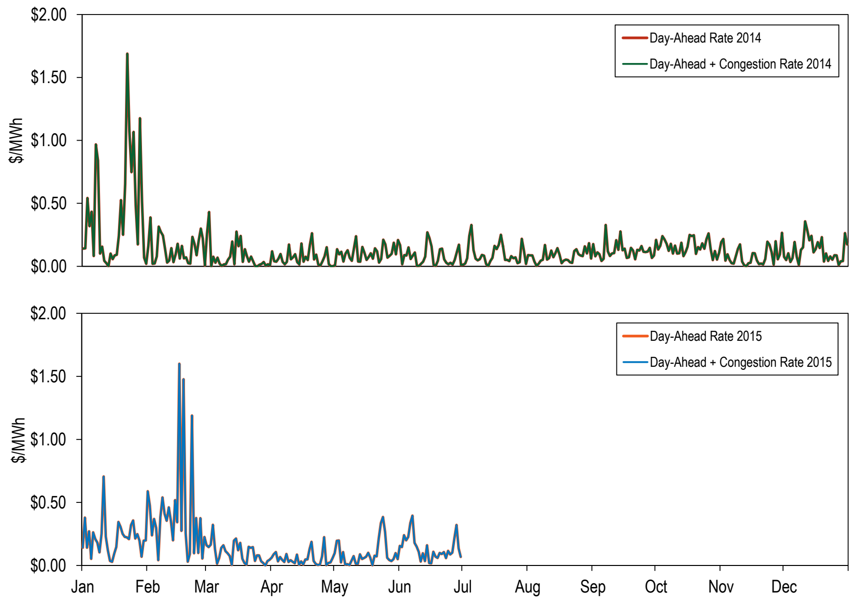


Figure 4-2 Daily balancing operating reserve reliability rates ($/MWh): 2014 and 2015

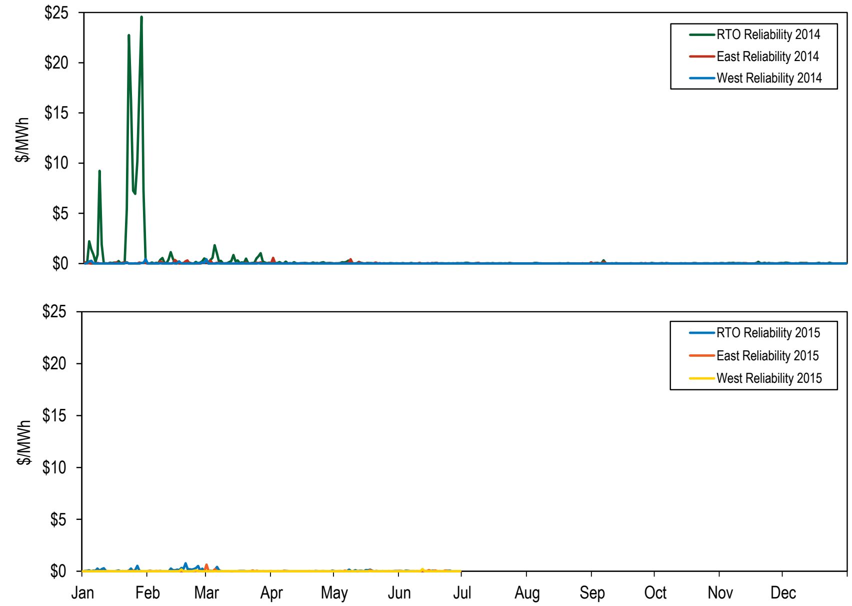


Figure 4-2 shows the RTO and the regional reliability rates for 2014 and the first six months of 2015. The average daily RTO reliability rate was $0.060 per MWh. The highest RTO reliability rate in the first six months of 2015 occurred on February 19, when the rate reached $0.0772 per MWh, $23.821 per MWh lower than the $24.593 per MWh rate reached in the first six months of 2014, on January 28.

Figure 4-3 shows the RTO and regional deviation rates for 2014 and the first six months of 2015. The average daily RTO deviation rate was $0.824 per MWh. The highest daily rate in the first six months of 2015 occurred on February 17, when the RTO deviation rate reached $12.340 per MWh, $7.758 per MWh lower than the $20.098 per MWh rate reached in the first six months of 2014, on January 25.

Figure 4-3 Daily balancing operating reserve deviation rates ($/MWh): 2014 and 2015

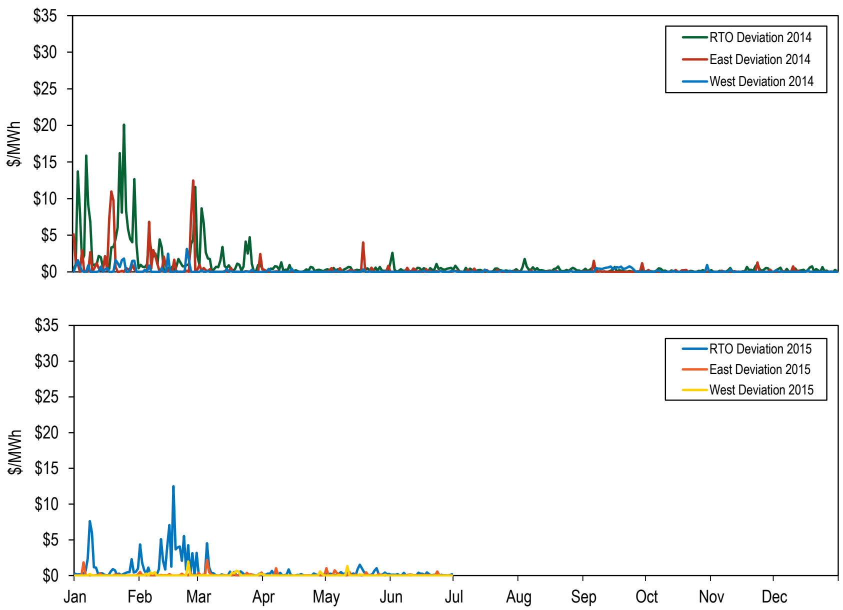


Figure 4-4 Daily lost opportunity cost and canceled resources rates ($/MWh): 2014 and 2015

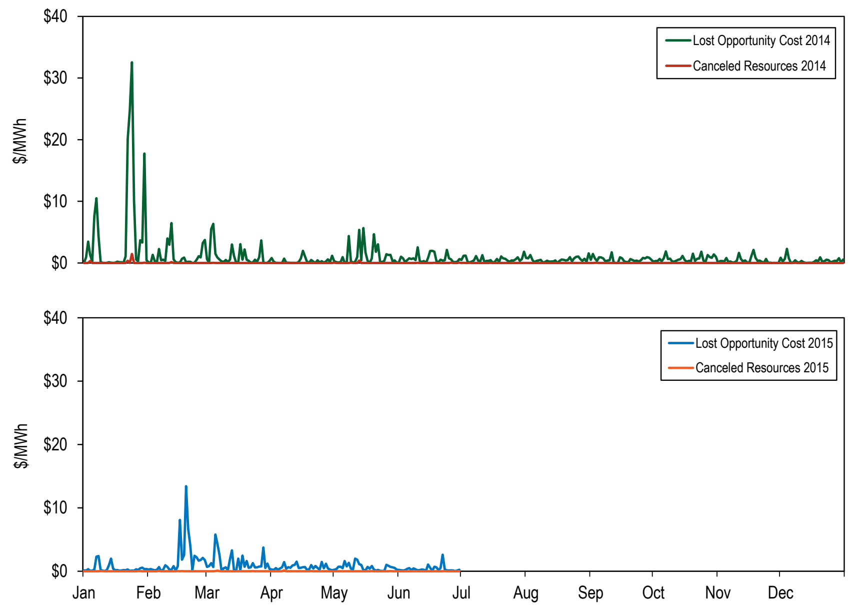


Figure 4-4 shows the daily lost opportunity cost rate and the daily canceled resources rate for 2014 and the first six months of 2015. The lost opportunity cost rate averaged $0.967 per MWh. The highest lost opportunity cost rate occurred on February 19, when it reached $13.398 per MWh, $19.158 per MWh lower than the $32.556 per MWh rate reached in the first six months of 2014, January 24.

Table 4-12 shows the average rates for each region in each category in 2014 and 2015.

Table 4-12 Operating reserve rates ($/MWh): January through June 2014 and 2015

Rate	Jan - Jun 2014 ($/MWh)	Jan - Jun 2015 ($/MWh)	Difference ($/MWh)	Percent Difference
Day-Ahead	0.161	0.175	0.015	9.1%
Day-Ahead with Unallocated Congestion	0.161	0.175	0.015	9.1%
RTO Reliability	1.047	0.060	(0.987)	(94.2%)
East Reliability	0.031	0.015	(0.017)	(53.0%)
West Reliability	0.015	0.004	(0.011)	(72.6%)
RTO Deviation	2.097	0.824	(1.273)	(60.7%)
East Deviation	0.596	0.097	(0.499)	(83.8%)
West Deviation	0.182	0.049	(0.133)	(73.0%)
Lost Opportunity Cost	1.935	0.967	(0.967)	(50.0%)
Canceled Resources	0.021	0.002	(0.019)	(88.5%)

Table 4-13 shows the operating reserve cost of a one MW transaction in the first six months of 2015. For example, a decrement bid in the Eastern Region (if not offset by other transactions) paid an average rate of $1.858 per MWh with a maximum rate of $17.602 per MWh, a minimum rate of $0.240 per MWh and a standard deviation of $2.582 per MWh. The rates in Table 4-13 include all operating reserve charges including RTO deviation 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 June 2015

		Rates Charged ($/MWh)			
Region	Transaction	Maximum	Average	Minimum	Standard Deviation
East	INC	17.344	1.690	0.020	2.512
	DEC	17.602	1.858	0.240	2.582
	DA Load	1.600	0.167	0.000	0.210
	RT Load	0.773	0.066	0.000	0.116
	Deviation	17.344	1.690	0.020	2.512
West	INC	17.344	1.649	0.020	2.482
	DEC	17.602	1.816	0.208	2.556
	DA Load	1.600	0.167	0.000	0.210
	RT Load	0.772	0.057	0.000	0.109
	Deviation	17.344	1.649	0.020	2.482

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. These charges are separate from the reactive service revenue requirement charges which are a fixed annual charged based on approved FERC filings.

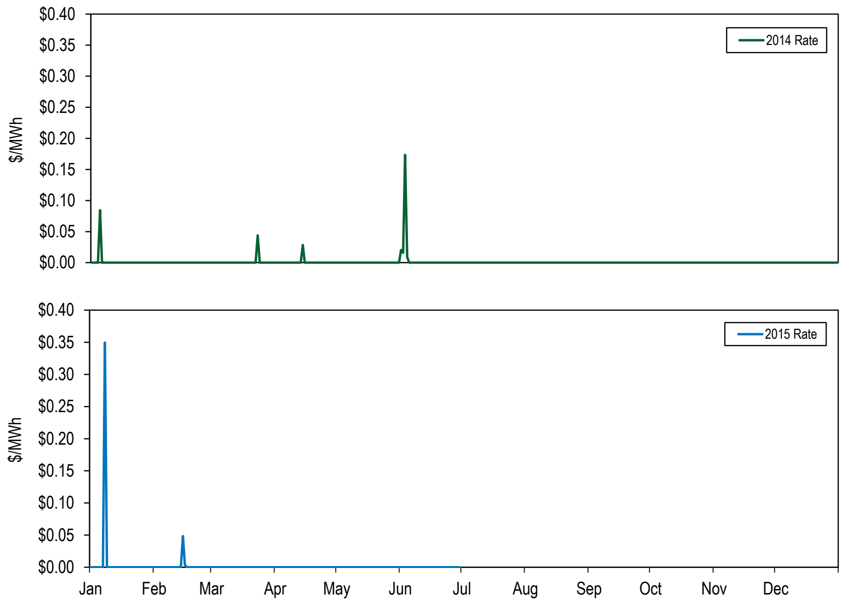
While reactive services rates are not posted by PJM, a local voltage support rate for each control zone can be calculated and a reactive transfer interface support rate can be calculated for the entire RTO. Table 4-14 shows the reactive services rates associated with local voltage support in the first six months of 2014 and 2015. Table 4-14 shows that in the first six months of 2015 the DPL Control Zone had the highest rate. Real-time load in the DPL Control Zone paid an average of $0.145 per MWh for reactive services associated with local voltage support, $0.580 or 80 percent lower than the average rate paid in the first six months of 2014.

Table 4-14 Local voltage support rates: January through June 2014 and 2015

Control Zone	Jan - Jun 2014 ($/MWh)	Jan - Jun 2015 ($/MWh)	Difference ($/MWh)	Percent Difference
AECO	0.016	0.000	(0.016)	(100.0%)
AEP	0.005	0.003	(0.002)	(39.0%)
AP	0.009	0.000	(0.009)	(100.0%)
ATSI	0.279	0.110	(0.169)	(60.5%)
BGE	0.001	0.000	(0.001)	(100.0%)
ComEd	0.001	0.000	(0.001)	(100.0%)
DAY	0.001	0.000	(0.001)	(95.1%)
DEOK	0.000	0.000	0.000	NA
DLCO	0.000	0.000	0.000	0.0%
Dominion	0.026	0.049	0.024	91.4%
DPL	0.726	0.145	(0.580)	(80.0%)
EKPC	0.000	0.000	0.000	0.0%
JCPL	0.000	0.000	0.000	0.0%
Met-Ed	0.000	0.004	0.004	NA
PECO	0.004	0.000	(0.004)	(100.0%)
PENELEC	0.017	0.027	0.011	64.7%
Pepco	0.276	0.001	(0.276)	(99.8%)
PPL	0.001	0.000	(0.001)	(93.5%)
PSEG	0.000	0.000	(0.000)	(100.0%)
RECO	0.016	0.000	(0.016)	(100.0%)

Figure 4-5 shows the daily RTO wide reactive transfer interface rate in 2014 and in the first six months of 2015. The average rate in the first six months of 2015 was $0.003 per MWh, 43.4 percent higher than the $0.002 per MWh average rate in the first six months of 2014.

Figure 4-5 Daily reactive transfer interface support rates ($/MWh): 2014 and 2015



Balancing Operating Reserve Determinants

Table 4-15 shows the determinants used to allocate the regional balancing operating reserve charges in the first six months of 2014 and 2015. Total real-time load and real-time exports were 6,441,762 MWh or 1.6 percent lower in the first six months of 2015 compared to the first six months of 2014. Total deviations summed across the demand, supply, and generator categories were 2,219,163 MWh or 3.4 percent lower in the first six months of 2015 compared to the first six months of 2014.

Table 4-15 Balancing operating reserve determinants (MWh): January through June 2014 and 2015

		Reliability Charge Determinants (MWh)			Deviation Charge Determinants (MWh)			
		Real-Time Load	Real-Time Exports	Reliability Total	Demand Deviations (MWh)	Supply Deviations (MWh)	Generator Deviations (MWh)	Deviations Total
Jan - Jun 2014	RTO	393,167,510	15,540,405	408,707,915	37,592,572	10,165,696	17,485,169	65,243,438
	East	183,834,623	5,559,090	189,393,713	18,462,220	5,796,626	7,741,950	32,000,797
	West	209,332,887	9,981,315	219,314,202	18,709,722	4,147,986	9,743,219	32,600,927
Jan - Jun 2015	RTO	393,404,757	8,861,396	402,266,153	39,634,531	11,453,787	16,374,284	67,462,602
	East	186,913,254	5,303,148	192,216,402	20,442,988	6,032,657	8,129,660	34,605,305
	West	206,491,503	3,558,248	210,049,751	18,786,204	5,233,732	8,244,624	32,264,560
Difference	RTO	237,247	(6,679,009)	(6,441,762)	2,041,958	1,288,091	(1,110,885)	2,219,163
	East	3,078,632	(255,942)	2,822,690	1,980,767	236,031	387,710	2,604,509
	West	(2,841,385)	(6,423,067)	(9,264,452)	76,482	1,085,747	(1,498,595)	(336,367)

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 six months of 2015, 22.5 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 77.5 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 June 2015

Deviation Category	Transaction	Deviation (MWh) RTO	East	West	Share RTO	East	West
Demand	Bilateral Sales Only	207,583	188,428	19,155	0.3%	0.5%	0.1%
	DECs Only	5,457,128	2,584,323	2,467,466	8.1%	7.5%	7.6%
	Exports Only	1,938,821	1,030,658	908,163	2.9%	3.0%	2.8%
	Load Only	27,628,491	13,912,242	13,716,249	41.0%	40.2%	42.5%
	Combination with DECs	2,883,460	1,997,456	886,004	4.3%	5.8%	2.7%
	Combination without DECs	1,519,047	729,881	789,166	2.3%	2.1%	2.4%
Supply	Bilateral Purchases Only	92,080	70,740	21,340	0.1%	0.2%	0.1%
	Imports Only	4,450,192	2,296,333	2,153,859	6.6%	6.6%	6.7%
	INCs Only	4,854,917	2,390,021	2,277,499	7.2%	6.9%	7.1%
	Combination with INCs	1,993,596	1,222,473	771,123	3.0%	3.5%	2.4%
	Combination without INCs	63,002	53,090	9,911	0.1%	0.2%	0.0%
Generators		16,374,284	8,129,660	8,244,624	24.3%	23.5%	25.6%
Total		67,462,602	34,605,305	32,264,560	100.0%	100.0%	100.0%

Energy Uplift Credits

Table 4-17 shows the totals for each credit category in the first six months of 2014 and 2015. During the first six months of 2015, 63.8 percent of total energy uplift credits were in the balancing operating reserve category, a decrease of 23.8 percentage points from 87.6 percent in the first six months of 2014.

Table 4-17 Energy uplift credits by category: January through June 2014 and 2015

Category	Type	Jan - Jun 2014 Credits (Millions)	Jan - Jun 2015 Credits (Millions)	Change	Percent Change	Jan - Jun 2014 Share	Jan - Jun 2015 Share
Day-Ahead	Generators	$66.8	$73.0	$6.2	9.3%	8.0%	30.2%
	Imports	$0.0	$0.0	$0.0	120.2%	0.0%	0.0%
	Load Response	$0.0	$0.2	$0.2	6,418.5%	0.0%	0.1%
Balancing	Canceled Resources	$1.4	$0.2	($1.2)	(88.1%)	0.2%	0.1%
	Generators	$599.0	$88.3	($510.7)	(85.3%)	72.0%	36.6%
	Imports	$0.1	$0.2	$0.0	40.8%	0.0%	0.1%
	Load Response	$0.0	$0.0	($0.0)	(28.1%)	0.0%	0.0%
	Local Constraints Control	$1.3	$0.2	($1.1)	(87.2%)	0.2%	0.1%
	Lost Opportunity Cost	$126.2	$65.3	($61.0)	(48.3%)	15.2%	27.0%
Reactive Services	Day-Ahead	$18.4	$7.4	($11.0)	(59.9%)	2.2%	3.1%
	Local Constraints Control	$0.0	$0.0	($0.0)	(80.4%)	0.0%	0.0%
	Lost Opportunity Cost	$0.2	$0.1	($0.1)	(61.5%)	0.0%	0.0%
	Reactive Services	$2.7	$1.6	($1.1)	(41.9%)	0.3%	0.7%
	Synchronous Condensing	$0.8	$0.2	($0.7)	(80.9%)	0.1%	0.1%
Synchronous Condensing		$0.1	$0.0	($0.1)	(100.0%)	0.0%	0.0%
Black Start Services	Day-Ahead	$11.1	$4.3	($6.8)	(61.0%)	1.3%	1.8%
	Balancing	$3.1	$0.5	($2.7)	(85.3%)	0.4%	0.2%
	Testing	$0.1	$0.2	$0.1	64.0%	0.0%	0.1%
Total		$831.4	$241.5	($590.0)	(71.0%)	100.0%	100.0%

Characteristics of Credits

Types of Units

Table 4-18 shows the distribution of total energy uplift credits by unit type in the first six months 2014 and 2015. The decrease in energy uplift in the first six months of 2015 compared to the first six months of 2014 was due to credits paid to combined cycles, combustion turbines and steam turbines (not fired by coal) in the first six months of 2014. Credits to these units decreased $377.9 million or 75.5 percent mainly because these units' offers were affected by high natural gas prices in January 2014. Credits paid to remaining unit types decreased by $208.3 million.

Table 4-18 Energy uplift credits by unit type: January through June 2014 and 2015

Unit Type	Jan - Jun 2014 Credits (Millions)	Jan - Jun 2015 Credits (Millions)	Change	Percentage Change	Jan - Jun 2014 Share	Jan - Jun 2015 Share
Battery	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%
Combined Cycle	$389.1	$61.1	($327.9)	(84.3%)	46.8%	25.4%
Combustion Turbine	$212.2	$86.1	($126.1)	(59.4%)	25.5%	35.7%
Diesel	$2.3	$1.2	($1.1)	(46.5%)	0.3%	0.5%
Hydro	$1.4	$0.9	($0.5)	(37.1%)	0.2%	0.4%
Nuclear	$0.2	$0.2	$0.1	44.3%	0.0%	0.1%
Steam - Coal	$111.4	$61.4	($50.0)	(44.9%)	13.4%	25.5%
Steam - Other	$108.0	$27.3	($80.7)	(74.7%)	13.0%	11.3%
Wind	$6.8	$2.8	($4.0)	(59.5%)	0.8%	1.1%
Total	$831.3	$241.1	($590.2)	(71.0%)	100.0%	100.0%

Table 4-19 shows the distribution of energy uplift credits by category and by unit type in the first six months of 2015. Combined cycle units received 30.7 percent of the day-ahead generator credits in the first six months of 2015, 19.2 percentage points lower than the share received in the first six months of 2014. Combined cycle units received 41.2 percent of the balancing generator credits in the first six months of 2015, 16.7 percentage points higher than the share received in the first six months of 2014. Combustion turbines and diesels received 87.8 percent of the lost opportunity cost credits in the first six months of 2015, 23.4 percentage points higher than the share received in the first six months of 2014.

Table 4-19 Energy uplift credits by unit type: January through June 2015

Unit Type	Day-Ahead Generator	Balancing Generator	Canceled Resources	Local Constraints Control	Lost Opportunity Cost	Reactive Services	Black Start Services
Battery	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Combined Cycle	30.7%	41.2%	0.0%	0.0%	1.7%	12.8%	1.4%
Combustion Turbine	3.2%	29.8%	10.0%	38.7%	86.9%	5.5%	4.4%
Diesel	0.0%	0.7%	0.0%	31.5%	0.8%	0.1%	0.0%
Hydro	0.9%	0.1%	90.0%	0.0%	0.0%	0.0%	0.0%
Nuclear	0.0%	0.0%	0.0%	0.0%	0.4%	0.0%	0.0%
Steam - Coal	55.5%	9.4%	0.0%	29.8%	6.0%	42.4%	94.2%
Steam - Others	9.6%	18.8%	0.0%	0.0%	0.1%	39.3%	0.0%
Wind	0.0%	0.1%	0.0%	0.0%	4.0%	0.0%	0.0%
Total (Millions)	$73.0	$88.3	$0.2	$0.2	$65.3	$9.2	$5.0

Table 4-19 also shows the distribution of reactive service credits and black start services credits by unit type. In the first six months of 2015, coal units received 42.4 percent of all reactive services credits, 33.5 percentage points lower than the share received in the first six months of 2014. Coal units received 94.2 percent of all black start services credits in the first six months of 2015.

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, top 50 and top 100 units receiving energy uplift credits and units receiving 90 percent of all energy uplift credits. Figure 4-6 shows the concentration of energy uplift credits. The top 10 units received 33.9 percent of total energy uplift credits in the first six months of 2015, compared to 38.5 percent in the first six months of 2014. In the first six months of 2015, 177 units received 90 percent of all energy uplift credits, compared to 192 units in the first six months of 2014.

Figure 4-6 Cumulative share of energy uplift credits in the first six months of 2014 and 2015 by unit

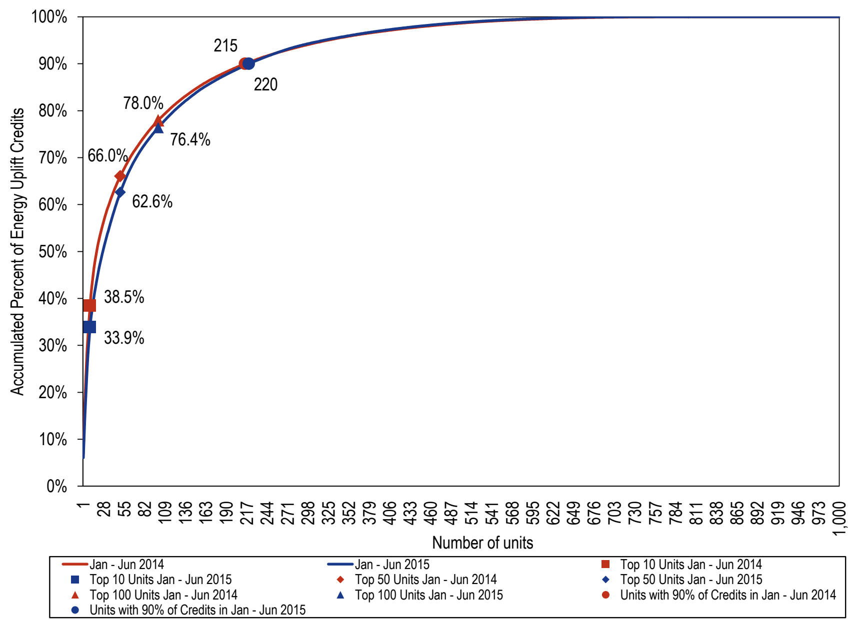


Table 4-20 shows the credits received by the top 10 units and top 10 organizations in each of the energy uplift categories paid to generators.

Table 4-20 Top 10 units and organizations energy uplift credits: January through June 2015

		Top 10 Units		Top 10 Organizations	
Category	Type	Credits (Millions)	Credits Share	Credits (Millions)	Credits Share
Day-Ahead	Generators	$42.4	58.0%	$70.0	95.9%
	Canceled Resources	$0.2	97.0%	$0.2	100.0%
	Generators	$42.0	47.6%	$74.8	84.7%
	Local Constraints Control	$0.1	77.9%	$0.2	100.0%
Balancing	Lost Opportunity Cost	$15.7	24.1%	$52.4	80.3%
Reactive Services		$8.2	88.8%	$9.2	99.9%
Black Start Services		$4.8	96.2%	$5.0	99.9%
Total		$81.7	33.9%	$199.8	82.9%

Table 4-21 shows balancing operating reserve credits received by the top 10 units identified for reliability or for deviations in each region. In the first six months of 2015, 78.9 percent of all credits paid to these units were allocated to deviations while the remaining 21.1percent were paid for reliability reasons.

Table 4-21 Identification of balancing operating reserve credits received by the top 10 units by category and region: January through June 2015

	Reliability			Deviations			
	RTO	East	West	RTO	East	West	Total
Credits (Millions)	$8.9	$0.0	$0.0	$33.0	$0.2	$0.0	$42.0
Share	21.1%	0.0%	0.0%	78.5%	0.4%	0.0%	100.0%

In the first six months of 2015, concentration in all energy uplift credit categories was high.[9,10] The HHI for energy uplift credits was calculated based on each organization's share of daily credits for each category. Table 4-22 shows the average HHI for each category. HHI for day-ahead operating reserve credits to generators was 4664, for balancing operating reserve credits to generators was 3691, for lost opportunity cost credits was 3338 and for reactive services credits was 8737.

Table 4-22 Daily energy uplift credits HHI: January through June 2015

Category	Type	Average	Minimum	Maximum	Highest Market Share (One day)	Highest Market Share (All days)
Day-Ahead	Generators	4664	1342	10000	100.0%	38.0%
	Imports	10000	10000	10000	100.0%	52.3%
	Load Response	10000	10000	10000	100.0%	99.3%
Balancing	Canceled Resources	9784	5650	10000	100.0%	58.7%
	Generators	3691	559	9906	99.5%	32.9%
	Imports	10000	10000	10000	100.0%	100.0%
	Load Response	9888	7043	10000	100.0%	50.4%
	Lost Opportunity Cost	3338	529	10000	100.0%	18.0%
Reactive Services		8737	2822	10000	100.0%	41.0%
Synchronous Condensing		NA	NA	NA	NA	NA
Black Start Services		7951	4140	10000	100.0%	95.4%
Total		2054	426	8377	91.4%	21.9%

9 See *State of the Market Report for PJM*, Volume II: Section 3: "Energy Market" at "Market Concentration" for a complete discussion of concentration ratios and the Herfindahl-Hirschman Index (HHI).
10 Table 4-22 excludes local constraints control categories.

Economic and Noneconomic Generation[11]

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 4-23 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 six months of 2015, 35.4 percent of the day-ahead generation was eligible for day-ahead operating reserve credits and 33.3 percent of the real-time generation was eligible for balancing operating reserve credits.[12]

Table 4-23 Day-ahead and real-time generation (GWh): January through June 2015

Energy Market	Total Generation	Generation Eligible for Operating Reserve Credits	Generation Eligible for Operating Reserve Credits Percent
Day-Ahead	406,832	143,942	35.4%
Real-Time	396,065	131,832	33.3%

Table 4-24 shows PJM's economic and noneconomic generation by hour eligible for operating reserve credits. In the first six months of 2015, 87.8 percent of the day-ahead generation eligible for operating reserve credits was economic and 72.9 percent of the real-time generation eligible for operating reserve credits was economic. A unit's generation may be noneconomic for a portion of their daily generation and economic for the rest. Table 4-24 shows the separate amounts of economic and noneconomic generation even if the daily generation was economic.

Table 4-24 Day-ahead and real-time economic and noneconomic generation from units eligible for operating reserve credits (GWh): January through June 2015

Energy Market	Economic Generation	Noneconomic Generation	Economic Generation Percent	Noneconomic Generation Percent
Day-Ahead	126,378	17,565	87.8%	12.2%
Real-Time	96,091	35,740	72.9%	27.1%

Noneconomic generation only leads to operating reserve credits when units' generation for the day or segment, scheduled or committed, is noneconomic, including no load and startup costs. Table 4-25 shows the generation receiving day-ahead and balancing operating reserve credits. In the first six months of 2015, 6.5 percent of the day-ahead generation eligible for operating reserve credits received credits and 4.3 percent of the real-time generation eligible for operating reserve credits was made whole.

11 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.

12 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 generation receiving operating reserve credits (GWh): January through June 2015

Energy Market	Generation Eligible for Operating Reserve Credits	Generation Receiving Operating Reserve Credits	Generation Receiving Operating Reserve Credits Percent
Day-Ahead	143,942	9,369	6.5%
Real-Time	131,832	5,703	4.3%

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.[13] 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.[14] 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 4-26 shows the total day-ahead generation and the subset of that generation scheduled as must run by PJM. In the first six months of 2015, 2.7 percent of the total day-ahead generation was scheduled as must run by PJM, 1.6 percentage points lower than in the first six months of 2014.

13 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>.

14 See PJM. "PJM eMkt Users Guide," Section Managing Unit Data (version January 9, 2015) p. 48, <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

Table 4-26 Day-ahead generation scheduled as must run by PJM (GWh): 2014 and January through June 2015

	2014			2015		
	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share	Total Day-Ahead Generation	Day-Ahead PJM Must Run Generation	Share
Jan	81,479	2,627	3.2%	77,937	2,143	2.7%
Feb	70,942	3,404	4.8%	74,224	2,904	3.9%
Mar	72,681	2,894	4.0%	68,201	1,860	2.7%
Apr	60,688	2,825	4.7%	55,957	1,138	2.0%
May	61,919	2,808	4.5%	61,955	1,523	2.5%
Jun	70,230	3,421	4.9%	68,558	1,447	2.1%
Jul	75,606	3,733	4.9%			
Aug	73,003	2,778	3.8%			
Sep	65,066	2,792	4.3%			
Oct	61,223	2,444	4.0%			
Nov	64,991	1,857	2.9%			
Dec	70,853	2,023	2.9%			
Total (Jan - Jun)	417,940	17,980	4.3%	406,832	11,015	2.7%
Total	828,682	33,608	4.1%	406,832	11,015	2.7%

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.

Table 4-27 shows the total day-ahead generation scheduled as must run by PJM by category. In the first six months of 2015, 40.2 percent of the day-ahead generation scheduled as must run by PJM received operating reserve credits, of which, 4.5 percent was generation from units scheduled to provide black start services, 5.2 percent was generation from units scheduled to provide reactive services and 30.4 percent was generation paid normal day-ahead operating reserve credits. The remaining 59.8 percent of the day-ahead generation scheduled as must run by PJM did not need to be made whole.

Table 4-27 Day-ahead generation scheduled as must run by PJM by category (GWh): January through June 2015

	Black Start Services	Reactive Services	Day-Ahead Operating Reserves	Economic	Total
Jan	173	145	848	977	2,143
Feb	137	26	725	2,016	2,904
Mar	177	139	388	1,156	1,860
Apr	4	236	263	634	1,138
May	3	29	459	1,032	1,523
Jun	0	0	670	778	1,447
Jul					
Aug					
Sep					
Oct					
Nov					
Dec					
Total (Jan-Jun)	495	575	3,353	6,592	11,015
Share	4.5%	5.2%	30.4%	59.8%	100.0%

Total day-ahead operating reserve credits in the first six months of 2015 were $73.0 million, of which $49.1 million or 67.2 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.[15] 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 4-28 shows the geography of charges and credits in the first six months of 2015. Table 4-28 includes only day-ahead operating reserve charges and balancing operating reserve reliability and deviation charges since these categories are allocated regionally, while other charges, such as reactive services, synchronous condensing and black start services are allocated by control zone, and balancing local constraint charges are charged to the requesting party.

Charges are categorized by the location (control zone, hub, aggregate or interface) where they are allocated according to PJM's operating reserve rules. Credits are categorized by the location where the resources are located. The shares columns reflect the operating reserve credits and charges balance for each location. For example, transactions in the AECO Control Zone paid 1.4 percent of all operating reserve charges allocated regionally, and resources in the AECO Control Zone were paid 0.9 percent of the corresponding credits. The AECO Control Zone received less operating reserve credits than operating reserve charges paid and had a 1.2 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 4.9 percent of all operating reserve charges allocated regionally, and resources in the PSEG Control Zone were paid 23.4 percent of the corresponding credits. The PSEG Control Zone received more operating reserve credits than operating reserve charges paid and had a 44.6 percent share of the surplus. The surplus is the sum of the positive entries in the balance column. Table 4-30 also shows that 87.7 percent of all charges were allocated in control zones, 2.9 percent in hubs and aggregates and 9.4 percent in interfaces.

15 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 4-28 Geography of regional charges and credits: January through June 2015[16]

					Shares			
Location		Charges (Millions)	Credits (Millions)	Balance	Total Charges	Total Credits	Deficit	Surplus
Zones	AECO	$3.2	$2.1	($1.1)	1.4%	0.9%	1.2%	0.0%
	AEP - EKPC	$33.5	$20.4	($13.0)	14.7%	9.0%	13.9%	0.0%
	AP - DLCO	$17.0	$12.3	($4.6)	7.5%	5.4%	4.9%	0.0%
	ATSI	$14.9	$5.0	($9.9)	6.6%	2.2%	10.6%	0.0%
	BGE - Pepco	$17.4	$55.4	$38.0	7.7%	24.4%	0.0%	40.5%
	ComEd - External	$20.7	$10.1	($10.6)	9.1%	4.5%	11.3%	0.0%
	DAY - DEOK	$12.6	$2.7	($10.0)	5.6%	1.2%	10.6%	0.0%
	Dominion	$23.1	$31.7	$8.6	10.2%	14.0%	0.0%	9.1%
	DPL	$6.2	$8.4	$2.2	2.7%	3.7%	0.0%	2.4%
	JCPL	$5.2	$1.8	($3.4)	2.3%	0.8%	3.6%	0.0%
	Met-Ed	$4.2	$1.1	($3.0)	1.8%	0.5%	3.2%	0.0%
	PECO	$10.6	$5.8	($4.9)	4.7%	2.5%	5.2%	0.0%
	PENELEC	$7.0	$10.1	$3.2	3.1%	4.5%	0.0%	3.4%
	PPL	$11.8	$6.6	($5.1)	5.2%	2.9%	5.5%	0.0%
	PSEG	$11.2	$53.1	$41.9	4.9%	23.4%	0.0%	44.6%
	RECO	$0.4	$0.0	($0.4)	0.2%	0.0%	0.4%	0.0%
	All Zones	$199.0	$226.7	$27.8	87.7%	99.9%	70.4%	100.0%
Hubs and Aggregates	AEP - Dayton	$0.5	$0.0	($0.5)	0.2%	0.0%	0.5%	0.0%
	Dominion	$0.8	$0.0	($0.8)	0.3%	0.0%	0.8%	0.0%
	Eastern	$0.3	$0.0	($0.3)	0.1%	0.0%	0.4%	0.0%
	New Jersey	$0.4	$0.0	($0.4)	0.2%	0.0%	0.4%	0.0%
	Ohio	$0.1	$0.0	($0.1)	0.0%	0.0%	0.1%	0.0%
	Western Interface	$0.2	$0.0	($0.2)	0.1%	0.0%	0.2%	0.0%
	Western	$4.4	$0.0	($4.4)	2.0%	0.0%	4.7%	0.0%
	RTEP B0328 Source	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	All Hubs and Aggregates	$6.7	$0.0	($6.7)	2.9%	0.0%	7.1%	0.0%
Interfaces	CPLE Imp	$0.0	$0.0	$0.0	0.0%	0.0%	0.0%	0.0%
	Hudson	$0.3	$0.0	($0.3)	0.1%	0.0%	0.3%	0.0%
	IMO	$4.8	$0.0	($4.8)	2.1%	0.0%	5.1%	0.0%
	Linden	$0.5	$0.0	($0.5)	0.2%	0.0%	0.5%	0.0%
	MISO	$2.8	$0.0	($2.8)	1.2%	0.0%	3.0%	0.0%
	Neptune	$0.5	$0.0	($0.5)	0.2%	0.0%	0.6%	0.0%
	NIPSCO	$0.0	$0.0	($0.0)	0.0%	0.0%	0.0%	0.0%
	Northwest	$0.1	$0.0	($0.1)	0.0%	0.0%	0.1%	0.0%
	NYIS	$4.5	$0.0	($4.5)	2.0%	0.0%	4.8%	0.0%
	OVEC	$0.9	$0.0	($0.9)	0.4%	0.0%	0.9%	0.0%
	South Exp	$2.1	$0.0	($2.1)	0.9%	0.0%	2.2%	0.0%
	South Imp	$4.8	$0.0	($4.8)	2.1%	0.0%	5.1%	0.0%
	All Interfaces	$21.2	$0.2	($21.1)	9.4%	0.1%	22.6%	0.0%
	Total	$226.9	$226.9	$0.0	100.0%	100.0%	100.2%	100.0%

16 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 4-29 shows the geography of reactive services charges. In the first six months of 2015, 87.2 percent of all reactive service charges were paid by real-time load in the single zone where the service was provided, 12.8 percent were paid by real-time load in across the entire RTO and there were zero charges paid by real-time load in multiple zones. In the first six months of 2015, the top three zones accounted for 82.0percent of all the reactive services charges allocated to single zones.

Table 4-29 Geography of reactive services charges: January through June 2015[17]

Location	Charges (Millions)	Share of Charges
Single Zone	$8.0	87.2%
Multiple Zones	$0.0	0.0%
Entire RTO	$1.2	12.8%
Total	$9.2	100.0%

Black start services charges are allocated to zone and non-zone peak transmission use. Resources in one zone accounted for 95.5 percent of all the black start services costs in the first six months of 2015. These costs resulted from noneconomic operation of units providing black start service under the automatic load rejection (ALR) option in the AEP Control Zone.

17 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).

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.[18] 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.

Table 4-30 Monthly lost opportunity cost credits (Millions): 2014 and January through June 2015

	2014			2015		
	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total	Day-Ahead Lost Opportunity Cost	Real-Time Lost Opportunity Cost	Total
Jan	$47.6	$29.9	$77.5	$4.5	$0.9	$5.4
Feb	$6.0	$5.4	$11.5	$23.6	$3.0	$26.5
Mar	$8.8	$4.1	$12.9	$14.1	$1.5	$15.6
Apr	$1.6	$1.4	$3.0	$5.2	$0.5	$5.7
May	$10.5	$2.5	$13.0	$5.7	$1.8	$7.5
Jun	$7.2	$1.2	$8.4	$4.1	$0.4	$4.5
Jul	$6.3	$0.3	$6.5			
Aug	$5.2	$0.1	$5.3			
Sep	$5.3	$0.7	$6.0			
Oct	$5.6	$1.5	$7.1			
Nov	$4.0	$0.7	$4.7			
Dec	$4.1	$0.2	$4.3			
Total (Jan - Jun)	$81.7	$44.5	$126.2	$57.2	$8.1	$65.3
Share (Jan - Jun)	64.7%	35.3%	100.0%	87.6%	12.4%	100.0%
Total	$112.1	$48.0	$160.2	$57.2	$8.1	$65.3
Share	70.0%	30.0%	100.0%	87.6%	12.4%	100.0%

In the first six months of 2015, LOC credits decreased by $61.0 million or 48.3 percent compared to the first six months of 2014. The decrease of $61.0 million is comprised of a decrease of $24.5 million in day-ahead LOC and a decrease of $36.4 million in real-time LOC. Table 4-30 shows the monthly composition of LOC credits in 2014 and the first six months of 2015. In the first six months of 2015, 26.3 percent of the day-ahead scheduled generation from combustion turbines and diesels was not committed in real time and paid LOC credits, 5.5 percentage points higher than in the first six months of 2014.

Table 4-31 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 4-31 shows that while day-ahead scheduled generation from CTs and diesels increased 1,920 GWh or 27.8 percent in the first six months of 2015 compared to the first six months of 2014, the generation that received LOC credits increased by 887 GWh or 61.1 percent.

18 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 4-31 Day-ahead generation from combustion turbines and diesels (GWh): 2014 and January through June 2015

	2014			2015		
	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	2,150	846	358	827	350	248
Feb	763	304	153	1,593	846	508
Mar	976	234	126	1,368	695	512
Apr	438	170	47	1,392	536	408
May	1,206	617	387	1,898	561	369
Jun	1,363	559	357	1,736	445	272
Jul	1,657	534	370			
Aug	1,791	637	453			
Sep	1,550	536	396			
Oct	1,380	573	427			
Nov	683	285	134			
Dec	671	342	259			
Total (Jan - Jun)	6,895	2,730	1,429	8,815	3,433	2,316
Share (Jan - Jun)	100.0%	39.6%	20.7%	100.0%	38.9%	26.3%
Total	14,628	5,636	3,469	8,815	3,433	2,316
Share	100.0%	38.5%	23.7%	100.0%	38.9%	26.3%

In the first six months of 2015, the top three control zones in which generation received LOC credits, AEP, Dominion and PENELEC, accounted for 51.2 percent of all LOC credits, 50.2 percent of all the day-ahead generation from combustion turbines and diesels, 56.0 percent of all day-ahead generation not committed in real time by PJM from those unit types and 64.5 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 4-32 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 4-32 shows that in the first six months of 2015, $35.6 million or 62.2 percent of all LOC credits were paid to combustion turbines and diesels that did not run for any hour in real time, 9.7 percentage points higher than in the first six months of 2014.

Table 4-32 Lost opportunity cost credits paid to combustion turbines and diesels by scenario (Millions): 2014 and January through June 2015

	2014			2015		
	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	$21.1	$26.4	$47.6	$2.5	$2.0	$4.5
Feb	$3.7	$2.4	$6.0	$15.6	$7.9	$23.6
Mar	$3.6	$5.2	$8.8	$9.1	$5.0	$14.1
Apr	$0.8	$0.8	$1.6	$3.0	$2.2	$5.2
May	$8.3	$2.2	$10.5	$3.1	$2.7	$5.7
Jun	$5.4	$1.8	$7.2	$2.3	$1.8	$4.1
Jul	$3.8	$2.5	$6.3			
Aug	$3.7	$1.6	$5.2			
Sep	$3.0	$2.2	$5.3			
Oct	$3.3	$2.3	$5.6			
Nov	$2.9	$1.1	$4.0			
Dec	$2.6	$1.5	$4.1			
Total (Jan - Jun)	$42.9	$38.8	$81.7	$35.6	$21.6	$57.2
Share (Jan - Jun)	52.5%	47.5%	100.0%	62.2%	37.8%	100.0%
Total	$62.2	$49.9	$112.1	$35.6	$21.6	$57.2
Share	55.5%	44.5%	100.0%	62.2%	37.8%	100.0%

Table 4-33 Day-ahead generation (GWh) from combustion turbines and diesels receiving lost opportunity cost credits by value: 2014 and January through June 2015[19]

	2014			2015		
	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)	Economic Scheduled Generation (GWh)	Noneconomic Scheduled Generation (GWh)	Total (GWh)
Jan	365	359	725	257	94	351
Feb	134	159	293	521	319	841
Mar	128	105	233	579	105	684
Apr	66	114	180	396	138	534
May	374	198	572	342	200	542
Jun	336	168	504	284	118	401
Jul	334	145	480			
Aug	336	281	617			
Sep	332	192	524			
Oct	355	208	564			
Nov	97	160	257			
Dec	234	96	330			
Total (Jan - Jun)	1,403	1,103	2,506	2,379	974	3,353
Share (Jan - Jun)	56.0%	44.0%	100.0%	70.9%	29.1%	100.0%
Total	3,092	2,186	5,278	2,379	974	3,353
Share	58.6%	41.4%	100.0%	70.9%	29.1%	100.0%

19 The total generation in Table 4-33 is lower than the day-ahead generation not requested in real time in Table 4-31 because the former only includes generation from units that received lost opportunity costs during at least one hour of the day. Table 4-33 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 4-33 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 4-33 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 six months of 2015, 70.9 percent of the scheduled generation not committed by PJM from units receiving LOC credits was economic and the remaining 29.1 percent was noneconomic.

Black Start Service Units

Certain units located in the AEP Control Zone that had been relied on for their black start capability were replaced as black start resources on April 1, 2015. These black start units provided black start service under the automatic load rejection (ALR) option, which means that the units had to be running even if not economic. Units providing black start service under the ALR option could remain running at a minimum level, disconnected from the grid. The costs of the noneconomic operation of these units resulted in make whole payments in the form of operating reserve credits.

As a result of the replacement of these ALR units, the cost of the noneconomic operation of ALR units in the AEP Control Zone in the first six months of 2015 decreased by $9.4 million compared to the first six months of 2014. In the first six months of 2015, the cost of the noneconomic operation of these units was $4.8 million, and 94.6 percent of this cost was paid by peak transmission use in the AEP Control Zone while the remaining 5.4 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 $1.02 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 $0.01 per MW of reserved capacity for black start costs related to the noneconomic operation of ALR units.

Reactive / Voltage Support Units

Closed Loop Interfaces

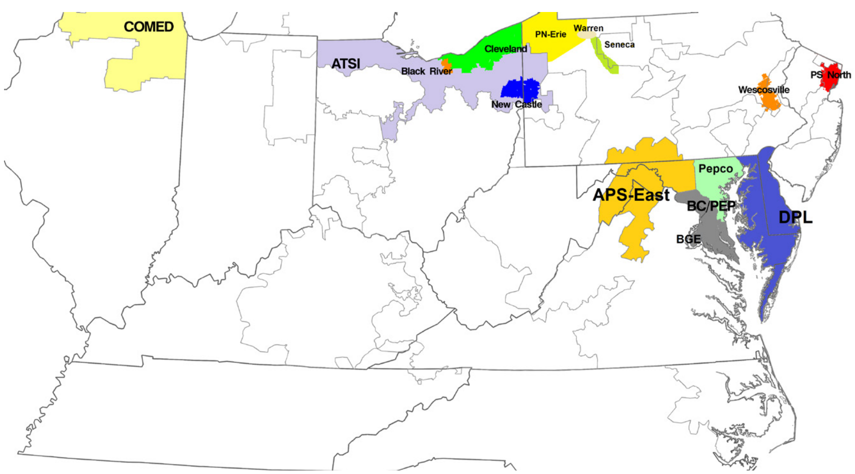
In 2013, PJM began to develop solutions to improve the incorporation of reactive constraints into energy prices. One of PJM's solutions was to create interfaces that could be used in such a way that units needed for reactive support could set the energy price. PJM also uses closed loop interfaces to set the real-time LMP with emergency DR resources. 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 4-34 shows the closed loop interfaces that PJM has defined.

Table 4-34 PJM Closed Loop Interfaces[20,21,22]

Interface	Control Zone(s)	Objective
ATSI	ATSI	Allow emergency DR resources set real-time LMP
APS-East	AP	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP
BGE	BGE	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP
BC/PEP	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)
DPL	DPL	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP
New Castle	ATSI	Allow emergency DR resources set real-time LMP
Pepco	Pepco	Allow emergency DR resources / unit(s) needed for reactive to set real-time LMP
PN-Erie	PENELEC	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

Figure 4-7 shows the approximate geographic location of PJM's closed loop interfaces.

Figure 4-7 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.[23]

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 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.

20 See PJM. Manual 3: Transmission Operations, Revision 46 (December 1, 2014) at "Section 3.8: Transfer Limits (Reactive/Voltage Transfer Limits)," for a description of reactive interfaces.
21 See closed loop interfaces definitions at <http://www.pjm.com/markets-and-operations/etools/oasis/system-information.aspx>.
22 See the PS North interface definition at <http://www.pjm.com/pub/account/auction-user-info/model-annual/Annual-PJM-interface-definitions-limits.csv>.

23 See "PJM Price-Setting Changes" at <http://www.pjm.com/~/media/committees-groups/task-forces/emustf/20131220/20131220-item-02c-price-setting-option.ashx>

Confidentiality of Energy Uplift Information

All data posted publicly by PJM or the MMU must comply with confidentiality rules. Current confidentiality rules do not allow posting data for three or fewer PJM participants and cannot be aggregated in a geographic area smaller than a control zone.[24]

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.

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. Units do not incur costs 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.[25]

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.

24 See OA. "Manual 33: Administrative Services for the PJM Interconnection Operating Agreement," Revision 11 (May 29, 2014), Market Data Posting.

25 The balancing operating reserve credit calculation includes net DASR revenues, net synchronized reserve revenues, net non-synchronized reserve revenues and reactive services revenues.

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 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.[26] These recommendations are superseded by the MMU's recommendation to eliminate day-ahead operating reserve payments.[27] 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 2014 and the first six months of 2015. In 2014 and the first six months of 2015, energy uplift costs associated with units scheduled in the Day-Ahead Energy Market would have had been reduced by $64.0 million or 19.2 percent ($5.7 million paid to units providing reactive support, $6.4 million paid to units providing black start support and $51.9 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.

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

26 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.

27 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>.

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 2014 and the first six months of 2015, 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 $12.4 million, of which $8.8 million or 71.4 percent was due to generators that elected to self-schedule for regulation while being noneconomic and receiving balancing operating reserve credits.[28]

Self Scheduled Start

Participants may offer their units as pool-scheduled (economic) or self-scheduled (must run).[29] 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.

Lost Opportunity Cost Calculation

The current energy LOC calculations are inaccurate and create unreasonable compensation. The MMU recommends four modifications.[30]

- **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 lost opportunity cost in the Energy and Ancillary Services Markets be calculated using the schedule on which the unit was scheduled to run in the Energy Market.
- **No load and startup costs:** Current rules do not include in the calculation of 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 lost opportunity cost 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

28 These estimates take into account the elimination of the day-ahead operating reserve category.

29 See "PJM eMkt Users Guide," Section Managing Unit Data (version January 9, 2015) p. 48. <http://www.pjm.com/~/media/etools/emkt/ts-userguide.ashx>.

30 See "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>.

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.

- **Segmented Calculation:** Current rules calculate LOC on an hourly basis. This means that units receive an LOC payment during hours in which it is economic for them run and receive the benefit of not being called on during hours in which it is not economic for them to run. PJM dispatchers might make the right decision to not call a unit in real time because the operation of the unit during all the hours in which the unit cleared the Day-Ahead Energy Market would not be economic, but the unit could still receive an LOC payment. This is not the intent of LOC payments. LOC should be paid to resources to ensure that they operate following PJM's direction and not lose their profit. In the case of hourly calculations, units are not made indifferent, but are overcompensated compared to the compensation they would have received had they run. The MMU recommends calculating LOC based on segments of hours not on an hourly basis in the calculation of credits paid to combustion turbines and diesels scheduled in the Day-Ahead Energy Market but not committed in real time.

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 4-35 shows the impact that each of these changes would have had on the LOC credits in the energy market in the first six months of 2015, for the two categories of lost opportunity cost credits. Energy LOC credits would have been reduced by a net of $18.8 million, or 28.8 percent, if all these changes had been implemented.[31]

Table 4-35 Impact on energy market lost opportunity cost credits of rule changes (Millions): January through June 2015

	LOC When Output Reduced in RT	LOC When Scheduled DA Not Called RT	Total
Current Credits	$8.1	$57.2	$65.3
Impact 1: Committed Schedule	$0.3	$4.4	$4.7
Impact 2: Using Offer Curve	($0.3)	$4.6	$4.3
Impact 3: Including No Load Cost	NA	($14.7)	($14.7)
Impact 4: Including Startup Cost	NA	($5.7)	($5.7)
Impact 5: Segmented Calculation	NA	($7.5)	($7.5)
Net Impact	$0.1	($18.9)	($18.8)
Credits After Changes	$8.1	$38.3	$46.4

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.

31 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.

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 $0.370 and $0.447 per MWh in 2014 and between $0.469 and $0.472 per MWh in the first six months of 2015 if the MMU's recommendations regarding energy uplift had been in place.[32,33]

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.[34] 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.[35] Demand transactions such as load, exports, internal bilateral sales and decrement bids may offset each other's deviations. The same applies to supply transactions such as imports, internal bilateral purchases and increment offers. Unlike all other transaction types, internal bilateral sales and purchases do not impact dispatch or market prices. Internal bilateral transactions are used by participants to transfer the financial responsibility or right of the energy withdrawn or injected into the system in the Day-Ahead and Real-Time Energy Markets.

The MMU recommends eliminating the use of internal bilateral transactions (IBTs) in the calculation of deviations used to allocate balancing operating reserve charges. IBTs should not pay for balancing operating reserves and should not be used to offset other transactions that deviate. IBTs shift the responsibility for an injection or withdrawal in PJM from one participant to another but IBTs are not part of the day-ahead unit commitment process, do not set energy prices and do not impact the energy flows in either the Day-Ahead or the Real-Time Energy Market, 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.

Day-Ahead Reliability Energy Uplift Allocation

PJM may schedule units as must run in the Day-Ahead Energy Market when needed in real time to address 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.[36] The energy uplift paid to units scheduled for voltage is allocated to real-time load. The energy uplift associated with units scheduled for black start is allocated to real-time load and interchange reservations. The energy uplift paid to units scheduled because of local contingencies not modeled in

32 The range of operating reserve rates paid by up-to congestion transactions depends on the location of the transactions' source and sink.

33 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 prior September 8, 2014 and all cleared up-to congestion transactions would have cleared after September 8, 2014. 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.

34 See PJM. OATT 3.2.3 (o) for a complete description of how generators deviate.

35 Locations can be control zones, hubs, aggregates and interfaces. See "Determinants and Deviation Categories" in this section for a description of balancing operating reserve locations.

36 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>.

the Day-Ahead Energy Market and scheduled because of their long lead times is allocated to day-ahead demand, day-ahead exports and decrement bids.

The MMU recommends allocating the energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market for reasons other than voltage/reactive or black start services as a reliability charge to real-time load, real-time exports and real-time wheels.

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.[37] 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.[38] 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.

37 See the *2014 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.
38 PJM. OATT Attachment K - Appendix § 3.2.3B (f).

In the first six months of 2015, units providing reactive services were paid $0.3 million in balancing operating reserve credits in order to cover their total energy offer. In 2014, this misallocation was $2.2 million, for a total of $2.4 million in 2014 and the first six months of 2015.

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.[39]

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 all day-ahead transactions and resources. All these transaction types have an impact on the outcome of the day-ahead 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. Energy uplift payments to units scheduled as must run in the Day-Ahead Energy Market (for reasons other than reactive or black start services) should be allocated to real-time load, real-time exports and real-time wheels.

39 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>.

The MMU recommends allocating energy uplift payments to units not scheduled in the Day-Ahead Energy Market and committed in real time but before the operating day to the current deviation categories with the addition of up-to congestion, wheels and units that clear the Day-Ahead Scheduling Reserve Market but do not perform.

The MMU recommends 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 allocating energy uplift payments to units committed during the operating day 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 affecting 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, real-time exports and real-time wheels independently of the timing of the commitment.

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 real-time load, real-time exports and real-time wheels.

Table 4-36 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 4-36 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 in the Day-Ahead Energy Market 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 4-37 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 transactions and resources. 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 4-37 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	Scheduled by the day ahead model (not must run)	Day-Ahead Transactions and Day-Ahead Resources
		Scheduled as must run in the day ahead model	Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels
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	Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels
Units canceled before coming online	Cancellation Credit	NA	Real-Time Load, Real-Time Exports and Withdrawal Side of Real-Time Wheels

Quantifiable Recommendations Impact

Table 4-38 shows energy uplift charges based on the current allocation and energy uplift charges based on the MMU allocation proposal including the MMU recommendations regarding energy uplift credit calculations. Total charges (excluding black start and reactive services charges) would have been reduced by $120.3 million or 10.7 percent in 2014 and the first six months of 2015 if three recommendations regarding energy uplift credit calculations proposed by the MMU had been implemented. The elimination of the day-ahead operating reserve credit would have resulted in a decrease of $51.9 million, the proposed changes to lost opportunity cost calculations would have resulted in a decrease of $56.1 million and the use of net regulation revenues offset would have resulted in a decrease of $12.3 million.[40] Table 4-38 shows that deviations charges would have been reduced by $301.7 million or 64.5 percent. The reason for this change is that, besides the reduction in the overall charges, under the MMU proposal, a subset of charges is reallocated to a new physical deviation category (based on the timing of the commitment of the resource being paid energy uplift) and another subset of charges is allocated to real-time load, real-time exports and real-time wheels (based on reliability actions).

40 The total impact of the elimination of the day-ahead operating reserve credit and the impact of net regulation revenues offset is greater because they also impact black start and reactive services charges.

Table 4-38 Current and proposed energy uplift charges by allocation (Millions): 2014 and January through June 2015[41]

Allocation	2014	Jan - Jun 2015	Total
Current			
Day-Ahead Demand, Day-Ahead Exports and Decrement Bids	$111.4	$73.0	$184.3
Real-Time Load and Real-Time Exports	$447.1	$28.0	$475.1
Deviations	$341.9	$125.9	$467.8
Total	$900.4	$226.9	$1,127.3
Proposal			
Day-Ahead Transactions and Day-Ahead Resources	$46.5	$18.8	$65.3
Real-Time Load and Real-Time Exports	$456.4	$75.4	$531.8
Deviations	$111.5	$54.6	$166.1
Physical Deviations	$203.8	$39.9	$243.8
Total	$818.2	$188.7	$1,006.9
Impact			
Impact ($)	($82.1)	($38.2)	($120.3)
Impact (%)	(9.1%)	(16.8%)	(10.7%)

The MMU calculated the rates that participants would have paid in 2014 and the first six months of 2015 if all the MMU's recommendations on energy uplift had been in place. 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 scheduled as must run in the Day-Ahead Energy Market (for reasons other than reactive or black start services); 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 shows the energy uplift cost of a 1 MW transaction if these recommendations had been implemented in 2014 and the first six months of 2015. Table 4-39 assumes two scenarios under the MMU proposal. The first scenario assumes that 50 percent of all up-to congestion transactions cleared volume would have remained prior to September 8, 2014 and all up-to congestion transactions cleared volume would have remained after September

41 These energy uplift charges do not include black start and reactive services charges.

8, 2104. The second scenario assumes zero volume of up-to congestion transactions in 2014 and the first six months of 2015. Table 4-39 shows for example that a decrement bid in the Eastern Region (if not offset by other transactions) would have paid an average rate of $0.223 and $0.236 per MWh in the 2014 and the first six months of 2015, under the first scenario, $2.202 and $1.622 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 $0.408 and $0.471 per MWh in 2014 and the first six months of 2015 under the first scenario. Table 4-39 shows the current and proposed averages energy uplift rates for all transactions.

Table 4-39 Current and proposed average energy uplift rate by transaction: 2014 and January through June 2015[42]

		2014			Jan - Jun 2015		
	Transaction	Current Rates ($/MWh)	Proposed Rates - 50% UTC ($/MWh)	Proposed Rates - 0% UTC ($/MWh)	Current Rates ($/MWh)	Proposed Rates - 50% UTC ($/MWh)	Proposed Rates - 0% UTC ($/MWh)
East	INC	2.296	0.223	0.701	1.690	0.236	0.587
	DEC	2.426	0.223	0.701	1.858	0.236	0.587
	DA Load	0.129	0.019	0.024	0.167	0.017	0.020
	RT Load	0.450	0.460	0.460	0.066	0.175	0.175
	Deviation	2.296	1.313	1.787	1.690	0.740	1.088
West	INC	2.091	0.185	0.586	1.649	0.234	0.595
	DEC	2.220	0.185	0.586	1.816	0.234	0.595
	DA Load	0.129	0.019	0.024	0.167	0.017	0.020
	RT Load	0.439	0.460	0.460	0.057	0.175	0.175
	Deviation	2.091	1.229	1.626	1.649	0.659	1.017
UTC	East to East	NA	0.447	1.402	NA	0.472	1.175
	West to West	NA	0.370	1.173	NA	0.469	1.190
	East to/from West	NA	0.408	1.287	NA	0.471	1.183

April through June Energy Uplift Charges Analysis

Energy uplift charges decreased by $590.1 million (71.0 percent), from $831.5 million in the first six months of 2014 to $241.4 million in the first six months of 2015. This decrease was primarily the result of lower energy uplift charges associated with units committed for conservative operations in the first three months of 2015 compared to the first three months of 2014.

Energy uplift charges in the months of April through June decreased by $30 million (35.7 percent), from $84.0 million in 2014 to $54.0 million This change resulted from an increase of $2.1 million in day-ahead operating reserve charges, a decrease of $13.8 million in balancing operating reserve charges, a decrease of $11.8 million in reactive services charges, a decrease of $0.1 million in synchronous condensing charges and a decrease of $6.5 in black start services charges.

Figure 4-8 shows the net impact of each category on the change in total energy uplift charges from the April through June 2014 level to the April through June 2015 level. The outside bars show the first six months of 2014 total energy uplift charges (left side) and the first six months of 2015 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 April through June 2014 compared to April through June 2015 (an increase of $2.1 million).

42 The deviation transaction means load, interchange transactions, generators and DR deviations.

Figure 4-8 Energy uplift charges change from April through June of 2014 to April through June of 2015 by category

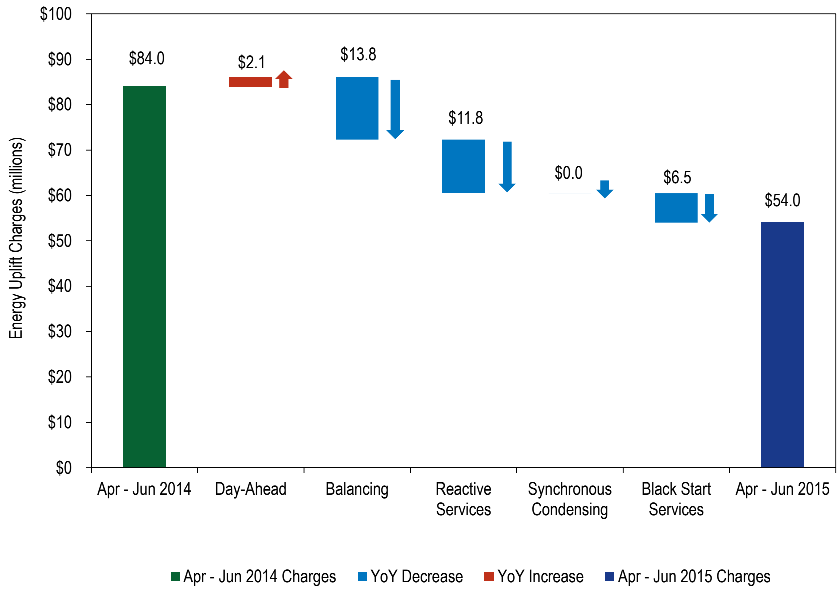
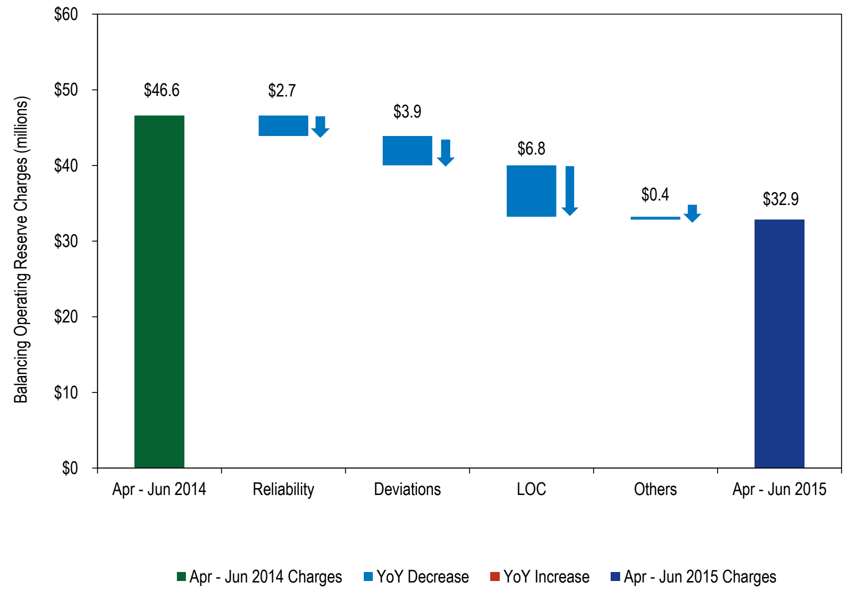


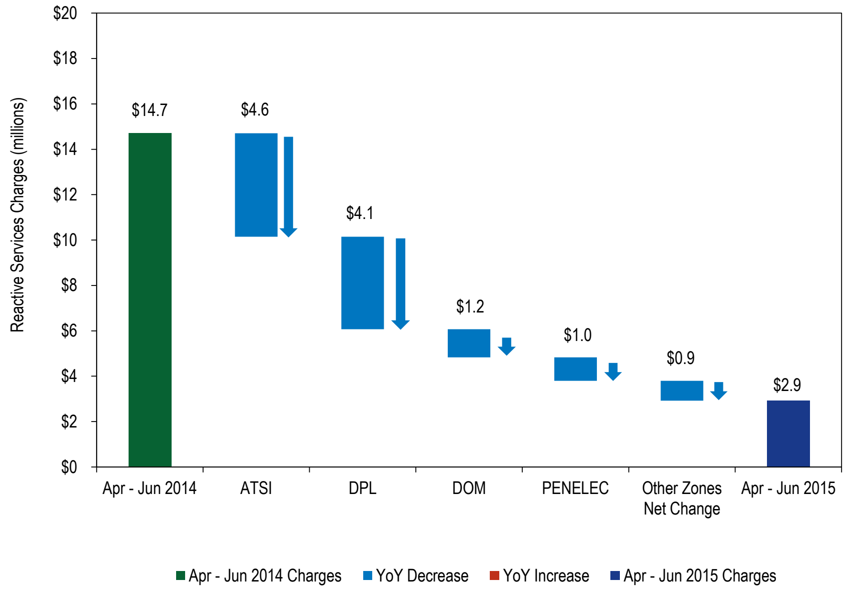
Figure 4-9 Balancing operating reserve charges change from April through June 2014 to April through June 2015



The decrease in balancing operating reserve charges was mainly a result of a decrease in lost opportunity cost payments. Energy uplift costs as a result of lost opportunity cost payments decreased by $6.8 million in April through June 2015 compared to April through June 2014. Figure 4-9 shows the net change in balancing operating reserve charges.

The decrease in reactive was mainly a result of a decrease in reactive services payments in the ATSI and DPL control zones. Energy uplift costs as a result of reactive services payments decreased by $4.6 million in the ATSI Control Zone and by $4.1 million in the DPL Control Zone in April through June 2015 compared to April through June 2014. Figure 4-10 shows the net change in reactive services charges.

Figure 4-10 Reactive services charges change from April through June 2014 to April through June 2015



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 six months of 2015, 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 *2015 Quarterly State of the Market Report for PJM: January through June*, 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 six months of 2015, PJM installed capacity decreased 6,985.5 MW or 3.8 percent, from 183,726 MW on January 1 to 176,740.5 MW on June 30. Installed capacity includes net capacity imports and exports and can vary on a daily basis.
- **PJM Installed Capacity by Fuel Type.** Of the total installed capacity on June 30, 2015, 37.8 percent was coal; 33.6 percent was gas; 18.7 percent was nuclear; 3.9 percent was oil; 4.9 percent was hydroelectric; 0.5 percent was wind; 0.4 percent was solid waste; and 0.1 percent was solar.
- **Market Concentration.** In the first six months of 2015, no RPM Auctions were held as the Base Residual Auction for the 2018/2019 Delivery Year was delayed.[9]
- **Imports and Exports.** In the first six months of 2015, no RPM Auctions were held as the Base Residual Auction for the 2018/2019 Delivery Year was delayed.
- **Demand-Side and Energy Efficiency Resources.** Capacity in the RPM load management programs was 12,149.5 MW for June 1, 2015, as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2015/2016 Delivery Year (16,643.3 MW) less replacement capacity from sources other than Demand Resources and Energy Efficiency (4,493.8 MW).

Market Conduct

- In the first six months of 2015, no RPM Auctions were held as the Base Residual Auction for the 2018/2019 Delivery Year was delayed.

Market Performance

- In the first six months of 2015, no RPM Auctions were held as the Base Residual Auction for the 2018/2019 Delivery Year was delayed.
- For the 2015/2016 Delivery Year, RPM annual charges to load were $9.6 billion.
- The Delivery Year weighted average capacity price was $126.40 per MW-day in 2014/2015 and $160.01 per MW-day in 2015/2016.

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.
9 151 FERC ¶ 61,067 (2015).

Generator Performance

- **Forced Outage Rates.** The average PJM EFORd for the first six months of 2015 was 7.7 percent, a decrease from 11.3 percent for the first six months of 2014.[10]
- **Generator Performance Factors.** The PJM aggregate equivalent availability factor for 2015 was 82.5 percent, an increase from 80.2 percent for 2014.
- **Outages Deemed Outside Management Control (OMC).** In the first six months of 2015, 4.4 percent of forced outages were classified as OMC outages, and 0.1 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[11]

The MMU recognizes that PJM has proposed the Capacity Performance construct to replace some of the existing core market rules and to address fundamental performance incentive issues. The MMU recognizes that the Capacity Performance construct addresses many of the MMU's recommendations. Until new rules are in place, the MMU's recommendations and the reported status of those recommendations are based on the existing capacity market rules. The status is reported as adopted if the recommendation was included in FERC's order approving PJM's Capacity Performance filing.[12]

- 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.[13,14] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- 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. Status: Adopted.)
- 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. Status: Adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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 2010. Status: Not adopted.)
- The MMU recommends three changes with respect to capacity imports into PJM:

10 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 six months ending June 30, as downloaded from the PJM GADS database on July 24, 2015. 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.

11 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.

12 *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,208 (June 9, 2015).

13 See also Comments of the Independent Market Monitor for PJM. Docket No. ER14-503-000 (December 20, 2013).

14 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).

- The MMU recommends that all capacity have firm transmission to the PJM border acquired prior to the offering in an RPM auction. (Priority: High. First reported 2014. Status: Adopted.)
- The MMU recommends that all capacity imports be required to be pseudo tied prior to the relevant Delivery Year in order to ensure that imports are as close to full substitutes for internal, physical capacity resources as possible. (Priority: High. First reported 2014. Status: Adopted.)
- The MMU recommends that all resources importing capacity into PJM accept a must offer requirement. (Priority: High. First reported 2014. Status: Adopted.)

- The MMU recommends that the net revenue calculation used by PJM to calculate the net Cost of New Entry (CONE) VRR parameter reflect the actual flexibility of units in responding to price signals rather than using assumed fixed operating blocks that are not a result of actual unit limitations.[15,16] The result of reflecting the actual flexibility is higher net revenues, which affect the parameters of the RPM demand curve and market outcomes. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that the rule requiring that relatively small proposed increases in the capability of a Generation Capacity Resource be treated as planned for purposes of mitigation and exempted from offer capping be removed. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that, as part of the MOPR unit specific standard of review, all projects be required to use the same basic modeling assumptions. That is the only way to ensure that projects compete on the basis of actual costs rather than on the basis of modeling assumptions.[17] (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends two changes to the RPM solution methodology related to make-whole payments and the iterative reconfiguration of the VRR curve:
  - The MMU recommends changing the RPM solution methodology to explicitly incorporate the cost of make-whole payments in the objective function. (Priority: Medium. First reported 2014. Status: Not adopted.)
  - The MMU also recommends changing the RPM solution methodology to define variables for the nesting relationships in the BRA optimization model directly rather than employing the current iterative approach, in order to improve the efficiency and stability. (Priority: Medium. First reported 2014. Status: Not adopted.)
- 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. Status: Adopted.)
  - 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. Status: Not adopted. Pending before FERC.)
  - 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. Status: Adopted.)
  - 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.[18] (Priority: Medium. First reported 2013. Status: Not adopted. Pending before FERC.)

15 See PJM Interconnection, L.L.C., Docket No. ER12-513 (December 1, 2011) ("Triennial Review").
16 See the *2012 State of the Market Report for PJM*, Volume II, Section 6, Net Revenue.
17 See 143 FERC ¶ 61,090 (2013) ("We encourage PJM and its stakeholders to consider, for example, whether the unit-specific review process would be more effective if PJM requires the use of common modeling assumptions for establishing unit-specific offer floors while, at the same time, allowing sellers to provide support for objective, individual cost advantages. Moreover, we encourage PJM and its stakeholders to consider these modifications to the unit-specific review process together with possible enhancements to the calculation of Net CONE."); see also, Comments of the Independent Market Monitor for PJM, Docket No. ER13-535-001 (March 25, 2013); Complaint of the Independent Market Monitor for PJM v. Unnamed Participant, Docket No. EL12-63-000 (May 1, 2012); Motion for Clarification of the Independent Market Monitor for PJM, Docket No. ER11-2875-000, et al. (February 17, 2012); Protest of the Independent Market Monitor for PJM, Docket No. ER11-2875-002 (June 2, 2011); Comments of the Independent Market Monitor for PJM, Docket Nos. EL11-20 and ER11-2875 (March 4, 2011).
18 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_

Conclusion

The analysis of PJM Capacity Markets begins with market structure, which provides the framework for the actual behavior or conduct of market participants. The analysis examines participant behavior within that market structure. In a competitive market structure, market participants are constrained to behave competitively. The analysis examines market performance, measured by price and the relationship between price and marginal cost, that results from the interaction of market structure and participant behavior.

The MMU found serious market structure issues, measured by the three pivotal supplier test results, but no exercise of market power in the PJM Capacity Market in the first six months of 2015. Explicit market power mitigation rules in the RPM construct offset the underlying market structure issues in the PJM Capacity Market under RPM. The PJM Capacity Market results were competitive in the first six months of 2015.

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 2014 and 2015, the MMU prepared a number of RPM-related reports and testimony, shown in Table 5-2.

Capacity_White_Papers_On_OPSI_Issues_20120820.pdf> (August 20, 2012).

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).

Table 5-2 RPM related MMU reports, 2014 through 2015

Date	Name
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
October 16, 2014	IMM Comments re PJM Triennial Review Docket No. ER14-2940-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_ER14-2940-000_20141016.pdf
October 22, 2014	IMM Comments re FE Complaint Docket No. EL14-55-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Comments_Docket_No_EL14-55-000_20141022.pdf
October 28, 2014	IMM Proposal re PJM's Capacity Performance Proposal http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Proposal_re_PJM_Capacity_Performance_Proposal_20141028.pdf
November 19, 2014	IMM Motion to Intervene and Comments re 30 Day Notice Exception Docket No. ER15-135-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Motion_to_Intervene_and_Comments_Docket_No_ER15-135-000_20141119.pdf
December 3, 2014	IMM Reply Brief re Net Revenues Docket No. EL14-94-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Reply_Brief_Docket_No_EL14-94-000_20141203.pdf
December 12, 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_20141212.pdf
December 17, 2014	IMM Answer and Motion for Leave to Answer re Net Revenues Docket No. EL14-94-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_and_Motion_to_Answer_Docket_No_EL14-94-000_20141217.pdf
December 18, 2014	IMM Answer and Motion for Leave to Answer re DR Docket No. ER15-135-000 http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Answer_and_Motion_to_Answer_Docket_No_ER15-135-000_20141218.pdf
January 14, 2015	IMM Comments re Capacity Performance Docket Nos. EL15-738-000 and EL15-739-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_No_EL15-738-000_EL15-739-000_20150114.pdf
January 20, 2015	IMM Comments re Capacity Performance Docket No. ER15-623-000 and EL15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_No_ER15-623-000_EL15-29-000_20150120.pdf
January 29, 2015	IMM Protest re IMEA Waiver Docket No. ER15-834-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Protest_Docket_No_ER15-834-000_20150129.pdf
January 30, 2015	IMM Answer and Motion for Leave to Answer re Calpine Waiver Docket No. ER15-376-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_for_Leave_to_Answer_Docket_No_ER15-376-000_20150130.pdf
February 13, 2015	Comments of the Independent Market Monitor for PJM re DR in RPM Docket No. ER15-852-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_No_ER15-852-000_20150213.pdf
February 22, 2015	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_20150222.pdf
February 25, 2015	IMM Answer and Motion for Leave to Answer re Capacity Performance Docket Nos. ER15-623-000 and EL15-29-000, Not Consolidated http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_for_Leave_to_Answer_Docket_Nos_ER15-623-000_EL15-29-000_20150225.pdf
February 27, 2015	IMM Answer and Motion for Leave to Answer Errata re Capacity Performance Docket Nos. ER15-623-000 and EL15-29-000, Not Consolidated http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_for_Leave_to_Answer_Errata_Docket_Nos_ER15-623-000_EL15-29-000_20150227.pdf
March 6, 2015	IMM Comments re Champion Energy Complaint Docket No. EL15-46-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_No_EL15-46-000_20150306.pdf
March 20, 2015	IMM Answer and Motion for Leave to Answer re Capacity Performance Docket Nos. ER15-623-000 and EL15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_for_Leave_to_Answer_ER15-623-000_EL15-29-000_20150320.pdf
March 25, 2015	IMM Protest re IMEA Waiver Docket No. ER15-1232-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Protest_Docket_No_ER15-1232-000_20150325.pdf
March 26, 2015	IMM Answer re Capacity Performance Docket Nos. ER15-623-000 and EL15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Answer_and_Motion_to_Answer_Docket_Nos_ER15-623-000_EL15-29-000_20150326.pdf
April 15, 2015	IMM Comments re Capacity Performance Docket Nos. ER15-623-001 and ER15-1470-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_Nos_ER15-623-001_ER15-1470-000_20150415.pdf
June 30, 2015	Generation Capacity Resources in PJM Region Subject to RPM Must Offer Obligation for 2016/2017, 2017/2018 and 2018/2019 Delivery Years http://www.monitoringanalytics.com/reports/Market_Messages/Messages/RPM_Must_Offer_Obligation_20150630.pdf
July 6, 2015	IMM Limited Request for Rehearing re Capacity Performance Docket Nos. ER15-623-000, -001 and El15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Limited_Request_for_Rehearing_Docket_Nos_ER15-623-000_001_and_20EL15-29-000_20150706.pdf
July 8, 2015	Intermittent Resources Capacity Performance Value Methodology http://www.monitoringanalytics.com/reports/Market_Messages/Messages/Intermittent_Resources_Capacity_Performance_Value_Methodology_20150708.pdf
July 20, 2015	IMM Comments re Capacity Performance Docket Nos. ER15-623-004 and EL15-29-000 http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Comments_Docket_Nos_ER15-623-004_EL15-29-000_20150720.pdf

Installed Capacity

On January 1, 2015, PJM installed capacity was 183,726.0 MW (Table 5-3).[24] Over the next six months, new generation, unit deactivations, facility reratings, plus import and export shifts resulted in PJM installed capacity of 176,740.5 MW on June 30, 2015, a decrease of 6,985.5 MW or 3.8 percent from the January 1 level.[25,26] The 6,985.5 MW decrease was the result of deactivations (9,770.5 MW) and derates (212.0 MW) offset by capacity modifications (1,207.8 MW), new or reactivated generation (948.2 MW), an increase in imports (818.2 MW), and a decrease in exports (22.8 MW).

At the beginning of the new Delivery Year on June 1, 2014, PJM installed capacity was 176,737.4 MW, a decrease of 6,239.4 MW or 3.4 percent from the May 31 level.

Figure 5-1 shows the share of installed capacity by fuel source for the first day of each Delivery Year, from June 1, 2007, to June 1, 2015, as well as the expected installed capacity for the next three Delivery Years, based on the results of all auctions held through the first six months of 2015.[27] On June 1, 2007, coal comprised 40.7 percent of the installed capacity, reached a maximum of 42.9 percent in 2012, and then decreased to 37.8 percent on June 1, 2015. Coal's share of installed capacity is projected to decrease further to 31.4 percent by June 1, 2017. The share of gas increased from 29.1 percent in 2007 to 33.6 percent in 2015, and is expected to increase to 42.2 percent in 2017. The percentage of hydroelectric installed capacity increased from 4.5 percent in 2007 to 4.9 percent in 2015, and is expected to decrease to 4.8 percent in 2017. The share of nuclear fell from 18.9 percent in 2007 to 18.7 percent in 2015, and is expected to continue to decrease to 16.5 percent in 2017. The share of oil decreased from 6.5 percent in 2007 to 3.9 percent in 2015, and is expected to increase to 4.1 percent in 2017, while solid waste remained at 0.4 percent and is expected to increase to 0.5 percent in 2017. Solar resources have increased their installed capacity share from 0.0 percent to 0.1 percent, and are expected to remain the same through 2017, and wind resources increased their installed capacity share from 0.0 percent to 0.5 percent, and are expected to remain unchanged through 2017.

24 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.

25 Unless otherwise specified, 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.

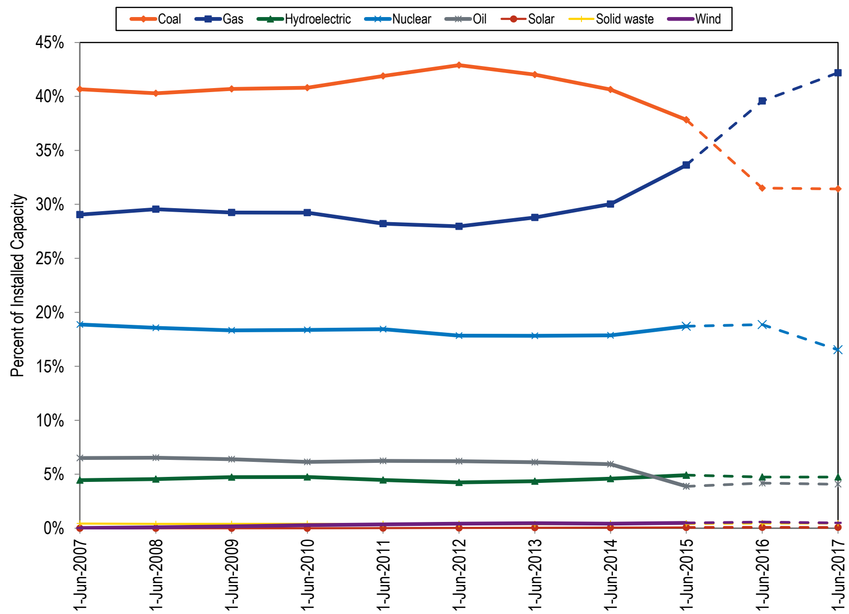
26 Wind resources accounted for 822.7 MW of installed capacity in PJM on March 31, 2015. This value represents approximately 13 percent of wind nameplate capability in PJM. PJM administratively reduces the capabilities of all wind generators to 13 percent of nameplate capacity when determining the system 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.

27 Due to EFORd values not being finalized for future Delivery Years, the projected installed capacity is based on cleared unforced capacity (UCAP) MW using the EFORd submitted with the offer.

Table 5-3 PJM installed capacity (By fuel source): January 1, May 31, June 1, and June 30, 2015

	1-Jan-15		31-May-15		1-Jun-15		30-Jun-15	
	MW	Percent	MW	Percent	MW	Percent	MW	Percent
Coal	72,741.3	39.6%	72,343.5	39.5%	66,878.1	37.8%	66,878.1	37.8%
Gas	59,662.6	32.5%	59,862.3	32.7%	59,460.1	33.6%	59,463.1	33.6%
Hydroelectric	8,765.3	4.8%	8,690.8	4.7%	8,698.8	4.9%	8,698.9	4.9%
Nuclear	32,947.1	17.9%	33,078.4	18.1%	33,071.5	18.7%	33,071.5	18.7%
Oil	7,907.6	4.3%	7,299.7	4.0%	6,853.4	3.9%	6,853.4	3.9%
Solar	97.5	0.1%	97.5	0.1%	128.0	0.1%	128.0	0.1%
Solid waste	781.9	0.4%	781.9	0.4%	771.3	0.4%	771.3	0.4%
Wind	822.7	0.4%	822.7	0.4%	876.2	0.5%	876.2	0.5%
Total	183,726.0	100.0%	182,976.8	100.0%	176,737.4	100.0%	176,740.5	100.0%

Figure 5-1 Percentage of PJM installed capacity (By fuel source): June 1, 2007 through June 1, 2017



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.[28] In the first six months of 2015, no RPM Auctions were held as the Base Residual Auction for the 2018/2019 Delivery Year was delayed.[29]

28 See *PJM Interconnection, L.L.C.*, Letter Order in Docket No. ER10-366-000 (January 22, 2010).
29 151 FERC ¶ 61,067 (2015).

Market Structure

Supply

Table 5-4 shows generation capacity changes since the implementation of the Reliability Pricing Model through the 2014/2015 Delivery Year. The 13,078.0 MW increase was the result of new Generation Capacity Resources (9,787.1 MW), reactivated Generation Capacity Resources (430.0 MW), uprates (5,101.3 MW), integration of external zones (18,109.0 MW), a net increase in capacity imports (5,310.8 MW), a net decrease in capacity exports (2,547.0 MW), offset by deactivations (25,297.3 MW) and derates (2,909.9 MW).

Table 5-4 Generation capacity changes: 2007/2008 through 2015/2016

	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	2,229.2	21.6	4,027.7	420.0	(1,556.6)
2014/2015	184,011.3	3,036.0	0.0	480.4	0.0	946.9	73.3	11,442.9	221.0	(7,273.9)
2015/2016	176,737.4									
Total		9,787.1	430.0	5,101.3	18,109.0	5,310.8	(2,547.0)	25,297.3	2,909.9	13,078.0

Demand

On June 1, 2015, PJM EDCs and their affiliates maintained a large market share of load obligations under RPM, together totaling 65.1 percent (Table 5-5), down from 71.1 percent on June 1, 2014. The combined market share of LSEs not affiliated with any EDC and of non-PJM EDC affiliates was 34.9 percent, up from 28.9 percent on June 1, 2014. Prior to the 2012/2013 Delivery Year, obligation was defined as cleared and make-whole MW in the Base Residual Auction and the Second Incremental Auction plus ILR forecast obligations. Effective with the 2012/2013 Delivery Year, obligation is defined as the sum of the unforced capacity obligations satisfied through all RPM Auctions for the Delivery Year.

Table 5-5 Capacity Market load obligations served: June 1, 2015

	Obligation (MW)							
	PJM EDCs	PJM EDC Generating Affiliates	PJM EDC Marketing Affiliates	Non-PJM EDC Generating Affiliates	Non-PJM EDC Marketing Affiliates	Non-EDC Generating Affiliates	Non-EDC Marketing Affiliates	Total
Obligation	45,896.8	25,878.6	14,327.3	4,630.2	16,352.3	1,265.5	23,994.8	132,345.5
Percent of total obligation	34.7%	19.6%	10.8%	3.5%	12.4%	1.0%	18.1%	100.0%

Market Concentration

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 is 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 are modeled as potentially constrained LDAs regardless of the results of the above three tests.[30] 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."[31] 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 Delivery Year, Sub-Annual and Limited Resource Constraints, replacing the Minimum Annual and a Minimum Extended Summer Resource Requirements, are established for each modeled LDA.[32] Effective for the 2018/2019 through the 2019/2020 Delivery Years, Base Capacity Demand Resource Constraint and a Base

30 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.
31 PJM. OATT Attachment DD § 5.10 (a) (ii).
32 146 FERC ¶ 61,052 (2014).

Capacity Resource Constraint, replacing the Sub-Annual and Limited Resource Constraints, are established for each modeled 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.[33]

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 energy offers daily of $999 per MWh would not fulfill the requirements of a capacity resource to make a competitive offer, but would constitute economic withholding. This is one of the reasons that the rules governing the obligation to make a competitive offer in the Day-Ahead Energy Market should be clarified for both internal and external resources.

Demand Resources

As shown in Table 5-6 and Table 5-8, capacity in the RPM load management programs was 12,149.5 MW for June 1, 2015 as a result of cleared capacity for Demand Resources and Energy Efficiency Resources in RPM Auctions for the 2015/2016 Delivery Year (16,643.3 MW) less replacement capacity (4,493.8 MW). Table 5-7 shows RPM commitments for DR and EE resources as the result of RPM Auctions prior to adjustments for replacement capacity transactions and certified ILR.

33 PJM. OATT Attachment DD § 5.6.6(b).

Table 5-6 RPM load management statistics by LDA: June 1, 2014 to June 1, 2017[34,35,36]

	UCAP (MW)												
	RTO	MAAC	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ATSI Cleveland	ComEd	BGE	PPL
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	15,453.7	6,675.4	2,624.0	2,022.4	86.3	787.3	263.5	867.7	2,167.9				
EE cleared	1,189.6	279.0	73.1	164.8	3.1	26.4	11.5	59.3	142.0				
DR net replacements	(4,829.7)	(2,393.0)	(1,078.7)	(672.5)	(7.0)	(363.6)	(128.4)	(310.7)	(1,082.2)				
EE net replacements	335.9	230.4	48.5	149.2	0.0	12.4	2.7	61.1	15.2				
RPM load management @ 01-Jun-15	12,149.5	4,791.8	1,666.9	1,663.9	82.4	462.5	149.3	677.4	1,242.9				
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

34 See PJM. OATT Attachment DD § 8.4. The reported DR cleared MW may reflect reductions in the level of committed MW due to relief from Capacity Resource Deficiency Charges

35 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.

36 See PJM. OATT. Attachment DD § 5.14C. The reported DR cleared MW for the 2015/2016 Delivery Year reflect reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.

Table 5-7 RPM load management cleared capacity and ILR: 2007/2008 through 2017/2018[37,38,39]

	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	14,891.6	15,453.7	1,147.7	1,189.6	0.0	0.0
2016/2017	12,253.1	12,710.5	1,117.1	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 5-8 RPM load management statistics: June 1, 2007 to June 1, 2017[40,41]

	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	16,039.3	16,643.3	(4,653.7)	(4,829.7)	323.7	335.9	11,709.3	12,149.5
01-Jun-16	13,370.2	13,867.8	0.0	0.0	0.0	0.0	13,370.2	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

37 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.

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

39 See PJM. OATT. Attachment DD § 5.14C. The reported DR cleared MW for the 2015/2016 Delivery Year reflect reductions in the level of committed MW due to the Demand Response Operational Resource Flexibility Transition Provision.

40 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.

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 included transactions associated with RTP Controls, Inc. which was declared in collateral default on March 9, 2012.

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).[42]

Capacity Factor

Capacity factor measures the actual output of a power plant over a period of time compared to the potential output of the unit had it been running at full nameplate capacity during that period. In the first six months of 2015, nuclear units had a capacity factor of 93.5 percent, compared to 92.1 percent in 2014; combined cycle units had a capacity factor of 58.3 percent in the first six months of 2015, compared to a capacity factor of 51.4 percent in the first three months of 2014; and steam units, which are primarily coal fired, had a capacity factor of 47.7 percent in the first six months of 2015, compared to 52.9 percent in the first three months of 2014.

42 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.

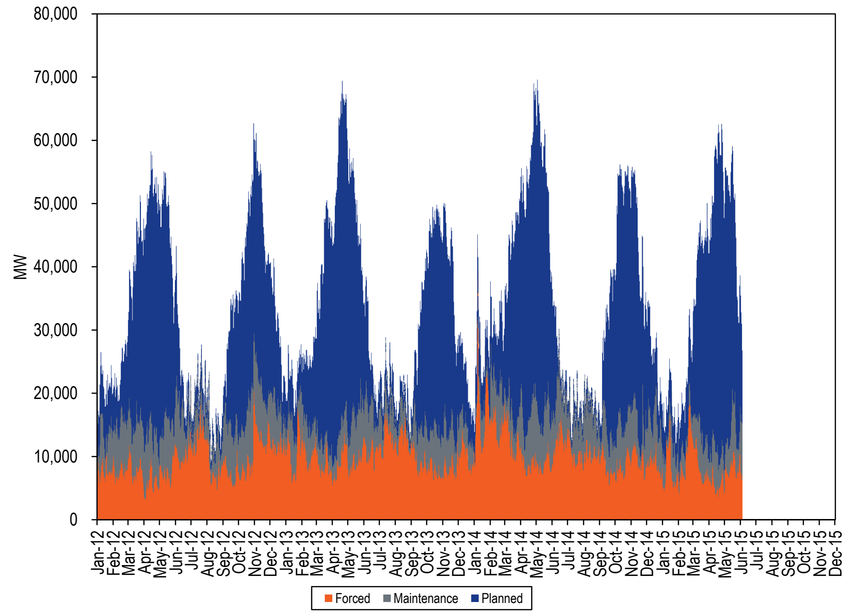
Table 5-9 PJM capacity factor (By unit type (GWh)): January through June of 2014 and 2015[43]

	2014 (Jan-Jun)		2015 (Jan-Jun)		Change in
Unit Type	Generation (GWh)	Capacity Factor	Generation (GWh)	Capacity Factor	2015 from 2014
Battery	5.4	1.3%	1.5	0.3%	(0.9%)
Combined Cycle	57,523.0	51.4%	74,378.7	58.3%	6.9%
Combustion Turbine	5,054.4	3.8%	5,780.2	4.5%	0.7%
Diesel	314.8	17.6%	277.2	14.8%	(2.8%)
Diesel (Landfill gas)	724.2	45.1%	772.8	47.1%	1.9%
Fuel Cell	109.3	83.9%	113.6	87.2%	3.3%
Nuclear	134,954.5	92.1%	136,978.9	93.5%	1.4%
Pumped Storage Hydro	3,463.2	14.5%	2,709.2	11.4%	(3.2%)
Run of River Hydro	4,778.7	42.1%	3,875.4	32.7%	(9.4%)
Solar	197.7	16.6%	253.0	16.4%	(0.2%)
Steam	191,462.1	52.9%	162,230.8	47.7%	(5.2%)
Wind	8,678.0	31.5%	8,683.0	30.3%	(1.2%)
Total	407,265.3	49.6%	396,057.7	48.7%	(0.9%)

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 5-2, 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 5-2 PJM outages (MW): 2012 through June 2015



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 six months of 2015 was 82.5 percent, an increase from 80.2 percent for the first six months of 2014. The PJM aggregate

43 The capacity factors in this table are based on nameplate capacity values, and are calculated based on when the units come on line.

EAF, EFOF, EPOF, and EMOF are shown in Figure 5-3. Metrics by unit type are shown in Table 5-10 through Table 5-13.

Figure 5-3 PJM equivalent outage and availability factors: 2007 to 2015

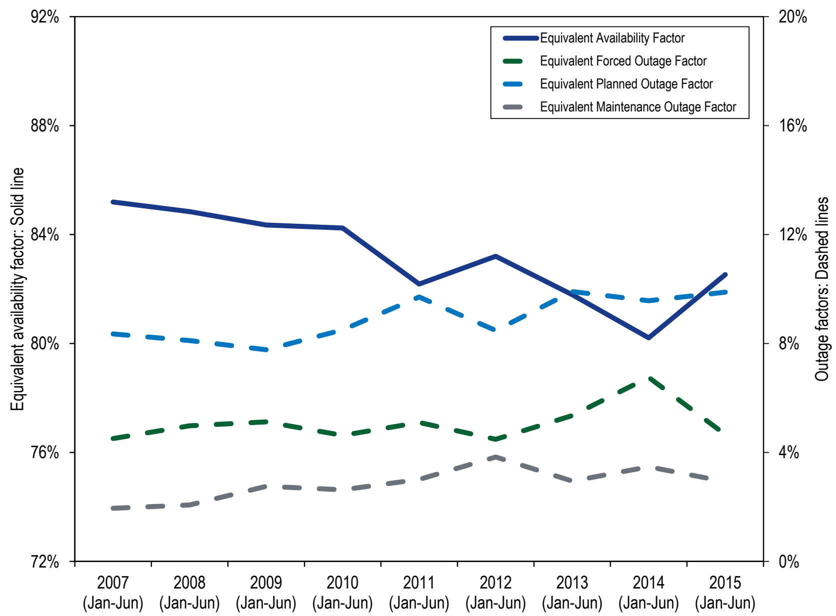


Table 5-10 EAF by unit type: 2007 through 2015

	2007 (Jan-Jun)	2008 (Jan-Jun)	2009 (Jan-Jun)	2010 (Jan-Jun)	2011 (Jan-Jun)	2012 (Jan-Jun)	2013 (Jan-Jun)	2014 (Jan-Jun)	2015 (Jan-Jun)
Combined Cycle	88.9%	89.5%	86.5%	84.1%	83.5%	86.0%	82.4%	82.0%	84.3%
Combustion Turbine	89.1%	89.4%	92.5%	93.4%	93.0%	93.1%	89.6%	85.2%	89.4%
Diesel	87.8%	87.7%	91.4%	94.1%	94.9%	94.1%	93.7%	81.7%	86.9%
Hydroelectric	90.5%	89.4%	85.1%	86.1%	83.8%	88.9%	89.9%	83.3%	86.7%
Nuclear	93.9%	91.4%	89.6%	92.2%	88.6%	89.8%	90.8%	89.2%	90.9%
Steam	79.2%	79.5%	79.3%	78.3%	76.0%	76.4%	74.7%	74.0%	75.6%
Total	85.2%	84.8%	84.4%	84.2%	82.2%	83.2%	81.8%	80.2%	82.5%

Table 5-11 EMOF by unit type: 2007 through 2015

	2007 (Jan-Jun)	2008 (Jan-Jun)	2009 (Jan-Jun)	2010 (Jan-Jun)	2011 (Jan-Jun)	2012 (Jan-Jun)	2013 (Jan-Jun)	2014 (Jan-Jun)	2015 (Jan-Jun)
Combined Cycle	1.9%	1.7%	3.3%	4.0%	2.9%	2.2%	3.2%	2.3%	2.1%
Combustion Turbine	2.6%	2.5%	2.4%	1.8%	1.8%	1.8%	1.7%	1.9%	2.4%
Diesel	2.3%	1.4%	1.5%	1.0%	2.7%	1.9%	1.6%	2.9%	2.8%
Hydroelectric	2.1%	2.4%	3.0%	2.2%	1.6%	1.6%	2.1%	3.6%	1.6%
Nuclear	0.3%	0.5%	0.7%	0.6%	2.0%	0.8%	0.6%	0.7%	1.1%
Steam	2.4%	2.6%	3.5%	3.4%	3.9%	6.2%	4.3%	5.5%	4.2%
Total	1.9%	2.1%	2.8%	2.6%	3.0%	3.8%	2.9%	3.5%	2.9%

Table 5-12 EPOF by unit type: 2007 through 2015

	2007 (Jan-Jun)	2008 (Jan-Jun)	2009 (Jan-Jun)	2010 (Jan-Jun)	2011 (Jan-Jun)	2012 (Jan-Jun)	2013 (Jan-Jun)	2014 (Jan-Jun)	2015 (Jan-Jun)
Combined Cycle	7.5%	7.3%	7.3%	9.3%	11.2%	9.7%	11.4%	12.7%	11.3%
Combustion Turbine	3.1%	5.1%	3.6%	3.0%	3.8%	3.0%	3.7%	4.1%	5.0%
Diesel	0.8%	1.8%	0.4%	0.7%	0.0%	0.1%	0.4%	0.8%	0.6%
Hydroelectric	5.9%	6.8%	9.8%	11.0%	13.2%	5.7%	7.5%	11.2%	10.4%
Nuclear	4.7%	7.1%	5.7%	6.0%	7.7%	8.3%	7.2%	8.1%	6.8%
Steam	11.9%	9.8%	9.9%	10.8%	11.7%	10.2%	12.9%	11.1%	12.5%
Total	8.3%	8.1%	7.8%	8.5%	9.7%	8.5%	9.9%	9.6%	9.9%

Table 5-13 EFOF by unit type: 2007 through 2015

	2007 (Jan-Jun)	2008 (Jan-Jun)	2009 (Jan-Jun)	2010 (Jan-Jun)	2011 (Jan-Jun)	2012 (Jan-Jun)	2013 (Jan-Jun)	2014 (Jan-Jun)	2015 (Jan-Jun)
Combined Cycle	1.7%	1.6%	2.9%	2.7%	2.4%	2.2%	3.0%	2.9%	2.2%
Combustion Turbine	5.3%	3.0%	1.6%	1.9%	1.3%	2.1%	5.0%	8.8%	3.2%
Diesel	9.1%	9.2%	6.8%	4.1%	2.4%	3.9%	4.3%	14.6%	9.6%
Hydroelectric	1.5%	1.5%	2.2%	0.7%	1.4%	3.9%	0.5%	1.9%	1.4%
Nuclear	1.1%	1.0%	4.0%	1.2%	1.8%	1.0%	1.4%	1.9%	1.1%
Steam	6.5%	8.2%	7.4%	7.5%	8.4%	7.2%	8.0%	9.4%	7.7%
Total	4.5%	5.0%	5.1%	4.6%	5.1%	4.5%	5.4%	6.8%	4.7%

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.[44] The EFORd metric includes all forced outages, regardless of the reason for those outages.

The average PJM EFORd for the first six months of 2015 was 7.7 percent, a decrease from the 11.3 percent average PJM EFORd for the same period 2014. Figure 5-4 shows the average EFORd since 2007 for all units in PJM.

44 Equivalent forced outage hours are the sum of all forced outage hours in which a generating unit is fully inoperable and all partial forced outage hours in which a generating unit is partially inoperable prorated to represent full hours.

Figure 5-4 Trends in the PJM equivalent demand forced outage rate (EFORd): 2007 through 2015

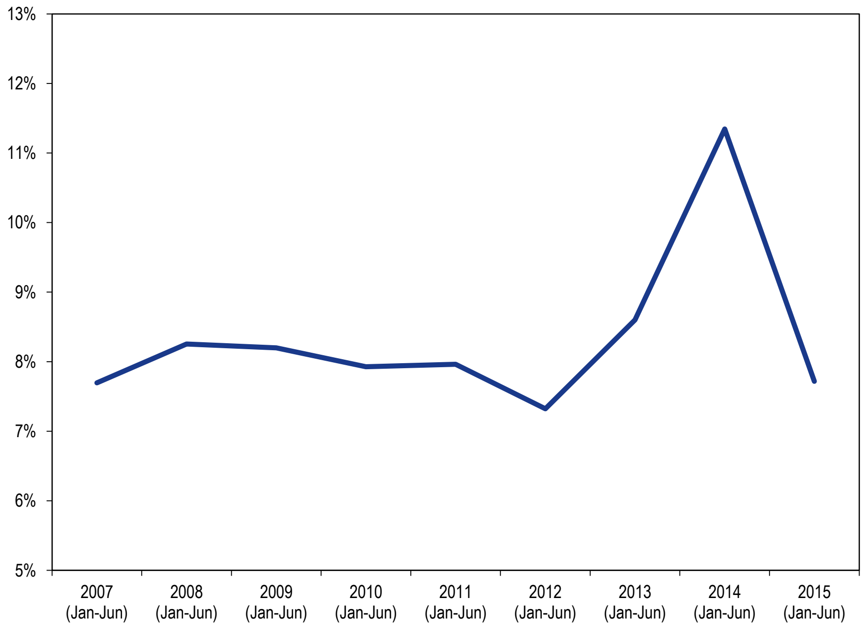


Table 5-14 shows the class average EFORd by unit type. Combustion turbine units had the highest class average rate of EFORd.

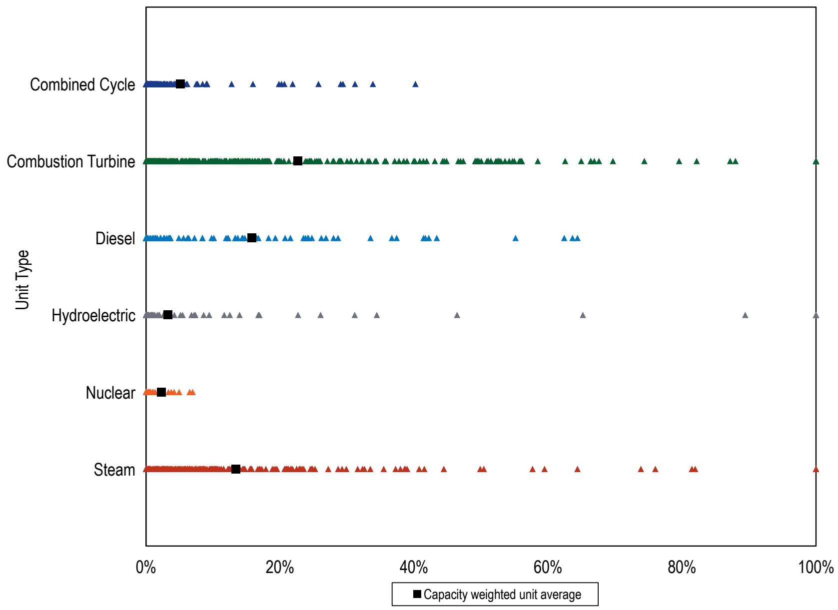
Table 5-14 PJM EFORd data for different unit types: 2007 through 2015

	2007 (Jan-Jun)	2008 (Jan-Jun)	2009 (Jan-Jun)	2010 (Jan-Jun)	2011 (Jan-Jun)	2012 (Jan-Jun)	2013 (Jan-Jun)	2014 (Jan-Jun)	2015 (Jan-Jun)
Combined Cycle	3.9%	3.4%	5.0%	4.3%	3.5%	2.8%	3.8%	5.1%	3.0%
Combustion Turbine	16.7%	14.2%	10.3%	13.8%	8.4%	8.8%	14.1%	22.7%	12.8%
Diesel	10.6%	10.0%	8.5%	5.8%	6.4%	5.1%	4.4%	15.8%	10.9%
Hydroelectric	2.1%	2.2%	2.5%	1.1%	2.0%	5.5%	0.8%	3.3%	1.6%
Nuclear	1.2%	1.1%	4.0%	1.5%	2.1%	1.2%	1.6%	2.3%	1.2%
Steam	8.7%	10.7%	10.2%	9.8%	11.5%	10.4%	11.4%	13.4%	10.6%
Total	7.7%	8.3%	8.2%	7.9%	8.0%	7.3%	8.6%	11.3%	7.7%

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 5-5. 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 2015.

Figure 5-5 PJM distribution of EFORd data by unit type



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).[45] 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.[46] 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.[47] That choice was made by PJM and can be modified without violating any NERC requirements.[48] 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 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 5-15 shows OMC forced outages by cause code, as classified by PJM. OMC forced outages accounted for 4.4 percent of all forced outages in the first six months of 2015. The largest contributor to OMC outages, other switchyard equipment outages, was the cause of 32.2 percent of OMC outages and 1.4 percent of all forced outages. The level of OMC outages, 4.4 percent of all forced outages, is down significantly from 2013, when OMC outages were 16.8 percent of all forced outages.

45 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>.

46 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>.

47 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.

48 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.

Table 5-15 OMC Outages

OMC Cause Code	Percent of OMC Forced Outages	Percent of all Forced Outages
Other switchyard equipment	32.2%	1.4%
Switchyard circuit breakers	24.6%	1.1%
Transmission line	17.5%	0.8%
Transmission equipment beyond the 1st substation	5.1%	0.2%
Switchyard transformers and associated cooling systems	4.6%	0.2%
Transmission system problems other than catastrophes	3.7%	0.2%
Other fuel quality problems	2.0%	0.1%
Flood	1.9%	0.1%
Lack of fuel	1.7%	0.1%
Transmission equipment at the 1st substation	1.6%	0.1%
Other miscellaneous external problems	1.2%	0.1%
Lightning	1.2%	0.1%
Lack of water	1.0%	0.0%
Storms	0.9%	0.0%
Switchyard system protection devices	0.5%	0.0%
Tornado	0.3%	0.0%
Wet coal	0.1%	0.0%
Other catastrophe	0.1%	0.0%
Miscellaneous regulatory	0.0%	0.0%
Total	100.0%	4.4%

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.[49]

The level of OMC lack of fuel outages, 1.7 percent of OMC outages and 0.1 percent of all forced outages, is lower than recent years. In 2011 and 2012, OMC lack of fuel outages were 5.5 percent of all forced outages in 2011 and 4.6 percent of all forced outages in 2012.

Lack of fuel is an example of why, even if the OMC concept were accepted, many types of OMC outages are not actually 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.

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. OMC outages should not be reflected in forced outage metrics which affect market payments to generating units.

Performance Incentives

There are a number of performance incentives in the current capacity market design, but they fall short of the incentives that a unit would face if it earned all its revenue in an energy market.[50] These incentives will change when the Capacity Performance market design is implemented but remain essential

49 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).

50 This section focuses on capacity resources that are not in FRR plans. The FRR incentives differ from the incentives discussed here.

reasons why the incentive components of Capacity Performance design were necessary. 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 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.[51]

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,[52] 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.[53]

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.[54]

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.[55] 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.[56]

51 PJM. OATT Attachment DD § 10 (j).

52 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), p. 159
53 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), Section 8.4.5.
54 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012), Section 8.4.5.1.
55 PJM. OATT Attachment DD § 7.10 (e).
56 PJM. OATT Attachment DD § 7.10 (e).

There is a separate exception for wind and solar capacity resources which are exempt from this performance incentive.[57]

The peak hour availability charge does not apply if the unit unavailability resulted in another performance related charge or penalty.[58]

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.

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.[59]

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.

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.[60] On a systemwide basis, the resultant lost equivalent availability from the forced outages is equal to the equivalent forced outage factor.[61]

PJM EFOF was 4.7 percent in the first six months of 2015. This means there was 4.7 percent lost availability because of forced outages. Table 5-16 shows that forced outages for boiler tube leaks, at 24.5 percent of the systemwide EFOF, were the largest single contributor to EFOF.

57 PJM. OATT Attachment DD § 7.10 (e).
58 PJM. OATT Attachment DD § 7.10 (e).
59 PJM. "Manual 18: PJM Capacity Market," Revision 15 (June 28, 2012) p. 98.
60 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.
61 EFOF incorporates all outages regardless of their designation as OMC.

Table 5-16 Contribution to EFOF by unit type by cause: 2015

	Combined Cycle	Combustion Turbine	Diesel	Hydroelectric	Nuclear	Steam	System
Boiler Tube Leaks	6.6%	0.0%	0.0%	0.0%	0.0%	31.7%	24.5%
Boiler Air and Gas Systems	0.0%	0.0%	0.0%	0.0%	0.0%	8.4%	6.4%
Economic	8.1%	26.9%	10.0%	2.9%	0.0%	3.6%	6.3%
Electrical	6.1%	18.2%	7.8%	0.6%	20.7%	2.6%	5.3%
Feedwater System	0.3%	0.0%	0.0%	0.0%	19.4%	5.3%	4.9%
Boiler Fuel Supply from Bunkers to Boiler	0.3%	0.0%	0.0%	0.0%	0.0%	5.9%	4.5%
Fuel Quality	0.6%	0.2%	5.9%	0.0%	0.0%	5.5%	4.3%
Condensing System	0.7%	0.0%	0.0%	0.0%	2.1%	2.8%	2.3%
Miscellaneous (Boiler)	0.1%	0.0%	0.0%	0.0%	0.0%	2.7%	2.1%
Generator	13.6%	0.1%	5.8%	1.9%	0.0%	1.5%	2.1%
Boiler Piping System	6.2%	0.0%	0.0%	0.0%	0.0%	2.1%	2.0%
Valves	1.8%	0.0%	0.0%	0.0%	0.0%	2.3%	1.9%
Controls	1.3%	0.4%	0.0%	0.6%	5.8%	1.9%	1.8%
Inlet Air System and Compressors	15.0%	7.1%	0.0%	0.0%	0.0%	0.0%	1.7%
Boiler Tube Fireside Slagging or Fouling	0.0%	0.0%	0.0%	0.0%	0.0%	2.2%	1.7%
Reserve Shutdown	0.2%	4.9%	4.1%	20.8%	0.0%	1.0%	1.7%
Auxiliary Systems	5.2%	6.3%	0.0%	0.5%	0.0%	0.8%	1.6%
Wet Scrubbers	0.0%	0.0%	0.0%	0.0%	0.0%	2.1%	1.6%
Slag and Ash Removal	0.0%	0.0%	0.0%	0.0%	0.0%	1.8%	1.4%
All Other Causes	33.9%	36.0%	66.4%	72.7%	51.9%	15.7%	21.8%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Table 5-17 shows the categories which are included in the economic category.[62] Lack of fuel that is considered outside management control accounted for 1.2 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.”[63] 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.

62 The definitions of these outages are defined by NERC GADS.
63 The definitions of these outages are defined by NERC GADS.

Table 5-17 Contributions to Economic Outages: 2015

	Contribution to Economic Reasons
Lack of fuel (Non-OMC)	95.6%
Fuel conservation	1.3%
Lack of fuel (OMC)	1.2%
Lack of water (Hydro)	0.7%
Other economic problems	0.6%
Problems with primary fuel for units with secondary fuel operation	0.6%
Wet fuel (Biomass)	0.0%
Total	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.[64] 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 5-18 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.

Table 5-18 PJM EFORd, XEFORd and EFORp data by unit type[65]

	EFORd	XEFORd	EFORp	Difference EFORd and XEFORd	Difference EFORd and EFORp
Combined Cycle	3.0%	3.0%	1.5%	0.0%	1.5%
Combustion Turbine	12.8%	11.7%	8.2%	1.1%	4.6%
Diesel	10.9%	10.0%	5.0%	0.9%	5.9%
Hydroelectric	1.6%	1.4%	1.8%	0.1%	(0.2%)
Nuclear	1.2%	1.1%	0.7%	0.1%	0.4%
Steam	10.6%	10.5%	7.1%	0.1%	3.5%
Total	7.7%	7.5%	5.0%	0.3%	2.7%

64 See PJM. "Manual 22: Generator Resource Performance Indices," Revision 16 (November 16, 2011), Definitions.

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

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. *EPSA v. FERC* is now subject to a stay pending the Supreme Court's review of the decision in its October 2015 term. The Supreme Court granted certiorari on May 4, 2015.

  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.[2]

  On March 31, 2015, the FERC rejected as premature certain tariff revisions filed by PJM on January 14, 2015, which had been intended to adapt the PJM demand response rules depending on the outcomes and timing of the outcomes on potential review of EPSA v. FERC and PJM's pending capacity performance proposal.[3]

- **Demand Response Activity.** Demand response includes the economic program and the emergency program. Emergency program revenue includes both capacity and energy revenue. The capacity market is still the primary source of revenue to participants in PJM demand response programs, including both capacity market revenue and the associated emergency energy revenue. In the first six months of 2015, capacity market revenue increased by $70.0 million, or 24.4 percent, from $287.4 million in the first six months of 2014 to $357.4 million in the first six months of 2015.[4] Emergency energy revenue decreased by $42.5 million, from $43.0 million in the first six months of 2014 to $0.5 million in the first six months of 2015. Economic program revenue is energy revenue only. Economic program credits decreased by $9.3 million, from $14.3 million in the first six mo nths of 2014 to $5.0 million in the first six months of 2015, a 65.2 percent decrease.[5] Total revenue in the first six months of 2015 increased by 4.9 percent from $348.8 million in the first six months of 2014 to $365.9 million in the first six months of 2015. Not all DR activities in the first six months of 2015 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 paid by 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.[6]

- **Demand Response Market Concentration.** Economic demand response was highly concentrated in the first six months of 2014 and 2015. The HHI for economic demand response reductions increased from 7522 in the first six months of 2014 to 7852 in the first six months of 2015. Emergency demand response was moderately concentrated in the first six months of 2015. The HHI for emergency demand response registrations was 1760. In 2015, the four largest companies contributed 65.3 percent of all registered emergency demand response resources.

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.
3 150 FERC ¶ 61,251.
4 The total credits and MWh numbers for demand resources were calculated as of July 27, 2015 and may change as a result of continued PJM billing updates.
5 Economic credits are synonymous with revenue received for reductions under the economic load response program.
6 PJM: "Manual 28: Operating Agreement Accounting," Revision 64 (April 11, 2014), p 70.

- **Locational Dispatch of Demand Resources.** Beginning with the 2014/2015 Delivery Year, demand resources are dispatchable for mandatory reduction on a subzonal basis, defined by zip codes, only if the subzone is defined at least one day before dispatched. More locational dispatch of demand resources in a nodal market improves market efficiency. The goal should be nodal dispatch of demand resources with no advance notice required.

Recommendations

The MMU recognizes the substantial uncertainty related to the treatment of demand response in wholesale power markets which depends on Supreme Court review and on FERC treatment of PJM's Capacity Performance filing. The MMU recognizes that PJM has incorporated some of these recommendations in the Capacity Performance filing. The status of each recommendation reflects the status at June 30, 2015.

- The MMU recommends that the tariff rules for demand response clarify that a resource and its CSP, if any, must notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate registrations that are no longer capable of responding to PJM dispatch directives, such as in the case of bankrupt and out of service facilities. (Priority: Medium. New recommendation. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, 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. Status: Not Adopted.[7] Pending before FERC.)
- The MMU recommends that, if demand response remains in the PJM market, 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 and not triggering the definition of an emergency. (Priority: High. First reported 2012. Status: Partially adopted.)
- The MMU recommends that, if demand response remains in the PJM market, a daily energy market must offer requirement apply to demand resources, comparable to the rule applicable to generation capacity resources.[8] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that, if demand response remains in the PJM market, 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.[9] (Priority: High. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that, if demand response remains in the PJM market, the lead times for demand resources be shortened to 30 minutes with an hour minimum dispatch for all resources. (Priority: Medium. First reported 2013. Status: Adopted in full, Q1, 2014.)
- The MMU recommends that, if demand response remains in the PJM market, demand resources be required to provide their nodal location on the electricity grid. (Priority: High. First reported 2011. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, measurement and verification methods for demand resources be further modified to more accurately reflect compliance. (Priority: Medium. First reported 2009. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, 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. Status: Not adopted.)
- The MMU recommends that, if demand response remains in the PJM market, 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

7 PJM's Capacity Performance proposal includes this change. See "Reforms to the Reliability Pricing Market ("RPM") and Related Rules in the PJM Open Access Transmission Tariff ("Tariff") and Reliability Assurance Agreement Among Load Serving Entities ("RAA")," Docket No. ER15-632-000 and "PJM Interconnection, L.L.C." Docket No. EL15-29-000.

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

9 *Id* at 1.

based on interval meter data at the site of the demand reductions.[10] (Priority: Medium. First reported 2013. Status: Not adopted.)

- The MMU recommends that, if demand response remains in the PJM market, demand response event compliance be calculated for each hour and the penalty structure reflect hourly compliance. (Priority: Medium. First reported 2013. Status: Not adopted. Pending before FERC.)
- The MMU recommends that, if demand response remains in the PJM market, demand resources whose load drop method is designated as "Other" explicitly record the method of load drop. (Priority: Low. First reported 2013. Status: Adopted in full, Q2, 2014.)
- The MMU recommends that, if demand response remains in the PJM market, load management testing be initiated by PJM with limited warning to CSPs in order to more accurately represent the conditions of an emergency event. (Priority: Low. First reported 2012. Status: Not adopted.)
- The MMU recommends, as a preferred alternative to having PJM demand side programs, that demand response be on the demand side of the markets and that customers be able to avoid capacity and energy charges by not using capacity and energy at their discretion and that customer payments be determined only by metered load. (Priority: High. First reported 2014. Status: Not adopted. Pending before FERC.)

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 Energy Market and

10 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 February 17, 2015) 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.

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.

In order to be a substitute for generation, any demand resource and its CSP, if any, should be required to notify PJM of material changes affecting the capability of the resource to perform as registered and to terminate registrations that are no longer capable of responding to PJM dispatch directives, such as in the case of bankrupt and out of service facilities. Generation resources are required to inform PJM of any change in availability status, including outages and shutdown status.

As a preferred alternative, demand response would be on the demand side of the Capacity Market rather than on the supply side. Rather than complex demand response programs with their attendant complex and difficult to administer rules, customers would be able to avoid capacity and energy charges by not using capacity and energy at their discretion.

The long term appropriate end state for demand resources in the PJM markets should be comparable to the demand side of any market. Customers should use energy as they wish and that usage will determine the amount of capacity and energy for which each customer pays. There would be no counterfactual measurement and verification.

Under this approach, customers that wish to avoid capacity payments would reduce their load during expected high load hours. Capacity costs would be assigned to LSEs and by LSEs to customers, based on actual load on the system during these critical hours. Customers wishing to avoid high energy prices would reduce their load during high price hours. Customers would pay for what they actually use, as measured by meters, rather than relying on flawed measurement and verification methods. No M&V estimates are required. No promises of future reductions which can only be verified by M&V are required. To the extent that customers enter into contracts with CSPs or LSEs to manage their payments, M&V can be negotiated as part of a bilateral commercial contract between a customer and its CSP or LSE.

This approach provides more flexibility to customers to limit usage at their discretion. There is no requirement to be available year round or every hour of every day. There is no 30 minute notice requirement. There is no requirement to offer energy into the day-ahead market. All decisions about interrupting are up to the customers only and they may enter into bilateral commercial arrangements with CSPs at their sole discretion. Customers would pay for capacity and energy depending solely on metered load.

A transition to this end state should be defined in order to ensure that appropriate levels of demand side response are incorporated in PJM's load forecasts and thus in the demand curve in the capacity market for the next three years. That transition should be defined by the PRD rules, modified as suggested by the Market Monitor.

This approach would work under the current RPM design and this approach would work under the CP design. This approach is entirely consistent with any Supreme Court decision on *EPSA* as it does not require FERC to have jurisdiction over the demand side. This approach will allow the Commission to more fully realize its overriding policy objective to create competitive and efficient wholesale energy markets.

PJM Demand Response Programs

All demand response programs in PJM can be grouped into economic and emergency programs.[11] 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 both the economic and emergency programs, CSPs are companies that seek to sign up end-use customers, participants, that have the ability to reduce load. After a demand response event occurs, PJM compensates CSPs for their participants' load reductions and CSPs in turn compensates their participants. Only CSPs are eligible to participate in the PJM Demand Response program, but a participant can register as a PJM special member and become a CSP without any additional cost of entry.

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.

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.[12] The court found Order No. 745 arbitrary and capricious on its merits.[13] 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."[14] 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. *EPSA v. FERC* is now subject to a stay pending the Supreme Court's review of the decision in the October 2015 term. The Supreme Court granted certiorari on May 4, 2015.

FirstEnergy filed an amended complaint on September 22, 2014, that seeks to 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.[15] 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.[16] The report concludes that "should a legal or policy decision be made to eliminate Demand

11 Throughout this document, emergency demand response refers to both emergency and pre emergency demand response.
12 Electric Power Supply Association v. FERC, No. 11-1486.
13 *Id.*, slip. op. at 14.
14 *Id.*
15 See FirstEnergy Service Company complaint, FERC Docket No. EL14-55-000, amending the complaint filed May 23, 2014.
16 See Monitoring Analytics, LLC, 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>.

Resources from its current participation as supply in the PJM capacity market, PJM markets could adapt."[17] The proceeding is pending before the Commission.

On March 31, 2015, the FERC rejected as premature certain tariff revisions filed by PJM on January 14, 2015, which had been intended to adapt the PJM demand response rules depending on the outcomes and timing of the outcomes on potential review of *EPSA v. FERC* and PJM's pending capacity performance proposal.[18,19]

EPSA presents an opportunity to reform the rules for demand response to make them consistent with the functioning of an efficient and competitive market. The current rules for demand response have evolved to create a negative impact on market efficiency and pose obstacles to the growth of an effective demand component to the market. This negative impact is not the result of demand side resources which are an invaluable part of the markets but is a result of current PJM rules. These flaws have been well documented, and some are the subject of pending litigation at the Commission.[20] Now is an appropriate time for decisive steps away from the flawed approach of treating demand as a form of supply and toward treating demand response as changes in demand.

17 *Id.* at 10.

18 150 FERC ¶ 61,251.

19 See Comments of the Independent Market Monitor for PJM, ER15-852-000 (February 13, 2015).

20 The Market Monitor has documented in numerous reports the price suppressing effects and market design flaws attributable to the current treatment of Demand Resources in the PJM Capacity Market, including:

- The failure to require performance from Demand Resources that is comparable to the performance provided by Generation Capacity Resources and that would therefore make Demand Resources substitutes for Generation Resources while providing substantially the same compensation to both. *See, e.g.,* Monitoring Analytics, LLC, 2013 State of the Market Report for PJM (March 13, 2013) ("2013 SOM") at 197, 203; *see also*, Monitoring Analytics, LLC, Analysis of the 2016/2017 RPM Base Residual Auction (April 18, 2014) at 3, 35–27 ("2016/2017 BRA Report"), which can be accessed at: <http://www.monitoringanalytics.com/reports/Reports/2014/IMM_Analysis_of_the_20162017_RPM_Base_Residual_Auction_20140418.pdf>.
- The failure to remove inferior Demand Resource products from the capacity markets which cannot, by definition of the products, be substitutes for Generation Resources and the failure to require demand resource products to respond year round during any hour.
- The failure to eliminate the 2.5 shift in the demand curve used in RPM Base Residual Actions. *See, e.g.,* 2013 SOM at 157, 160; 2016/2017 BRA Report at 4–5.
- The failure to require Demand Resources to make physical offers. *See, e.g.,* 2013 SOM at 160, 171–172; Monitoring Analytics, LLC, Analysis of Replacement Capacity for RPM Commitments: June 1, 2007 to June 1, 2013 (September 13, 2013), which can be accessed at: <http://www.monitoringanalytics.com/reports/Reports/2013/IMM_Report_on_Capacity_Replacement_Activity_2_20130913.pdf>; Comments of the Independent Market Monitor for PJM, Docket No. ER14-1461 (April 1, 2014).
- The failure to require Demand Resources to make daily offers into the Day-Ahead Energy Market as required of Generation Capacity Resources. *See, e.g.,* 2013 SOM at 197, 203; Complaint and Motion to Consolidate of the Independent Market Monitor for PJM, Docket No. EL14-20 (January 27, 2014).
- The failure to apply a uniform system offer cap to Demand Resources and Generation Capacity Resources. *Id.*
- The failure to develop measurement and verification rules sufficient to ensure that Demand Resources do not consume capacity when it is needed by those who pay for it. *See, e.g.,* 2013 SOM at 197–198, 210; Comments of the Independent Market Monitor for PJM, Docket No. ER14-822 (January 1, 2014).

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) price threshold is exceeded. This approach replaced the payment of LMP minus the charges for wholesale power and transmission already included in customers' tariff rates.

Figure 6-1 shows all revenue from PJM demand response programs by market for the first six months of each year for the period 2008 through 2015. 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.[21]

In the first six months of 2015, emergency revenue, which includes capacity and emergency energy revenue, accounted for 97.9 percent of all revenue received by demand response providers, credits from the economic program were 1.3 percent and revenue from synchronized reserve was 0.8 percent.

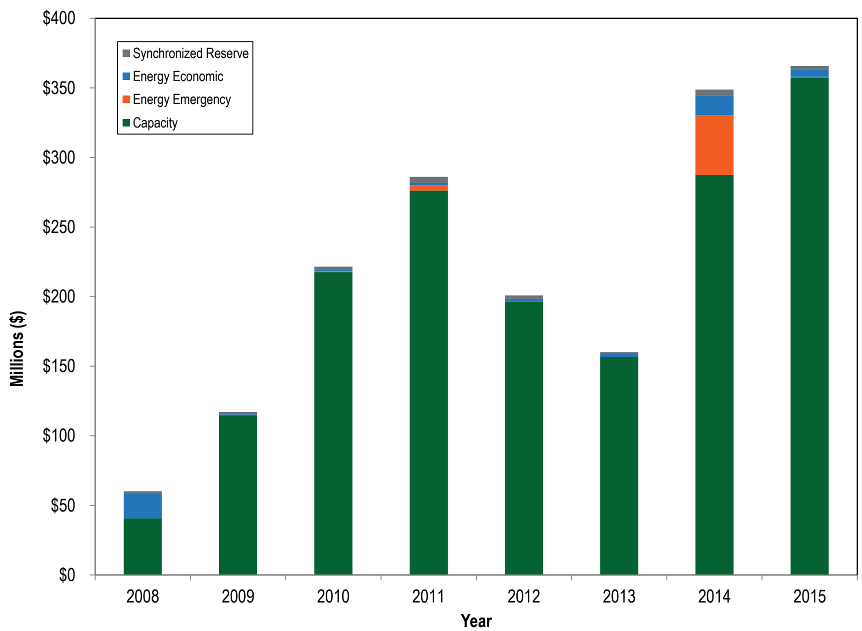
Total emergency revenue increased by $27.5 million, or 8.3 percent, from $330.4 million in the first six months of 2014 to $358.0 in 2015. Of the total emergency revenue, capacity market revenue increased by $70.0 million, or 24.4 percent, from $287.4 million in the first six months of 2014 to $357.4 million in the first six months of 2015, due to higher clearing prices and volumes in the capacity market for the 2013/2014 and 2014/2015 delivery years. The weighted average RPM price increased 23.1 percent from $99.39 per MW-day to $122.32 per MW-day.[22] Emergency energy revenue decreased by $42.5 million, from $43.0 million in the first six months of 2014 to $0.5 million in the first six months of 2015. Total revenue in the first six months of 2015 increased by 4.9 percent from $348.8 million in the first six months of 2014 to $365.9 million in the first six months of 2015.

21 This includes both capacity market revenue and emergency energy revenue for capacity resources.

22 *2014 State of the Market Report for PJM, Volume II*, Section 5: Capacity, Table 5-13.

Total credits under the economic program decreased by $9.3 million from $14.3 million in the first six months of 2014 to $5.0 million in the first six months of 2015, a 65.2 percent decrease.

Figure 6-1 Demand response revenue by market: January through June 2008 through 2015



Economic Program

Table 6-2 shows registered sites and MW for the last day of each month for the period January 2010 through June 2015. Registration is a prerequisite for CSPs to participate in the economic program. The average number of registrations for economic demand response decreased and the average registered MW increased in the first six months of 2015 compared to the same time period in 2014. The average number of monthly registrations decreased by 42 from 1,068 in the first six months of 2014 to 1,026 in the first six months of 2015. The average monthly registered MW for the first six months of 2015 increased by 272 MW, or 10.5 percent, from 2,605 MW in the six months of 2014 to 2,877 MW in the first six months of 2015.

Several demand response resources are registered for both the economic and emergency demand response programs. There were 235 registrations and 1,409 nominated MW in the emergency program that were also registered in the economic program during the first six months of 2015.

Table 6-2 Economic program registrations on the last day of the month: January 2010 through June 2015

	2010		2011		2012		2013		2014		2015	
Month	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW	Registrations	Registered MW
Jan	1,841	2,623	1,609	2,432	1,993	2,385	841	2,314	1,180	2,325	1,078	2,960
Feb	1,842	2,624	1,612	2,435	1,995	2,384	843	2,327	1,174	2,330	1,076	2,956
Mar	1,845	2,623	1,612	2,519	1,996	2,356	788	2,284	1,185	2,692	1,075	2,949
Apr	1,849	2,587	1,611	2,534	189	1,318	970	2,346	1,194	2,827	1,076	2,938
May	1,875	2,819	1,687	3,166	371	1,669	1,375	2,414	745	2,511	980	2,846
Jun	813	1,608	1,143	1,912	803	2,347	1,302	2,144	928	2,943	871	2,614
Jul	1,192	2,159	1,228	2,062	942	2,323	1,315	2,443	1,036	3,006		
Aug	1,616	2,398	1,987	2,194	1,013	2,373	1,299	2,527	1,080	3,033		
Sep	1,609	2,447	1,962	2,183	1,052	2,421	1,280	2,475	1,077	2,919		
Oct	1,606	2,444	1,954	2,179	828	2,269	1,210	2,335	1,060	2,943		
Nov	1,605	2,444	1,988	2,255	824	2,267	1,192	2,307	1,063	2,995		
Dec	1,598	2,439	1,992	2,259	846	2,283	1,192	2,311	1,071	2,923		
Avg. (Jan-Jun)	1,678	2,481	1,546	2,500	1,225	2,077	1,020	2,305	1,068	2,605	1,026	2,877

Table 6-3 Sum of peak MW reductions for all registrations per month: January through June, 2010 through 2015

	Sum of Peak MW Reductions for all Registrations per Month					
Month	2010	2011	2012	2013	2014	2015
Jan	183	132	110	193	450	169
Feb	121	89	101	119	307	336
Mar	115	81	72	127	369	198
Apr	111	80	108	133	146	143
May	172	98	143	192	151	154
Jun	209	561	954	433	483	605
Annual (Jan - Jun)	297	701	1,078	562	869	1,107

The registered MW in the economic load response program are not a good measure of the MW available for dispatch in the energy market. Economic resources can dispatch more, less or the same amount of MW registered in the program. Table 6-3 shows the sum of maximum economic MW dispatched by registration each month for January 2010 through June 2015. The monthly maximum is the sum of each registration's monthly noncoincident peak dispatched MW and the six month annual maximum is the sum of each registration's noncoincident peak dispatched MW during the first six months of the respective year. This aggregated maximum dispatched MW for all economic demand response registered resources in the first six months of 2015 increased by 238 MW, from 869 MW in the first six months of 2014 to 1,107 MW in the first six months of 2015.[23]

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.[24] The zonal allocation is shown in Table 6-13.

Table 6-4 shows the total MW reductions made by participants in the economic program and the total credits paid for these reductions in the first six months of 2010 through 2015. The average credits per MWh paid in the first six months of 2015 decreased by $75.71 per MWh, or 45.3 percent, from $167.17 per MWh in 2014 to $91.45 per MWh dispatched in 2015. The average real-time load weighted PJM LMP decreased by $27.62 per MWh, from $69.92 per MWh during the first six months of 2014 to $42.30 per MWh during the first six months of 2015. Curtailed energy for the economic program was 54,342 MWh in the first six months of 2015 and the total payments were $4,969,863. Total credits paid for economic DR in the first six months of 2015 decreased by $9.3 million or 65.2 percent, compared to the first six months of 2014.

23 As a result of the 60 day data lag from event date to settlement, not all settlements for June 2015 are incorporated in this report.
24 PJM, "Manual 28: Operating Agreement Accounting," Revision 71 (June 1, 2015) p. 78.

Table 6-4 Credits paid to the PJM economic program participants: January through June 2010 through 2015

Year (Jan-Jun)	Total MWh	Total Credits	$/MWh
2010	20,225	$761,854	$37.67
2011	9,055	$1,456,324	$160.84
2012	38,714	$2,165,599	$55.94
2013	48,711	$2,559,832	$52.55
2014	85,530	$14,297,951	$167.17
2015	54,342	$4,969,863	$91.45

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 were 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, from January 2010 through June 2015. Higher energy prices and FERC Order No. 745 increased incentives to participate starting in April 2012. The high prices in the first three months of 2014 resulted in higher credits. Lower prices in the first three months of 2015 resulted in lower prices and lower credits.

Figure 6-2 Economic program credits and MWh by month: January 2010 through June 2015

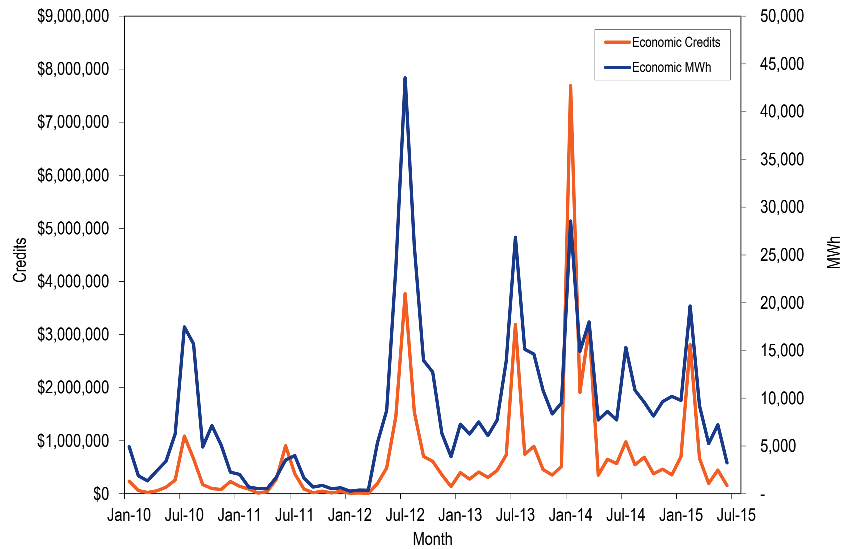


Table 6-5 shows performance for the first six months of 2014 and 2015 in the economic program by control zone and participation type. Total economic program reductions decreased 36.5 percent from 85,530 MW in the first six months of 2014 to 54,342 MW in the first six months of 2015. The economic credits decreased by 65.2 percent from $14,297,951 in the first six months of 2014, to $4,969,863 in the first six months of 2015.

Table 6-5 PJM economic program participation by zone: January through June of 2014 and 2015[25]

	Credits			MWh Reductions			Credits per MWh Reduction		
Zones	2014	2015	Percent Change	2014	2015	Percent Change	2014	2015	Percent Change
AECO, JCPL, PECO, Pepco, RECO	$2,288,088	$333,934	(85.4%)	7,887	1,618	(79.5%)	$290.10	$206.34	(28.9%)
AEP, AP	$287,039	$88,782	(69.1%)	2,867	953	(66.7%)	$100.13	$93.11	(7.0%)
ATSI, ComEd, DAY, DEOK, DLCO, EKPC	$872,696	$250,047	(71.3%)	6,568	5,365	(18.3%)	$132.87	$46.60	(64.9%)
BGE, DPL, Met-Ed, PENELEC	$648,738	$368,684	(43.2%)	4,965	6,416	29.2%	$130.67	$57.47	(56.0%)
Dominion	$7,901,371	$3,262,696	(58.7%)	51,310	31,442	(38.7%)	$153.99	$103.77	(32.6%)
PPL, PSEG	$2,300,020	$665,718	(71.1%)	11,933	8,547	(28.4%)	$192.74	$77.89	(59.6%)
Total	$14,297,951	$4,969,863	(65.2%)	85,530	54,342	(36.5%)	$167.17	$91.45	(45.3%)

Table 6-6 shows total settlements submitted for the first six months of 2009 through 2015. A settlement is counted for every day on which a registration is dispatched in the economic program.

Table 6-6 Settlements submitted by year in the economic program: January through June of 2009 through 2015

Year (Jan - Jun)	2009	2010	2011	2012	2013	2014	2015
Number of Settlements	1,156	1,345	317	1,154	659	1,482	739

Table 6-7 shows the number of curtailment service providers (CSPs), and the number of participants in their portfolios, submitting settlements by year through the first six months of 2009 through 2015. There were 76 fewer active participants in the first six months of 2015 than in the first six months of 2014. All participants must be included in a CSP.

Table 6-7 Participants and CSPs submitting settlements in the economic program by year: January through June of 2009 through 2015

	2009		2010		2011		2012		2013		2014		2015	
	Active CSPs	Active Participants	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	13	175	10	131	9	129	18	331	12	85	17	144	12	68

Parent companies may own one CSP or multiple CSPs. All HHI calculations in this section are at the parent company level.

Economic demand response was highly concentrated in the first six months of both 2014 and 2015. Table 6-8 shows the monthly HHI and the HHI for the first six months of 2015. The table also lists the share of reductions provided by, and the share of credits claimed by the four largest DR companies in each year. In the first six months of 2015, 88.4 percent of all Economic DR reductions and 91.1 percent of Economic DR revenue were attributable to the four largest DR companies. The HHI for demand response reductions increased 330 points, from 7522 in the first six months of 2014 to 7852 in the first six months of 2015.

Table 6-8 HHI and market concentration in the economic program: January through June of 2014 and 2015

	HHI			Top Four Companies Share of Reduction			Top Four Companies Share of Credit		
Month	2014	2015	Percent Change	2014	2015	Change Percent	2014	2015	Change Percent
Jan	7018	8081	15.1%	88.0%	96.8%	8.8%	84.2%	98.6%	14.4%
Feb	6547	7358	12.4%	84.1%	91.4%	7.4%	77.5%	87.8%	10.3%
Mar	7751	7539	(2.7%)	87.7%	89.1%	1.4%	88.5%	84.4%	(4.2%)
Apr	8343	7216	(13.5%)	100.0%	97.8%	(2.2%)	100.0%	97.8%	(2.2%)
May	8090	7791	(3.7%)	98.8%	98.8%	0.1%	99.1%	99.4%	0.3%
Jun	8141	9344	14.8%	91.5%	100.0%	8.5%	87.9%	100.0%	12.1%
Total	7522	7852	4.4%	83.9%	88.4%	4.5%	85.5%	91.1%	5.6%

25 PJM and the MMU cannot publish more detailed information about the Economic Program Zonal Settlements as a result of confidentiality requirements.

Table 6-9 shows average MWh reductions and credits by hour for the first six months of 2014 and 2015. In the first six months of 2014, 84.2 percent of reductions and 82.9 percent of credits occurred from hours ending 0700 to 2100, and in the first six months of 2015, 92.2 percent of reductions and 88.4 percent of credits occurred from 0700 to 2100.

Table 6-9 Hourly frequency distribution of economic program MWh reductions and credits: January through June 2014 and 2015

	MWh Reductions			Program Credits		
Hour Ending (EPT)	2014	2015	Percent Change	2014	2015	Percent Change
1	739	265	(64%)	$126,301	$37,651	(70%)
2	707	253	(64%)	$112,124	$33,089	(70%)
3	863	277	(68%)	$149,107	$40,472	(73%)
4	1,453	345	(76%)	$290,486	$45,609	(84%)
5	1,512	335	(78%)	$201,530	$46,170	(77%)
6	2,184	660	(70%)	$316,145	$98,896	(69%)
7	5,110	3,408	(33%)	$871,910	$435,079	(50%)
8	6,072	4,951	(18%)	$1,073,245	$555,844	(48%)
9	6,287	5,348	(15%)	$827,217	$376,300	(55%)
10	6,107	3,903	(36%)	$947,495	$332,666	(65%)
11	4,329	2,816	(35%)	$818,798	$249,323	(70%)
12	3,244	2,533	(22%)	$714,260	$223,854	(69%)
13	3,513	2,441	(31%)	$578,674	$182,058	(69%)
14	4,123	2,553	(38%)	$608,841	$179,950	(70%)
15	4,595	2,663	(42%)	$586,648	$163,299	(72%)
16	4,877	2,985	(39%)	$581,899	$191,929	(67%)
17	4,962	3,437	(31%)	$602,258	$234,214	(61%)
18	5,477	3,739	(32%)	$858,958	$307,919	(64%)
19	4,712	4,082	(13%)	$891,313	$375,457	(58%)
20	4,522	2,881	(36%)	$1,004,213	$305,493	(70%)
21	4,057	2,390	(41%)	$890,614	$278,512	(69%)
22	2,857	1,089	(62%)	$586,929	$139,627	(76%)
23	1,760	517	(71%)	$373,504	$71,336	(81%)
24	1,471	473	(68%)	$285,482	$65,117	(77%)
Total	85,530	54,342	(36%)	$14,297,951	$4,969,863	(65%)

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 six months of 2014 and 2015. Reductions occurred at all price levels. In the first six months of 2015, 1.3 percent of MWh reductions and 5.6 percent of program credits occurred during the hours when the applicable zonal LMP was higher than $400 per MWh.

Table 6-10 Frequency distribution of economic program zonal, load-weighted, average LMP (By hours): January through June 2014 and 2015

	MWh Reductions			Program Credits		
LMP	2014	2015	Percent Change	2014	2015	Percent Change
$0 to $25	154	1,079	600%	$1,329	$17,379	1,208%
$25 to $50	19,531	23,009	18%	$941,744	$900,284	(4%)
$50 to $75	14,921	8,712	(42%)	$1,014,853	$566,437	(44%)
$75 to $100	9,116	6,231	(32%)	$937,453	$566,354	(40%)
$100 to $125	4,373	3,963	(9%)	$582,507	$447,184	(23%)
$125 to $150	4,061	2,334	(43%)	$630,531	$318,157	(50%)
$150 to $175	3,820	1,625	(57%)	$694,708	$256,922	(63%)
$175 to $200	3,515	1,703	(52%)	$748,308	$323,408	(57%)
$200 to $225	3,064	1,465	(52%)	$672,056	$299,097	(55%)
$225 to $250	3,039	921	(70%)	$697,859	$214,464	(69%)
$250 to $275	2,537	613	(76%)	$636,510	$151,050	(76%)
$275 to $300	1,944	611	(69%)	$545,908	$171,521	(69%)
$300 to $325	1,538	363	(76%)	$447,031	$106,033	(76%)
$325 to $350	1,229	233	(81%)	$359,764	$70,018	(81%)
$350 to $375	1,404	609	(57%)	$435,346	$213,604	(51%)
$375 to $400	1,080	194	(82%)	$333,491	$71,818	(78%)
> $400	10,197	677	(93%)	$4,618,554	$276,133	(94%)
Total	85,524	54,341	(36%)	$14,297,951	$4,969,863	(65%)

Following Order No. 745, each month the NBT threshold price is calculated above which the net benefits of DR are deemed to exceed the cost to load. Demand resource (DR) reductions have 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 payments cause an additional uplift charge. The NBT threshold price 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 price, 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 NBT threshold price. About 0.75 percent of DR dispatch occurred during hours with LMP lower than the NBT threshold price.

Table 6-11 shows the NBT threshold price from April 2012, when FERC Order No. 745 was implemented in PJM, through June of 2015.

Table 6-11 Result from net benefits tests: April 2012 through June 2015

	Net Benefits Test Threshold Price ($/MWh)			
Month	2012	2013	2014	2015
Jan		$25.72	$29.51	$29.63
Feb		$26.27	$30.44	$26.52
Mar		$25.60	$34.93	$24.99
Apr	$25.89	$26.96	$32.59	$24.92
May	$23.46	$27.73	$32.08	$23.79
Jun	$23.86	$28.44	$31.62	$23.80
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	$30.20	
Nov	$25.63	$31.63	$29.17	
Dec	$25.97	$28.82	$29.01	
Average	$24.80	$28.09	$30.91	$25.61

Table 6-12 shows the number of hours that at least one zone in PJM had day-ahead LMP or real-time LMP higher than the NBT threshold price. In the first six months of 2015, the highest zonal LMP in PJM was higher than the NBT threshold price 4,122 hours out of the entire 4,343 hours, or 94.9 percent of all hours. Reductions occurred in 3,660 hours, or 88.8 percent, of the 4,122 hours in the first six months of 2015. The last three columns illustrate how often economic demand response activity occurred when LMPs exceeded NBT threshold prices in the first six months 2014 and 2015.

Table 6-12 Hours with price higher than NBT and DR occurrences in those hours: January through June 2014 and 2015

	Number of Hours	Number of Hours with LMP Higher than NBT			Percent of NBT Hours with DR		
Month	2014/2015	2014	2015	Percent Change	2014	2015	Change Percent
Jan	744	742	669	(9.8%)	93.8%	83.0%	(10.8%)
Feb	672	672	670	(0.3%)	92.9%	93.1%	0.3%
Mar	743	732	719	(1.8%)	81.8%	90.8%	9.0%
Apr	720	661	713	7.9%	86.5%	96.6%	10.1%
May	744	694	692	(0.3%)	85.3%	92.2%	6.9%
Jun	720	557	659	18.3%	87.8%	76.0%	(11.8%)
Total	4,343	4,058	4,122	1.6%	88.0%	88.8%	0.8%

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. Real-time loads in AEP, Dominion, and ComEd paid the highest DR charges in the first six months of 2015.

Table 6-13 Zonal DR charge: January through June 2015

Zone	January	February	March	April	May	June	Total
AECO	$8,144	$32,233	$7,885	$1,675	$6,616	$2,281	$58,833
AEP	$110,175	$460,039	$108,168	$35,842	$72,041	$23,686	$809,951
AP	$46,313	$186,348	$43,950	$14,169	$28,086	$8,842	$327,707
ATSI	$53,788	$218,608	$55,824	$19,925	$38,295	$12,312	$398,751
BGE	$31,720	$124,739	$28,379	$8,934	$19,607	$6,967	$220,346
ComEd	$58,545	$275,905	$69,202	$18,046	$41,958	$17,432	$481,087
DAY	$14,864	$56,946	$14,135	$4,813	$9,766	$3,325	$103,849
DEOK	$20,275	$89,027	$21,328	$6,816	$15,867	$5,592	$158,905
DLCO	$93,812	$388,679	$84,586	$26,191	$58,781	$21,378	$673,427
Dominion	$18,319	$75,492	$16,560	$3,070	$10,424	$3,893	$127,758
DPL	$9,970	$35,023	$11,012	$3,864	$9,042	$2,805	$71,716
EKPC	$11,403	$54,120	$11,522	$2,788	$6,373	$2,386	$88,592
JCPL	$18,592	$72,039	$17,775	$4,136	$13,391	$5,573	$131,507
Met-Ed	$13,736	$53,971	$13,034	$2,642	$8,469	$2,246	$94,097
PECO	$34,695	$137,349	$32,562	$6,487	$22,784	$6,665	$240,543
PENELEC	$15,541	$60,547	$15,391	$4,838	$9,408	$2,849	$108,575
Pepco	$29,008	$114,217	$26,061	$8,609	$19,672	$6,939	$204,505
PPL	$38,227	$153,234	$36,723	$6,891	$21,723	$5,373	$262,171
PSEG	$36,731	$133,282	$33,547	$8,416	$24,227	$9,509	$245,712
RECO	$1,231	$4,301	$1,110	$291	$1,053	$360	$8,347
Export	$33,144	$83,014	$19,015	$5,828	$9,331	$3,151	$153,484
Total	$698,233	$2,809,114	$667,768	$194,270	$446,913	$153,565	$4,969,863

Table 6-14 shows the total zonal DR charge per MWh of real-time load and exports during the first six months of 2015. On a dollar per MWh basis, real-time load and exports in EKPC paid the highest charges for economic demand response in the first six months of 2015. The highest average monthly per MWh charges for economic demand response occurred in February 2015, when real-time load and exports paid an average of $0.05/MWh.

Table 6-14 Zonal DR charge per MWh of Load and Exports: January through June 2015

Zone	January	February	March	April	May	June	Zonal Average
AECO	$0.016	$0.046	$0.013	$0.005	$0.010	$0.006	$0.016
AEP	$0.021	$0.046	$0.013	$0.005	$0.010	$0.004	$0.017
AP	$0.017	$0.045	$0.012	$0.005	$0.010	$0.004	$0.016
ATSI	$0.018	$0.043	$0.012	$0.005	$0.010	$0.004	$0.015
BGE	$0.016	$0.046	$0.012	$0.005	$0.010	$0.004	$0.016
ComEd	$0.024	$0.049	$0.014	$0.006	$0.010	$0.005	$0.018
DAY	$0.020	$0.044	$0.013	$0.005	$0.010	$0.004	$0.016
DEOK	$0.022	$0.049	$0.015	$0.006	$0.010	$0.004	$0.018
DLCO	$0.019	$0.048	$0.013	$0.005	$0.010	$0.004	$0.016
Dominion	$0.017	$0.048	$0.013	$0.005	$0.009	$0.006	$0.016
DPL	$0.019	$0.048	$0.012	$0.005	$0.010	$0.004	$0.017
EKPC	$0.024	$0.053	$0.016	$0.006	$0.010	$0.004	$0.019
JCPL	$0.017	$0.047	$0.013	$0.005	$0.011	$0.007	$0.017
Met-Ed	$0.017	$0.047	$0.013	$0.005	$0.010	$0.005	$0.016
PECO	$0.017	$0.047	$0.013	$0.005	$0.011	$0.005	$0.016
PENELEC	$0.016	$0.042	$0.012	$0.006	$0.010	$0.004	$0.015
Pepco	$0.017	$0.047	$0.012	$0.005	$0.010	$0.004	$0.016
PPL	$0.017	$0.047	$0.013	$0.005	$0.010	$0.005	$0.016
PSEG	$0.015	$0.041	$0.012	$0.005	$0.010	$0.006	$0.015
RECO	$0.016	$0.040	$0.012	$0.005	$0.011	$0.006	$0.015
Export	$0.012	$0.031	$0.009	$0.004	$0.005	$0.002	$0.011
Monthly Average	$0.018	$0.045	$0.013	$0.005	$0.010	$0.005	$0.016

Table 6-15 shows the monthly day-ahead and real-time DR charges and the per MWh DR charges in the first six months of 2014 and 2015. The day-ahead DR charges decreased by $4.70 million, or 78.1 percent, from $6.02 million in the first six months of 2014 to $1.32 million in the first six months of 2015. The real-time DR charges decreased $4.63 million, or 55.9 percent, from $8.28 million in the first six months of 2014 to $3.65 million in the first six months of 2015. The per MWh charge paid by all real-time load and exports for economic DR decreased $0.05/MWh, or 90.7 percent, from $0.06/MWh in the first six months of 2014 to $0.01/MWh in the first six months of 2015.

Table 6-15 Monthly day-ahead and real-time DR charge: January through June 2014 and 2015

	Day-ahead DR Charge			Real-time DR Charge			Per MWh Charge ($/MWh)		
Month	2014	2015	Percent Change	2014	2015	Percent Change	2014	2015	Percent Change
Jan	$3,580,411	$202,040	(94%)	$4,108,903	$496,193	(88%)	$0.131	$0.025	(81%)
Feb	$1,148,053	$647,566	(44%)	$760,591	$2,161,548	184%	$0.038	$0.059	56%
Mar	$762,224	$140,310	(82%)	$2,366,688	$527,458	(78%)	$0.075	$0.020	(73%)
Apr	$67,996	$58,036	(15%)	$282,918	$136,234	(52%)	$0.012	$0.008	(35%)
May	$151,962	$258,773	70%	$498,703	$188,139	(62%)	$0.024	$0.015	(38%)
Jun	$309,885	$12,097	(96%)	$259,651	$141,468	(46%)	$0.018	$0.006	(69%)
Total	$6,020,531	$1,318,823	(78%)	$8,277,454	$3,651,040	(56%)	$0.060	$0.006	(91%)

Emergency Program

The emergency load response program consists of 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 in the Day-Ahead Energy Market 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.[26]

Emergency demand response was moderately concentrated in the first six months of 2015. The HHI for emergency demand response registrations was 1760 in 2014. In 2015 the four largest companies contributed 65.3 percent of all registered emergency demand response resources.

Table 6-16 shows zonal monthly capacity market revenue to demand resources for the first six months of 2015. Capacity market revenue increased in the first six months of 2015 by $70.0 million, or 24.4 percent, compared to the first six months of 2014, from $287.4 million to $357.4 million, as a result of higher RPM prices and more cleared DR in RPM for the 2013/2014 and 2014/2015 delivery years.

Table 6-16 Zonal monthly capacity revenue: January through June 2015

Zone	January	February	March	April	May	June	Total
AECO	$411,097	$371,313	$411,097	$805,435	$832,282	$985,380	$3,816,604
AEP, EKPC	$425,101	$383,962	$425,101	$6,203,447	$6,410,228	$6,659,173	$20,507,011
AP	$185,478	$167,528	$185,478	$3,380,132	$3,492,803	$3,174,034	$10,585,454
ATSI	$19,859	$17,937	$19,859	$3,717,154	$3,841,060	$18,481,726	$26,097,594
BGE	$5,430,108	$4,904,613	$5,430,108	$5,140,527	$5,311,878	$5,367,246	$31,584,480
ComEd	$405,926	$366,643	$405,926	$5,846,358	$6,041,237	$6,463,717	$19,529,806
DAY	$63,670	$57,508	$63,670	$872,987	$902,087	$736,289	$2,696,212
DEOK	$8,185	$7,393	$8,185	$330,654	$341,676	$1,277,237	$1,973,329
DLCO	$49,718	$44,907	$49,718	$840,774	$868,800	$849,964	$2,703,881
Dominion	$306,929	$277,226	$306,929	$5,165,946	$5,338,145	$5,066,825	$16,461,999
DPL	$1,547,049	$1,397,335	$1,547,049	$1,542,580	$1,593,999	$2,130,080	$9,758,093
JCPL	$1,495,628	$1,350,890	$1,495,628	$1,709,946	$1,766,944	$1,665,010	$9,484,045
Met-Ed	$1,044,281	$943,222	$1,044,281	$1,558,377	$1,610,323	$1,613,449	$7,813,933
PECO	$2,660,069	$2,402,643	$2,660,069	$3,249,878	$3,358,207	$3,700,859	$18,031,725
PENELEC	$1,144,857	$1,034,064	$1,144,857	$1,675,004	$1,730,838	$2,540,797	$9,270,417
Pepco	$1,906,591	$1,722,082	$1,906,591	$3,467,834	$3,583,429	$4,096,205	$16,682,731
PPL	$3,247,272	$2,933,020	$3,247,272	$5,215,729	$5,389,586	$5,411,083	$25,443,961
PSEG	$2,354,400	$2,126,555	$2,354,400	$5,460,187	$5,642,193	$3,738,271	$21,676,007
RECO	$14,896	$13,454	$14,896	$118,962	$122,927	$99,707	$384,842
Total	$22,721,111	$20,522,294	$22,721,111	$56,301,913	$58,178,643	$74,057,052	$254,502,124

Table 6-17 shows the amount of energy efficiency (EE) resources in PJM for 2012/2013 through 2015/2016 delivery years. Energy efficiency resources are offered in the PJM Capacity Market. The total MW of energy efficiency resources cleared in the capacity auction increased by 19.5 percent from 1,231.8 MW in the 2014/2015 delivery year to 1,471.4 MW in 2015/2016 Delivery Year.

26 See "Complaint and Motion to Consolidate of the Independent Market Monitor for PJM," Docket No. EL14-20-000 (January 28, 2014); "Comments of the Independent Market Monitor for PJM," Docket No. ER15-852-000 (February 13, 2015).

Table 6-17 Energy efficiency resources by MW: 2012/2013 through 2015/2016 Delivery Year

	EE ICAP (MW)				EE UCAP (MW)			
	2012/2013	2013/2014	2014/2015	2015/2016	2012/2013	2013/2014	2014/2015	2015/2016
Total	609.7	991.0	1,231.8	1,471.4	631.2	1,029.2	1,282.4	1,525.5

Table 6-18 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 product, which is obligated to respond within 30 minutes compared to short lead at 60 minutes and long lead at 120 minutes, is also new for the 2014/2015 Delivery Year. The quick lead time product has 7.5 percent of all nominated MW with 704.0 MW and only 22 locations.

The quick lead time product was defined after the auctions cleared. FERC accepted PJM's proposed 30 minute lead time as a phased in approach on May 9, 2014.[27] 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.[28]

Table 6-18 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 6-19 shows the number of customers and nominated MW by product type and lead time during the 2015/2016 Delivery Year. The quick lead time product is the default lead time for the 2015/2016 Delivery Year, unless a CSP submits an exception request for 60 or 120 minute notification time due to a physical constraint.[29] There were 3,174 locations which have 4,334.6 MW of nominated MW capacity approved by PJM to respond in 60 or 120 minutes.

Table 6-19 Lead time by product type: 2015/2016 Delivery Year

Lead Type	Product Type	Locations	Nominated MW
Long Lead (120 Minutes)	Annual and Extended Summer	791	697
	Limited	1,957	3,058
Short Lead (60 Minutes)	Extended Summer and Limited	426	580
Quick Lead (30 Minutes)	Annual	191	174
	Extended Summer	3,723	2,043
	Limited	10,635	5,092
Total		17,723	11,643

Table 6-20 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).

27 See "Order Rejecting, in part, and Accepting, in part, Proposed Tariff Changes, Subject to Conditions," Docket No. ER14-822-001 (May 9, 2014).
28 See "PJM Interconnection, L.L.C.," Docket No. ER14-135-000 (October 20, 2014).
29 See "Manual 18: Capacity Market," Revision 2 (August 3, 2015), p. 57.

Table 6-20 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	Percent 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%
Percent by method	22.9%	28.6%	2.2%	8.0%	37.0%	1.2%	100.0%	

Table 6-21 shows the MW registered by measurement and verification method and by load drop method for the 2015/2016 Delivery Year. Of the DR MW committed, 1.6 percent use the guaranteed load drop (GLD) measurement and verification method, 94.3 percent use the firm service level (FSL) method and 4.1 percent use direct load control (DLC). FSL registrations increased by 2,437.9 MW while GLD registrations decreased by 38.8 MW and DLC registrations decreased by 111.9 MW from the 2014/2015 delivery year to the 2015/2016 delivery year.

Table 6-21 Reduction MW by each demand response method: 2015/2016 Delivery Year

Program Type	On-site Generation MW	HVAC MW	Refrigeration and Lighting MW	Manufacturing or Water Heating MW	Other, Batteries or Plug Load MW	Total MW	Percent by Type
Firm Service Level	2,636.7	2,541.3	1,162.8	4,575.0	58.8	10,974.6	94.3%
Guaranteed Load Drop	20.6	106.1	13.5	47.6	0.0	187.8	1.6%
Non hourly metered sites (DLC)	0.0	444.9	0.0	35.3	0.0	480.1	4.1%
Total	2,657.3	3,092.3	1,176.3	4,657.8	58.8	11,642.6	100.0%
Percent by method	22.8%	26.6%	10.1%	40.0%	0.5%	100.0%	

Table 6-22 shows the fuel type used in the on-site generators identified in Table 6-20 for the 2014/2015 Delivery Year. Of the 22.9 percent of emergency demand response identified as using on-site generation, 85.5 percent of MW are diesel, 11.7 percent are natural gas and 2.8 percent is coal, gasoline, kerosene, oil, propane or waste products.

Table 6-22 On-site generation fuel type by MW: 2014/2015 Delivery Year

Fuel Type	MW	Percent
Coal, Gasoline, Kerosene, Oil, Propane, Waste Products	59.6	2.8%
Diesel	1,834.1	85.5%
Natural Gas	251.0	11.7%
Total	2,144.7	100.0%

Table 6-23 shows the fuel type used in the on-site generators identified in Table 6-21 for the 2015/2016 Delivery Year. Of the 22.8 percent of emergency demand response identified as using on-site generation, 84.7 percent of MW are diesel, 12.0 percent are natural gas and 3.3 percent is coal, gasoline, kerosene, oil, propane or waste products.

Table 6-23 On-site generation fuel type by MW: 2015/2016 Delivery Year

Fuel Type	MW	Percent
Coal, Gasoline, Kerosene, Oil, Propane, Waste Products	87.9	3.3%
Diesel	2,250.9	84.7%
Natural Gas	318.5	12.0%
Total	2,657.3	100.0%

Emergency Event Reported Compliance

PJM declared two events in 2015, one on April 21, 2015 and one on April 22, 2015. There were two events during the 2014/2015 Delivery Year, 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 events in 2015 were called in PENELEC and there were no annual Demand Resources there, none were considered in PJM's compliance assessment.[30] Table 6-24 shows the demand response cleared UCAP MW for PJM by Delivery Year. Total demand response cleared in PJM increased by 3.4 percent from 14,943 MW in the 2014/2015 Delivery Year to 15,453.7 MW in the 2015/2016 Delivery Year. The total percent of capacity resources in the 2015/2016 Delivery Year decreased by 0.4 percent from 9.3 percent in the 2014/2015 Delivery Year to 8.9 percent in the 2015/2016 Delivery Year.

Table 6-24 Demand response cleared MW UCAP for PJM: 2011/2012 through 2015/2016 Delivery Year

	2011/2012 Delivery Year		2012/2013 Delivery Year		2013/2014 Delivery Year		2014/2015 Delivery Year		2015/2016 Delivery Year	
	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP	DR Cleared MW UCAP	DR Percent of Capacity MW UCAP	DR Cleared MW UCAP	DR Percent 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%	15,453.7	8.9%

Table 6-25 lists PJM pre-emergency and emergency load management events declared in PJM in 2015 and the affected zones. Subzonal dispatch was mandatory for the 2014/2015 Delivery Year but only if the subzone is defined no later than the day before. The Erie subzone was not defined the day before the PJM event and therefore it could not be dispatched. The Erie subzone was defined on April 21, 2015, which made it eligible for the April 22, 2015, call. The PENELEC Zone was the only zone called for both events. All demand response events called in 2015 were voluntary, so no penalties are assessed for under compliance.

Table 6-25 PJM declared load management events: 2015

Event Date	Event Times	Compliance Hours	Minutes not Measured for Compliance	Lead Time	Geographical Area
21-Apr-15	20:20-21:30	None	70	Long Lead	PENELEC
	19:20-21:30	None	130	Short Lead	PENELEC
	18:50-21:30	None	160	Quick Lead	PENELEC
22-Apr-15	7:30-12:30	None	300	Long Lead	PENELEC
	6:30-12:30	None	360	Short Lead	PENELEC
	6:00-12:30	None	390	Quick Lead	PENELEC

Participants in the pre-emergency and 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 hourly to accurately report reductions during demand response events. The current rules use the average reduction for the duration of an event. The average duration across multiple hours does not provide an accurate metric for each hour of the event. Measuring compliance hourly would provide accurate information to the PJM system. This would be consistent with the rules that apply to generation resources. The MMU recommends demand response event

30 Extended summer and limited demand response products do not need to respond in April.

compliance be calculated for each hour and the penalty structure reflect hourly compliance. With the new CP rules, demand response will be structured for hourly performance.

Subzonal dispatch by zip code is mandatory beginning on June 1, 2014, with the 2014/2015 Delivery Year only if the subzone is defined at least one day before dispatch. PJM allows compliance to be measured across zones within a compliance aggregation area (CAA). This changes 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.[31] The multiple zone approach is less locational than the zonal and subzonal approach and creates larger mismatches between the locational need for the resources and the actual response. If multiple zones within a CAA are called by PJM, a CSP will dispatch the least cost resources across the zones to cover the CSP's obligation. This can result in more MW dispatched in one zone that are locationally distant from the need and 0 MW dispatched in another zone, yet the CSP could be considered 100 percent compliant and pay no penalties. 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.[32] 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 6-26 shows the performance for the April 21, 2015, event. The nominated value column shows 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 committed MW are the MW cleared in the RPM auction. The sixth 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 seventh 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 average row is the average results across both events for the PENELEC Zone.

The PENELEC Zone did not have any annual demand resources, resulting in voluntary compliance from the limited and extended summer products. The reported compliance for the PENELEC Control Zone on April 21, 2015, was 9.7 percent, or 27.4 MW out of 281.5 MW committed. The observed compliance for the PENELEC Control Zone on April 21, 2015 was 9.1 percent,

31 See "Manual 18: Capacity Market," Revision 28 (August, 3, 2015) p. 152.
32 PJM. OATT Attachment K § PJM Emergency Load Response Program at Reporting and Compliance.

or 25.5 MW out of 281.5 MW committed. The reported compliance for the PENELEC Control Zone on April 22, 2015 was 13.6 percent, or 38.3 MW out of 281.5 MW committed. The observed compliance for the PENELEC Control Zone on April 22, 2015 was 13.0 percent, or 36.7 MW out of 281.5 MW committed. Overall, the reported compliance for the PENELEC Control Zone was 11.7 percent, or 32.9 MW out of 281.5 MW committed. The observed compliance was 11.0 percent, or 31.1 MW, a difference of 1.8 MW compared to the reported load reduction.

Table 6-26 Demand response event performance: April 21, 2015 and April 22, 2015

Event Date	Zone	Product Type	Nominated ICAP (MW)	Committed MW	Load Reduction Reported (MW)	Load Reduction Observed (MW)	Difference	Percent Compliance Reported	Percent Compliance Observed
21-Apr-15	PENELEC	Limited and Extended Summer	39.5	281.5	27.4	25.5	1.93	9.7%	9.1%
22-Apr-15	PENELEC	Limited and Extended Summer	40.8	281.5	38.3	36.7	1.67	13.6%	13.0%
Average	PENELEC	Limited and Extended Summer	40.1	281.5	32.9	31.1	1.80	11.7%	11.0%

Performance for specific customers varied significantly. Table 6-27 shows the distribution of participant event days by performance levels for the two events in the April 2015. Table 6-27 includes the participation for all resources dispatched for the emergency events. For these events, 45.9 percent of participant event days showed no reduction, load increased or participants did not report data. For these events, 61.4 percent of participants event days provided less than half of their nominated MW, while 58.7 percent of the nominated MW provided less than half of their nominated MW. There were 38.6 percent of participants that reduced more than 50 percent of their nominated MW, while 41.3 percent of the nominated MW reduced more than 50 percent of their nominated MW.

Table 6-27 Distribution of participant event days and nominated MW across ranges of performance levels across the events: 2015

Ranges of performance as a percent 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	101	45.9%	37.4	40.9%
0% - 50%	34	15.5%	16.4	17.9%
50% - 300%	85	38.6%	37.8	41.3%
Total	220	100.0%	91.6	100.0%

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.[33] 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

33 PJM. OATT. PJM Emergency Load Response Program.

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.

Settlements that are not submitted to PJM are treated as zero compliance for the event. 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.

An extreme example makes clear the fundamental problems with the use of measurement and verification methods to define the level of power that would have been used but for the DR actions, and the payments to DR customers that result from these methods. The current rules for measurement and verification for Demand Resources make a bankrupt company, a customer that no longer exists due to closing of a facility or a permanently shut down company, or a company with a permanent reduction in peak load due to a partial closing of a facility, an acceptable demand response customer under some interpretations of the tariff, although it is the view of the MMU that such customers should not be permitted to be included as registered demand resources. Companies that remain in business but with a substantially reduced load can maintain their pre-bankruptcy FSL (firm service level to which the customer agrees to reduce in an event) commitment which can be greater than or equal to the post-bankruptcy total load. The customer agrees to reduce to a level which is greater than or equal to its new peak load after bankruptcy. When demand response events occur the customer would receive credit for 100 percent reduction, even though the customer took no action and could take no action to reduce load. This problem exists regardless of whether the customer is still paying for capacity. Such a customer no longer has the ability to reduce load in response to price or a PJM demand response event. CSPs in PJM have and continue to register bankrupt customers as DR customers. PJM finds acceptable the practice of CSPs maintaining the registration of customers with a bankruptcy related reduction in demand that are unable, as a result, to respond to emergency events.

Table 6-28 shows the number of locations that did not report during the April 2015 event days. In total, 37.7 percent of locations did not report during the event days in 2015 and were assigned zero load response and as a result there is no way to know whether the load at those locations increased. These locations accounted for 30.1 percent of all nominated MW for those events. Response was voluntary as there was not any Annual Demand Resources in the PENELEC Control Zone.

Table 6-28 Non-reporting locations and nominated ICAP: 2015 event days

	Locations not Reporting	Percent non Reporting	Nominated ICAP not Reporting	Percent non Reporting
Total	83	37.7%	34.6	30.1%

Emergency Energy Payments

For any PJM declared load management event in 2015, 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 increased to $1,849 per MWh for the 2015/2016 Delivery Year. The maximum generator offer will remain at $1,000 per MWh.[34,35]

Participants may elect to be paid their emergency offer, regardless of the zonal LMP.

Shutdown costs for demand response resources are not adequately defined in Manual 15. PJM's Cost Development Subcommittee (CDS) 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.[36]

Table 6-29 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 and $141.56 per MW..

Table 6-29 Distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices: 2014/2015 Delivery Year[37]

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

Table 6-30 shows the distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices for the 2015/2016 Delivery Year. The majority of participants, 77.0 percent, have a minimum dispatch price between $1,550 and $1,850 per MWh, which is the maximum price allowed for the 2015/2016 Delivery Year, and 3.4 percent of participants have a dispatch price between $0 and $1 per MWh. 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 $1,000 to $1,100 per MWh strike prices had the highest average at $183.69 per location.

34 139 FERC ¶ 61,057 (2012).
35 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.
36 PJM. "Manual 15: Cost Development Guidelines," Revision 26 (November 5, 2014), p. 54.

37 In this analysis nominated MW does not include capacity only resources, which do not receive energy market credits.

Table 6-30 Distribution of registrations and associated MW in the emergency full option across ranges of minimum dispatch prices: 2015/2016 Delivery Year[38]

Ranges of Strike Prices ($/MWh)	Locations	Percent of Total	Nominated MW (ICAP)	Percent of Total	Shutdown Cost per Location	Shutdown Cost Per Nominated MW (ICAP)
$0-$1	609	3.4%	562.9	4.8%	$0.00	$0.00
$1-$999	192	1.1%	217.0	1.9%	$136.08	$120.42
$1,000-$1,100	2,850	16.1%	3,698.1	31.8%	$183.69	$141.56
$1,101-$1,275	0	0.0%	0.0	0.0%	$0.00	$0.00
$1,276-$1,549	422	2.4%	514.0	4.4%	$59.11	$48.53
$1,550-$1,850	13,650	77.0%	6,651.3	57.1%	$26.97	$55.35
Total	17,723	100.0%	11,643.2	100.0%	$53.19	$80.97

Table 6-31 includes the energy reduction MWh and average real time LMP during the two demand response event days. The first column shows the hour 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.[39] 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 load during the hour before the reductions occur.[40] If a resource could reduce prior to their designated lead time, that resource was eligible for energy settlements. The average LMP columns show the average LMP for each hour of the event day based on the zones that were called. The hourly LMP during the demand response events peaked at $51.66 per MWh in the hour beginning 20 on April 21, 2015.

38 In this analysis nominated MW does not include capacity only resources, which do not receive energy market credits.
39 This table assumes that PJM's CBL calculation is correct.
40 See "PJM Manual 11: Energy & Ancillary Services," Revision 76 (August 3, 2015) p. 134.

Table 6-31 Energy reduction MWh and average real-time LMP during demand response event days: 2015

	April 21, 2015		April 22, 2015	
Hour Beginning	MWh Reduction	Average LMP ($/MWh)	MWh Reduction	Average LMP ($/MWh)
0		23.02		25.71
1		23.07		24.53
2		21.10		22.90
3		21.81		22.32
4		23.85		23.79
5		26.28		24.18
6		30.72	30.9	48.87
7		30.01	42.3	37.34
8		30.07	50.3	27.57
9		26.12	53.8	28.64
10		28.01	50.9	29.87
11		28.22	52.1	31.96
12		26.83	44.0	30.09
13		27.34		33.10
14		27.02		29.43
15		27.11		30.45
16		29.29		27.44
17		29.62		30.83
18	7.6	27.76		27.32
19	11.8	27.32		30.38
20	19.6	51.66		43.51
21	34.9	31.02		38.22
22		23.28		25.84
23		18.88		23.84
Total	73.9	27.48	324.2	29.92

Table 6-32 shows emergency energy revenue for each event day in the first six months of 2015. 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.[41] Emergency demand response energy costs are not

41 PJM. "Manual 28: Operating Agreement Account," Revision 71 (June 1, 2015) p. 72.

covered by LMP. All demand response energy payments and shutdown costs are out of market payments. These payments are 100 percent uplift.

The events in April were both voluntary events since there were not any annual demand resources in PENELEC. April 22, 2015 had the longest event and the most MWh reductions, resulting in total emergency revenue of $416,883. The total emergency revenue for the two voluntary emergency event days were $510,860.

Table 6-32 Emergency Revenue by event: 2015

Event Date	Total
April 21, 2015	$93,976
April 22, 2015	$416,883
Total	$510,860

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

- Net revenues are significantly affected by fuel prices, energy prices and capacity prices. Coal and natural gas prices and energy prices were lower in the first six months of 2015 than in the first six months of 2014. Net revenues from the energy market for all plant types were affected by the lower prices.
- In the first six months of 2015, average energy market net revenues decreased by 24 percent for a new CT, 26 percent for a new CC, 58 percent for a new CP, 70 percent for a new DS, 45 percent for a new nuclear plant, 24 percent for a new wind installation, and 10 percent for a new solar installation. The comparison to the first six months of 2014 reflects the very high net revenues in January 2014.

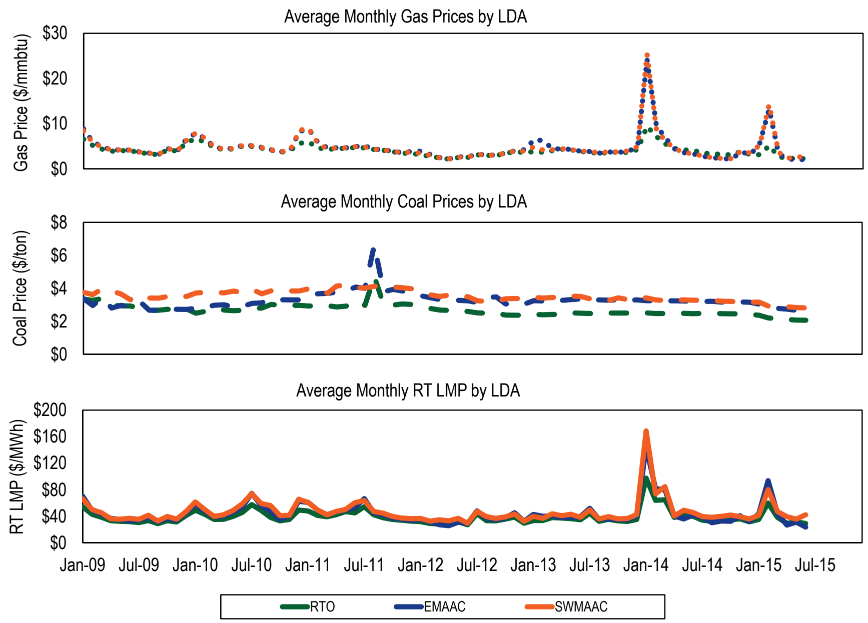
Conclusion

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.

Net Revenue

Net revenues are significantly affected by energy prices, fuel prices and capacity prices. The real-time load-weighted average LMP was 63.4 percent lower in the first six months of 2015 than in the first six months of 2014, $42.30 per MWh versus $69.92 per MWh. Coal and natural gas prices decreased in 2015. Comparing fuel prices in the first six months of 2015 to the first six months of 2014, the price of Northern Appalachian coal was 16.6 percent lower; the price of Central Appalachian coal was 23.1 percent lower; the price of Powder River Basin coal was 11.9 percent lower; the price of eastern natural gas was 45.2 percent lower; and the price of western natural gas was 55.1 percent lower (Figure 7-1).

Figure 7-1 Energy Market net revenue factor trends: 2009 through 2015



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 641.2 MW and consists of two GE Frame 7HA.02 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 971.4 MW and consists of two GE Frame 7HA.02 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.[1]
- 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 two Siemens 2.3 MW wind turbines totaling 50.6 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.[2] [3] Plant heat rates account for the efficiency changes and corresponding cost changes resulting from ambient air temperatures.

NO_x and SO_2 emission allowance costs are included in the hourly plant dispatch cost. These costs are included in the definition of marginal cost. NO_x and SO_2 emission allowance costs were obtained from actual historical daily spot cash prices.[4]

1 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.
2 Hourly ambient conditions supplied by Schneider Electric.
3 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 resulting in a single offer point.
4 NO_x and SO_2 emission daily prompt prices obtained from Evolution Markets, Inc.

A forced outage rate for each class of plant was calculated from PJM data and incorporated into all revenue calculations.[5] 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.

Zonal net revenues reflect zonal fuel costs based on locational fuel indices, actual unit consumption patterns, and zone specific delivery charges.[6] 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.[7] 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.[8]

Operating costs are the short run marginal cost of operations and include fuel costs, emissions costs, and VOM costs.[9] [10] Average operating costs are shown in Table 7-1.

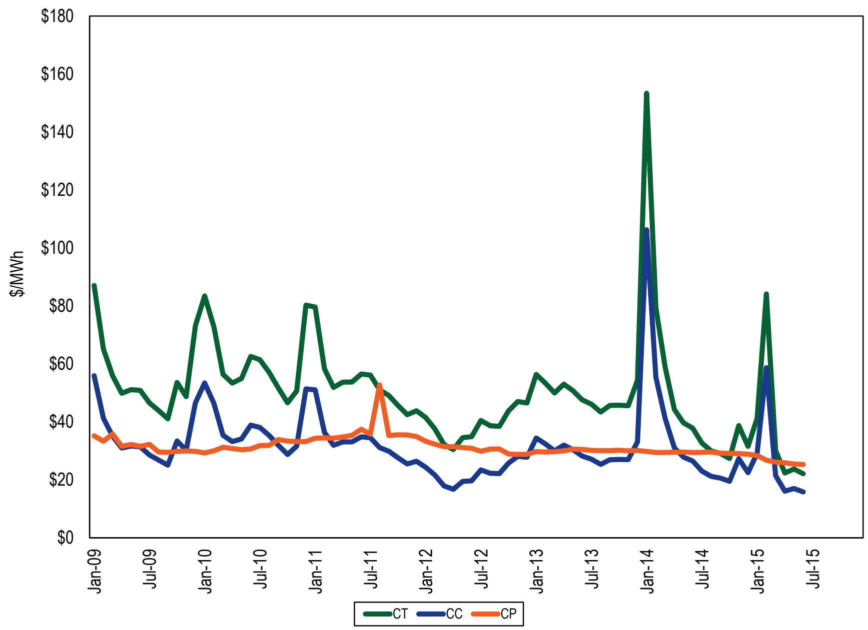
Table 7-1 Average operating costs: January through June, 2015

Unit Type	Operating Costs ($/MWh)	Heat Rate (Btu/kWh)	VOM ($/MWh)
CT	$36.67	9,476	$0.25
CC	$25.95	6,667	$1.00
CP	$26.30	9,250	$4.00
DS	$124.47	9,660	$0.25
Nuclear	$8.50	NA	$3.00
Wind	$0.00	NA	$0.00
Solar	$0.00	NA	$0.00

A comparison of the operating costs of the theoretical CT, CC and CP plants since January 2009 shows that the CC plant has been competitive with the CP plant but that the costs of the CC plant have been more volatile than the costs of the CP plant as a result of the higher volatility of gas prices compared to coal prices (Figure 7-2). A significant increase in gas prices on cold days resulted in a corresponding increase in the average operating cost of CTs and CCs in January 2014 and February 2015 (Figure 7-2).

5 Outage figures obtained from the PJM eGADS database.
6 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.
7 Gas daily cash prices obtained from Platts.
8 Coal prompt prices obtained from Platts.
9 Fuel costs are calculated using the daily spot price and may not equal what participants actually paid.
10 VOM rates provided by Pasteris Energy, Inc.

Figure 7-2 Average operating costs: 2009 through 2015



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 lower in most zones in the first six months of 2015 (Table 7-2).

Table 7-2 Energy net revenue for a new entrant gas-fired CT under economic dispatch (Dollars per installed MW-year)[11]

Zone	2009 (Jan-Jun)	2010 (Jan-Jun)	2011 (Jan-Jun)	2012 (Jan-Jun)	2013 (Jan-Jun)	2014 (Jan-Jun)	2015 (Jan-Jun)	Change in 2015 from 2014
AECO	$6,869	$10,990	$22,176	$9,154	$6,217	$29,189	$24,040	(18%)
AEP	$2,645	$3,294	$10,072	$6,506	$4,044	$35,297	$22,192	(37%)
AP	$7,380	$8,838	$17,998	$8,920	$5,892	$47,785	$34,734	(27%)
ATSI	NA	NA	$3,887	$7,035	$4,328	$40,604	$24,110	(41%)
BGE	$8,948	$16,148	$22,801	$18,267	$11,608	$37,934	$29,226	(23%)
ComEd	$1,510	$2,488	$6,457	$4,810	$2,812	$15,766	$9,436	(40%)
DAY	$2,169	$3,104	$10,573	$7,527	$3,799	$35,512	$21,805	(39%)
DEOK	NA	NA	NA	$6,276	$3,504	$37,064	$40,244	9%
DLCO	$1,991	$7,759	$11,324	$8,888	$4,011	$31,567	$18,660	(41%)
Dominion	$10,180	$15,932	$20,954	$10,824	$8,626	$25,775	$18,155	(30%)
DPL	$8,039	$11,056	$20,404	$12,583	$7,539	$33,259	$19,460	(41%)
EKPC	NA	NA	NA	NA	$953	$38,230	$39,842	4%
JCPL	$6,880	$10,365	$22,156	$9,113	$8,784	$31,657	$24,814	(22%)
Met-Ed	$6,303	$10,247	$20,526	$10,719	$5,810	$28,205	$23,797	(16%)
PECO	$5,960	$9,899	$22,279	$8,940	$5,788	$28,752	$22,679	(21%)
PENELEC	$4,379	$4,754	$16,793	$9,641	$6,738	$62,444	$60,412	(3%)
Pepco	$8,731	$17,583	$23,702	$15,663	$10,588	$36,152	$23,339	(35%)
PPL	$5,699	$8,128	$23,555	$9,315	$5,631	$29,229	$23,375	(20%)
PSEG	$5,569	$10,595	$18,406	$8,121	$5,867	$23,416	$12,952	(45%)
RECO	$4,641	$9,398	$15,019	$7,433	$9,091	$23,158	$14,655	(37%)
PJM	$5,758	$9,446	$17,171	$9,460	$6,081	$33,550	$25,396	(24%)

11 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

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.[12] 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 lower in all zones in the first six months of 2015 (Table 7-3).

Table 7-3 Energy net revenue for a new entrant CC under economic dispatch (Dollars per installed MW-year)[13]

Zone	2009 (Jan-Jun)	2010 (Jan-Jun)	2011 (Jan-Jun)	2012 (Jan-Jun)	2013 (Jan-Jun)	2014 (Jan-Jun)	2015 (Jan-Jun)	Change in 2015 from 2014
AECO	$33,603	$38,947	$62,121	$46,043	$35,022	$63,075	$50,149	(20%)
AEP	$16,922	$15,925	$36,190	$47,485	$32,564	$64,587	$47,531	(26%)
AP	$34,971	$31,741	$57,293	$53,068	$37,751	$81,964	$63,038	(23%)
ATSI	NA	NA	$7,782	$48,219	$35,652	$73,196	$50,059	(32%)
BGE	$35,820	$46,360	$58,573	$65,068	$46,951	$81,378	$54,431	(33%)
ComEd	$11,750	$11,146	$20,045	$32,064	$18,556	$30,184	$24,073	(20%)
DAY	$14,869	$15,488	$35,218	$50,017	$33,990	$65,038	$46,758	(28%)
DEOK	NA	NA	NA	$43,834	$29,904	$69,709	$63,636	(9%)
DLCO	$13,349	$20,449	$34,603	$49,325	$28,250	$54,743	$41,367	(24%)
Dominion	$39,627	$48,402	$55,313	$53,528	$38,659	$55,141	$42,551	(23%)
DPL	$35,081	$38,047	$58,282	$52,419	$37,736	$75,333	$43,636	(42%)
EKPC	NA	NA	NA	NA	$5,588	$70,809	$62,741	(11%)
JCPL	$34,849	$38,364	$62,003	$47,192	$39,818	$67,223	$50,755	(24%)
Met-Ed	$30,295	$35,568	$53,979	$46,123	$33,789	$58,479	$47,625	(19%)
PECO	$31,586	$36,415	$59,319	$44,569	$32,399	$60,692	$47,918	(21%)
PENELEC	$28,307	$26,368	$54,748	$52,669	$45,629	$106,517	$85,985	(19%)
Pepco	$35,108	$48,524	$57,567	$60,952	$45,542	$77,393	$47,607	(38%)
PPL	$28,834	$31,924	$56,764	$43,663	$32,735	$59,953	$47,803	(20%)
PSEG	$32,014	$37,188	$54,922	$41,909	$35,184	$59,116	$31,634	(46%)
RECO	$27,911	$33,298	$41,477	$39,167	$41,545	$57,052	$32,495	(43%)
PJM	$28,523	$32,597	$48,122	$48,280	$34,363	$66,579	$49,090	(26%)

12 All starts associated with combined cycle units are assumed to be hot starts.
13 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

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 lower in all zones in the first six months of 2015 (Table 7-4).

Table 7-4 Energy net revenue for a new entrant CP (Dollars per installed MW-year)[14]

Zone	2009 (Jan-Jun)	2010 (Jan-Jun)	2011 (Jan-Jun)	2012 (Jan-Jun)	2013 (Jan-Jun)	2014 (Jan-Jun)	2015 (Jan-Jun)	Change in 2015 from 2014
AECO	$53,500	$72,755	$50,906	$4,770	$19,077	$152,716	$59,725	(61%)
AEP	$12,156	$30,216	$45,065	$8,847	$43,564	$121,650	$55,020	(55%)
AP	$28,457	$48,592	$64,365	$16,888	$48,155	$142,785	$73,893	(48%)
ATSI	NA	NA	$2,320	$11,212	$43,306	$132,694	$59,454	(55%)
BGE	$33,650	$31,207	$35,241	$6,046	$23,233	$173,533	$76,386	(56%)
ComEd	$21,454	$58,534	$56,062	$20,764	$31,847	$98,868	$32,726	(67%)
DAY	$16,030	$38,952	$37,575	$7,932	$47,888	$122,542	$52,412	(57%)
DEOK	NA	NA	NA	$5,566	$42,249	$113,717	$48,854	(57%)
DLCO	$11,527	$44,867	$25,635	$14,168	$8,289	$73,626	$22,897	(69%)
Dominion	$32,259	$74,707	$56,248	$4,273	$57,348	$176,115	$93,401	(47%)
DPL	$27,411	$70,732	$70,490	$7,324	$16,482	$179,577	$79,658	(56%)
EKPC	NA	NA	NA	NA	$4,776	$104,159	$40,167	(61%)
JCPL	$48,842	$71,881	$48,582	$6,673	$22,415	$159,466	$61,160	(62%)
Met-Ed	$40,316	$68,588	$39,034	$10,500	$18,000	$149,054	$58,310	(61%)
PECO	$50,278	$68,647	$47,079	$5,147	$17,094	$151,465	$59,463	(61%)
PENELEC	$45,609	$61,272	$55,127	$12,844	$54,252	$153,588	$75,325	(51%)
Pepco	$44,662	$81,825	$49,178	$6,428	$21,863	$166,897	$67,563	(60%)
PPL	$46,726	$56,939	$55,910	$4,456	$17,374	$149,901	$58,746	(61%)
PSEG	$108,889	$62,882	$33,954	$5,137	$35,565	$179,012	$68,232	(62%)
RECO	$46,756	$71,055	$38,904	$6,099	$41,685	$173,203	$68,437	(60%)
PJM	$39,325	$59,627	$45,093	$8,688	$30,723	$143,728	$60,591	(58%)

14 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.

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 lower in all zones in the first six months of 2015 (Table 7-5).

Table 7-5 PJM energy market net revenue for a new entrant DS (Dollars per installed MW-year)

Zone	2009 (Jan-Jun)	2010 (Jan-Jun)	2011 (Jan-Jun)	2012 (Jan-Jun)	2013 (Jan-Jun)	2014 (Jan-Jun)	2015 (Jan-Jun)	Change in 2015 from 2014
AECO	$3,620	$2,023	$3,882	$509	$296	$36,975	$12,257	(67%)
AEP	$367	$119	$1,689	$111	$140	$15,989	$3,605	(77%)
AP	$2,019	$354	$1,863	$317	$169	$20,825	$7,496	(64%)
ATSI	NA	NA	$232	$179	$144	$15,705	$3,509	(78%)
BGE	$4,778	$3,403	$5,444	$1,112	$1,288	$55,614	$15,785	(72%)
ComEd	$96	$92	$797	$69	$99	$12,544	$2,021	(84%)
DAY	$354	$114	$1,823	$116	$149	$15,783	$3,619	(77%)
DEOK	NA	NA	NA	$61	$114	$14,914	$3,042	(80%)
DLCO	$180	$1,941	$1,899	$155	$100	$14,417	$3,147	(78%)
Dominion	$4,552	$3,994	$3,674	$562	$817	$47,487	$11,054	(77%)
DPL	$4,685	$2,221	$3,966	$396	$334	$42,178	$15,571	(63%)
EKPC	NA	NA	NA	NA	NA	$15,932	$2,639	(83%)
JCPL	$3,526	$1,474	$4,064	$691	$490	$37,231	$13,119	(65%)
Met-Ed	$3,180	$1,543	$3,478	$711	$276	$36,123	$13,002	(64%)
PECO	$3,151	$2,056	$3,671	$788	$281	$36,382	$12,023	(67%)
PENELEC	$782	$180	$2,023	$1,301	$134	$18,475	$6,096	(67%)
Pepco	$4,994	$3,908	$5,662	$676	$1,086	$57,205	$11,716	(80%)
PPL	$2,939	$1,423	$3,631	$834	$279	$37,039	$12,883	(65%)
PSEG	$3,023	$1,384	$3,596	$688	$356	$36,893	$12,525	(66%)
RECO	$2,585	$1,213	$3,054	$717	$1,532	$34,269	$14,209	(59%)
PJM	$2,637	$1,614	$3,025	$526	$425	$30,099	$8,966	(70%)

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 plant energy market net revenues were lower in all zones in the first six months of 2015 (Table 7-6).

Table 7-6 Energy net revenue for a new entrant nuclear plant (Dollars per installed MW-year)[15]

Zone	2009 (Jan-Jun)	2010 (Jan-Jun)	2011 (Jan-Jun)	2012 (Jan-Jun)	2013 (Jan-Jun)	2014 (Jan-Jun)	2015 (Jan-Jun)	Change in 2015 from 2014
AECO	$160,153	$173,883	$185,935	$97,296	$129,329	$282,012	$149,413	(47%)
AEP	$120,267	$128,425	$136,783	$91,943	$116,873	$203,076	$117,444	(42%)
AP	$141,629	$150,447	$158,423	$97,257	$122,019	$227,441	$139,159	(39%)
ATSI	NA	NA	$24,914	$92,464	$120,011	$215,244	$120,990	(44%)
BGE	$162,915	$186,219	$185,228	$116,081	$142,458	$306,554	$179,595	(41%)
ComEd	$95,219	$110,780	$113,051	$80,313	$103,459	$176,244	$90,352	(49%)
DAY	$116,564	$126,391	$135,933	$94,485	$118,457	$204,373	$116,696	(43%)
DEOK	NA	NA	NA	$88,625	$112,086	$194,228	$112,486	(42%)
DLCO	$110,930	$129,705	$132,205	$93,643	$112,298	$187,496	$108,723	(42%)
Dominion	$154,919	$181,816	$176,342	$103,261	$132,509	$265,915	$161,778	(39%)
DPL	$162,014	$174,609	$185,565	$103,269	$133,516	$301,925	$166,759	(45%)
EKPC	NA	NA	NA	NA	$17,915	$192,048	$106,828	(44%)
JCPL	$161,053	$172,738	$185,534	$98,385	$133,870	$288,044	$149,872	(48%)
Met-Ed	$155,239	$168,870	$175,959	$97,125	$127,740	$273,804	$144,791	(47%)
PECO	$157,090	$170,744	$182,740	$95,776	$126,599	$277,164	$146,005	(47%)
PENELEC	$138,103	$147,122	$157,146	$97,372	$127,972	$240,822	$135,326	(44%)
Pepco	$161,136	$187,644	$184,388	$112,125	$140,540	$298,992	$168,901	(44%)
PPL	$153,401	$164,806	$178,387	$94,696	$126,794	$274,920	$145,257	(47%)
PSEG	$164,028	$177,048	$189,633	$99,727	$149,736	$309,226	$158,964	(49%)
RECO	$158,761	$171,835	$173,614	$96,719	$156,690	$303,585	$159,938	(47%)
PJM	$145,495	$160,181	$158,988	$97,398	$122,544	$251,156	$138,964	(45%)

New Entrant Wind Installation

Energy market net revenues for a wind installation located in the ComEd and PENELEC zones were calculated hourly 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. Energy market net revenues for a wind installation include revenue from the Production Tax Credit (PTC) of $23 per MWh, from the Investment Tax Credit of $1 per MWh, and from Renewable Energy Certificates (RECs) of $1.24/MWh in ComEd and $14.81/MWh in PENELEC.[16]

15 The energy net revenues presented for the PJM area in this section represent the zonal average energy net revenues.
16 REC prices provided by Evolution Markets.

Wind energy market net revenues were lower in the first six months of 2015 (Table 7-7).

Table 7-7 Energy market net revenue for a wind installation (Dollars per installed MW-year)

Zone	2012 (Jan-Jun)	2013 (Jan-Jun)	2014 (Jan-Jun)	2015 (Jan-Jun)	Change in 2015 from 2014
ComEd	$41,876	$47,692	$112,049	$84,357	(25%)
PENELEC	$68,117	$98,661	$137,270	$111,735	(19%)

New Entrant Solar Installation

Energy market net revenues for a solar installation located in the PSEG Zone were calculated hourly 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. Energy market net revenues for a solar installation in New Jersey include revenue from Solar Renewable Energy Certificates (SRECs) of $161.88/MWh.[17]

Solar energy market net revenues were lower in the first six months of 2015 (Table 7-8).

Table 7-8 PSEG Energy Market net revenue for a solar installation (Dollars per installed MW-year)

Zone	2012 (Jan-Jun)	2013 (Jan-Jun)	2014 (Jan-Jun)	2015 (Jan-Jun)	Change in 2015 from 2014
PSEG	$190,813	$189,135	$214,195	$193,229	(10%)

Spark Spreads

The spark spread is defined as the difference in $/MWh between the LMP received for selling power and the cost of fuel used to generate power. The spark spread is a measure of the spread between revenues and fuel costs and is thus an indicator of net revenue and profitability.

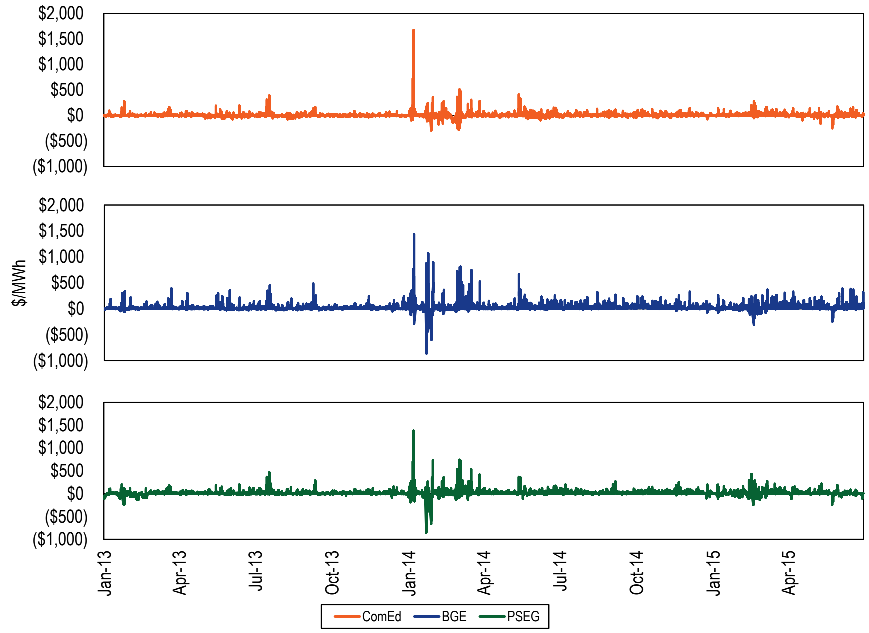
$$Spark\ Spread\left(\frac{\$}{MWh}\right) = LMP\left(\frac{\$}{MWh}\right) - Gas\ Price\left(\frac{\$}{mmBtu}\right) * Heat\ Rate\left(\frac{mmBtu}{MWh}\right)$$

17 SREC prices provided by Evolution Markets.

Spark spread volatility is a result of fluctuations in LMP and the price of gas. Spark spreads can be positive or negative.

Figure 7-3 shows the spark spread since January 2013 for three PJM zones.[18] The average spark spread for the period January 2013 through June 2015 was $1.75 per MWh for ComEd, $13.23/MWh for BGE, and $4.61/MWh for PSEG.

Figure 7-3 Spark spread for selected zones: 2013 through 2015



18 Spark spreads use a heat rate of 7,500 Btu/kWh, zonal LMPs and gas prices at Chicago City Gate for ComEd, Zone 6 Non-NY for BGE, and Zone 6 NY for PSEG.

Environmental and Renewable Energy Regulations

Environmental requirements and renewable energy mandates have a significant impact on PJM markets.

At the federal level, 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.

State regulations and multi-state agreements have an impact on PJM markets. 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.

Federal and state renewable energy mandates and associated incentives 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.

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.[1] 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 June 29, 2015, the U.S. Supreme Court remanded MATS to the D.C. Circuit Court and ordered the EPA to consider cost earlier in the process when making the decision whether to regulate power plants under MATS.[2]

- **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.[3]

  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).[4,5]

  In the same decision, the Supreme Court remanded "particularized as-applied challenge[s]" to the EPA's 2014 emissions budgets.[6] On July 28, 2015, on remand, the U.S. Court of Appeals for the District of Columbia Circuit invalidated the 2014 SO_2 budgets for a number of states, including PJM states Maryland, New Jersey, North Carolina, Ohio, Pennsylvania,

1 *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).
2 Michigan et al. v. EPA, Slip Op. No. 14-46.
3 CAA § 110(a)(2)(D)(i)(I).
4 See EPA et al. v. EME Homer City Generation, L.P. et al., 134 S. Ct. 1584 (2014), *reversing* 696 F.3d 7 (D.C. Cir. 2012).
5 See EME Homer City Generation, L.P. v EPA et al., No. 11-1302.
6 134 S. Ct. at 1609.

Virginia and West Virginia.[7] The court directed the EPA to reconsider the 2015 emissions budgets for these states based on the actual amount of reduced emissions states in upwind states needed to bring each downwind state into attainment.[8] Under the invalidated approach, EPA calculated how much pollution each upwind state could eliminate if all of its sources applied pollution control at particular cost thresholds.[9] A new approach likely will significantly reduce the emission budgets for the indicated states. The court did not vacate the currently assigned budgets which remain effective until replaced.[10]

On November 21, 2014, EPA issued a rule tolling by three years CSAPR's original deadlines. Compliance with CSAPR's Phase 1 emissions budgets is now required in 2015 and 2016 and CSAPR's Phase 2 emissions in 2017 and beyond.[11]

- **National Emission Standards for Reciprocating Internal Combustion Engines.** On May 1, 2015, the U.S. Court of Appeals for the District of Columbia Circuit reversed the portion of the final rule exempting 100 hours of run time for certain stationary reciprocating internal combustion engines (RICE) participating in emergency demand response programs from the otherwise applicable emission standards.[12] The Court held that "EPA acted arbitrarily and capriciously when it modified the National Emissions Standards and the Performance Standards to allow backup generators to operate without emissions controls for up to 100 hours per year as part of an emergency demand-response program."[13] Specifically, the Court found that EPA failed to consider arguments concerning the rule's "impact on the efficiency and reliability of the energy grid," including arguments raised by the MMU.[14]

- **Greenhouse Gas Emissions Rule.** On August 3, 2015, the EPA issued a final rule for regulating CO_2 from certain existing power generation facilities titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units.[15] Individual state plans must be submitted by September 6, 2016, while multistate plans are eligible for a two-year extension.

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.[16] 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.[17]

- **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").[18] MPS and CPS establish standards that are more stringent and take effect earlier than comparable Federal regulations, such as the EPA MATS rule.

- **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 and facilitate trading of emissions allowances. Auction prices in 2015 for the 2015-2017 compliance period were $5.50 per ton. The clearing price is equivalent to a price of $6.06 per metric tonne, the unit used in other carbon markets.

7 EME Homer City Generation, L.P. v EPA et al., Slip Op. No. 11-1302 (July 28, 2015).
8 *Id.* at 11–12.
9 *Id.* at 11.
10 Emissions Budget Decision at 24–25.
11 *Rulemaking to Amend Dates in Federal Implementation Plans Addressing Interstate Transport of Ozone and Fine Particulate Matter*, EPA-HQ-OAR-2009-0491 (Nov. 21, 2014).
12 Delaware Department of Natural Resources and Environmental Control (DENREC) v. EPA, Slip Op. No. 13-1093; *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).
13 DENREC v. EPA at 3, 20–21.
14 *Id.* at 22, citing Comments of the Independent Market Monitor for PJM, EPA Docket No. EPA-HQ-OAR-2008-0708 (August 9, 2012) at 2.
15 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (June 18August 3, 20145), also known as the "Clean Power Plan."
16 N.J.A.C. § 7:27–19.
17 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).
18 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_X and SO_2 (CPS)).

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, 2015, 78.3 percent of coal steam MW had some type of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions, while 99.5 percent of coal steam MW had some type of particulate control, and 92.8 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 retail suppliers' 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, 2015, 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. Ohio delayed a scheduled increase from 2.5 percent to 3.5 percent in its RPS standards from 2015 until 2017 and removed the 12.5 percent alternative energy requirement. Ohio currently has an ongoing Ohio Energy Mandates Study Committee that is discussing the costs and benefits of the RPS as outlined in Senate Bill 310.[19] West Virginia had a voluntary standard, but the state Legislature repealed their renewable portfolio standard on January 22, 2015.

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 FERC has determined that RECs are not regulated under the Federal Power Act unless bundled with a wholesale sale of electric energy.[20]

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 and more generally provide an incentive to operate whenever possible. These subsidies affect the offer behavior and the operational behavior of these resources in PJM markets and thus the market prices and the mix of clearing resources.

RECs clearly affect prices in the PJM wholesale power market. Some resources are not economic except for the ability to purchase or sell RECs. REC markets are not transparent. Data on REC 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 resources 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.

PJM markets could also provide a flexible mechanism for states to comply with the EPA's Clean Power Plan, for example by incorporating a carbon price in unit offers which would be reflected in PJM's economic dispatch.

19 See Ohio Senate Bill 310.

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.")

The imposition of specific environmental dispatch rules would, in contrast, pose a threat to economic dispatch and create very difficult market power monitoring and mitigation issues.

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 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 June 29, 2015, the U.S. Supreme Court remanded MATS to the D.C. Circuit Court and ordered the EPA to consider cost earlier in the process when making the decision whether to regulate power plants under MATS.[25] The remand is not expected to have a large impact on PJM markets because most of the retirement decisions related to MATS in PJM have already been made and because the remand does not eliminate MATS.

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 related to these 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]

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

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 Michigan et al. v. EPA, Slip Op. No. 14-46.
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).

pollution in other states, to levels consistent with the 1997 ozone and fine particle and 2006 fine particle NAAQS.[28] The CSAPR covers 28 states, including all of the PJM states except Delaware, and also excluding the District of Columbia.[29]

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.[30] Group 2 does not include any states in the PJM region.[31] 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[32] 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.

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 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).[33]

In the same decision, the Supreme Court remanded "particularized as-applied challenge[s]" to the EPA's 2014 emissions budgets.[34] On July 28, 2015, on remand, the U.S. Court of Appeals for the District of Columbia Circuit invalidated the 2014 SO_2 budgets for a number of states, including PJM states Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, Virginia and West Virginia.[35] The court directed the EPA to reconsider the 2015 emissions budgets for these states based on the actual amount of reduced emissions states in upwind states needed to bring each downwind state into attainment.[36] Under the invalidated approach, EPA calculated how much pollution each upwind state could eliminate if all of its sources applied pollution control at particular cost thresholds.[37] A new approach likely will significantly reduce

28 *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).

29 *Id.*

30 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.

31 Group 2 states include: Minnesota, Nebraska, Kansas, Texas, Alabama, Georgia and South Carolina.

32 The 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.

33 See EPA et al. v. EME Homer City Generation, L.P. et al., 134 S. Ct. 1584 (2014). 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 the EPA's motion.

34 134 S. Ct. at 1609.

35 EME Homer City Generation, L.P. v EPA et al., Slip Op. No. 11-1302 (July 28, 2015).

36 *Id.* at 11–12.

37 *Id.* at 11.

the emission budgets for the indicated states. The court did not vacate the currently assigned budgets which remain effective until replaced.[38]

On November 21, 2014, EPA issued a rule tolling by three years CSAPR's original deadlines. Compliance with CSAPR's Phase 1 emissions budgets is now required in 2015 and 2016 and CSAPR's Phase 2 emissions in 2017 and beyond.[39]

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).[40] RICE include certain types of electrical generation facilities like diesel engines typically used for backup, emergency or supplemental power. RICE include facilities located behind the meter. These rules include: National Emission Standard for Hazardous Air Pollutants (NESHAP) for Reciprocating Internal Combustion Engines (RICE); New Source Performance Standards (NSPS) of Performance for Stationary Spark Ignition Internal Combustion Engines; and Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (collectively "RICE Rules").[41]

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).[42]

On May 22, 2012, the EPA proposed amendments to the RICE NESHAP Rule.[43] 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 exempted emergency demand response programs include demand resources in RPM.[44]

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.[45] 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."[46] 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 because it accorded discriminatory preference to resources that have negative consequences for reliability, the markets and the environment.[47]

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."[48] In its compliance filing, PJM attempted to justify the exception.[49] An order from the Commission on PJM's compliance filing is now pending.

38 Emissions Budget Decision at 24–25.

39 *Rulemaking to Amend Dates in Federal Implementation Plans Addressing Interstate Transport of Ozone and Fine Particulate Matter*, EPA-HQ-OAR-2009-0491 (Nov. 21, 2014).

40 *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").

41 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.

42 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."

43 *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.

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. This matter remains pending.

45 PJM Tariff filing, FERC Docket No. ER14-822 (December 24, 2014).

46 *Id.* at 8–9.

47 Comments, Complaint and Motion to Consolidate of the Independent Market Monitor for PJM, FERC Docket No. ER14-822-000 (January 14, 2014) at 3–6.

48 See 147 FERC ¶ 61,103 at P 41.

49 See PJM compliance filing, FERC Docket No. ER14-822-002 (June 2, 2014) at 4–8.

On May 1, 2015, the U.S. Court of Appeals for the District of Columbia Circuit reversed the portion of the final rule exempting 100 hours of run time for certain stationary reciprocating internal combustion engines (RICE) participating in emergency demand response programs from the otherwise applicable emission standards.[50] The Court held that "EPA acted arbitrarily and capriciously when it modified the National Emissions Standards and the Performance Standards to allow backup generators to operate without emissions controls for up to 100 hours per year as part of an emergency demand-response program."[51] Specifically, the Court found that EPA failed to consider arguments concerning the rule's "impact on the efficiency and reliability of the energy grid," including arguments raised by the MMU.[52]

Regulation of Greenhouse Gas Emissions

The EPA has regulates CO_2 as a pollutant using CAA provisions that apply to pollutants not subject to NAAQS.[53,54]

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 with 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).

On August 3, 2015, the EPA issued a final rule for regulating CO_2 from certain existing power generation facilities titled Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units ("CPE Guidelines").[57]

States have flexibility to meet the EPA's GHG goals, including through participation in multistate CO_2 credit trading programs. By September 6, 2016, a state must submit an individual final compliance plan or request a two-year extension, including for the purpose of developing a multi-state plan. The EPA has begun to develop a federal plan applicable in states that do not submit plans which it plans to finalize in the summer of 2016.

The CPE Guidelines set state by state rate and mass based CO_2 emissions targets.[58] States would be required to develop and obtain EPA approval of plans to achieve the interim goals effective 2022 and the final goals effective 2030.[59] The EPA anticipates that meeting these goals would reduce CO_2 emissions from Electric Generating Units (EGUs) by 2030 to a level 32 percent below the level of emissions in 2005.[60]

The EPA has calculated rate- and mass-based goals based on EGU emissions rates for each state. The EPA uses three building blocks to calculate state goals.[61] The EPA calculates emissions as of 2005 from EGUs in each state, and then assumes reduced emissions based on implementation of the building blocks.[62]

To calculate state interim and final goals, the EPA assumes the following building blocks: (i) heat rate improvement of 2.1–3.4 percent (depending

50 Delaware Department of Natural Resources and Environmental Control (DENREC) v. EPA, Slip Op. No. 13-1093; *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).
51 DENREC v. EPA at 3, 20–21.
52 *Id.* at 22, citing Comments of the Independent Market Monitor for PJM, EPA Docket No. EPA-HQ-OAR-2008-0708 (August 9, 2012) at 2.
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 *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, Final Rule *mimeo* (August 3, 2015), also known as the "Clean Power Plan."
58 *Id.* at 1560.
59 *Id.* at 1559.
60 *Id.* at 34839.
61 *Id.* at 1559.
62 *Id.* at 1559–1560.

upon the region) at affected EGUs; (ii) displacement of generation from lower emitting existing natural gas combined cycle units for reduced generation from higher-emitting affected steam generating units; and (iii) displacement of generation from new zero emitting generating capacity for reduced generation from affected fossil fuel-fired generating units.[63]

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.

Table 8-1 Interim and final targets for CO_2 emissions goals for PJM states (Short Tons of CO_2)[64]

Jurisdiction	2020 Interim New Source Complements (Short Tons of CO_2)	2030 Final New Source Complements (Short Tons of CO_2)	2020 Interim Mass Goal (Short Tons CO_2)	2030 Final Final Goal (Short Tons CO_2)
Delaware	78,842	69,561	5,141,711	4,781,386
District of Columbia	NA	NA	NA	NA
Illinois	818,349	722,018	75,619,224	67,119,174
Indiana	939,343	828,769	86,556,407	76,942,604
Kentucky	752,454	663,880	72,065,256	63,790,001
Maryland	170,930	150,809	16,380,325	14,498,436
Michigan	623,651	550,239	53,680,801	48,094,302
New Jersey	313,526	276,619	17,739,906	16,876,364
North Carolina	692,091	610,623	57,678,116	51,876,856
Ohio	949,997	838,170	83,476,510	74,607,975
Pennsylvania	1,257,336	1,109,330	100,588,162	90,931,637
Tennessee	358,838	316,598	32,143,698	28,664,994
Virginia	450,039	397,063	30,030,110	27,830,174
West Virginia	602,940	531,966	58,686,029	51,857,307
Total	8,008,336	7,065,645	689,786,255	617,871,210

The difference in goals reflects different evaluation of state specific factors, referred to as "building blocks," including heat rate improvements, dispatch among affected EGUs, expanded use of less carbon-intensive generating capacity and demand-side energy efficiency.[65] The essence of the approach is that the baseline is set by the current opportunity in a state to achieve additional CO_2 emissions reductions. No credit is given for prior steps that states have taken, some more than others, to achieve CO_2 emissions reductions.

63 *Id.* 1559.
64 The District of Columbia has no affected EGUs and is not subject to the CPE Guidelines (at 1560).
65 CPE Guidelines 1559–1560.

Each state would be required to develop an EPA approved plan to meet its interim and final goals.[66] The CPE Guidelines would not require states to implement the building blocks in their plan, but would require states to meet the goals through an approach included in an EPA-approved plan.

States could implement a "state measures" approach, which involves a state "adopt[ing] a set of policies and programs, which would not be federally enforceable, except that any standards imposed on affected EGUs would be federally enforceable."[67] 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.[68]

The CPE Guidelines recognize that many states have already implemented programs to reduce CO_2 emissions from fossil fuel fired EGUs and specifically highlight the Regional Greenhouse Gas Initiative (RGGI) and California's Global Warming Solutions Act of 2006.[69] Each of these programs would require significant changes in order to comply with the approach in the CPE Guidelines. 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 CPE Guidelines would be needed. The rules would also take into account that the CPE Guidelines rely on reduced emissions from EGUs to reach state goals and does not count non EGU offsets towards meeting those goals.[70]

The CPE Guidelines permit states to partner and submit multistate plans to reduce CO_2 emissions from EGUs.[71]

66 *Id.*
67 *Id.* at 1560.
68 *Id.* at 898.
69 *Id.* at 1560.
70 *Id.* at 34910.
71 *Id.* at 1560.

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.[72] 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.[73]

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.[74] NO_x emissions limits for other unit types became effective May 1, 2015.[75]

Table 8-2 HEDD maximum NO_x emission rates[76]

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

72 N.J.A.C. § 7:27-19.
73 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).
74 N.J.A.C. § 7:27-19.4.
75 N.J.A.C. § 7:27-19.5.
76 Regenerative cycle CTs are combustion turbines that recover heat from their exhaust gases and use that heat to preheat the inlet combustion air which is fed into the combustion turbine.

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").[77] 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.[78] In order to obtain variances, companies in PJM agreed to terms with the Illinois Pollution Control Board that 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.[79]

State Regulation of Greenhouse Gas Emissions

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.[80,81] RGGI generates revenues for the participating states which have spent approximately 65 percent of revenues to date on energy efficiency, 6 percent on clean and renewable energy, 6 percent on greenhouse gas abatements and 17 percent on direct bill assistance.[82]

Table 8-3 shows the RGGI CO_2 auction clearing prices and quantities for the 2009-2011 compliance period auctions, the 2012-2014 compliance period auctions and 2015-2017 compliance period auctions held as of June 30,

77 35 Ill. Admin. Code §§ 225.233 (Multi-Pollutant Standard (MPS), 224.295 (Combined Pollutant Standard: Emissions Standards for NO_x and SO_2 (CPS)).
78 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).
79 See *Id.*
80 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>.
81 For more details see the *2013 State of the Market Report for PJM*, Volume 2: Section 8, "Environmental and Renewables."
82 *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 July 1, 2015).

2015, in short tons and metric tonnes. Prices for auctions held June 3, 2015, for the 2015-2017 compliance period were at the highest clearing price to date, \$5.51 per allowance (equal to one ton of CO_2), above the current price floor of \$2.05 for RGGI auctions.[83] The RGGI base budget for CO_2 will be reduced by 2.5 percent per year each year from 2015 through 2020. The price increased from the previous high of \$5.41 in March 2015 as the result of a 16.1 percent reduction in the quantity of allowances offered in this auction for the 2015-2017 compliance period. This auction did not include additional Cost Containment Reserves (CCRs) since the clearing price for allowances was below the CCR trigger price of \$6.00 per ton in 2015. The auction on March 5, 2014 was the first and only auction to use CRRs.

83 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).

Table 8-3 RGGI CO_2 allowance auction prices and quantities in short tons and metric tonnes: 2009-2011, 2012-2014 and 2015-2017 Compliance Periods[84]

	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
December 3, 2014	$5.21	18,198,685	18,198,685	$5.74	16,509,574	16,509,574
March 11, 2015	$5.41	15,272,670	15,272,670	$5.96	13,855,137	13,855,137
June 3, 2015	$5.50	15,507,571	15,507,571	$6.06	14,068,236	14,068,236

CAIR and CSAPR

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.[85,86] On November 21, 2014, EPA issued a

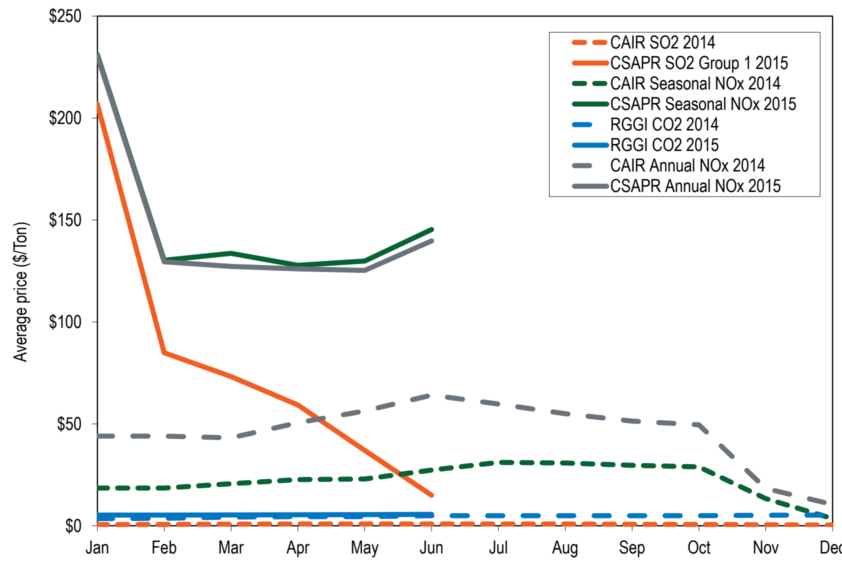
84 See Regional Greenhouse Gas Initiative, "Auction Results," <http://www.rggi.org/market/co2_auctions/results>
85 See EPA et al. v. EME Homer City Generation, L.P. et al., 134 S. Ct. 1584 (2014), *reversing* 696 F.3d 7 (D.C. Cir. 2012).
86 Order, City Generation, L.P. EPA et al. v. EME Homer et al., No. 11-1302.

rule requiring compliance with CSAPR's Phase 1 emissions budgets effective January 1, 2015 and 2016 and CSAPR's Phase 2 emissions effective January 1, 2017.[87] The ruling and the EPA rules eliminated CAIR and replaced it with CSAPR and had a corresponding impact on market prices for CAIR emissions allowances and CSAPR emissions allowances.

Figure 8-1 shows average, monthly settled prices for NO_x, CO_2 and SO_2 emissions allowances including CAIR and CSAPR related allowances for 2014 and the first six months of 2015.[88] Figure 8-1 also shows the average, monthly settled price for the Regional Greenhouse Gas Initiative (RGGI) CO_2 allowances.

Annual and seasonal CAIR NO_x prices decreased in the last three months of 2014. In the first six months of 2015, CSAPR annual NO_x prices were 191 percent higher than the CAIR annual NO_x prices in the first six months of 2014. In the first six months of 2015, CSAPR SO_2 prices were 10,143 percent higher than the CAIR SO_2 prices in the first six months of 2014. The average price of CSAPR SO_2 prices in the first six months of 2015 was $79.36 compared the average price of $0.77 for CAIR SO_2 in the first six months of 2014.

Figure 8-1 Spot monthly average emission price comparison: January 2014 through June 2015[89]



Renewable Portfolio Standards

Many PJM jurisdictions have enacted legislation to require that a defined percentage of retail 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, 2015, 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. Ohio delayed a scheduled increase from 2.5 percent to 3.5 percent in its RPS standards from 2015 until 2017 and removed the 12.5 percent alternative energy requirement. Ohio currently has an ongoing Ohio Energy Mandates Study Committee that is discussing the costs and benefits of the RPS as outlined in Senate Bill 310.[90] West Virginia

87 *Rulemaking to Amend Dates in Federal Implementation Plans Addressing Interstate Transport of Ozone and Fine Particulate Matter*, EPA-HQ-OAR-2009-0491 (Nov. 21, 2014).

88 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.

89 Spot monthly average emission price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed July 31, 2015).

90 See Ohio Senate Bill 310.

had a voluntary standard, but the state legislature repealed their renewable portfolio standard on January 27, 2015, effective February 3, 2015.[91]

Under the existing renewable portfolio standards, approximately 7.4 percent of PJM load must be served by renewable resources in 2015 and 16.2 percent of PJM load by 2028 under defined RPS rules. As shown in Table 8-4, Delaware and Illinois will require 25.0 percent of load to be served by renewable resources in 2028, the highest standard of PJM jurisdictions. Renewable resources earn renewable energy credits (RECs) (also known as alternative energy credits) when they generate electricity. These RECs are bought by retail suppliers to fulfill the requirements for generation from renewable resources.

Table 8-4 Renewable standards of PJM jurisdictions to 2028[92]

Jurisdiction	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Delaware	13.00%	14.50%	16.00%	17.50%	19.00%	20.00%	21.00%	22.00%	23.00%	24.00%	25.00%	25.00%	25.00%	25.00%
Illinois	9.00%	10.00%	11.50%	13.00%	14.50%	16.00%	17.50%	19.00%	20.50%	22.00%	23.50%	25.00%	25.00%	25.00%
Indiana	4.00%	4.00%	4.00%	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	10.00%	10.00%	10.00%	10.00%
Kentucky	No Standard													
Maryland	13.00%	15.20%	15.60%	18.30%	17.40%	18.00%	18.70%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
Michigan	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
New Jersey	13.76%	14.90%	15.99%	18.03%	19.97%	21.91%	23.85%	23.94%	24.03%	24.12%	24.21%	24.30%	24.39%	24.48%
North Carolina	6.00%	6.00%	6.00%	10.00%	10.00%	10.00%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%	12.50%
Ohio	2.50%	2.50%	3.50%	4.50%	5.50%	6.50%	7.50%	8.50%	9.50%	10.50%	11.50%	12.50%	12.50%	12.50%
Pennsylvania	11.20%	13.70%	14.20%	14.70%	15.20%	15.70%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%	18.00%
Tennessee	No Standard													
Virginia	4.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	12.00%	12.00%	12.00%	15.00%	15.00%	15.00%	15.00%
Washington, D.C.	12.00%	13.50%	15.00%	16.50%	18.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
West Virginia	No Standard													

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. Delaware, North Carolina, Michigan and Virginia allow various types of renewable resources to earn multiple RECs per MWh, though typically one REC is equal to one MWh. For example, Delaware provided a three MWh REC for each MWh produced by in-state customer sited photovoltaic generation and fuel cells using renewable fuels that are installed on or before December 31, 2014.[93] This is equivalent to providing a REC price equal to three times its stated value per MWh. 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.[94]

Some PJM jurisdictions have also added specific requirements for the purchase of solar resources. These solar requirements are included in the total requirements shown in Table 8-4 but may be met by solar RECs (SRECs) only. Delaware, Illinois, Maryland, New Jersey, North Carolina, Ohio, Pennsylvania, and Washington, D.C. have requirements for the proportion of load served by solar. Pennsylvania and Delaware allow only solar photovoltaic resources to fulfill the solar requirement. Solar thermal units like solar hot water heaters that do not generate electricity are considered Tier II. Indiana, Kentucky, Michigan, Tennessee, Virginia, and West Virginia have no specific solar standards. In 2015, New Jersey had the most stringent solar standard in PJM, requiring that 2.45 percent of retail electric sales within the state be served by solar resources. As Table 8-5 shows, by 2028, New Jersey will continue to have the most stringent standard, requiring that at least 4.10 percent of load be served by solar.

91 See Enr. Com. Sub. For H. B. No. 2001.
92 This shows the total standard of renewable resources in all PJM jurisdictions, including Tier I, Tier II and Tier III resources.
93 See Delaware Renewable Portfolio Standard, <http://programs.dsireusa.org/system/program/detail/1231> (Accessed August 10, 2015).
94 GATS publishes details on every renewable generator registered within the PJM footprint and aggregate emissions of renewable generation, but does not publish generation data by unit.

Table 8-5 Solar renewable standards by percent of electric load for PJM jurisdictions: 2015 to 2028

Jurisdiction	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Delaware	1.00%	1.25%	1.50%	1.75%	2.00%	2.25%	2.50%	2.75%	3.00%	3.25%	3.50%	3.50%	3.50%	3.50%
Illinois	0.27%	0.60%	0.69%	0.78%	0.87%	0.96%	1.05%	1.14%	1.23%	1.32%	1.41%	1.50%	1.50%	1.50%
Indiana	No Solar Standard													
Kentucky	No Standard													
Maryland	0.50%	0.70%	0.95%	1.40%	1.75%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Michigan	No Solar Standard													
New Jersey	2.45%	2.75%	3.00%	3.20%	3.29%	3.38%	3.47%	3.56%	3.65%	3.74%	3.83%	3.92%	4.01%	4.10%
North Carolina	0.14%	0.14%	0.14%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%	0.20%
Ohio	0.12%	0.12%	0.15%	0.18%	0.22%	0.26%	0.30%	0.34%	0.38%	0.42%	0.46%	0.50%	0.50%	0.50%
Pennsylvania	0.14%	0.25%	0.29%	0.34%	0.39%	0.44%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Tennessee	No Standard													
Virginia	No Solar Standard													
Washington, D.C.	0.70%	0.83%	0.98%	1.15%	1.35%	1.58%	1.85%	2.18%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
West Virginia	No Standard													

REC prices are required to be publicly disclosed in Maryland, Pennsylvania and the District of Columbia, but in the other states REC prices are not publicly available. Figure 8-2 shows the average solar REC (SREC) price by jurisdiction for 2009 through 2015. The average NJ SREC prices dropped from $674 per SREC in 2010 to $219 per SREC in 2015. The DC SREC prices are currently the highest at $488 per SREC.[95]

Table 8-6 Additional renewable standards of PJM jurisdictions 2015 to 2028

Jurisdiction		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Illinois	Wind Requirement	6.75%	7.50%	8.63%	9.75%	10.88%	12.00%	13.13%	14.25%	15.38%	16.50%	17.63%	18.75%	18.75%	18.75%
Illinois	Distributed Generation	0.07%	0.10%	0.12%	0.13%	0.15%	0.16%	0.18%	0.19%	0.21%	0.22%	0.24%	0.25%	0.25%	0.25%
Maryland	Tier II Standard	2.50%	2.50%	2.50%	2.50%	0.00%	0.00%	0.00%	0.00%	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%	2.50%	2.50%	2.50%
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%	0.20%	0.20%	0.20%
North Carolina	Poultry Waste (in GWh)	700	900	900	900	900	900	900	900	900	900	900	900	900	900
Pennsylvania	Tier II Standard	6.20%	8.20%	8.20%	8.20%	8.20%	8.20%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
Washington, D.C.	Tier II Standard	2.50%	2.00%	1.50%	1.00%	0.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Some PJM jurisdictions have also added specific requirements to their renewable portfolio standards for other technologies. The standards shown in Table 8-6 are also included in the total RPS requirements. Illinois requires that a defined proportion of retail load be served by wind resources, increasing from 6.75 percent of load served in 2015 to 18.75 percent in 2026. 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. By 2019, North Carolina’s RPS requires that 0.2 percent of power be generated using swine waste and that 900 GWh of power be produced by poultry waste (Table 8-6).

95 Solar REC average price information obtained through Evomarkets, <http://www.evomarkets.com> (Accessed July 31, 2015).

Figure 8-2 Average solar REC price by jurisdiction: 2009 through 2015

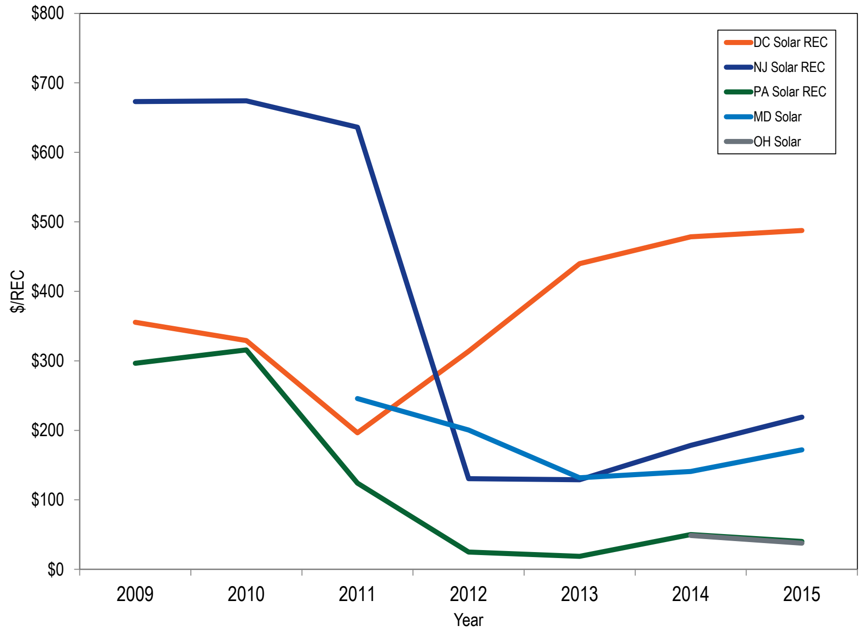


Figure 8-3 Average Tier I REC price by jurisdiction: 2009 through 2015

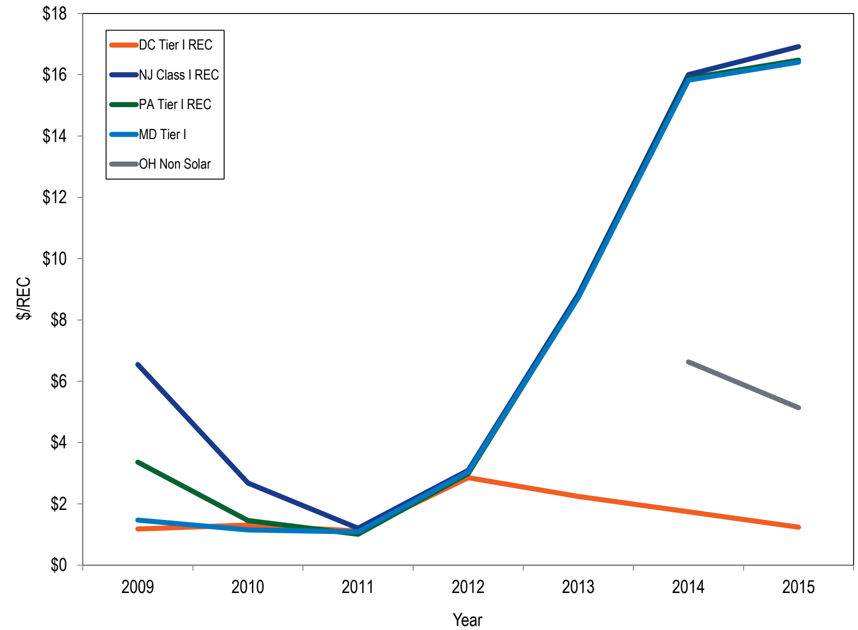


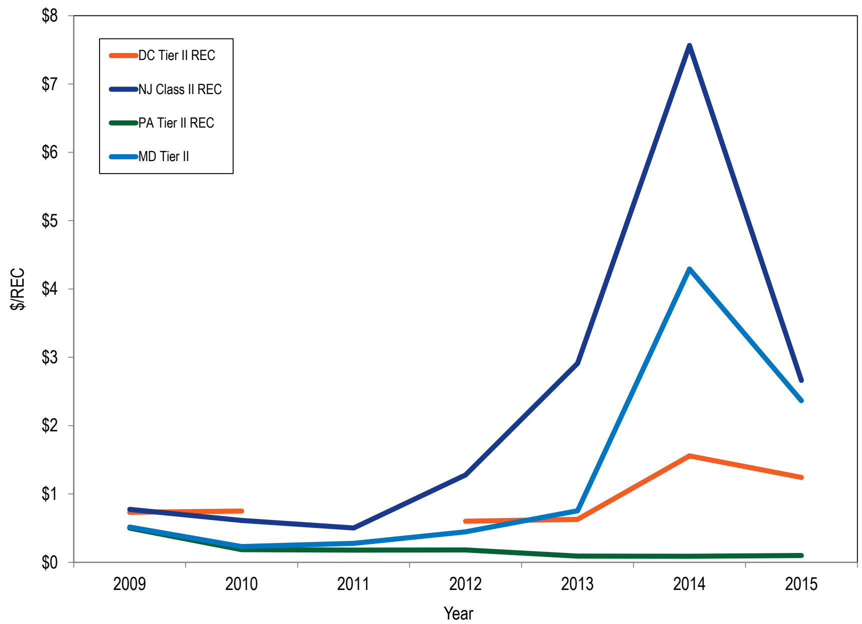
Figure 8-3 shows the average Tier I REC price by jurisdiction from 2009 through 2015. Tier I REC prices are lower than SREC prices. Ohio and Pennsylvania had the lowest SREC prices at $38 per SREC and $40 per SREC while New Jersey and Maryland have the highest Tier I REC prices at $17 per REC and $16 per REC.[96]

Tier II prices are lower than SREC and Tier I REC prices. Figure 8-4 shows the average Tier II REC price by jurisdiction for 2009 through 2015. Prices peaked in 2014 and have declined to a high of $3 per REC in New Jersey for 2015.[97]

96 Tier I REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed July 31, 2015).

97 Tier II REC price information obtained through Evomarkets <http://www.evomarkets.com> (Accessed July 31, 2015). There is no data reported by Evomarkets for DC in 2011.

Figure 8-4 Average Tier II REC price by jurisdiction: 2009 through 2015



PJM jurisdictions include various methods for complying with required renewable portfolio standards. If a retail supplier is unable to comply with the renewable portfolio standards required by the jurisdiction, suppliers may make alternative compliance payments, with varying standards, to cover any shortfall between the RECs required by the state and those the retail supplier actually purchased. In New Jersey, solar alternative compliance payments are $331.00 per MWh.[98] 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 is defined in different ways by different jurisdictions. For example, Illinois requires that 50 percent of the state's renewable portfolio standard be met through alternative compliance payments. Table 8-7 shows the alternative compliance standards in PJM jurisdictions, where such standards exist.

Table 8-7 Renewable alternative compliance payments in PJM jurisdictions: As of June 30, 2015[99]

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		$331.00
North Carolina	No specific penalties		
Ohio	$45.00		$300.00
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	No standard		

Table 8-8 shows renewable resource generation by jurisdiction and resource type in the first six months of 2015. This includes only units that would qualify for REC credits by primary fuel type, including waste coal, battery, and pumped-storage hydroelectric, all of which can qualify for Pennsylvania Tier II credits if they are located in the PJM footprint. Wind output was 7,713.1 GWh of 13,125.6 Tier I GWh, or 58.8 percent, in the PJM footprint. As shown in Table 8-8, 23,359.3 GWh were generated by renewable resources, including both Tier II and Tier I renewable credits, of which, Tier I type resources accounted for 56.2 percent. Total renewable generation was 5.9 percent of total generation in PJM for the first six months of 2015. Landfill gas, solid waste and waste coal were 9,026 GWh of renewable resource generation or 38.6 percent of the total Tier I and Tier II.

98 See Database of State Incentives for Renewables & Efficiency (DSIRE), New Jersey Incentives/ Policies for Renewables & Efficiency, "Solar Renewables Energy Certificates (SRECs)," <http://programs.dsireusa.org/system/program/detail/5687>

99 See PJM – EIS (Environmental Management System). "Program Information," <http://www.pjm-eis.com/> (Accessed July 1, 2015).

Table 8-8 Renewable resource generation by jurisdiction and renewable resource type (GWh): January through June 2015

Jurisdiction	Landfill Gas	Pumped-Storage Hydro	Run-of-River Hydro	Solar	Solid Waste	Waste Coal	Wind	Tier I Credit Only	Total Credit GWh
Delaware	21.3	0.0	0.0	0.0	0.0	0.0	0.0	21.3	42.6
Illinois	72.8	0.0	0.0	7.2	0.0	0.0	3,130.1	3,210.0	3,210.0
Indiana	26.7	0.0	20.6	0.0	0.0	0.0	1,833.7	1,881.0	1,881.0
Kentucky	0.0	0.0	59.9	0.0	0.0	0.0	0.0	59.9	59.9
Maryland	43.2	0.0	951.2	30.9	308.4	0.0	233.3	1,258.6	1,567.0
Michigan	12.4	0.0	29.8	0.0	0.0	0.0	0.0	42.1	42.1
New Jersey	149.4	230.0	7.8	166.6	651.0	0.0	6.0	329.8	1,210.7
North Carolina	0.0	0.0	283.7	21.6	0.0	0.0	0.0	305.3	305.3
Ohio	172.8	0.0	190.1	0.7	0.0	0.0	608.9	972.6	972.6
Pennsylvania	618.7	829.6	1,929.6	13.3	669.6	3,887.4	1,901.2	4,462.7	9,849.4
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	278.6	1,543.8	303.7	0.0	651.4	1,462.4	0.0	582.3	4,240.0
Washington, D.C.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West Virginia	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	1,396.0	2,603.4	3,776.3	240.2	2,280.5	5,349.8	7,713.1	13,125.6	23,359.3
Percent Total	6.0%	11.1%	16.2%	1.0%	9.8%	22.9%	33.0%	56.2%	100.0%

Table 8-9 PJM renewable capacity by jurisdiction (MW) on June 30, 2015

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	43.1	0.0	0.0	0.0	0.0	9.0	0.0	0.0	2,187.4	2,239.5
Indiana	0.0	8.0	0.0	0.0	0.0	8.2	0.0	0.0	0.0	1,452.4	1,468.6
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	494.4	48.8	128.2	0.0	160.0	925.5
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	81.7	0.0	0.0	453.0	11.5	254.2	162.0	0.0	4.5	966.8
North Carolina	0.0	0.0	0.0	0.0	0.0	352.5	20.0	0.0	0.0	0.0	372.5
Ohio	13,864.0	64.7	580.0	156.0	0.0	119.1	1.1	0.0	0.0	403.0	15,187.9
Pennsylvania	0.0	214.0	2,346.0	0.0	1,269.0	888.3	19.5	345.8	1,611.0	1,337.7	8,031.3
Tennessee	0.0	0.0	0.0	0.0	0.0	52.0	0.0	50.0	0.0	0.0	102.0
Virginia	0.0	224.1	0.0	17.0	5,166.2	350.5	0.0	444.9	585.0	0.0	6,787.7
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	679.0	5,242.0	255.0	6,888.2	2,565.2	352.7	1,130.9	2,361.0	6,313.2	48,423.2

Table 8-9 shows the capacity of renewable resources in PJM by jurisdiction, as defined by primary fuel type. This capacity includes coal and natural gas units that have a renewable fuel as an alternative fuel, and thus are able to earn renewable energy credits based on the fuel used to generate energy. New Jersey has the largest amount of solar capacity in PJM, 254.2 MW, or 72.1 percent of the total solar capacity. New Jersey's SREC prices were the highest in 2010 at $674 per REC and in 2015 are at $219 per REC. Wind resources are located primarily in western PJM, in Illinois and Indiana, which include 3,639.7 MW, or 57.7 percent of the total wind capacity.

Table 8-10 shows renewable capacity registered in the PJM generation attribute tracking system (GATS). This includes solar capacity of 2,008.6 MW of which 1,198.1 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. Some of this capacity is located in jurisdictions outside PJM, but may qualify for specific renewable energy credits in some PJM jurisdictions. This includes both solar generation located inside PJM but not PJM units, and generation connected to other RTOs outside PJM.

Table 8-10 Renewable capacity by jurisdiction, non-PJM units registered in GATS (MW) on June 30, 2015[100]

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
Arkansas	0.0	135.0	0.0	0.0	18.0	0.0	0.0	0.0	0.0	153.0
Delaware	0.0	0.0	2.2	0.0	0.0	0.0	62.7	0.0	2.1	67.0
Georgia	0.0	0.0	0.0	0.0	0.0	0.0	38.7	258.9	0.0	297.6
Illinois	0.0	6.6	86.8	0.0	0.6	0.0	26.6	0.0	600.5	721.1
Indiana	0.0	0.0	43.2	0.0	6.2	94.6	2.9	0.0	180.0	326.9
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	17.6	0.0	0.0	0.0	1.5	93.0	0.0	714.3
Louisiana	0.0	0.0	0.0	0.0	0.0	0.0	0.0	129.2	0.0	129.2
Maryland	65.0	0.0	13.7	129.0	0.0	0.0	234.1	11.2	0.3	453.3
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	446.0	446.0
New Jersey	0.0	0.0	55.0	0.0	8.3	0.0	1,198.1	0.0	4.9	1,266.4
New York	0.0	158.7	0.0	0.0	0.0	0.0	0.4	0.0	0.0	159.1
North Carolina	0.0	242.5	0.0	0.0	0.0	0.0	107.1	30.0	0.0	379.6
Ohio	0.0	1.0	33.6	92.6	15.4	32.4	113.2	109.3	23.1	420.7
Pennsylvania	109.7	37.0	44.2	91.0	12.6	5.0	195.2	38.6	3.3	536.5
Tennessee	0.0	52.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	52.0
Texas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	57.7	0.0	57.7
Virginia	0.0	18.2	13.4	1.1	0.0	0.0	9.0	287.6	0.0	329.3
West Virginia	0.0	9.0	0.0	0.0	0.0	0.0	0.4	44.6	0.0	54.0
Wisconsin	0.0	42.0	0.0	0.0	0.0	0.0	2.4	0.0	0.0	44.4
District of Columbia	0.0	0.0	0.0	0.0	0.0	0.0	14.7	0.0	0.0	14.7
Total	829.7	705.4	312.9	313.7	61.1	132.0	2,008.6	1,147.6	1,445.3	6,956.2

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 number 5 and number 6 fuel oil have the highest SO_2 emission rates, while natural gas and number 1 through number 4 fuel oil have lower SO_2 emission rates.[101] Of the current 70,850.8 MW of coal capacity in PJM, 55,485.0 MW of capacity, 78.3 percent, has some form of FGD (flue-gas desulfurization) technology to reduce SO_2 emissions. Table 8-11 shows SO_2 emission controls by fossil fuel fired units in PJM.[102,103]

Table 8-11 SO_2 emission controls (FGD) by fuel type (MW), as of June 30, 2015

	SO_2 Controlled	No SO_2 Controls	Total	Percent Controlled
Coal	55,485.0	15,365.8	70,850.8	78.3%
Diesel Oil	0.0	6,856.8	6,856.8	0.0%
Natural Gas	0.0	52,685.9	52,685.9	0.0%
Other	325.0	4,763.5	5,088.5	6.4%
Total	55,810.0	79,672.0	135,482.0	41.2%

NO_x emission control technology is used by all fossil fuel fired unit types. Of current fossil fuel fired units in PJM, 125,751.0 MW, 92.8 percent, of 135,482.0 MW of capacity in PJM, have emission controls for NO_x. Table 8-12 shows NO_x emission controls by unit type in PJM. While most units in PJM have NO_x emission controls, many of these controls may need to be upgraded in order to meet each state's emission compliance standards based on whether a state is part of CSAPR, CAIR, Acid Rain Program (ARP) or a combination of the three. Future NO_x compliance standards will require select catalytic converters (SCRs) or selective non-catalytic reduction (SCNRs) for coal steam units, as well as SCRs or water injection technology for peaking combustion turbine units.[104]

100 See PJM – EIS (Environmental Information Services), "Renewable Generators Registered in GATS," <http://www.pjm-eis.com/reports-and-news/public-reports.aspx> (Accessed July 1, 2015).

101 Light oil includes diesel, number 2 fuel oil and light crudes.

102 See EPA. "Air Market Programs Data," <http://ampd.epa.gov/ampd/> (Accessed July 1, 2015).

103 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 July 1, 2015).

104 See EPA. "Mercury and Air Toxics Standards," <http://www.epa.gov/mats/index.html> (Accessed July 1, 2015).

Table 8-12 NO_x emission controls by fuel type (MW), as of June 30, 2015

	NO_x Controlled	No NO_x Controls	Total	Percent Controlled
Coal	69,624.2	1,226.6	70,850.8	98.3%
Diesel Oil	2,617.8	4,239.0	6,856.8	38.2%
Natural Gas	50,709.3	1,819.4	52,528.7	96.5%
Other	2,799.7	2,446.0	5,245.7	53.4%
Total	125,751.0	9,731.0	135,482.0	92.8%

Most coal units in PJM have particulate controls due to the NAAQS and CSAPR. Typically, technologies such as electrostatic precipitators (ESP) or fabric filters (baghouses) are used to reduce particulate matter from coal steam units.[105] Fabric filters work by allowing the flue gas to pass through a tightly woven fabric which filters out the particulates. Table 8-13 shows particulate emission controls by unit type in PJM. In PJM, 70,516.8 MW, 99.5 percent, of all coal steam unit MW, have some type of particulate emissions control technology, as of June 30, 2015. 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 state and federal 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.[106] Currently, 49 of the 211 coal steam units have baghouse or FGD technology installed, representing 53,937.0 MW out of the 70,850.8 MW total coal capacity, or 76.1 percent.

Table 8-13 Particulate emission controls by fuel type (MW) as of June 30, 2015

	Particulate Controlled	No Particulate Controls	Total	Percent Controlled
Coal	70,516.8	334.0	70,850.8	99.5%
Diesel Oil	0.0	6,856.8	6,856.8	0.0%
Natural Gas	260.0	52,268.7	52,528.7	0.5%
Other	3,102.0	2,143.7	5,245.7	59.1%
Total	73,878.8	61,603.2	135,482.0	54.5%

Fossil fuel fired units in PJM emit multiple pollutants, including CO_2, SO_2, and NO_x. Table 8-14 shows the emissions from units in the PJM footprint for 2012 through the first six months of 2015. PJM CO_2 emissions decreased by 19.7 percent from 261 million tons of CO_2 in the first six months of 2014 to 209 million tons of CO_2 in the first six months of 2015. PJM SO_2 emissions decreased by 36.0 percent from 552 thousand tons of SO_2 in the first six months of 2014 to 353 thousand tons of SO_2 in the first six months of 2015. PJM NO_x emissions decreased by 23.8 percent from 232 thousand tons of NO_x in the first six months of 2014 to 176 thousand tons of NO_x in the first six months of 2015 by PJM units.

105 See EPA, "Air Pollution Control Technology Fact Sheet," <http://www.epa.gov/ttnchie1/mkb/documents/ff-pulse.pdf> (Accessed July 1, 2015).

106 See EPA. "Mercury and Air Toxics Standards," <http://www.epa.gov/mats/index.html> (Accessed July 1, 2015).

Table 8-14 CO_2, SO_2 and NO_x emissions by month (short tons), by PJM units: January 2012 through June 2015[107]

	Short Tons											
	2012			2013			2014			2015		
	CO_2	SO_2	NO_x	CO_2	SO_2	NO_x	CO_2	SO_2	NO_x	CO_2	SO_2	NO_x
January	42,184,331	97,935	32,761	44,149,311	87,880	37,194	53,343,342	121,741	49,412	42,963,944	75,087	36,364
February	37,061,691	78,185	28,184	40,847,569	80,971	35,589	47,071,173	107,227	43,960	44,372,829	82,285	39,279
March	33,526,901	63,176	24,712	40,927,564	90,434	34,885	47,331,266	106,699	42,872	36,032,444	62,649	30,652
April	32,670,018	70,444	24,648	33,864,020	70,628	27,017	36,220,205	79,474	32,592	24,994,764	46,831	21,862
May	37,509,471	70,185	28,830	37,261,120	60,893	30,033	33,937,074	60,172	28,879	29,100,401	45,306	23,379
June	43,278,529	90,376	32,199	42,185,172	78,067	34,477	43,002,722	76,733	34,030	32,027,270	41,079	24,950
July	55,944,634	120,256	45,683	49,342,754	103,522	39,448	48,174,787	88,401	36,853			
August	50,622,632	104,590	39,666	46,306,760	86,744	34,161	45,074,885	79,827	35,949			
September	38,655,748	71,785	30,502	41,326,649	73,373	31,555	38,923,359	60,507	31,280			
October	34,630,973	57,200	29,031	38,321,257	66,528	29,953	34,291,532	61,146	30,866			
November	38,238,507	66,965	32,624	39,314,409	80,159	32,704	39,580,803	77,146	36,121			
December	41,606,237	82,321	35,709	44,944,175	88,764	38,514	40,496,686	71,679	34,700			
Total	485,929,672	973,418	384,548	498,790,759	967,963	405,529	507,447,832	990,750	437,511	209,491,653	353,239	176,487

Wind Units

Table 8-15 shows the capacity factor of wind units in PJM. In the first six months of 2015, the capacity factor of wind units in PJM was 30.3 percent. Wind units that were capacity resources had a capacity factor of 31.1 percent and an installed capacity of 6,109 MW. Wind units that were classified as energy only had a capacity factor of 19.8 percent and an installed capacity of 493 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.[108]

Table 8-15 Capacity factor of wind units in PJM: January through June 2015[109]

Type of Resource	Capacity Factor	Installed Capacity (MW)
Energy-Only Resource	19.8%	493
Capacity Resource	31.1%	6,109
All Units	30.3%	6,602

107 The emissions are calculated from the continuous emission monitoring system (CEMS) data from generators located within the PJM footprint.
108 Wind resources are derated to 13 percent unless demonstrating higher availability during peak periods.
109 Capacity factor is calculated based on online date of the resource.

Figure 8-5 shows the average hourly real time generation of wind units in PJM, by month. The highest average hour, 2,550.4 MW, occurred in February, and the lowest average hour, 1,110.1 MW, occurred in June. Wind output in PJM is generally higher in off-peak hours and lower in on-peak hours.

Figure 8-5 Average hourly real-time generation of wind units in PJM: January through June 2015

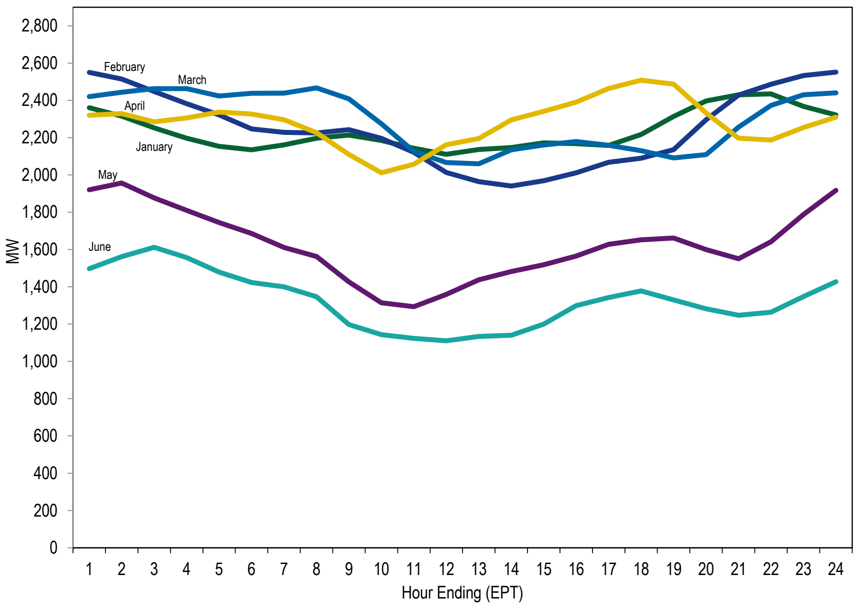


Table 8-16 shows the generation and capacity factor of wind units in each month of January 2014 through June 2015.

Table 8-16 Capacity factor of wind units in PJM by month: January 2014 through June 2015

	2014		2015	
Month	Generation (MWh)	Capacity Factor	Generation (MWh)	Capacity Factor
January	1,918,441.4	40.7%	1,664,426.8	33.9%
February	1,342,055.5	31.5%	1,511,093.1	34.1%
March	1,661,382.1	35.3%	1,701,249.6	34.7%
April	1,697,703.3	37.2%	1,641,965.0	34.5%
May	1,238,061.3	26.2%	1,209,088.5	24.6%
June	820,312.2	18.0%	955,156.7	20.1%
July	757,166.8	16.0%		
August	566,425.3	12.0%		
September	721,411.2	15.8%		
October	1,416,878.2	30.0%		
November	1,949,112.9	41.5%		
December	1,451,542.0	29.7%		
Annual	15,540,492.0	27.8%	8,682,979.6	30.3%

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 8-6 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 8-6 Average hourly day-ahead generation of wind units in PJM: January through June 2015

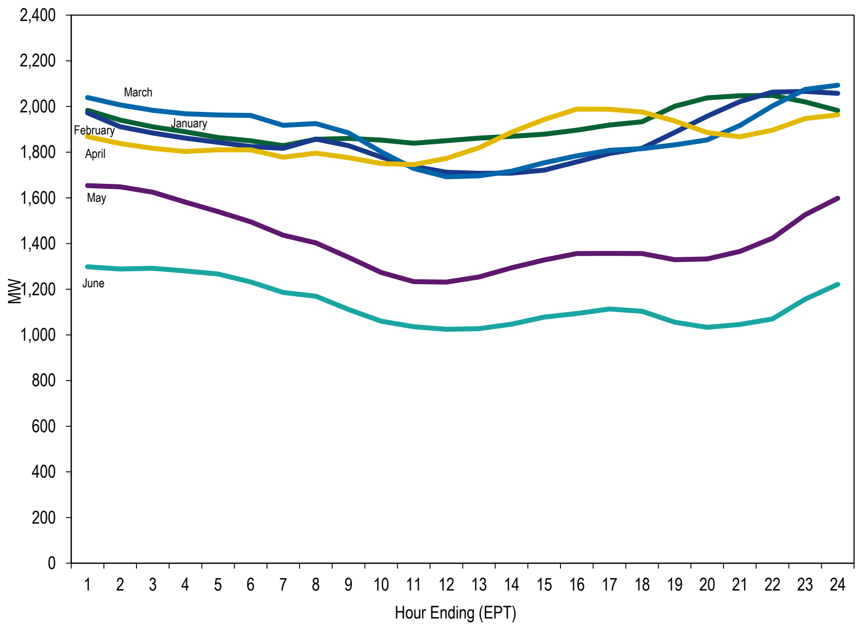
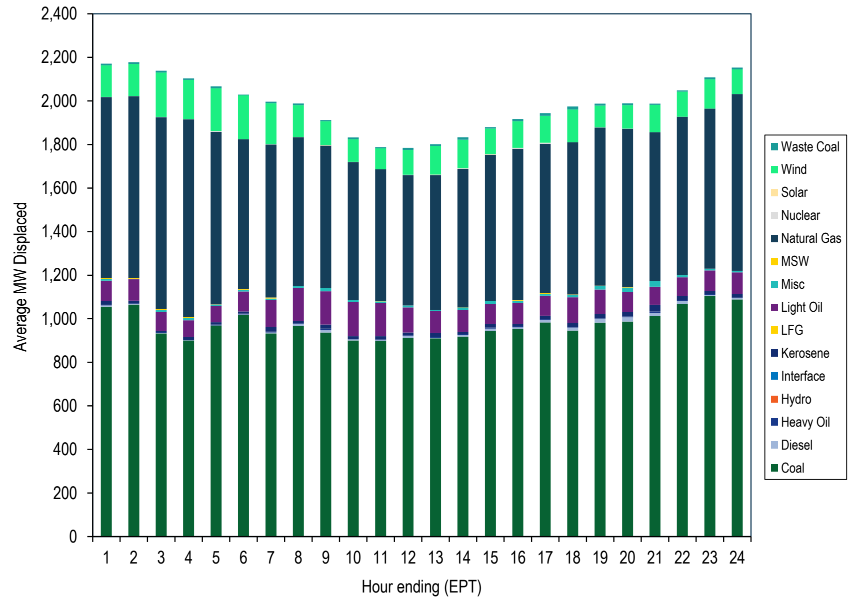


Figure 8-7 Marginal fuel at time of wind generation in PJM: January through June 2015

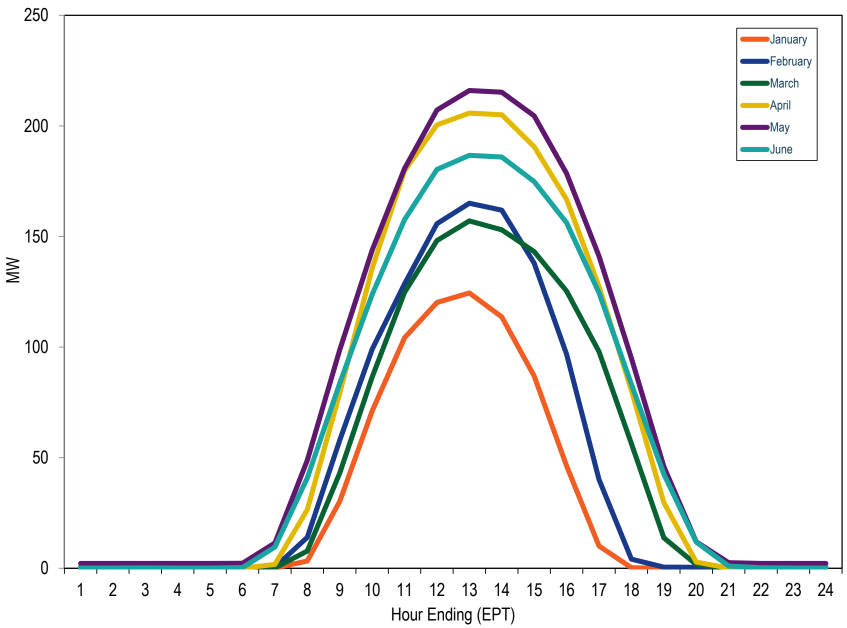


Output from wind turbines displaces output from other generation types. This displacement affects the output of marginal units in PJM. The magnitude and type of effect on marginal unit output depends on the level of the wind turbine output, its location, time and duration. One measure of this displacement is based on the mix of marginal units when wind is producing output. Figure 8-7 shows the hourly average proportion of marginal units by fuel type mapped to the hourly average MW of real-time wind generation through the first six months of 2015. Figure 8-7 shows potentially displaced marginal unit MW by fuel type in the first six months of 2015. 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.

Solar Units

Solar output differs from month to month, based on seasonal variation and daylight hours during the month. Figure 8-8 shows the average hourly real time generation of solar units in PJM, by month. Solar generation was highest in May, the month with the highest average hour, 216.0 MW, compared to 306.9 MW of solar installed capacity in PJM. Solar generation in PJM is highest during the hours of 11:00 through 13:00 EPT.

Figure 8-8 Average hourly real-time generation of solar units in PJM: January through June 2015



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 six months of 2015, PJM was a net importer of energy in the Real-Time Energy Market in all months.[1] In the first six months of 2015, the real-time net interchange of 10,817.3 GWh was higher than net interchange of 489.5 GWh in the first six months of 2014.
- **Aggregate Imports and Exports in the Day-Ahead Energy Market.** During the first six months of 2015, PJM was a net exporter of energy in the Day-Ahead Energy Market in February, and a net importer in the remaining months. In the first six months of 2015, the total day-ahead net interchange of 2,864.9 GWh was higher than net interchange of -8,952.7 GWh in the first six months of 2014. The large difference in the day-ahead net interchange totals was a result of the reduction in up-to congestion transaction volumes.[2]
- **Aggregate Imports and Exports in the Day-Ahead and the Real-Time Energy Market.** In the first six months of 2015, gross imports in the Day-Ahead Energy Market were 78.2 percent of gross imports in the Real-Time Energy Market (123.6 percent in the first six months of 2014). In the first six months of 2015, gross exports in the Day-Ahead Energy Market were 110.0 percent of the gross exports in the Real-Time Energy Market (162.8 percent in the first six months of 2014).
- **Interface Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, in the first six months of 2015, there were net scheduled exports at nine of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Real-Time Energy Market.** In the Real-Time Energy Market, in the first six months of 2015, there were net scheduled exports at 10 of PJM's 18 interface pricing points eligible for real-time transactions.[3]
- **Interface Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, in the first six months of 2015, there were net scheduled exports at nine of PJM's 20 interfaces.
- **Interface Pricing Point Imports and Exports in the Day-Ahead Energy Market.** In the Day-Ahead Energy Market, in the first six months of 2015, there were net scheduled exports at 10 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, in the first six months of 2015, up-to congestion transactions were net exports at four of PJM's 19 interface pricing points eligible for day-ahead transactions.
- **Loop Flows.** In the first six months of 2015, net scheduled interchange was 10,817 GWh and net actual interchange was 10,424 GWh, a difference of 393 GWh. In the first six months of 2014, net scheduled interchange was 489 GWh and net actual interchange was 586 GWh, a difference of 96 GWh. This difference is inadvertent interchange.

Interactions with Bordering Areas

PJM Interface Pricing with Organized Markets

- **PJM and MISO Interface Prices.** In the first six months of 2015, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface in 55.5 percent of the hours.

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.

2 On August 29, 2014, FERC issued an Order which created an obligation for UTCs to pay any uplift determined to be appropriate in the Commission review, effective September 8, 2014.

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

- **PJM and New York ISO Interface Prices.** In the first six months of 2015, the direction of the hourly flow was consistent with the real-time hourly price differences between the PJM/NYIS Interface and the NYISO/PJM proxy bus in 56.6 percent of the hours.
- **Neptune Underwater Transmission Line to Long Island, New York.** In the first six months of 2015, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Neptune Interface and the NYISO Neptune Bus in 56.0 percent of the hours.
- **Linden Variable Frequency Transformer (VFT) Facility.** In the first six months of 2015, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Linden Interface and the NYISO Linden Bus in 50.3 percent of the hours.
- **Hudson DC Line.** In the first six months of 2015, the hourly flow (PJM to NYISO) was consistent with the real-time hourly price differences between the PJM Hudson Interface and the NYISO Hudson Bus in 39.1 percent of the hours.

Interchange Transaction Issues

- **PJM Transmission Loading Relief Procedures (TLRs).** PJM issued 20 TLRs of level 3a or higher in the first six months of 2015, compared to three such TLRs issued in the first six months of 2014.
- **Up-To Congestion.** On August 29, 2014, FERC issued an Order which created an obligation for UTCs to pay any uplift determined to be appropriate in the Commission review, effective September 8, 2014.[4]

  The average number of up-to congestion bids decreased by 67.8 percent and the average cleared volume of up-to congestion bids decreased by 74.0 percent in the first six months of 2015, compared to the first six months in 2014 (Figure 9-13).
- **45 Minute Schedule Duration Rule.** Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule in response to Order No. 764.[5,6] PJM and the MMU issued a statement indicating ongoing concern about market participants' scheduling behavior, and a commitment to address any scheduling behavior that raises operational or market manipulation concerns.[7]

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 2012. Status: Not adopted.)
- 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. First reported 2009. Status: Not adopted.)
- The MMU recommends that the submission deadline for real-time dispatchable transactions be modified from 1200 on the 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. First reported Q3 2014. Status: Not adopted.)
- The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that remove the need for market participants to schedule physical transactions across seams.

4 148 FERC ¶ 61,144 (2014).Order Instituting Section 206 Proceeding and Establishing Procedures.

5 *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).

6 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).

7 *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>.

Such a solution would include an optimized joint dispatch approach that treats seams between balancing authorizes as constraints, similar to any other constraint within an LMP market. (Priority: Medium. First reported 2013. Status: Not adopted.)

- 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- The MMU recommends that the validation method also require market participants to submit transactions on market paths that reflect the expected actual power flow in order to reduce unscheduled loop flows. (Priority: Medium. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted. Stakeholder process.)
- 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. Status: Not adopted.)
- The MMU recommends that PJM immediately provide the required 12-month notice to Duke Energy Progress (DEP) to unilaterally terminate the Joint Operating Agreement. (Priority: Low. First reported 2013. Status: Not adopted.)
- 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. Status: Adopted partially, Q4 2013.)
- The MMU recommends that PJM implement additional business rules to remove the incentive to engage in sham scheduling activities using the PJM/IMO interface price. (Priority: Medium. First reported 2014. Status: Not adopted. Stakeholder process.)
- The MMU recommends that PJM file revisions to the marginal loss surplus allocation method to fully comply with the February 24, 2009, Order. The MMU recommends that marginal loss surplus allocations be capped such that the marginal loss surplus credits cannot exceed the contributions made to the fixed costs of the transmission system for any reason. (Priority: Medium. First reported 2014. Status: Not adopted.)

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.

Interchange Transaction Activity

Aggregate Imports and Exports

In the first six months of 2015, PJM was a monthly net importer of energy in the Real-Time Energy Market in all months (Figure 9-1).[8] In the first six months of 2015, the total real-time net interchange of 10,817.3 GWh was higher than the net interchange of 489.5 GWh in the first six months of 2014. In the first six months of 2015, the peak month for net importing interchange was April, 2,293.9 GWh; in the first six months of 2014 it was January, 1,556.0 GWh. Gross monthly export volumes in the first six months of 2015 averaged 2,923.4 GWh compared to 4,066.2 GWh in the first six months of 2014, while gross monthly imports in the first six months of 2015 averaged 4,726.3 GWh compared to 4,147.8 GWh in the first six months of 2014.

In the first six months of 2015, PJM was a monthly net exporter of energy in the Day-Ahead Energy Market in February, and a net importer in the remaining months (Figure 9-1). In the first six months of 2015, the total day-ahead net interchange of 2,864.9 GWh was higher than the net interchange of -8,952.7 GWh in the first six months of 2014. The large difference in the day-ahead net interchange totals was a result of the reduction in up-to congestion transaction volumes.[9] In the first six months of 2015, the peak month for net exporting interchange was February, -122.7 GWh; in the first six months of 2014 it was April, -1,992.1 GWh. Gross monthly export volumes in the first six months of 2015 averaged 3,216.2 GWh compared to 6,619.5 GWh in the first six months of 2014, while gross monthly imports in the first six months of 2015 averaged 3,693.7 GWh compared to 5,127.3 GWh in the first six months of 2014.

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 six months of 2015, gross imports in the Day-Ahead Energy Market were 78.2 percent of gross imports in the Real-Time Energy Market (123.6 percent in the first six months of 2014). In the first six months of 2015, gross exports in the Day-Ahead Energy Market were 110.0 percent of gross exports in the Real-Time Energy Market (162.8 percent in the first six months of 2014). In the first six months of 2015, net interchange was 2,864.9 GWh in the Day-Ahead Energy Market and 10,817.3 GWh in the Real-Time Energy Market compared to -8,952.7 GWh in the Day-Ahead Energy Market and 489.5 GWh in the Real-Time Energy Market in the first six months of 2014.

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.[10] In the first six months of 2015, the total day-ahead imports and exports were lower 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.

8 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.

9 On August 29, 2014, FERC issued an Order which created an obligation for UTCs to pay any uplift determined to be appropriate in the Commission review, effective September 8, 2014.

10 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 June 2015

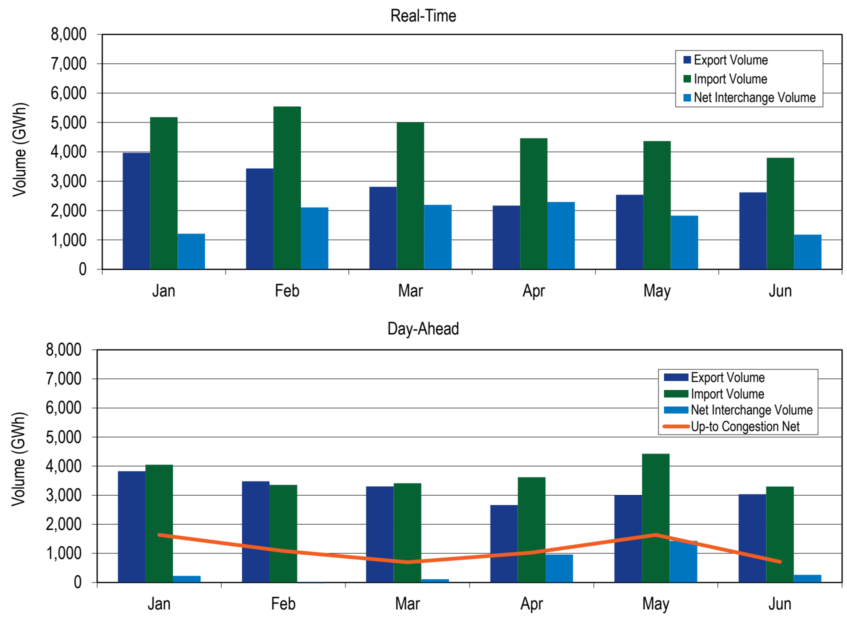
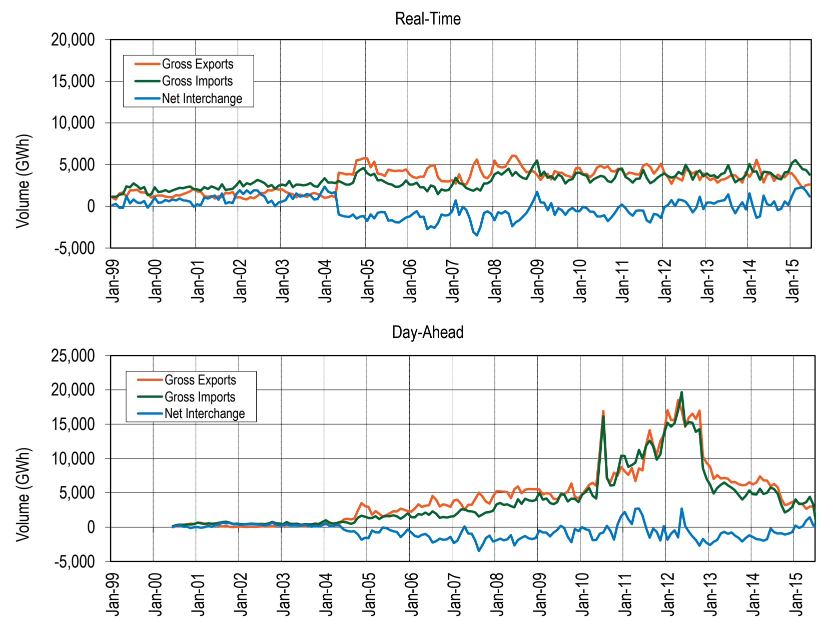


Figure 9-2 shows the real-time and day-ahead import and export volume for PJM from 1999 through June, 2015. PJM became a consistent net exporter of energy in 2004 in both the Real-Time and Day-Ahead Energy Markets, coincident with the expansion of the PJM footprint that included the integrations of Commonwealth Edison, American Electric Power and Dayton Power and Light into PJM. 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: January 1999 through June 2015



Real-Time Interface Imports and Exports

In the Real-Time Energy Market, scheduled imports and exports are defined 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. Table 9-16 includes a list of active interfaces in the first six months of 2015. Figure 9-3 shows the approximate geographic location of the interfaces. In the first six months of 2015, 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 ten separate interfaces that make up the MISO Interface between 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 six months of 2015 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 six months of 2015, there were net scheduled exports at nine of PJM's 20 interfaces. The top three net exporting interfaces in the Real-Time Energy Market accounted for 74.7 percent of the total net exports: PJM/MidAmerican Energy Company (MEC) with 31.7 percent, PJM/Neptune (NEPT) with 21.9 percent and PJM/New York Independent System Operator (NYIS) with 21.1 percent of the net export volume. The four separate interfaces that connect PJM to the NYISO (PJM/NYIS, PJM/NEPT, PJM/HUDS and PJM/Linden (LIND)) together represented 50.6 percent of the total net PJM exports in the Real-Time Energy Market. In the first six months of 2015, four of the ten separate interfaces that connect PJM to MISO were net exporters in the Real-Time Energy Market. Those four interfaces represented 47.9 percent of the total net PJM exports in the Real-Time Energy Market. Ten PJM interfaces had net scheduled imports, with three importing interfaces accounting for 57.5 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 22.4 percent, PJM/Ameren-Illinois (AMIL) with 18.6 percent and PJM/Tennessee Valley Authority (TVA) with 16.6 percent of the net import volume.[11]

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.[12]

Table 9-1 Real-time scheduled net interchange volume by interface (GWh): January through June 2015

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	(19.8)	(27.2)	(34.2)	(18.3)	(0.4)	(28.4)	(128.3)
CPLW	0.0	0.0	0.0	0.0	0.0	0.2	0.2
DUK	423.3	377.0	443.5	528.0	367.9	110.9	2,250.6
LGEE	233.4	277.9	225.6	157.0	221.2	196.1	1,311.2
MISO	521.9	1,287.7	1,369.8	630.1	150.9	195.4	4,155.9
ALTE	(346.8)	(76.5)	279.7	(230.8)	(111.0)	(351.6)	(837.0)
ALTW	2.6	(0.1)	(0.7)	(2.9)	(38.3)	(0.8)	(40.1)
AMIL	778.3	863.7	394.9	518.6	445.9	577.6	3,579.0
CIN	281.9	355.4	336.2	399.5	71.6	25.7	1,470.4
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	145.7	294.5	292.0	166.9	119.5	86.2	1,104.8
MEC	(483.8)	(422.6)	(348.3)	(465.5)	(500.2)	(460.5)	(2,680.9)
MECS	260.2	347.2	412.9	292.5	263.0	357.3	1,933.0
NIPS	1.4	18.9	31.1	23.9	34.9	3.3	113.6
WEC	(117.7)	(92.9)	(27.9)	(72.1)	(134.4)	(41.8)	(486.9)
NYISO	(1,571.6)	(1,341.2)	(1,109.3)	(129.3)	75.1	(198.7)	(4,275.2)
HUDS	(117.6)	(82.7)	(49.0)	(0.1)	(5.2)	(5.4)	(260.1)
LIND	(218.7)	(130.3)	(156.3)	7.4	76.9	38.0	(383.1)
NEPT	(326.4)	(318.6)	(437.9)	(289.5)	(167.5)	(309.1)	(1,849.0)
NYIS	(908.9)	(809.6)	(466.2)	152.9	170.9	77.8	(1,783.1)
OVEC	875.5	765.9	828.2	635.4	560.3	641.1	4,306.4
TVA	750.1	766.4	473.6	491.1	453.5	262.0	3,196.6
Total	1,212.7	2,106.6	2,197.2	2,293.9	1,828.4	1,178.6	10,817.3

11 In the Real-Time Energy Market, one PJM interface had a net interchange of zero (PJM/City Water Light & Power (CWLP)).

12 See "Ohio Valley Electric Corporation: Company Background," <http://www.ovec.com/OVECHistory.pdf>.

Table 9-2 Real-time scheduled gross import volume by interface (GWh): January through June 2015

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	7.6	7.8	6.6	6.4	12.2	2.8	43.4
CPLW	0.0	0.0	0.0	0.0	0.0	0.2	0.2
DUK	586.1	510.0	485.3	563.1	460.9	271.0	2,876.4
LGEE	233.8	277.9	225.6	157.4	221.2	196.9	1,312.8
MISO	1,720.3	1,966.0	1,935.1	1,575.0	1,617.8	1,361.4	10,175.6
ALTE	3.1	16.9	379.5	6.8	326.1	1.6	734.0
ALTW	2.8	0.4	0.0	0.0	0.0	1.3	4.5
AMIL	794.4	866.7	405.6	526.3	451.5	587.4	3,631.9
CIN	360.4	369.6	378.8	461.8	175.3	159.1	1,905.0
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	220.2	337.6	311.0	237.7	241.9	129.7	1,478.2
MEC	0.8	0.1	0.0	0.0	0.4	0.1	1.3
MECS	337.2	355.4	421.1	318.4	386.8	479.0	2,298.0
NIPS	1.4	18.9	31.1	23.9	35.8	3.3	114.4
WEC	0.0	0.4	7.9	0.0	0.0	0.0	8.3
NYISO	959.9	1,196.4	1,020.1	1,013.1	1,000.7	992.1	6,182.4
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LIND	2.2	28.4	1.8	41.3	84.8	55.0	213.6
NEPT	0.0	0.0	0.0	0.0	0.1	0.0	0.2
NYIS	957.7	1,168.0	1,018.3	971.7	915.8	937.0	5,968.5
OVEC	901.8	790.7	849.6	651.8	576.6	655.7	4,426.2
TVA	769.8	794.5	486.4	496.7	476.7	316.7	3,340.8
Total	5,179.2	5,543.3	5,008.7	4,463.6	4,366.2	3,796.9	28,357.8

Table 9-3 Real-time scheduled gross export volume by interface (GWh): January through June 2015

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	27.4	35.0	40.8	24.7	12.7	31.2	171.7
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	162.8	132.9	41.8	35.1	93.0	160.1	625.8
LGEE	0.3	0.0	0.0	0.4	0.0	0.8	1.6
MISO	1,198.4	678.3	565.2	944.9	1,466.9	1,166.1	6,019.8
ALTE	350.0	93.4	99.8	237.6	437.1	353.2	1,571.1
ALTW	0.2	0.4	0.7	2.9	38.3	2.0	44.5
AMIL	16.1	3.0	10.7	7.7	5.6	9.8	53.0
CIN	78.5	14.1	42.7	62.3	103.7	133.3	434.6
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	74.5	43.1	19.0	70.8	122.5	43.5	373.4
MEC	484.6	422.6	348.3	465.5	500.6	460.6	2,682.2
MECS	76.9	8.2	8.3	25.9	123.9	121.7	364.9
NIPS	0.0	0.0	0.0	0.0	0.9	0.0	0.9
WEC	117.7	93.3	35.8	72.1	134.4	41.8	495.1
NYISO	2,531.5	2,537.7	2,129.5	1,142.4	925.6	1,190.9	10,457.6
HUDS	117.6	82.7	49.0	0.1	5.2	5.5	260.1
LIND	220.9	158.8	158.1	33.9	7.9	17.0	596.6
NEPT	326.4	318.6	437.9	289.5	167.6	309.1	1,849.2
NYIS	1,866.6	1,977.5	1,484.5	818.9	744.9	859.2	7,751.7
OVEC	26.3	24.7	21.4	16.5	16.4	14.6	119.8
TVA	19.7	28.1	12.8	5.7	23.2	54.7	144.2
Total	3,966.5	3,436.7	2,811.6	2,169.7	2,537.8	2,618.3	17,540.5

Real-Time Interface Pricing Point Imports and Exports

Interfaces differ from interface pricing points. An interface is a point of interconnection between PJM and a neighboring balancing authority which market participants may designate as a market path on which scheduled imports or exports will flow.[13] 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

13 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, the transmission costs for moving energy from generation to load and interface prices.

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 PJM/MISO Interface based on the scheduled market path of the transaction. However, the physical flow of energy does not enter the PJM footprint at the PJM/MISO 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.[14]

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.[15] 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.[16] 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 six months of 2015. On September 16, 2014, PJM updated the mappings of external balancing authorities to individual pricing points. The MMU recommends that PJM review these mappings, at least annually, to reflect the fact that changes to the system topology can affect the impact of external power sources on PJM tie lines.

The interface pricing method 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.[17] 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.

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), but participants do not always do so. This path is utilized by PJM to determine the interface pricing point that 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 and the breaking of transactions into portions can be a way to manipulate markets.

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 six months of 2015, there were net scheduled exports at 10 of PJM's 18 interface pricing points eligible for

14 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.

15 See "Interface Pricing Point Assignment Methodology," (August 28, 2014) <http://www.pjm.com/~/media/etools/exschedule/interface-pricing-point-assignment-methodology.ashx>. PJM periodically updates these definitions on its website.

16 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>.

17 On June 1, 2015, PJM began using a dynamic weighting factor in the calculation for the Ontario Interface Pricing Point. For additional information, see "Elimination of Ontario Interface Pricing Point."

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 84.0 percent of the total net exports: PJM/MISO with 48.7 percent, PJM/NEPTUNE with 18.4 percent and PJM/NYIS with 16.9 percent and of the net export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 41.8 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 76.2 percent of the total net imports: PJM/SouthIMP with 55.5 percent and PJM/Ohio Valley Electric Corporation (OVEC) with 20.6 percent of the net import volume.[20]

Table 9-4 Real-time scheduled net interchange volume by interface pricing point (GWh): January through June 2015

	Jan	Feb	Mar	Apr	May	Jun	Total
IMO	666.5	687.6	890.4	713.1	654.4	427.7	4,039.6
MISO	(1,028.3)	(396.8)	(312.1)	(801.1)	(1,323.3)	(1,027.7)	(4,889.3)
NORTHWEST	(1.0)	0.2	(3.7)	(2.2)	(2.3)	(2.3)	(11.4)
NYISO	(1,568.5)	(1,262.5)	(1,090.7)	(129.7)	70.9	(213.3)	(4,193.9)
HUDSONTP	(117.6)	(82.7)	(49.0)	(0.1)	(5.2)	(5.4)	(260.1)
LINDENVFT	(218.7)	(130.3)	(156.3)	7.4	76.9	38.0	(383.1)
NEPTUNE	(326.4)	(318.6)	(437.9)	(289.5)	(167.5)	(309.1)	(1,849.0)
NYIS	(905.8)	(730.9)	(447.6)	152.5	166.7	63.2	(1,701.8)
OVEC	875.5	765.9	828.2	635.4	560.3	641.1	4,306.4
Southern Imports	2,482.1	2,508.5	1,980.8	1,944.4	1,997.4	1,600.3	12,513.4
CPLEIMP	7.6	7.3	5.2	6.3	11.8	2.4	40.6
DUKIMP	50.4	54.7	36.8	51.5	52.7	42.6	288.7
NCMPAIMP	105.6	47.1	28.9	170.1	164.8	86.4	603.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	2,318.5	2,399.4	1,909.8	1,716.5	1,768.1	1,468.8	11,581.1
Southern Exports	(213.5)	(196.2)	(95.6)	(66.1)	(129.0)	(247.1)	(947.6)
CPLEEXP	(19.7)	(31.2)	(36.4)	(24.7)	(10.8)	(31.0)	(153.8)
DUKEXP	(115.6)	(113.1)	(28.9)	(16.8)	(59.8)	(96.3)	(430.5)
NCMPAEXP	0.0	(0.2)	(0.1)	0.0	(0.0)	0.0	(0.3)
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	(78.2)	(51.7)	(30.3)	(24.5)	(58.4)	(119.9)	(363.0)
Total	1,212.7	2,106.6	2,197.2	2,293.9	1,828.4	1,178.6	10,817.3

Table 9-5 Real-time scheduled gross import volume by interface pricing point (GWh): January through June, 2015

	Jan	Feb	Mar	Apr	May	Jun	Total
IMO	672.1	766.7	909.0	713.7	654.7	428.0	4,144.2
MISO	165.2	280.9	249.0	141.2	141.2	135.8	1,113.3
NORTHWEST	0.0	0.2	0.1	0.0	0.0	0.0	0.3
NYISO	958.0	1,196.4	1,020.1	1,012.4	996.2	977.2	6,160.4
HUDSONTP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LINDENVFT	2.2	28.4	1.8	41.3	84.8	55.0	213.6
NEPTUNE	0.0	0.0	0.0	0.0	0.1	0.0	0.2
NYIS	955.8	1,168.0	1,018.3	971.1	911.4	922.1	5,946.6
OVEC	901.8	790.7	849.6	651.8	576.6	655.7	4,426.2
Southern Imports	2,482.1	2,508.5	1,980.8	1,944.4	1,997.4	1,600.3	12,513.4
CPLEIMP	7.6	7.3	5.2	6.3	11.8	2.4	40.6
DUKIMP	50.4	54.7	36.8	51.5	52.7	42.6	288.7
NCMPAIMP	105.6	47.1	28.9	170.1	164.8	86.4	603.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	2,318.5	2,399.4	1,909.8	1,716.5	1,768.1	1,468.8	11,581.1
Southern Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	5,179.2	5,543.3	5,008.7	4,463.6	4,366.2	3,796.9	28,357.8

19 There is one interface pricing point eligible for day-ahead transaction scheduling only (NIPSCO).
20 In the Real-Time Energy Market, two PJM interface pricing points had a net interchange of zero (Southeast and Southwest).

Table 9-6 Real-time scheduled gross export volume by interface pricing point (GWh): January through June 2015

	Jan	Feb	Mar	Apr	May	Jun	Total
IMO	5.6	79.1	18.6	0.6	0.3	0.3	104.5
MISO	1,193.5	677.7	561.2	942.3	1,464.4	1,163.4	6,002.5
NORTHWEST	1.0	0.0	3.9	2.2	2.3	2.3	11.7
NYISO	2,526.6	2,459.0	2,110.8	1,142.1	925.3	1,190.5	10,354.3
HUDSONTP	117.6	82.7	49.0	0.1	5.2	5.5	260.1
LINDENVFT	220.9	158.8	158.1	33.9	7.9	17.0	596.6
NEPTUNE	326.4	318.6	437.9	289.5	167.6	309.1	1,849.2
NYIS	1,861.6	1,898.8	1,465.8	818.5	744.7	858.9	7,648.4
OVEC	26.3	24.7	21.4	16.5	16.4	14.6	119.8
Southern Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	213.5	196.2	95.6	66.1	129.0	247.1	947.6
CPLEEXP	19.7	31.2	36.4	24.7	10.8	31.0	153.8
DUKEXP	115.6	113.1	28.9	16.8	59.8	96.3	430.5
NCMPAEXP	0.0	0.2	0.1	0.0	0.0	0.0	0.3
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	78.2	51.7	30.3	24.5	58.4	119.9	363.0
Total	3,966.5	3,436.7	2,811.6	2,169.7	2,537.8	2,618.3	17,540.5

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.[21] 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.[22]

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 six months of 2015 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 six months of 2015, there were net scheduled exports at nine of PJM's 20 interfaces. The top three net exporting interfaces in the Day-Ahead Energy Market accounted for 78.0 percent of the total net exports: PJM/New York Independent System Operator, Inc. (NYIS) with 32.5 percent, PJM/MidAmerican Energy Company (MEC) with

21 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.

22 See the *2010 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," for details.

26.8 percent and PJM/Neptune (NEPT) with 18.7 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 53.7 percent of the total net PJM exports in the Day-Ahead Energy Market. In the first six months of 2015, four of the ten separate interfaces that connect PJM to MISO were net exporters in the Day-Ahead Energy Market. Those four interfaces represented 45.4 percent of the total net PJM exports in the Day-Ahead Energy Market. Nine PJM interfaces had net scheduled imports, with two importing interfaces accounting for 77.4 percent of the total net imports: PJM/Ohio Valley Electric Corporation (OVEC) with 51.2 percent and PJM/DUK with 26.2 percent of the net import volume.[23]

Table 9-7 Day-Ahead scheduled net interchange volume by interface (GWh): January through June 2015

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	(13.7)	(13.2)	(16.7)	(18.3)	(7.9)	(27.5)	(97.2)
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	291.6	240.9	239.7	348.2	332.3	130.2	1,583.0
LGEE	0.0	0.3	0.0	0.0	0.0	0.0	0.3
MISO	(840.5)	(432.2)	(156.1)	(565.4)	(808.8)	(743.2)	(3,546.2)
ALTE	(346.7)	(87.6)	(70.8)	(204.1)	(318.8)	(300.5)	(1,328.5)
ALTW	0.0	0.5	0.0	(2.6)	(27.7)	(2.0)	(31.8)
AMIL	35.1	38.0	51.7	61.2	4.0	38.2	228.2
CIN	10.2	56.8	42.7	32.8	39.0	(0.6)	180.9
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	6.3	1.0	11.9	35.9	(0.8)	54.3
MEC	(485.4)	(422.6)	(348.0)	(460.5)	(496.4)	(459.2)	(2,672.2)
MECS	65.2	61.4	161.4	64.8	81.8	21.5	456.1
NIPS	0.0	8.3	32.4	4.5	7.7	3.2	56.1
WEC	(118.9)	(93.3)	(26.4)	(73.4)	(134.3)	(43.0)	(489.3)
NYISO	(1,551.8)	(1,555.6)	(1,284.5)	(381.6)	(226.7)	(351.0)	(5,351.2)
HUDS	(105.4)	(76.4)	(41.6)	0.0	(1.5)	(1.9)	(226.7)
LIND	(13.1)	(8.4)	(10.7)	0.5	3.3	4.0	(24.5)
NEPT	(329.9)	(317.8)	(441.5)	(294.6)	(170.0)	(307.1)	(1,860.8)
NYIS	(1,103.3)	(1,153.1)	(790.7)	(87.6)	(58.5)	(46.1)	(3,239.3)
OVEC	645.3	515.5	579.0	444.5	414.5	499.1	3,097.9
TVA	60.1	38.1	56.1	105.7	93.1	41.3	394.3
Total without Up-To Congestion	(1,408.8)	(1,206.3)	(582.5)	(66.9)	(203.5)	(451.1)	(3,919.2)
Up-To Congestion	1,633.0	1,083.6	693.6	1,025.9	1,636.5	711.4	6,784.0
Total	224.1	(122.7)	111.1	959.0	1,433.0	260.3	2,864.9

23 In the Day-Ahead Energy Market, two PJM interfaces had a net interchange of zero (PJM/Duke Energy Progress West (CPLW) and PJM/City Water Light & Power (CWLP)).

Table 9-8 Day-Ahead scheduled gross import volume by interface (GWh): January through June 2015

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	2.2	2.0	2.1	2.2	2.1	2.1	12.8
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	309.3	255.9	241.6	348.2	333.9	155.8	1,644.7
LGEE	0.0	0.3	0.0	0.0	0.0	0.0	0.3
MISO	187.7	193.2	320.9	199.5	225.2	158.7	1,285.2
ALTE	1.2	15.4	9.1	5.3	0.0	0.0	31.0
ALTW	0.0	0.5	0.0	0.0	0.0	0.0	0.5
AMIL	35.1	38.0	51.7	61.2	4.0	38.2	228.2
CIN	14.3	57.0	42.9	32.8	42.1	22.3	211.6
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	6.3	1.0	11.9	35.9	0.0	55.1
MEC	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MECS	137.0	67.7	174.5	83.8	135.5	94.9	693.4
NIPS	0.0	8.3	32.4	4.5	7.7	3.2	56.1
WEC	0.0	0.0	9.4	0.0	0.0	0.0	9.4
NYISO	677.5	679.3	617.1	707.4	645.0	742.4	4,068.7
HUDS	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LIND	0.2	1.5	0.3	0.8	3.5	4.6	10.9
NEPT	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NYIS	677.4	677.8	616.7	706.6	641.5	737.8	4,057.8
OVEC	672.2	540.2	600.4	459.3	430.9	499.1	3,202.1
TVA	69.8	68.1	63.6	105.7	102.9	75.4	485.5
Total without Up-To Congestion	1,918.8	1,739.0	1,845.7	1,822.4	1,740.0	1,633.4	10,699.3
Up-To Congestion	2,131.5	1,617.4	1,568.5	1,798.0	2,684.6	1,662.8	11,462.8
Total	4,050.2	3,356.4	3,414.3	3,620.4	4,424.6	3,296.2	22,162.1

Table 9-9 Day-Ahead scheduled gross export volume by interface (GWh): January through June 2015

	Jan	Feb	Mar	Apr	May	Jun	Total
CPLE	15.9	15.2	18.9	20.5	10.0	29.6	110.0
CPLW	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUK	17.6	15.1	1.9	0.0	1.6	25.5	61.8
LGEE	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MISO	1,028.2	625.4	477.0	764.9	1,033.9	901.9	4,831.3
ALTE	347.9	103.0	79.9	209.4	318.8	300.5	1,359.5
ALTW	0.0	0.0	0.0	2.6	27.7	2.0	32.3
AMIL	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CIN	4.1	0.2	0.3	0.0	3.1	23.0	30.6
CWLP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
IPL	0.0	0.0	0.0	0.0	0.0	0.8	0.8
MEC	485.4	422.6	348.0	460.5	496.4	459.2	2,672.2
MECS	71.9	6.3	13.1	19.0	53.7	73.4	237.3
NIPS	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WEC	118.9	93.3	35.8	73.4	134.3	43.0	498.7
NYISO	2,229.3	2,235.0	1,901.6	1,089.0	871.7	1,093.4	9,419.9
HUDS	105.4	76.4	41.6	0.0	1.5	1.9	226.7
LIND	13.3	9.9	11.1	0.3	0.2	0.6	35.3
NEPT	329.9	317.8	441.5	294.6	170.0	307.1	1,860.8
NYIS	1,780.7	1,830.9	1,407.5	794.2	700.0	783.8	7,297.1
OVEC	26.9	24.7	21.4	14.9	16.4	0.0	104.3
TVA	9.8	30.0	7.4	0.0	9.9	34.1	91.2
Total without Up-To Congestion	3,327.6	2,945.3	2,428.2	1,889.3	1,943.5	2,084.5	14,618.4
Up-To Congestion	498.5	533.8	875.0	772.1	1,048.1	951.3	4,678.8
Total	3,826.1	3,479.1	3,303.2	2,661.4	2,991.6	3,035.8	19,297.2

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 six months of 2015, up-to congestion transactions accounted for 51.7 percent of all scheduled import MW transactions, 24.2 percent of all scheduled export MW transactions and 236.8 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 six months of 2015 in Table 9-10. Up-to congestion transactions by interface pricing point in the first six months of 2015 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. On August 29, 2014, FERC issued an Order which created an obligation for UTCs to pay any uplift determined to be appropriate in the Commission review, effective September 8, 2014.[24] 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.

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 for the stated purpose of facilitating the long term day-ahead positions created at the NIPSCO Interface prior to the integration. In the first six months of 2015, the day-ahead net scheduled interchange at the NIPSCO interface pricing point was -593.6 GWh (See Table 9-10) and the up-to congestion net scheduled interchange at the NIPSCO interface pricing point was -593.6 GWh (See Table 9-11). While there is no corresponding interface pricing point available for real-time transaction scheduling, a real-time LMP is still calculated. This real-time price is used for balancing the deviations between the Day-Ahead and Real-Time Energy Markets.

PJM consolidated the Southeast and Southwest interface pricing points to a single interface with separate import and export prices (SouthIMP

24 148 FERC ¶ 61,144 (2014). *Order Instituting Section 206 Proceeding and Establishing Procedures.*

and SouthEXP) on October 31, 2006. At that time, the real-time Southeast and Southwest interface pricing points remained only to support certain grandfathered agreements with specific generating units and to price energy under the reserve sharing agreement with VACAR. PJM also kept the day-ahead Southeast and Southwest interface pricing points to facilitate long-term day-ahead positions that were entered prior to the consolidation.

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 six months of 2015, there were net scheduled exports at 10 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 75.9 percent of the total net exports: PJM/NYIS with 33.6 percent, PJM/NEPTUNE with 22.2 percent and PJM/Northwest with 20.0 percent of the net export volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 58.3 percent of the total net PJM exports in the Day-Ahead Energy Market. Nine PJM interface pricing points had net imports, with three importing interface pricing points accounting for 84.7 percent of the total net imports: PJM/SouthImp with 35.3 percent, PJM/Ohio Valley Electric Corporation (OVEC) with 34.8 percent and PJM/Southeast with 14.6 percent of the net import volume.

In the Day-Ahead Energy Market, in the first six months of 2015, up-to congestion transactions had net exports at four of PJM's 19 interface pricing points eligible for day-ahead transactions. The top two net exporting interface pricing points eligible for up-to congestion transactions accounted for 73.2 percent of the total net up-to congestion exports: PJM/NIPSCO with 48.8 percent and PJM/SouthEXP with 24.4 percent of the net export up-to congestion volume. The four separate interface pricing points that connect PJM to the NYISO (PJM/NYIS, PJM/NEPTUNE, PJM/HUDSONTP and PJM/LINDENVFT) together represented 14.7 percent of the net up-to congestion PJM exports in the Day-Ahead Energy Market. All of the net exports were on PJM/NEPTUNE while the PJM/HUDSONTP, PJM/LINDENVFT and PJM/NYIS interface pricing points all had net import up-to congestion. Nine PJM interface pricing points had net up-to congestion imports, with three importing interface pricing points accounting for 66.5 percent of the total net up-to congestion imports: PJM/SouthIMP with 30.4 percent, PJM/Southeast with 21.9 percent and PJM/MISO with 14.1 percent of the net import volume.[25]

Table 9-10 Day-ahead scheduled net interchange volume by interface pricing point (GWh): January through June 2015

	Jan	Feb	Mar	Apr	May	Jun	Total
IMO	249.6	154.7	182.3	22.2	(57.3)	65.0	616.5
MISO	(364.2)	(0.2)	198.3	(83.2)	(321.4)	(264.5)	(835.2)
NIPSCO	(52.8)	(42.7)	(146.5)	(132.0)	(155.5)	(64.1)	(593.6)
NORTHWEST	(449.3)	(418.3)	(279.5)	(299.4)	(171.0)	(223.2)	(1,840.7)
NYISO	(1,494.9)	(1,528.5)	(1,398.2)	(366.2)	(134.3)	(330.6)	(5,252.7)
HUDS	(62.2)	(43.7)	(138.3)	(3.8)	30.9	(8.4)	(225.5)
LINDENVFT	17.5	44.6	27.7	8.3	0.9	2.2	101.3
NEPTUNE	(421.7)	(341.7)	(443.8)	(299.5)	(179.5)	(353.1)	(2,039.2)
NYIS	(1,028.5)	(1,187.8)	(843.9)	(71.2)	13.4	28.7	(3,089.3)
OVEC	1,113.6	653.6	715.3	525.2	501.0	688.2	4,197.0
Southern Imports	1,395.3	1,230.8	971.5	1,469.8	2,065.7	829.0	7,962.2
CPLEIMP	2.2	2.0	2.1	2.2	2.1	2.1	12.8
DUKIMP	2.4	0.4	2.7	4.9	1.1	3.0	14.5
NCMPAIMP	109.5	51.0	30.5	165.1	158.6	83.8	598.6
SOUTHEAST	360.0	150.0	183.5	184.8	664.9	270.1	1,813.3
SOUTHWEST	179.4	135.9	172.3	291.4	315.0	171.7	1,265.8
SOUTHIMP	741.7	891.5	580.4	821.4	923.9	298.3	4,257.3
Southern Exports	(173.3)	(172.1)	(132.0)	(177.5)	(294.2)	(439.6)	(1,388.7)
CPLEEXP	(15.1)	(14.6)	(18.0)	(19.3)	(9.5)	(29.3)	(105.8)
DUKEXP	(8.3)	(13.1)	(1.9)	0.0	0.0	(18.2)	(41.4)
NCMPAEXP	(0.8)	(1.4)	(0.9)	(1.1)	(0.5)	(0.4)	(5.1)
SOUTHEAST	(2.3)	(17.7)	(9.5)	(5.3)	(0.6)	(22.5)	(57.8)
SOUTHWEST	(98.5)	(57.1)	(44.2)	(127.2)	(208.0)	(236.4)	(771.5)
SOUTHEXP	(48.3)	(68.2)	(57.6)	(24.5)	(75.6)	(133.0)	(407.1)
Total	224.1	(122.7)	111.1	959.0	1,433.0	260.3	2,864.9

25 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 up-to congestion net interchange of zero.

Table 9-11 Up-to congestion scheduled net interchange volume by interface pricing point (GWh): January through June 2015

	Jan	Feb	Mar	Apr	May	Jun	Total
IMO	113.6	93.9	1.4	(92.8)	(211.0)	(52.2)	(147.2)
MISO	164.3	126.4	247.7	211.4	225.0	152.8	1,127.6
NIPSCO	(52.8)	(42.7)	(146.5)	(132.0)	(155.5)	(64.1)	(593.6)
NORTHWEST	36.1	4.3	68.4	161.1	311.3	236.0	817.3
NYISO	56.5	22.6	(115.6)	15.4	92.4	20.5	91.9
HUDSONTP	43.2	32.7	(96.7)	(3.8)	32.4	(6.6)	1.3
LINDENVFT	30.7	53.0	38.4	7.8	(2.4)	(1.7)	125.7
NEPTUNE	(91.8)	(23.9)	(2.3)	(4.9)	(9.5)	(46.0)	(178.5)
NYIS	74.4	(39.1)	(54.9)	16.3	71.9	74.7	143.4
OVEC	468.3	138.2	136.3	84.9	86.5	186.4	1,100.5
Southern Imports	977.0	852.8	605.7	934.9	1,560.5	582.3	5,513.2
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	360.0	150.0	183.5	184.8	664.9	270.1	1,813.3
SOUTHWEST	179.4	135.9	172.3	291.4	315.0	171.7	1,265.8
SOUTHIMP	437.6	566.9	249.9	458.7	580.6	140.5	2,434.2
Southern Exports	(130.0)	(111.9)	(103.9)	(157.0)	(272.7)	(350.3)	(1,125.8)
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	(2.3)	(17.7)	(9.5)	(5.3)	(0.6)	(22.5)	(57.8)
SOUTHWEST	(98.5)	(57.1)	(44.2)	(127.2)	(208.0)	(236.4)	(771.5)
SOUTHEXP	(29.2)	(37.1)	(50.1)	(24.5)	(64.1)	(91.5)	(296.5)
Total Interfaces	1,633.0	1,083.6	693.6	1,025.9	1,636.5	711.4	6,784.0
INTERNAL	9,285.6	9,492.4	11,338.1	9,294.5	10,524.3	10,311.4	60,246.3
Total	10,918.6	10,575.9	12,031.7	10,320.5	12,160.8	11,022.9	67,030.4

Table 9-12 Day-ahead scheduled gross import volume by interface pricing point (GWh): January through June 2015

	Jan	Feb	Mar	Apr	May	Jun	Total
IMO	254.0	170.6	240.5	156.0	202.8	159.2	1,183.1
MISO	196.0	221.4	364.0	258.4	295.5	249.0	1,584.4
NIPSCO	16.3	12.7	4.1	44.4	43.3	117.5	238.2
NORTHWEST	115.3	80.7	179.0	223.3	379.2	319.4	1,297.0
NYISO	900.8	873.1	833.4	851.1	810.0	865.1	5,133.5
HUDS	70.9	61.4	29.2	59.6	49.5	16.2	286.8
LINDENVFT	32.4	58.4	59.4	23.3	15.5	20.2	209.1
NEPTUNE	14.1	24.1	33.1	7.6	0.8	6.6	86.3
NYIS	783.4	729.3	711.7	760.6	744.2	822.2	4,551.3
OVEC	1,172.5	767.0	821.7	617.4	628.1	757.0	4,763.7
Southern Imports	1,395.3	1,230.8	971.5	1,469.8	2,065.7	829.0	7,962.2
CPLEIMP	2.2	2.0	2.1	2.2	2.1	2.1	12.8
DUKIMP	2.4	0.4	2.7	4.9	1.1	3.0	14.5
NCMPAIMP	109.5	51.0	30.5	165.1	158.6	83.8	598.6
SOUTHEAST	360.0	150.0	183.5	184.8	664.9	270.1	1,813.3
SOUTHWEST	179.4	135.9	172.3	291.4	315.0	171.7	1,265.8
SOUTHIMP	741.7	891.5	580.4	821.4	923.9	298.3	4,257.3
Southern Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	4,050.2	3,356.4	3,414.3	3,620.4	4,424.6	3,296.2	22,162.1

Table 9-13 Up-to congestion scheduled gross import volume by interface pricing point (GWh): January through June 2015

	Jan	Feb	Mar	Apr	May	Jun	Total
IMO	117.7	105.3	57.8	40.9	49.1	42.0	412.8
MISO	181.7	145.2	284.3	248.6	290.3	223.7	1,373.9
NIPSCO	16.3	12.7	4.1	44.4	43.3	117.5	238.2
NORTHWEST	115.3	80.7	179.0	223.3	379.2	319.4	1,297.0
NYISO	223.3	193.8	216.3	143.7	165.0	122.8	1,064.9
HUDSONTP	70.9	61.4	29.2	59.6	49.5	16.2	286.8
LINDENVFT	32.2	56.8	59.1	22.5	12.0	15.6	198.2
NEPTUNE	14.1	24.1	33.1	7.6	0.8	6.6	86.3
NYIS	106.0	51.5	94.9	54.0	102.7	84.4	493.5
OVEC	500.2	226.8	221.3	162.2	197.3	255.1	1,562.9
Southern Imports	977.0	852.8	605.7	934.9	1,560.5	582.3	5,513.2
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	360.0	150.0	183.5	184.8	664.9	270.1	1,813.3
SOUTHWEST	179.4	135.9	172.3	291.4	315.0	171.7	1,265.8
SOUTHIMP	437.6	566.9	249.9	458.7	580.6	140.5	2,434.2
Southern Exports	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Interfaces	2,131.5	1,617.4	1,568.5	1,798.0	2,684.6	1,662.8	11,462.8

Table 9-14 Day-ahead scheduled gross export volume by interface pricing point (GWh): January through June 2015

	Jan	Feb	Mar	Apr	May	Jun	Total
IMO	4.4	15.9	58.2	133.7	260.1	94.2	566.6
MISO	560.2	221.6	165.8	341.6	617.0	513.5	2,419.6
NIPSCO	69.0	55.3	150.6	176.4	198.8	181.6	831.7
NORTHWEST	564.6	499.0	458.5	522.7	550.2	542.7	3,137.6
NYISO	2,395.7	2,401.7	2,231.6	1,217.3	944.3	1,195.7	10,386.3
HUDSONTP	133.1	105.1	167.5	63.3	18.5	24.6	512.2
LINDENVFT	14.8	13.8	31.7	15.0	14.6	17.9	107.8
NEPTUNE	435.8	365.7	476.9	307.1	180.3	359.7	2,125.6
NYIS	1,811.9	1,917.0	1,555.5	831.8	730.9	793.5	7,640.6
OVEC	58.9	113.4	106.4	92.2	127.1	68.7	566.7
Southern Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	173.3	172.1	132.0	177.5	294.2	439.6	1,388.7
CPLEEXP	15.1	14.6	18.0	19.3	9.5	29.3	105.8
DUKEXP	8.3	13.1	1.9	0.0	0.0	18.2	41.4
NCMPAEXP	0.8	1.4	0.9	1.1	0.5	0.4	5.1
SOUTHEAST	2.3	17.7	9.5	5.3	0.6	22.5	57.8
SOUTHWEST	98.5	57.1	44.2	127.2	208.0	236.4	771.5
SOUTHEXP	48.3	68.2	57.6	24.5	75.6	133.0	407.1
Total	3,826.1	3,479.1	3,303.2	2,661.4	2,991.6	3,035.8	19,297.2

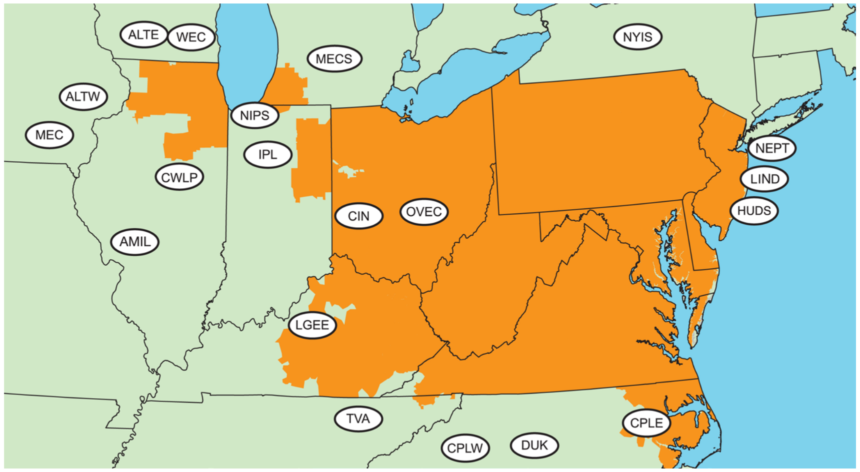
Table 9-15 Up-to congestion scheduled gross export volume by interface pricing point (GWh): January through June 2015

	Jan	Feb	Mar	Apr	May	Jun	Total
IMO	4.1	11.5	56.4	133.7	260.1	94.2	559.9
MISO	17.4	18.8	36.7	37.2	65.3	70.8	246.2
NIPSCO	69.0	55.3	150.6	176.4	198.8	181.6	831.7
NORTHWEST	79.2	76.4	110.5	62.2	68.0	83.4	479.7
NYISO	166.8	171.2	331.8	128.3	72.6	102.3	973.0
HUDSONTP	27.7	28.7	125.9	63.3	17.0	22.7	285.5
LINDENVFT	1.5	3.9	20.6	14.7	14.4	17.3	72.5
NEPTUNE	105.9	48.0	35.4	12.6	10.4	52.6	264.8
NYIS	31.6	90.6	149.9	37.7	30.8	9.7	350.2
OVEC	32.0	88.7	85.0	77.3	110.7	68.7	462.4
Southern Imports	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CPLEIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHWEST	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHIMP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Southern Exports	130.0	111.9	103.9	157.0	272.7	350.3	1,125.8
CPLEEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DUKEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NCMPAEXP	0.0	0.0	0.0	0.0	0.0	0.0	0.0
SOUTHEAST	2.3	17.7	9.5	5.3	0.6	22.5	57.8
SOUTHWEST	98.5	57.1	44.2	127.2	208.0	236.4	771.5
SOUTHEXP	29.2	37.1	50.1	24.5	64.1	91.5	296.5
Total Interfaces	498.5	533.8	875.0	772.1	1,048.1	951.3	4,678.8

Table 9-16 Active interfaces: January through June 2015[26]

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

Figure 9-3 PJM's footprint and its external interfaces



26 On July 2, 2012, Duke Energy Corp. (DUK) completed a merger with Progress Energy Inc. (CPLE and CPLW). As of June 30, 2015, 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 June 2015

	Jan	Feb	Mar	Apr	May	Jun
CPLEEXP	Active	Active	Active	Active	Active	Active
CPLEIMP	Active	Active	Active	Active	Active	Active
DUKEXP	Active	Active	Active	Active	Active	Active
DUKIMP	Active	Active	Active	Active	Active	Active
HUDSONTP	Active	Active	Active	Active	Active	Active
LINDENVFT	Active	Active	Active	Active	Active	Active
MISO	Active	Active	Active	Active	Active	Active
NCMPAEXP	Active	Active	Active	Active	Active	Active
NCMPAIMP	Active	Active	Active	Active	Active	Active
NEPTUNE	Active	Active	Active	Active	Active	Active
NIPSCO	Active	Active	Active	Active	Active	Active
Northwest	Active	Active	Active	Active	Active	Active
NYIS	Active	Active	Active	Active	Active	Active
Ontario IESO	Active	Active	Active	Active	Active	Active
OVEC	Active	Active	Active	Active	Active	Active
Southeast	Active	Active	Active	Active	Active	Active
SOUTHEXP	Active	Active	Active	Active	Active	Active
SOUTHIMP	Active	Active	Active	Active	Active	Active
Southwest	Active	Active	Active	Active	Active	Active

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 one or more specific interfaces. Loop flows can exist at the same time that inadvertent interchange is zero. For example, actual imports could exceed scheduled imports at one interface and actual exports could exceed scheduled exports at another interface by the same amount. The result is loop flow, despite the fact that system actual and scheduled power flow net to a zero difference.[27]

27 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

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 PJM's borders. For example, if a 100 MW transaction were submitted, there would be 100 MW of scheduled flow at the PJM/MISO interface border, but there would be no actual flows on the interface. Conversely, there would be no scheduled flows at the PJM/Southern interface border, but there would be 100 MW of actual flows on the interface. In the first six months of 2015, there were net scheduled flows of 4,936 GWh through MISO that received an interface pricing point associated with the southern interface. Conversely, in the first six months of 2015, there were no net scheduled flows across the southern interface that received the MISO interface pricing point.

In the first six months of 2015, net scheduled interchange was 10,817 GWh and net actual interchange was 10,424 GWh, a difference of 393 GWh. In the first six months of 2014, net scheduled interchange was 489 GWh and net actual interchange was 586 GWh, a difference of 96 GWh. This difference is system inadvertent. PJM attempts to minimize the amount of accumulated inadvertent interchange by continually monitoring and correcting for inadvertent interchange.[28]

Table 9-18 Net scheduled and actual PJM flows by interface (GWh): January through June 2015

	Actual	Net Scheduled	Difference (GWh)
CPLE	4,747	(128)	4,876
CPLW	(708)	0	(708)
DUK	395	2,251	(1,855)
LGEE	1,531	1,311	220
MISO	(1,559)	4,156	(5,714)
ALTE	(3,101)	(837)	(2,264)
ALTW	(797)	(40)	(756)
AMIL	5,011	3,579	1,432
CIN	(4,002)	1,470	(5,473)
CWLP	(169)	0	(169)
IPL	(557)	1,105	(1,662)
MEC	(1,105)	(2,681)	1,576
MECS	2,260	1,933	327
NIPS	(3,861)	114	(3,974)
WEC	4,762	(487)	5,249
NYISO	(4,265)	(4,275)	10
HUDS	(260)	(260)	0
LIND	(383)	(383)	0
NEPT	(1,849)	(1,849)	0
NYIS	(1,773)	(1,783)	10
OVEC	5,596	4,306	1,290
TVA	4,685	3,197	1,488
Total	10,424	10,817	(393)

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.[29] The actual flow on an interface pricing point is defined as the metered flow across the transmission lines that are included in the interface pricing point.

The differences between the scheduled and actual power flows at the interface pricing points provide a better measure of loop flows than differences at the 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 are compared to the net scheduled flows from the southern region. The net actual flows from the southern region are determined by summing the total southern import actual flows and the total southern exports actual flows (10,651 GWh

28 See PJM. "Manual 12: Balancing Operations," Revision 32 (April 6, 2015).

29 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.)

of imports). The net scheduled flows from the southern region are determined by summing the total southern imports scheduled flows and the total southern exports scheduled flows (11,566 GWh of imports). In the first six months of 2015, the loop flows at the southern region were 915 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 physical 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. Table 9-19 shows actual flows associated with the IMO interface pricing point 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 June 2015

	Actual	Net Scheduled	Difference (GWh)
IMO	0	4,040	(4,040)
MISO	(1,559)	(4,889)	3,331
NORTHWEST	0	(11)	11
NYISO	(4,265)	(4,194)	(71)
HUDSONTP	(260)	(260)	0
LINDENVFT	(383)	(383)	0
NEPTUNE	(1,849)	(1,849)	0
NYIS	(1,773)	(1,702)	(71)
OVEC	5,596	4,306	1,290
Southern Imports	16,403	12,513	3,889
CPLEIMP	0	41	(41)
DUKIMP	0	289	(289)
NCMPAIMP	0	603	(603)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	16,403	11,581	4,822
Southern Exports	(5,752)	(948)	(4,804)
CPLEEXP	0	(154)	154
DUKEXP	0	(431)	431
NCMPAEXP	0	(0)	0
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHEXP	(5,752)	(363)	(5,389)
Total	10,424	10,817	(393)

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 June 2015

	Actual	Net Scheduled	Difference (GWh)
MISO	(1,559)	(768)	(790)
NORTHWEST	0	(11)	11
NYISO	(4,265)	(4,275)	10
HUDSONTP	(260)	(260)	0
LINDENVFT	(383)	(383)	0
NEPTUNE	(1,849)	(1,849)	0
NYIS	(1,773)	(1,783)	10
OVEC	5,596	4,306	1,290
Southern Imports	16,403	12,513	3,889
CPLEIMP	0	41	(41)
DUKIMP	0	289	(289)
NCMPAIMP	0	603	(603)
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHIMP	16,403	11,581	4,822
Southern Exports	(5,752)	(948)	(4,804)
CPLEEXP	0	(154)	154
DUKEXP	0	(431)	431
NCMPAEXP	0	(0)	0
SOUTHEAST	0	0	0
SOUTHWEST	0	0	0
SOUTHEXP	(5,752)	(363)	(5,389)
Total	10,424	10,817	(393)

PJM attempts to ensure 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 a reasonable approach to ensuring that transactions receive or pay the PJM market value of the transaction based on expected flows, but this method 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 six months of 2015, 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 (1,135 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 (83 GWh).

Table 9-21 Net scheduled and actual PJM flows by interface and interface pricing point (GWh): January through June 2015

Interface	Interface Pricing Point	Actual	Net Scheduled	Difference (GWh)
ALTE		(3,101)	(837)	(2,264)
	IMO	0	0	(0)
	MISO	(3,101)	(1,511)	(1,591)
	SOUTHIMP	0	674	(674)
ALTW		(797)	(40)	(756)
	MISO	(797)	(42)	(754)
	SOUTHIMP	0	2	(2)
AMIL		5,011	3,579	1,432
	IMO	0	1	(1)
	MISO	5,011	439	4,573
	SOUTHIMP	0	3,139	(3,139)
CIN		(4,002)	1,470	(5,473)
	IMO	0	1,135	(1,135)
	MISO	(4,002)	(83)	(3,919)
	NORTHWEST	0	(11)	11
	SOUTHEXP	0	(4)	4
	SOUTHIMP	0	433	(433)
CPLE		4,747	(128)	4,876
	CPLEEXP	0	(154)	154
	CPLEIMP	0	41	(41)
	SOUTHEXP	(577)	(18)	(559)
	SOUTHIMP	5,324	3	5,322
CPLW		(708)	0	(708)
	SOUTHEXP	(752)	0	(752)
	SOUTHIMP	44	0	44
CWLP		(169)	0	(169)
	MISO	(169)	0	(169)
DUK		395	2,251	(1,855)
	DUKEXP	0	(431)	431
	DUKIMP	0	289	(289)
	NCMPAEXP	0	(0)	0
	NCMPAIMP	0	603	(603)
	SOUTHEXP	(334)	(195)	(139)
	SOUTHIMP	729	1,985	(1,256)
HUDS		(260)	(260)	0
	HUDSONTP	(260)	(260)	0
IPL		(557)	1,105	(1,662)
	IMO	0	1,359	(1,359)
	MISO	(557)	(318)	(239)
	SOUTHEXP	0	(0)	0
	SOUTHIMP	0	64	(64)
LGEE		1,531	1,311	220
	SOUTHEXP	(3,131)	(2)	(3,129)
	SOUTHIMP	4,662	1,313	3,350
LIND		(383)	(383)	0
	LINDENVFT	(383)	(383)	0
MEC		(1,105)	(2,681)	1,576
	MISO	(1,105)	(2,682)	1,577
	SOUTHIMP	0	1	(1)
MECS		2,260	1,933	327
	IMO	0	1,625	(1,625)
	MISO	2,260	(311)	2,571
	SOUTHEXP	0	(0)	0
	SOUTHIMP	0	620	(620)
NEPT		(1,849)	(1,849)	0
	NEPTUNE	(1,849)	(1,849)	0
NIPS		(3,861)	114	(3,974)
	IMO	0	0	(0)
	MISO	(3,861)	107	(3,968)
	SOUTHIMP	0	6	(6)
NYIS		(1,773)	(1,783)	10
	IMO	0	(81)	81
	NORTHWEST	0	0	(0)
	NYIS	(1,773)	(1,702)	(71)
OVEC		5,596	4,306	1,290
	OVEC	5,596	4,306	1,290
TVA		4,685	3,197	1,488
	DUKIMP	0	0	(0)
	SOUTHEXP	(958)	(144)	(814)
	SOUTHIMP	5,643	3,341	2,302
WEC		4,762	(487)	5,249
	MISO	4,762	(487)	5,249
Grand Total		10,424	10,817	(393)

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 six months of 2015, 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 (1,625 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 (81 GWh).

Table 9-22 Net scheduled and actual PJM flows by interface pricing point and interface (GWh): January through June 2015

Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)	Interface Pricing Point	Interface	Actual	Net Scheduled	Difference (GWh)
CPLEEXP		0	(154)	154	NCMPAIMP		0	603	(603)
	CPLE	0	(154)	154		DUK	0	603	(603)
CPLEIMP		0	41	(41)	NEPTUNE		(1,849)	(1,849)	0
	CPLE	0	41	(41)		NEPT	(1,849)	(1,849)	0
DUKEXP		0	(431)	431	NORTHWEST		0	(11)	11
	DUK	0	(431)	431		CIN	0	(11)	11
DUKIMP		0	289	(289)		NYIS	0	0	(0)
	DUK	0	289	(289)	NYIS		(1,773)	(1,702)	(71)
	TVA	0	0	(0)		NYIS	(1,773)	(1,702)	(71)
HUDSONTP		(260)	(260)	0	OVEC		5,596	4,306	1,290
	HUDS	(260)	(260)	0		OVEC	5,596	4,306	1,290
IMO		0	4,040	(4,040)	SOUTHEXP		(5,752)	(363)	(5,389)
	ALTE	0	0	(0)		CIN	0	(4)	4
	AMIL	0	1	(1)		CPLE	(577)	(18)	(559)
	CIN	0	1,135	(1,135)		CPLW	(752)	0	(752)
	IPL	0	1,359	(1,359)		DUK	(334)	(195)	(139)
	MECS	0	1,625	(1,625)		IPL	0	(0)	0
	NIPS	0	0	(0)		LGEE	(3,131)	(2)	(3,129)
	NYIS	0	(81)	81		MECS	0	(0)	0
LINDENVFT		(383)	(383)	0		TVA	(958)	(144)	(814)
	LIND	(383)	(383)	0	SOUTHIMP		16,403	11,581	4,822
MISO		(1,559)	(4,889)	3,331		ALTE	0	674	(674)
	ALTE	(3,101)	(1,511)	(1,591)		ALTW	0	2	(2)
	ALTW	(797)	(42)	(754)		AMIL	0	3,139	(3,139)
	AMIL	5,011	439	4,573		CIN	0	433	(433)
	CIN	(4,002)	(83)	(3,919)		CPLE	5,324	3	5,322
	CWLP	(169)	0	(169)		CPLW	44	0	44
	IPL	(557)	(318)	(239)		DUK	729	1,985	(1,256)
	MEC	(1,105)	(2,682)	1,577		IPL	0	64	(64)
	MECS	2,260	(311)	2,571		LGEE	4,662	1,313	3,350
	NIPS	(3,861)	107	(3,968)		MEC	0	1	(1)
	WEC	4,762	(487)	5,249		MECS	0	620	(620)
NCMPAEXP		0	(0)	0		NIPS	0	6	(6)
	DUK	0	(0)	0		TVA	5,643	3,341	2,302
					Grand Total		10,424	10,817	(393)

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.

Under the PJM/MISO Joint Operating Agreement, the two RTOs mutually determine a set of transmission facilities on which both RTOs have an impact, and therefore jointly operate to those constraints. These jointly controlled facilities are M2M (Market to Market) flowgates. When a M2M constraint binds, PJM's LMP calculations at the 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. Similarly, MISO's LMP calculations at the selected buses that make up MISO's PJM interface pricing point are based on the MISO model's distribution factors of the selected buses to the binding M2M constraint and MISO's shadow price of the binding M2M constraint. MISO's PJM interface pricing point is the average of all of the PJM generator bus LMPs.[30,31]

In 2013, questions were raised in the PJM/MISO Joint and Common Market (JCM) Initiative meetings about whether the interface definitions utilized by PJM and MISO were accurately capturing the congestion impact of transactions in the interface prices when a M2M constraint was binding in either footprint. A joint stakeholder group was formed to address the question.

Prior to June 1, 2014, the PJM interface definition for MISO consisted of nine buses located near the middle of the MISO system and not at the border between the RTOs. The MISO interface definition for PJM currently consists of all PJM generator buses which are spread across the entire PJM system. The interface definitions led to questions about the level of congestion included in interchange pricing.

Two solutions were proposed to resolve the issue, one by Potomac Economics (the MISO IMM) and one by PJM. The Potomac Economics proposal has two essential components: move the interface definition that each RTO uses to the center of the other RTO's load; and eliminate the congestion component for M2M constraints from the non-monitoring RTO's interface price. The PJM proposal is for PJM and MISO to establish a common interface price definition at the border between the RTOs and further incorporate an adjustment to the Market Flow calculations utilized in the market-to-market settlement process.[32]

PJM modified the definition of the PJM/MISO Interface effective June 1, 2014, consistent with the PJM proposal. PJM's new MISO interface pricing point 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. MISO has not made any changes to their interface pricing point.

Real-Time and Day-Ahead PJM/MISO Interface Prices

In the first six months of 2015, the direction of the average hourly flow was inconsistent with the real-time average hourly price difference between the PJM/MISO Interface and the MISO/PJM Interface. In the first six months of 2015, the PJM average hourly real-time LMP at the PJM/MISO border was $30.04 while the MISO real-time LMP at the border was $28.41, a difference of $1.63. While the average hourly LMP difference at the PJM/MISO border was $1.63, the average of the absolute values of the hourly differences was $8.11. The average hourly flow in the first six months of 2015 was -359 MW (The negative sign means that the flow was an export from PJM to MISO, which is inconsistent with the fact that the average MISO/PJM price was lower than the average PJM/MISO price.) In the first six months of 2015, the direction of flow was consistent with price differentials in 55.5 percent of the hours. Table 9-23 shows the number of hours and average hourly price differences between the PJM/MISO Interface and the MISO/PJM Interface based on LMP differences and flow direction.

30 See "LMP Aggregate Definitions," (December 18, 2008) <http://www.pjm.com/~/media/markets-ops/energy/lmp-model-info/20081218-aggregate-definitions.ashx>. PJM periodically updates these definitions on its web site. See <http://www.pjm.com>.
31 Based on information obtained from MISO's extranet <http://extranet.midwestiso.org> (Accessed January 27, 2015).
32 See "Interface Pricing Issue – PJM Position Paper Draft," (February 17, 2015) <http://www.pjm.com/~/media/committees-groups/stakeholder-meetings/pjm-miso-joint-common/20150219/20150219-item-04-interface-pricing-position-paper.ashx>.

Table 9-23 PJM and MISO flow based hours and average hourly price differences: January through June 2015

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
MISO/PJM LMP > PJM/MISO LMP	Any Flow	2,223	$6.34
	Consistent Flow (PJM to MISO)	1,404	$4.84
	Inconsistent Flow (MISO to PJM)	819	$8.90
	No Flow	0	$0.00
PJM/MISO LMP > MISO/PJM LMP	Any Flow	2,120	$10.01
	Consistent Flow (MISO to PJM)	1,008	$15.23
	Inconsistent Flow (PJM to MISO)	1,112	$5.25
	No Flow	0	$0.00

In the first six months of 2015, the day-ahead PJM average hourly LMP at the PJM/MISO border was $30.56 while the MISO/PJM LMP at the border was $29.70, a difference of $0.86 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).

Figure 9-4 Real-time and day-ahead daily hourly average price difference (MISO/PJM Interface minus PJM/MISO Interface): January through June 2015

Distribution and Prices of Hourly Flows at the PJM/MISO Interface

In the first six months of 2015, the direction of hourly energy flows was consistent with PJM and MISO interface price differentials in 2,412 hours (55.5 percent of all hours), and was inconsistent with price differentials in 1,931 hours (44.5 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. Of the 1,931 hours where flows were in a direction inconsistent with price differences, 1,442 of those hours (74.7 percent) had a price difference greater than or equal to $1.00 and 577 of those hours (29.9 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $297.23. Of the 2,412 hours where flows were consistent with price differences, 1,889 of those hours

(78.3 percent) had a price difference greater than or equal to $1.00 and 872 of all such hours (36.2 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $278.65.

Table 9-24 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and MISO: January through June 2015

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Total Hours	Consistent Hours	Percent of Total Hours
$0.00	1,931	100.0%	2,412	100.0%
$1.00	1,442	74.7%	1,889	78.3%
$5.00	577	29.9%	872	36.2%
$10.00	290	15.0%	488	20.2%
$15.00	184	9.5%	327	13.6%
$20.00	130	6.7%	251	10.4%
$25.00	97	5.0%	195	8.1%
$50.00	36	1.9%	81	3.4%
$75.00	17	0.9%	48	2.0%
$100.00	11	0.6%	33	1.4%
$200.00	5	0.3%	7	0.3%
$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/MISO Interface Prices Post June 1, 2014, Interface Pricing Point Modification

PJM modified the definition of the PJM/MISO Interface effective June 1, 2014. Interface prices under both definitions were calculated for the period from June 1, 2014, through May 31, 2015, recognizing that the counterfactual prices could have been affected by the new definition. The average hourly PJM/MISO Interface price during this period was $30.81, an increase of $1.82 per MWh compared to the price of $29.00 under the prior definition.

In 725 of the 8,760 hours analyzed (8.3 percent) the incentive to flow from the RTO with the lower price to the RTO with the higher price switched directions under the new definition. In 27 of the 725 hours (3.7 percent), the MISO/PJM interface price was lower than the PJM/MISO interface price under the old definition but higher under the new definition. Under the old definition the incentive was to flow power from PJM to MISO while under the new definition the incentive was to flow power from MISO to PJM for these 27 hours.

In 698 of the 725 hours (96.3 percent), the MISO/PJM Interface price was higher than the PJM/MISO interface price under the old definition but lower under the new definition. Under the old definition the incentive was to flow power from MISO to PJM while under the new definition the incentive was to flow power from PJM to MISO for these 698 hours.

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.[33]

Real-Time and Day-Ahead PJM/NYISO Interface Prices

In the first six months of 2015, 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 six months of 2015, the direction of the average hourly flow was inconsistent with the average price difference between PJM/NYIS Interface and at the NYISO/PJM proxy bus. In the first six months of 2015, the PJM average hourly LMP at the PJM/NYISO border was $45.86 while the NYISO LMP at the border was $42.09, a difference of $3.77. While the average hourly LMP difference at the PJM/NYISO border was $3.77, the average of the absolute value of the hourly difference was $18.93. The average hourly flow in the first six months of 2015 was -408 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is inconsistent with the

33 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

fact that the average PJM price was higher than the average NYISO price.) The direction of flow was consistent with price differentials in 56.6 percent of the hours in the first six months of 2015. Table 9-25 shows the number of hours and average hourly price differences between the PJM/NYIS Interface and the NYIS/PJM proxy bus based on LMP differences and flow direction.

Table 9-25 PJM and NYISO flow based hours and average hourly price differences: January through June 2015[34]

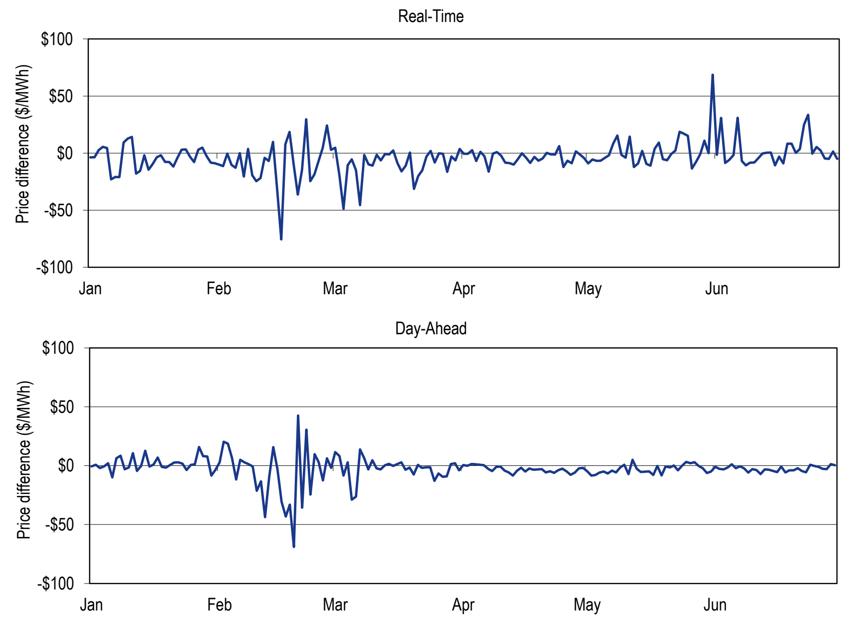
LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/PJM proxy bus LBMP > PJM/NYIS LMP	Any Flow	1,714	$19.20
	Consistent Flow (PJM to NYIS)	1,197	$16.91
	Inconsistent Flow (NYIS to PJM)	517	$24.50
	No Flow	0	$0.00
PJM/NYIS LMP > NYIS/PJM proxy bus LBMP	Any Flow	2,629	$18.76
	Consistent Flow (NYIS to PJM)	1,260	$12.99
	Inconsistent Flow (PJM to NYIS)	1,369	$24.08
	No Flow	0	$0.00

In the first six months of 2015, the day-ahead PJM average hourly LMP at the PJM/NYIS border was $45.15 while the NYIS/PJM LMP at the border was $42.49, a difference of $2.66.

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).

34 The NYISO Locational Based Marginal Price (LBMP) is the equivalent term to PJM's Locational Marginal Price (LMP).

Figure 9-5 Real-time and day-ahead daily hourly average price difference (NY/PJM proxy - PJM/NYIS Interface): January through June 2015



Distribution and Prices of Hourly Flows at the PJM/NYISO Interface

In the first six months of 2015, the direction of hourly energy flows was consistent with PJM/NYISO and NYISO/PJM price differences in 2,457 (56.6 percent of all hours), and was inconsistent with price differences in 1,886 hours (43.4 percent of all hours). Table 9-26 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 1,886 hours where flows where flows were in a direction inconsistent with price differences, 1,751 of those hours (92.8 percent) had a price difference greater than or equal to $1.00 and 1,256 of all those hours (66.6 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $988.45. Of the 2,457 hours where flows were consistent with price differences, 2,303 of those hours (93.7 percent) had a price difference greater than or equal to $1.00 and 1,653 of all such hours (67.3 percent) had a price difference greater than or equal to $5.00. The largest price difference with such flows was $347.23.

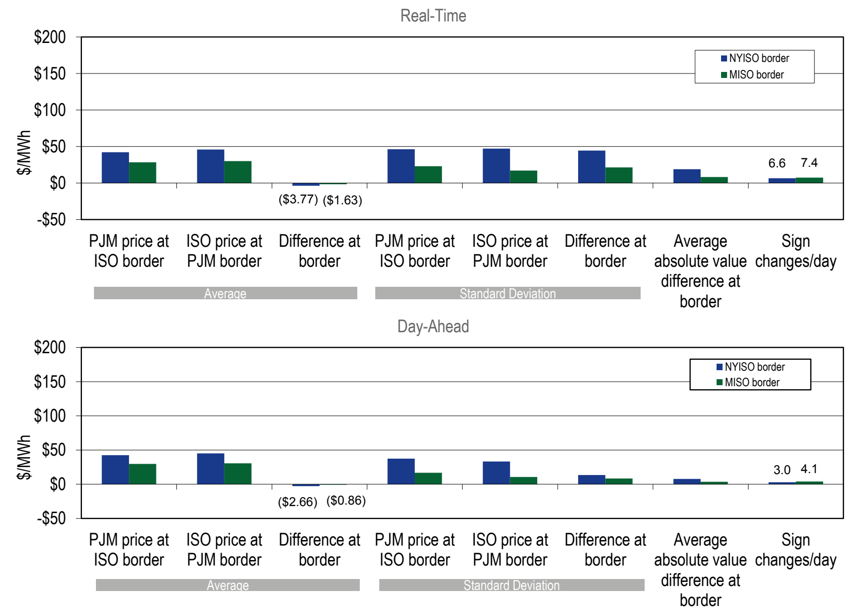
Table 9-26 Distribution of hourly flows that are consistent and inconsistent with price differences between PJM and NYISO: January through June 2015

Price Difference Range (Greater Than or Equal To)	Inconsistent Hours	Percent of Total Hours	Consistent Hours	Percent of Total Hours
$0.00	1,886	100.0%	2,457	100.0%
$1.00	1,751	92.8%	2,303	93.7%
$5.00	1,256	66.6%	1,653	67.3%
$10.00	897	47.6%	987	40.2%
$15.00	686	36.4%	631	25.7%
$20.00	562	29.8%	430	17.5%
$25.00	474	25.1%	323	13.1%
$50.00	248	13.1%	128	5.2%
$75.00	128	6.8%	69	2.8%
$100.00	81	4.3%	44	1.8%
$200.00	13	0.7%	11	0.4%
$300.00	7	0.4%	2	0.1%
$400.00	6	0.3%	0	0.0%
$500.00	3	0.2%	0	0.0%

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 June 2015



Neptune Underwater Transmission Line to Long Island, New York

The Neptune line is a 65 mile direct current (DC) merchant 230 kV transmission line, with a capacity of 660 MW, providing a direct connection between PJM (Sayreville, New Jersey), and NYISO (Nassau County on Long Island). Schedule 14 of the PJM Open Access Transmission Tariff provides that power flows will only be from PJM to New York. In the first six months of 2015, 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 six months of 2015, the PJM average hourly LMP at the Neptune Interface was $44.27 while the NYISO LMP at the Neptune Bus was $52.53, a difference of $8.27. While the average hourly LMP difference at the PJM/Neptune border was $8.27, the average of the absolute value of the hourly difference was $28.28. The average hourly flow in the first six months of 2015 was -426 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is consistent with the fact that the average PJM price was lower than the average NYISO price.) The flows were consistent with price differentials in 56.0 percent of the hours in the first six months of 2015. Table 9-27 shows the number of hours and average hourly price differences between the PJM/NEPT Interface and the NYIS/Neptune bus based on LMP differences and flow direction.

Table 9-27 PJM and NYISO flow based hours and average hourly price differences (Neptune): January through June 2015

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Neptune Bus LBMP > PJM/NEPT LMP	Any Flow	2,502	$31.72
	Consistent Flow (PJM to NYIS)	2,430	$32.27
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	72	$13.23
PJM/NEPT LMP > NYIS/Neptune Bus LBMP	Any Flow	1,841	$23.63
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	1,761	$24.30
	No Flow	80	$8.88

To move power from PJM to NYISO using the Neptune line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Neptune HVDC line ("Out Service") and another transmission service reservation is required on the Neptune HVDC line ("Neptune Service").[35] The PJM Out Service is covered by normal PJM OASIS business operations.[36] The Neptune Service falls under the provisions for controllable merchant facilities, Schedule 14 of the PJM Tariff. The Neptune Service is also acquired on the PJM OASIS.

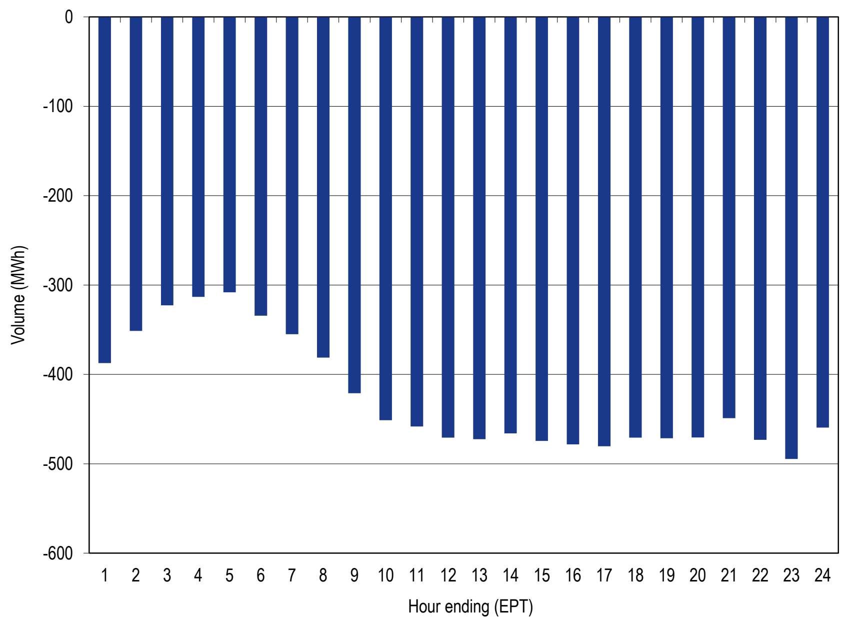
Neptune Service is owned by a primary rights holder, and any service that is not used (as defined by a schedule on a NERC tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or non-firm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder does not elect to voluntarily release non-firm service, and does not utilize the service, the available transmission will be released by default at 12:00, one business day before the start of service. Firm service is not subject to default release. On June 30, 2015, the rate for the non-firm service released by default was $10 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service. Table 9-28 shows the percentage of scheduled transmission usage across the Neptune line by the primary rights holder since commercial operations began in July, 2007.

Table 9-28 Percentage of Neptune transmission usage by primary rights holder: July 2007 through June 2015

	2007	2008	2009	2010	2011	2012	2013	2014	2015
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
April	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	99.99%
May	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
June	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
July	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
August	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
September	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
October	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
November	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	
December	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	

35 See "PJM Business Practices for Neptune Transmission Service," <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/neptune-oasis-business-practices-doc-clean.ashx>.
36 See "Regional Transmission and Energy Scheduling Practices," <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

Figure 9-7 Neptune hourly average flow: January through June 2015



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 six months of 2015, 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 six months of 2015, the PJM average hourly LMP at the Linden Interface was $43.33 while the NYISO LMP at the Linden Bus was $46.82, a difference of $3.49. While the average hourly LMP difference at the PJM/Linden border was $3.49, the average of the absolute value of the hourly difference was $19.36. The average hourly flow in the first six months of 2015 was -88 MW. (The negative sign means that the flow was an export from PJM to NYISO, which is consistent with the fact that the average PJM price was lower than the average NYISO price.) The flows were consistent with price differentials in 50.3 percent of the hours in the first six months of 2015. Table 9-29 shows the number of hours and average hourly price differences between the PJM/LIND Interface and the NYIS/Linden bus based on LMP differences and flow direction.

Table 9-29 PJM and NYISO flow based hours and average hourly price differences (Linden): January through June 2015

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Linden Bus LBMP > PJM/LIND LMP	Any Flow	2,270	$21.85
	Consistent Flow (PJM to NYIS)	2,183	$22.37
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	87	$8.71
PJM/LIND LMP > NYIS/Linden Bus LBMP	Any Flow	2,073	$16.63
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	2,017	$16.92
	No Flow	56	$6.44

To move power from PJM to NYISO on the Linden VFT line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Linden VFT ("Out Service") and another transmission service reservation is required on the Linden VFT ("Linden VFT Service").[37] The PJM Out Service is covered by normal PJM OASIS business operations.[38] The Linden VFT Service falls under the provisions for controllable merchant facilities, Schedule 16 and Schedule 16-A of the PJM Tariff. The Linden VFT Service is also acquired on the PJM OASIS.

Linden VFT Service is owned by a primary rights holder, and any service that is not used (as defined by a schedule on a NERC tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or non-firm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder elects to not voluntarily release non-firm

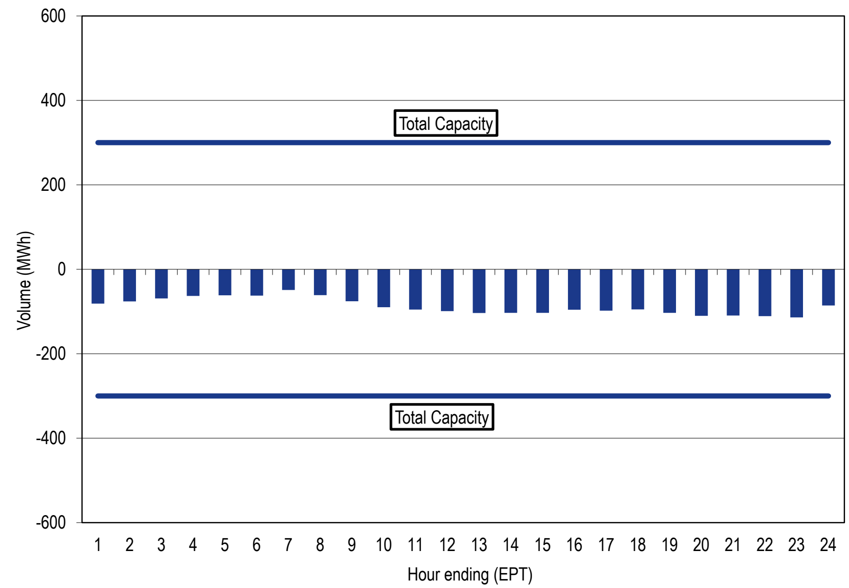
37 See "PJM Business Practices for Linden VFT Transmission Service," <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/linden-vft-oasis-business-practices-doc-clean.ashx>.
38 See "Regional Transmission and Energy Scheduling Practices," <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

service, and does not utilize the service, the available transmission will be released by default at 12:00, one business day before the start of service. Firm service is not subject to default release. On June 30, 2015, the rate for the non-firm service released by default was $6 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service. Table 9-30 shows the percentage of scheduled transmission usage across the Linden VFT line by the primary rights holder since commercial operations began in November, 2009.

Table 9-30 Percentage of Linden transmission usage by primary rights holder: November 2009 through June 2015

	2009	2010	2011	2012	2013	2014	2015
January	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
February	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
March	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
April	NA	99.97%	100.00%	100.00%	100.00%	99.98%	100.00%
May	NA	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
June	NA	100.00%	100.00%	100.00%	100.00%	27.27%	100.00%
July	NA	100.00%	100.00%	100.00%	100.00%	29.56%	
August	NA	100.00%	100.00%	100.00%	100.00%	82.50%	
September	NA	100.00%	100.00%	100.00%	100.00%	81.70%	
October	NA	100.00%	100.00%	100.00%	100.00%	100.00%	
November	100.00%	100.00%	100.00%	100.00%	99.86%	100.00%	
December	100.00%	100.00%	100.00%	98.22%	100.00%	100.00%	

Figure 9-8 Linden hourly average flow: January through June 2015[39]



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 (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 six months of 2015, 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. In the

39 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.

first six months of 2015, the PJM average hourly LMP at the Hudson Interface was $59.97 while the NYISO LMP at the Hudson Bus was $47.42, a difference of $12.55. While the average hourly LMP difference at the PJM/Hudson border was $12.55, the average of the absolute value of the hourly difference was $34.74. The average hourly flow in the first six months of 2015 was -60 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 flows were consistent with price differentials in 39.1 percent of the hours in the first six months of 2015. Table 9-31 shows the number of hours and average hourly price differences between the PJM/HUDS Interface and the NYIS/Hudson bus based on LMP differences and flow direction.

Table 9-31 PJM and NYISO flow based hours and average hourly price differences (Hudson): January through June 2015

LMP Difference	Flow Direction	Number of Hours	Average Hourly Price Difference
NYIS/Hudson Bus LBMP > PJM/HUDS LMP	Any Flow	1,911	$25.21
	Consistent Flow (PJM to NYIS)	1,697	$26.67
	Inconsistent Flow (NYIS to PJM)	0	$0.00
	No Flow	214	$13.63
PJM/HUDS LMP > NYIS/Hudson Bus LBMP	Any Flow	2,432	$42.22
	Consistent Flow (NYIS to PJM)	0	$0.00
	Inconsistent Flow (PJM to NYIS)	2,056	$44.32
	No Flow	376	$30.74

To move power from PJM to NYISO, on the Hudson line, two PJM transmission service reservations are required. A transmission service reservation is required from the PJM Transmission System to the Hudson line ("Out Service") and another transmission service reservation is required on the Hudson line ("Hudson Service").[40] The PJM Out Service is covered by normal PJM OASIS business operations.[41] The Hudson Service falls under the provisions for controllable merchant facilities, Schedule 17 of the PJM Tariff. The Hudson Service is also acquired on the PJM OASIS.

40 See "PJM Business Practices for Hudson Transmission Service," <http://www.pjm.com/~/media/etools/oasis/merch-trans-facilities/htp-business-practices.ashx>.

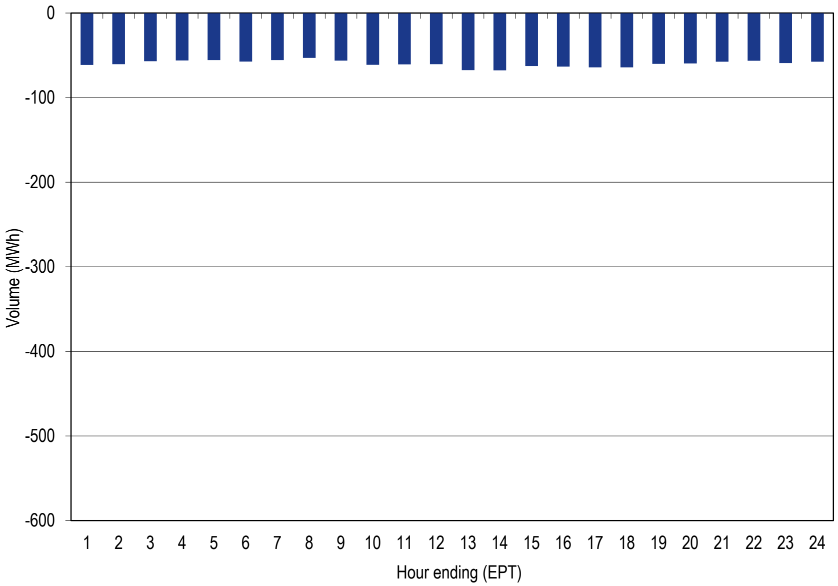
41 See "Regional Transmission and Energy Scheduling Practices," <http://www.pjm.com/~/media/etools/oasis/regional-practices-clean-doc.ashx>.

Hudson Service is owned by a primary rights holder, and any service that is not used (as defined by scheduled on a NERC tag) may be released either voluntarily by the primary rights holder or by default by PJM. The primary rights holder may elect to voluntarily release monthly, weekly, daily or hourly firm or non-firm service. Voluntarily releasing the service allows for the primary rights holder to specify a rate to be charged for the released service. If the primary rights holder elects to not voluntarily release non-firm service, and does not utilize the service, the available transmission will be released by default at 12:00, one business day before the start of service. Firm service is not subject to default release. On June 30, 2015, the rate for the non-firm service released by default was $10 per MWh. The primary rights holder remains obligated to pay for the released service unless a second transmission customer acquires the released service. Table 9-32 shows the percentage of scheduled transmission usage across the Hudson line by the primary rights holder since commercial operations began in May, 2013.

Table 9-32 Percentage of Hudson transmission usage by primary rights holder: May 2013 through June 2015

	2013	2014	2015
January	NA	51.22%	16.27%
February	NA	49.00%	14.67%
March	NA	40.40%	71.88%
April	NA	100.00%	100.00%
May	100.00%	26.87%	100.00%
June	100.00%	5.89%	59.72%
July	100.00%	18.51%	
August	100.00%	75.17%	
September	100.00%	75.31%	
October	100.00%	99.71%	
November	85.57%	99.60%	
December	28.32%	1.68%	

Figure 9-9 Hudson hourly average flow: January through June 2015



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 Duke Energy Progress, Inc., a reliability coordination agreement with VACAR South, a balancing authority operations agreement with the Wisconsin Electric Power Company (WEC) and a Northeastern planning coordination protocol with NYISO and ISO New England.

Table 9-33 shows a summary of the elements included in each of the operating agreements PJM has with its bordering areas. These elements include such items as whether PJM and its neighbor participate in the exchange of data, near-term system coordination, long-term system coordination, congestion management and joint checkout procedures.

Table 9-33 Summary of elements included in operating agreements with bordering areas

Agreement:	PJM-MISO	PJM-NYISO	PJM-TVA	PJM-DEP	PJM-VACAR	PJM-WEP	Northeastern Protocol
Date:	September 10, 2014	January 20, 2015	October 15, 2014	December 3, 2014	November 7, 2014	July 20, 2013	December 8, 2004
Data Exhange							
Real-Time Data	YES	YES	YES	YES	YES	YES	NO
Projected Data	YES	YES	YES	YES	NO	NO	NO
SCADA Data	YES	YES	YES	YES	NO	NO	NO
EMS Models	YES	YES	YES	YES	NO	NO	YES
Operations Planning Data	YES	YES	YES	YES	NO	NO	YES
Available Flowgate Capability Data	YES	YES	YES	YES	NO	NO	YES
Near-Term System Coordination							
Operating Limit Violation Assistance	YES	YES	YES	YES	YES	NO	NO
Over/Under Voltage Assistance	YES	YES	YES	YES	YES	NO	NO
Emergency Energy Assistance	YES	YES	NO	YES	YES	NO	NO
Outage Coordination	YES	YES	YES	YES	YES	NO	NO
Long-Term System Coordination	YES	YES	YES	YES	NO	NO	YES
Congestion Management Process							
ATC Coordination	YES	YES	YES	YES	NO	NO	NO
Market Flow Calculations	YES	YES	YES	NO	NO	NO	NO
Firm Flow Entitlements	YES	YES	YES	NO	NO	NO	NO
Market to Market Redispatch	YES - Redispatch	YES - Redispatch	NO	YES - Dynamic Schedule	NO	NO	NO
Joint Checkout Procedures	YES	YES	YES	YES	NO	YES	NO

PJM-MISO = MISO/PJM Joint Operating Agreement
PJM-NYISO = New York ISO/PJM Joint Operating Agreement
PJM-TVA = Joint Reliablity Coordination Agreement Between PJM - Tennessee Valley Authority (TVA)
PJM-DEP = Duke Energy Progress (DEP) - PJM Joint Operating Agreement
PJM-VACAR = PJM-VACAR South Reliability Coordination Agreement
PJM-WEP = Balancing Authority Operations Coordination Agreement Between Wisconsin Electric Power Company and PJM Interconnection, LLC
Northeastern Protocol = Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol

PJM and MISO Joint Operating Agreement[42]

The Joint Operating Agreement between MISO and PJM Interconnection, L.L.C. was executed on December 31, 2003. The PJM/MISO JOA includes provisions for market based congestion management that, for designated flowgates within MISO and PJM, allow for redispatch of units within the PJM and MISO regions to jointly manage congestion on these flowgates and to assign the costs of congestion management appropriately. In 2012, MISO and PJM initiated a joint stakeholder process to address issues associated with the operation of the markets at the seam.[43]

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

42 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>.
43 See "2012 PJM/MISO Joint and Common Market Initiative," <http://www.pjm.com/committees-and-groups/stakeholder-meetings/stakeholder-groups/pjm-miso-joint-common.aspx>.

generator buses in its model of the PJM system in its computation of the MISO/PJM interface pricing point.[44]

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.

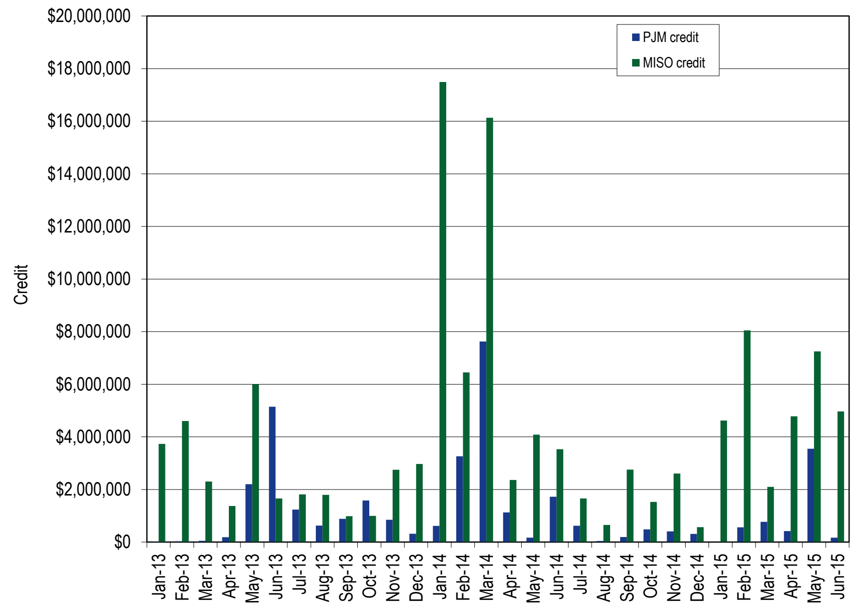
As of January 1, 2015, PJM had 102 flowgates eligible for M2M (Market to Market) coordination. In the first six months of 2015, PJM added 28 flowgates and deleted 20 flowgate, leaving 110 flowgates eligible for M2M coordination as of June 30, 2015. As of January 1, 2015, MISO had 275 flowgates eligible for M2M coordination. In the first six months of 2015, MISO added 37 and deleted 44 flowgates, leaving 268 flowgates eligible for M2M coordination as of June 30, 2015.

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. Effective June 1, 2014, PJM and MISO established a baseline set of flowgates to be modeled and procedures were developed to coordinate the exchange of FTR limits to be used in their annual FTR processes. A process was developed to ensure that temporary constraints represent known outages and other system conditions. Not allowing for M2M settlements on short-term outages that miss the monthly FTR model deadline could contribute to a solution to the FTR underfunding created by these short-term outages.

In the first six months of 2015, the market to market operations resulted in MISO and PJM redispatching units to control congestion on M2M flowgates and in the exchange of payments for this redispatch. Figure 9-10 shows credits for coordinated congestion management between PJM and MISO.

44 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

Figure 9-10 Credits for coordinated congestion management: January 2013 through June 2015[45]



PJM and New York Independent System Operator Joint Operating Agreement (JOA)[46]

The Joint Operating Agreement between NYISO and PJM Interconnection, L.L.C. became effective on January 15, 2013. Under the market to market rules, the organizations coordinate pricing at their borders. PJM and NYISO each calculate an interface LMP using network models including distribution factor impacts. PJM uses two buses within NYISO to calculate the PJM/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

45 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

46 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (January 20, 2015) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx>.

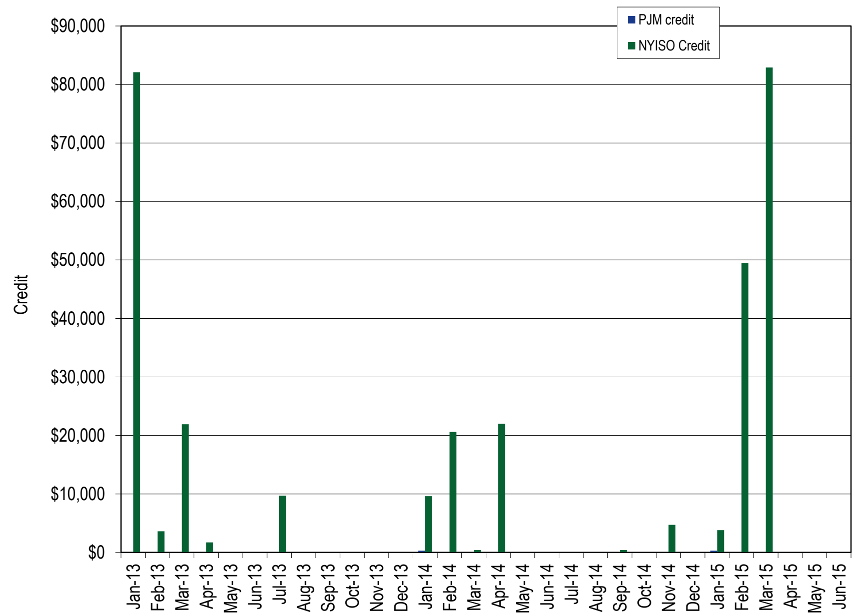
the Branchburg to Ramapo PAR controlled tie, and the remaining 60 percent will enter the NYISO on their free flowing A/C tie lines.

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.

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 six months of 2015, market to market operations resulted in NYISO and PJM redispatching units to control congestion on M2M flowgates 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 2013 through June 2015[47]



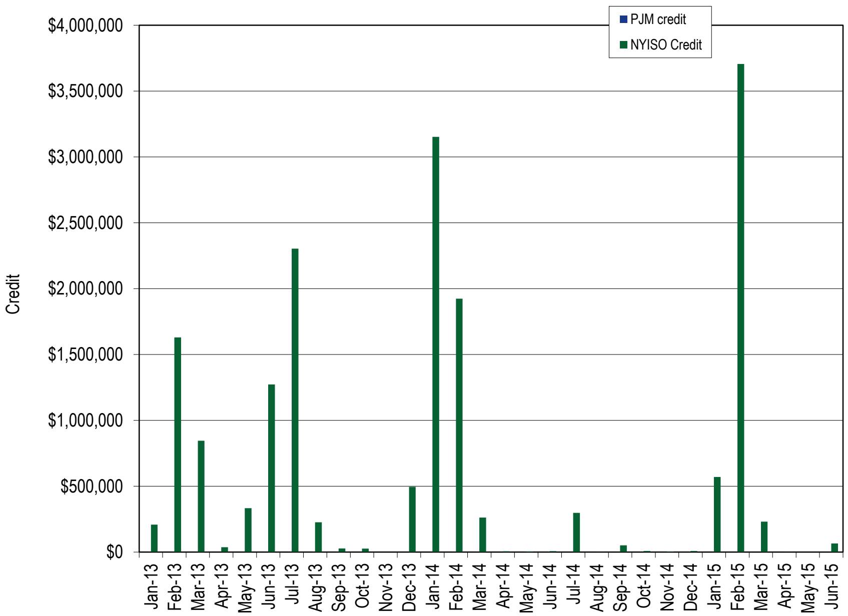
The M2M coordination process focuses on real-time market coordination to manage transmission limitations that occur on the M2M Flowgates in a more cost effective manner. Coordination between NYISO and PJM includes not only joint redispatch, but also incorporates coordinated operation of the Ramapo PARs 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.[48] For each M2M flowgate, a Ramapo PAR settlement will occur for each interval during coordinated operations. The Ramapo PAR settlements are determined based on whether the measured real-time flow on each of the Ramapo PARs is greater than or less than the calculated target value. If the actual flow is greater

47 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

48 See "New York Independent System Operator, Inc., Joint Operating Agreement with PJM Interconnection, L.L.C.," (November 4, 2014) <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx>.

than the target flow, NYISO will make a payment to PJM. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the actual and target PAR flow. If the actual flow is less than the target flow, PJM will make a payment to NYISO. This payment is calculated as the product of the M2M flowgate shadow price, the PAR shift factor and the difference between the target and actual PAR flow. In the first six months of 2015, 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 2013 through June 2015[49]



PJM and TVA Joint Reliability Coordination Agreement (JRCA)[50]

The joint reliability coordination agreement (JRCA) executed on April 22, 2005, provides for the exchange of information and the implementation of reliability and efficiency protocols between TVA and PJM. The agreement also provides for the management of congestion and arrangements for both near-term and long-term system coordination. Under the JRCA, PJM and TVA honor constraints on each other's flowgates in their Available Transmission Capability (ATC) calculations. Additionally, market flows are calculated on reciprocal flowgates. When a constraint occurs on a reciprocal flowgate within TVA, PJM has the option to redispatch generation to reduce market flow, and therefore alleviate the constraint. Unlike the M2M procedure between MISO and PJM, this redispatch does not result in M2M payments; however, electing to redispatch generation within PJM can avoid potential market disruption by curtailing a large number of transactions under the Transmission Line Loading Relief (TLR) procedure to achieve the same relief. The agreement continued to be in effect in the first six months of 2015.

PJM and Duke Energy Progress, Inc. Joint Operating Agreement[51]

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.[52] On January 20, 2011, the Commission conditionally accepted the compliance filing. On July 2, 2012, Duke Energy and Progress Energy Inc. completed a merger. At that time, Progress Energy Carolinas Inc. changed its name to Duke Energy Progress (DEP).

The PJM/DEP JOA states that the Marginal Cost Proxy Method (MCPM) will be used in the determination of the CPLEIMP and CPLEEXP interface

49 The totals represented in this figure represent the settlements as of the time of this report and may not include adjustments or resettlements.

50 See "Joint Reliability Coordination Agreement Among and Between PJM Interconnection, L.L.C., and Tennessee Valley Authority," (October 15, 2014) <http://www.pjm.com/~/media/documents/agreements/joint-reliability-coordination-agreement-miso-pjm-tva.ashx>.

51 See "Amended and Restated Joint Operating Agreement Among and Between PJM Interconnection, L.L.C., and Duke Energy Progress Inc.," (December 3, 2014) <http://www.pjm.com/~/media/documents/agreements/progress-pjm-joint-operating-agreement.ashx>.

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

price. Section 2.6A (2) of the PJM Tariff describes the process of calculating the interface price under the MCPM. Under the MCPM, PJM compares the individual bus LMP (as calculated by PJM) for each DEP generator in the PJM model with a telemetered output greater than zero MW to the marginal cost for that generator.

For the CPLEIMP price (imports to PJM), PJM uses the lowest LMP of any generator bus in the DEP balancing authority area, with an output greater than zero MW that has an LMP less than its marginal cost for each five minute interval. If no generator with an output greater than zero MW has an LMP less than its marginal cost, then the import price is the average of the bus LMPs for the set of generators in the DEP area with an output greater than zero MW that PJM determines to be the marginal units in the DEP area for that five minute interval. PJM determines the marginal units in the DEP area by summing the output of the units serving load in the DEP area in ascending order by the units' marginal costs until the sum equals the real time load in the DEP area. Units included in the sum shall be the marginal units for the DEP area for that interval.

PJM calculates the CPLEEXP price for exports from PJM to DEP as the highest LMP of any generator bus in the DEP area with an output greater than zero MW (excluding nuclear and hydro units) that has an LMP greater than its marginal cost in the 5 minute interval.[53] If no generator with an output greater than zero MW has an LMP greater than its marginal cost, then the export price will be the average of the bus LMPs for the set of generators with an output greater than zero MW that PJM determines to the be marginal units in the same manner as described for the CPLEIMP interface price. The hourly integrated import and export prices are the average of all of the 5 minute intervals in each hour.

The MCPM bases its calculation on the DEP units modeled in the PJM market that have an output greater than zero, and only uses the units whose output exceeds the reported DEP real-time load. When new units are added to the DEP footprint, and existing units in the DEP footprint retire, PJM does not have complete data to calculate the interface price. These new units can impact the interface price in several ways. By not having the additional units modeled, these units cannot be considered to be marginal units, and therefore cannot set price. For the import price, if the PJM calculated LMP of one of the new units were to be lower than any currently modeled unit, then PJM's CPLEIMP pricing point would be lower, and PJM would pay less for imports. Conversely, if the PJM calculated LMP of one of the new units were to be higher than any currently modeled unit, then PJM's CPLEEXP pricing point would be higher, and PJM would receive more for exports.

Not maintaining a current set of units in the DEP footprint in PJM's network model limits PJM's ability to recognize which units are marginal and it is often not possible to calculate the CPLEIMP and CPLEEXP interface prices using the MCPM. By not maintaining a complete set of units in the DEP footprint, the reported output of the modeled units are often insufficient to cover the reported real time load, and therefore no units are considered marginal. When this occurs, the MMU believes that the CPLEIMP and CPLEEXP pricing points should revert to the SOUTHIMP and SOUTHEXP interface prices; however, this has not been the case. When this occurs, PJM reverts the calculation using the high-low interface pricing method as described in Section 2.6A (1) of the PJM Tariff. The MMU does not believe that this is appropriate, and does not see the basis for this approach in either the PJM Tariff or the PJM/DEP JOA.

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.[54] 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.[55] 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

53 The MMU has objected to the omission of nuclear and hydro units from the calculation. This omission is not included in the definition of the MCPM interface pricing method in the PJM Tariff, but is included as a special condition in the PJM/DEP JOA. The MMU does not believe it is appropriate to exclude these units from the calculation as these units could be considered marginal and impact the prices.

54 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).

55 See *Duke Energy Progress, Inc. and PJM Interconnection, L.L.C*, Docket No. ER15-29-000 (October 3, 2014).

dispatch agreement.[56] 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 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."[57] 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 DEP to unilaterally terminate the Joint Operating Agreement.

PJM and VACAR South Reliability Coordination Agreement[58]

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 six months of 2015.

Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company (WEC) and PJM Interconnection, LLC[59]

The Balancing Authority Operations Coordination Agreement executed on July 20, 2013, provides for the exchange of information between WEC and PJM. The purpose of the data exchange is to allow for the coordination of balancing authority actions to ensure the reliable operation of the systems. The agreement continued to be in effect in the first six months of 2015.

Northeastern ISO-Regional Transmission Organization Planning Coordination Protocol[60]

The Northeastern ISO-RTO Planning Coordination Protocol executed on December 8, 2004, provides for the exchange of information between PJM, NYISO and ISO New England. The purpose of the data exchange is to allow for the long-term planning coordination among and between the ISOs and RTOs in the Northeast. The agreement continued to be in effect in the first six months of 2015.

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/DEP JOA allows for the PECIMP and PECEXP interface pricing points to be calculated using the Marginal Cost Proxy Pricing method.[61] The DUKIMP, DUKEXP, NCMPAIMP and NCMPAEXP interface pricing points are calculated based on the high-low pricing method as defined in Section 2.6A (1) of the PJM Tariff.

Table 9-34 Real-time average hourly LMP comparison for Duke, PEC and NCMPA: January through June 2015

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$32.34	$33.80	$32.41	$32.41	($0.08)	$1.38
PEC	$30.92	$34.62	$32.41	$32.41	($1.50)	$2.21
NCMPA	$33.06	$33.28	$32.41	$32.41	$0.65	$0.87

56 See Protest and Motion for Rehearing of the Independent Market Monitor for PJM in Docket No. ER15-29-000 (October 24, 2014).
57 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.
58 See "PJM-VACAR South RC Agreement," (November 7, 2014) <http://www.pjm.com/~/media/documents/agreements/executed-pjm-vacar-rc-agreement.ashx>.
59 See "Balancing Authority Operations Coordination Agreement between Wisconsin Electric Power Company and PJM Interconnection, LLC," (July 20, 2013) <http://www.pjm.com/~/media/documents/agreements/balancing-authority-operations-coordination-agreement.ashx>.
60 See "Northeastern ISO/RTO Planning Coordination Protocol," (December 8, 2004) <http://www.pjm.com/~/media/documents/agreements/northeastern-iso-rto-planning-coordination-protocol.ashx>.
61 See *PJM Interconnection, L.L.C,* Docket No. ER10-2710-000 (September 17, 2010).

Table 9-35 Day-ahead average hourly LMP comparison for Duke, PEC and NCMPA: January through June 2015

	Import LMP	Export LMP	SOUTHIMP	SOUTHEXP	Difference IMP LMP - SOUTHIMP	Difference EXP LMP - SOUTHEXP
Duke	$34.07	$35.22	$33.90	$33.88	$0.17	$1.35
PEC	$34.44	$35.48	$33.90	$33.88	$0.54	$1.60
NCMPA	$34.77	$34.95	$33.90	$33.88	$0.87	$1.07

It is not clear that agreements between PJM and neighboring external entities, in which those entities receive some of the benefits of the PJM LMP market without either integrating into an LMP market or applying LMP internally, are in the best interest of PJM's market participants. In the case of the DEP JOA for example, the merger between Progress and Duke has resulted in a single, combined entity where one part of that entity is engaged in congestion management with PJM and thereby receiving special pricing from PJM for the dynamic energy schedule, while the other part of the entity is not.

Other Agreements with Bordering Areas

Consolidated Edison Company of New York, Inc. (Con Edison) 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.[62] This wheeled power creates loop flow across the PJM system. The Con Edison contracts governing the New Jersey path evolved during the 1970s and were the subject of a Con Edison complaint to the FERC in 2001.[63]

After years of litigation concerning whether or on what terms Con Edison's protocol would be renewed, on February 23, 2009, PJM filed 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.[64] By order issued September 16, 2010, the Commission approved this settlement,[65] which extends Con Edison's special protocol indefinitely. The Commission approved transmission service agreements that 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.[66] 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.[67] 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.

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 20 TLRs of level 3a or higher in the first six months of 2015, compared to three such TLRs issued in the first six months of 2014.[68] The number of different flowgates for which PJM declared a TLR 3a or higher increased from seven in the first six months of 2014 to eight in the first six months of 2015. The total MWh of transaction curtailments increased by 3,316.3 percent from 1,852 MWh in the first six months of 2014 to 61,418 MWh in the first six months of 2015.

62 See the *2015 Quarterly State of the Market Report for PJM: January through June*, Section 4 – "Energy Market Uplift" of this report for the operating reserve credits paid to maintain the power flow established in the Con Edison wheeling contracts.
63 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.
64 See FERC 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.
65 132 FERC ¶ 61,221 (2010).
66 *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).
67 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.
68 TLR Level 3a is the first level of TLR that results in the curtailment of transactions. See the *2014 State of the Market Report for PJM*, Volume II, Appendix E, "Interchange Transactions," for a more complete discussion of TLR levels.

MISO issued 53 TLRs of level 3a or higher in the first six months of 2015, compared to 93 such TLRs issued in the first six months of 2014. The number of different flowgates for which MISO declared a TLR 3a or higher decreased from 26 in the first six months of 2014 to 15 in the first six months of 2015. The total MWh of transaction curtailments decreased by 63.0 percent from 138,714 MWh in the first six months of 2014 to 87,428 MWh in the first six months of 2015.

NYISO issued four TLRs of level 3a or higher in the first six months of 2015, compared to one such TLRs issued in the first six months of 2014. The number of different flowgates for which NYISO declared a TLR 3a or higher was one in the first six months of 2014 and was also one in the first six months of 2015. The total MWh of transaction curtailments increased by 305.4 percent from 991 MWh in the first six months of 2014 to 3,027 MWh in the first six months of 2015.

Table 9-36 PJM MISO, and NYISO TLR procedures: January, 2012 through June 2015

	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-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
Oct-14	1	5	0	1	5	0	1,386	20,581	0
Nov-14	0	10	0	0	6	0	0	23,736	0
Dec-14	2	2	0	2	2	0	1,792	1,264	0
Jan-15	2	8	1	1	4	1	7,293	626	2,261
Feb-15	6	11	2	2	6	1	37,222	9,173	331
Mar-15	8	0	1	3	0	1	14,704	0	435
Apr-15	2	6	0	2	3	0	1,033	23,518	0
May-15	1	8	0	1	2	0	961	12,048	0
Jun-15	1	20	0	1	4	0	205	42,063	0

Table 9-37 Number of TLRs by TLR level by reliability coordinator: January through June, 2015[69]

Year	Reliability Coordinator	3a	3b	4	5a	5b	6	Total
2015	MISO	15	23	0	10	5	0	53
	NYIS	4	0	0	0	0	0	4
	ONT	1	0	0	0	0	0	1
	PJM	11	7	0	1	1	0	20
	SOCO	0	0	0	0	0	0	0
	SWPP	68	36	0	21	9	0	134
	TVA	26	40	0	14	26	0	106
	VACS	0	2	0	0	1	0	3
Total		125	108	0	46	42	0	321

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.[70]

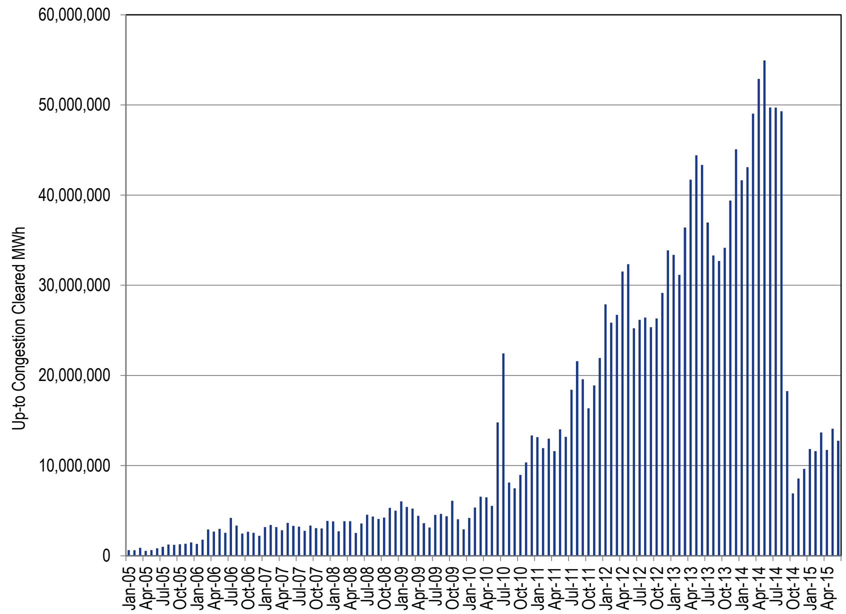
Following elimination of the requirement to procure and pay for transmission for up-to congestion transactions, the volume of transactions increased significantly.

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 affect FTR funding.[71]

On August 29, 2014, FERC issued an Order which created an obligation for UTCs to pay any uplift determined to be appropriate in the Commission review, effective September 8, 2014.[72]

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 67.8 percent, from 209,819 bids per day in the first six months of 2014 to 67,641 bids per day in the first six months of 2015. The average cleared volume of up-to congestion bids submitted in the Day-Ahead Energy Market decreased by 74.0 percent, from 1,609,507 MWh per day in the first six months of 2014, to 418,102 MWh per day in the first six months of 2015 (Figure 9-13).

Figure 9-13 Monthly up-to congestion cleared bids in MWh: January 2005 through June 2015



69 Southern Company Services, Inc. (SOCO) is the reliability coordinator covering a portion of Mississippi, Alabama, Florida and Georgia. Southwest Power Pool (SWPP) is the reliability coordinator for SPP. VACAR-South (VACS) is the reliability coordinator covering a portion of North Carolina and South Carolina.

70 See the *2012 State of the Market Report for PJM*, Volume II, Section 8, "Interchange Transactions," for a more detailed discussion.

71 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*, Section 13: FTRs and ARRs, "FTR Forfeitures."

72 148 FERC ¶ 61,144 (2014) *Order Instituting Section 206 Proceeding and Establishing Procedures.*

Table 9-38 Monthly volume of cleared and submitted up-to congestion bids: January 2010 through June 2015

	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-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

Table 9-38 Monthly volume of cleared and submitted up-to congestion bids: January 2010 through June 2015 *(continued)*

	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-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
Oct-14	2,556,049	2,633,382	202,516	17,301,235	22,693,183	91,922	83,113	8,743	775,152	958,930	778,085	527,692	73,370	5,538,329	6,917,477	36,303	27,787	3,557	313,084	380,731
Nov-14	2,907,118	3,090,553	233,597	20,157,436	26,388,704	99,298	98,695	14,611	964,684	1,177,288	802,153	732,365	106,754	6,931,319	8,572,590	38,126	33,342	7,584	397,534	476,586
Dec-14	3,294,133	3,074,993	120,694	21,170,152	27,659,972	128,753	113,591	11,020	1,063,697	1,317,061	1,090,084	683,527	43,036	7,819,905	9,636,553	51,293	39,262	4,747	477,788	573,090
Jan-15	5,546,341	2,401,938	184,935	26,556,180	34,689,394	198,934	97,676	9,072	1,280,378	1,586,060	2,047,961	414,985	83,498	9,285,631	11,832,075	85,916	23,956	3,520	486,044	599,436
Feb-15	5,375,057	2,198,495	235,687	30,708,158	38,517,397	199,947	97,499	8,555	1,504,921	1,810,922	1,569,220	485,647	48,134	9,492,364	11,595,365	66,858	27,559	2,228	502,766	599,411
Mar-15	6,104,575	3,878,773	590,547	43,668,068	54,241,963	219,079	120,017	18,573	1,806,387	2,164,056	1,463,247	769,655	105,300	11,338,070	13,676,272	69,309	36,927	6,028	615,310	727,574
Apr-15	7,172,015	3,787,440	656,913	41,264,789	52,881,157	268,196	112,440	19,215	1,568,301	1,968,152	1,669,627	643,703	128,394	9,294,533	11,736,258	79,809	26,693	5,148	472,254	583,904
May-15	9,104,665	4,738,308	866,026	45,821,190	60,530,188	352,787	142,643	29,817	1,870,020	2,395,267	2,510,355	873,849	174,280	10,524,318	14,082,802	114,601	34,456	6,437	544,781	700,275
Jun-15	7,686,270	3,678,135	717,311	46,563,639	58,645,356	273,749	107,444	18,962	1,918,405	2,318,560	1,490,960	779,517	171,815	10,311,431	12,753,722	68,977	27,114	4,044	544,756	644,891
TOTAL	1,167,930,865	1,148,499,652	67,268,073	2,738,167,674	5,121,866,263	28,315,616	25,535,966	1,661,529	92,394,929	147,908,040	411,439,204	398,507,448	24,749,862	825,037,517	1,659,734,031	11,303,605	10,061,648	634,105	32,924,021	54,923,379

In the first six months of 2015, the cleared MW volume of up-to congestion transactions was comprised of 14.2 percent imports, 5.2 percent exports, 0.9 percent wheeling transactions and 79.6 percent internal transactions. Less than 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.[73] 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 PJM/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 PJM/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 PJM/IMO interface pricing point is defined as the LMP at the Bruce bus, which is located in the IESO. In the same manner as the PJM/MISO interface price, when a M2M constraint binds, PJM's LMP calculation at the Bruce bus (as well as all buses in the PJM network model) is based on the PJM model's distribution factors of the Bruce bus to the binding M2M constraint and PJM's shadow price of the binding M2M constraint. 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 PJM/IMO interface pricing point creates opportunities for market participants to engage in sham scheduling activities. For example, a market participant can use two separate transactions to create a flow from Ontario to MISO. In this example, the market participant uses the PJM Energy Market as a temporary generation and load point by first submitting a wheeling transaction from Ontario, through MISO and into PJM, then by submitting a second transaction from PJM to MISO. These two transactions, combined, create an actual flow along the Ontario/MISO interface. Through sham scheduling, the market participant receives settlements from PJM when no changes in generation occur. This activity is similar to that observed when PJM had a Southwest and Southeast Interface pricing point. During that time, market participants would utilize the PJM spot market as a temporary load and generation point to wheel transactions through the PJM Energy Market. This was done to take advantage of the price differences between the interfaces without providing the market benefits of congestion relief.

At the February 11, 2015, meeting of the PJM Markets Implementation Committee, PJM introduced a new PJM/IMO interface price method.[74] The new method utilizes a dynamic weighting of the PJM/MISO interface price and the PJM/NYIS interface price, based on the performance of the Michigan-Ontario PARs. When the absolute value of the actual flows on the PARs are greater than or equal to the absolute value of the scheduled flows on the PARs, and the scheduled and actual flows are in the same direction, the PJM/IMO interface price will be equal to the PJM/MISO interface price (i.e. 100 percent weighting on the PJM/MISO interface). When actual flows on the PARs are in the opposite direction of the scheduled flows on the PARs, the PJM/IMO interface price will be equal to the PJM/NYIS interface price (i.e. 100 percent weighting on the PJM/NYIS interface). When the absolute value of the actual flows on the PARs are less than or equal to the absolute value of the scheduled flows on the PARs, and the scheduled and actual flows are in the same direction, the PJM/IMO interface price will be a combination to the PJM/MISO interface price and the PJM/NYIS interface price. In this case the weightings of the PJM/MISO and PJM/NYIS interface prices are determined

73 See "Interface Pricing Point Assignment Methodology," (August 28, 2014) <http://www.pjm.com/~/media/etools/exschedule/interface-pricing-point-assignment-methodology.ashx>. PJM periodically updates these definitions on its website. See <http://www.pjm.com>.

74 See "IMO Interface Definition Methodology Report," (February 11, 2015) <http://www.pjm.com/~/media/committees-groups/committees/mic/20150211/20150211-item-08b-imo-interface-definition-methodology-report.ashx>.

based on the scheduled and actual flows. For example, in a given interval, the scheduled flow on the Michigan-Ontario PARs is 1,000 MW, and the actual flow is 800 MW. If in that same interval, the PJM/MISO interface price is $45.00 and the PJM/NYIS interface price $30.00, the PJM/IMO interface price would be calculated with a weighting of 80 percent of the PJM/MISO interface price ($45.00 * 0.8, or $36.00) and 20 percent of the PJM/NYIS interface price ($30.00 * 0.2, or $6.00), for a PJM/IMO interface price of $42.00. The new PJM/IMO interface price method was implemented on June 1, 2015.

The MMU believes that the new PJM/IMO interface price method is a step in the right direction towards pricing energy that sources or sinks in Ontario based on the path of the actual, physical transfer of energy. The MMU remains concerned about the assumption of PAR operations, and will continue to evaluate the impact of PARs on the scheduled and actual flows and the impacts on the PJM/IMO interface price. The MMU remains concerned about the potential for market participants to continue to engage in sham scheduling activities after the new method is implemented.

The MMU recommends that if the PJM/IMO interface price remains and with PJM's new method in place, that PJM implement additional business rules to remove the incentive to engage in sham scheduling activities using the PJM/IMO interface price. Such rules would prohibit the same market participant from scheduling an export transaction from PJM to any balancing authority while at the same time an import transaction is scheduled to PJM that receives the PJM/IMO interface price. PJM should also prohibit the same market participant from scheduling an import transaction to PJM from any balancing authority while at the same time an export transaction is scheduled from PJM that receives the PJM/IMO interface price.

Of the 4,202 GWh of the net scheduled transactions between PJM and IESO, 4,121 GWh wheeled through MISO in the first six months of 2015 (see Table 9-22). The MMU recommends that PJM eliminate the PJM/IMO interface pricing point, and assign the transactions that originate or sink in the IESO balancing authority to the PJM/MISO interface pricing point.[75]

75 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 Transactions

Coordinated transaction scheduling (CTS) 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 is 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 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.[76] 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 4, 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.[77] On November 4, 2014, PJM and the NYISO implemented CTS.

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/NYIS interface prices. 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 six months of 2015. Table 9-39

76 See PJM Interconnection, L.L.C., OA Schedule 1 and Attachment K Revisions, Docket No. ER14-623-000 (December 13, 2013).
77 146 FERC ¶ 61,096 (2014).

shows that over all 12 forecast ranges, ITSCED predicted the real-time PJM/NYIS interface LMP within the range of $0.00 to $5.00 in 32.1 percent of the intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.90. In 9.9 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 $81.25, and in 9.6 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 $98.34.

Table 9-39 ITSCED real-time LMP - PJM/NYIS interface price comparison (all intervals): January through June 2015

Range	Percent of All Intervals	Average Price Difference
> $20	9.9%	$81.25
$10 to $20	5.7%	$14.04
$5 to $10	8.9%	$7.04
$0 to $5	32.1%	$1.90
-$5 to $0	24.5%	$1.72
-$10 to -$5	5.2%	$7.11
-$20 to -$10	4.0%	$14.24
< -$20	9.6%	$98.34

Table 9-40 shows how the accuracy of the ITSCED forecasted LMPs changes as the cases approach real-time.

Table 9-40 ITSCED real-time LMP - PJM/NYIS interface price comparison (by interval): January through June 2015

	~ 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	9.5%	$64.40	9.1%	$61.69	10.6%	$70.93	7.7%	$63.37
$10 to $20	6.0%	$14.04	5.7%	$14.14	6.2%	$13.91	5.3%	$13.92
$5 to $10	9.1%	$7.04	9.3%	$7.06	10.2%	$7.00	8.3%	$7.01
$0 to $5	30.6%	$1.99	31.3%	$1.98	32.8%	$2.00	34.2%	$1.79
-$5 to $0	23.6%	$1.90	23.6%	$1.88	22.9%	$1.68	25.7%	$1.63
-$10 to -$5	6.2%	$7.04	6.0%	$7.08	4.7%	$7.18	5.0%	$7.10
-$20 to -$10	4.4%	$14.35	4.4%	$14.05	3.5%	$14.30	4.1%	$14.25
< -$20	10.6%	$121.58	10.5%	$109.20	9.1%	$87.32	9.7%	$87.68

Table 9-40 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 60.0 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 54.2 percent in the 135 minute ahead ITSCED results.

In 17.4 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 $63.37 when the price difference was greater than $20.00, and $87.68 when the price difference was greater than -$20.00.

The NYISO utilizes PJM's ITSCED forecasted LMPs to compare against the NYISO Real-Time Commitment (RTC) results in its evaluation of CTS transactions. The NYISO approves 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 between forecast and actual 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, the CTS proposal represents an incremental step towards better interface pricing. 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 could play a significant role in improving pricing efficiency at the PJM/NYISO border on a standalone basis or in combination with the CTS transaction approach. CTS transactions are evaluated for each 15 minute interval. From November 4, 2014, through June 30, 2015, the first eight months of CTS operations, 23,565 15 minute transaction intervals were approved through the CTS process based on the forecast LMPs. When the forecast LMPs for the approved intervals were compared to the hourly integrated real-time LMPs, the direction of the flow in 7,694 (32.7 percent) of the intervals was inconsistent with the differences in real-time PJM/NYISO and NYISO/PJM prices. For example, if a market participant submits a CTS transaction from NYISO to PJM with a spread bid of $5.00, and NYISO's forecasted PJM interface price was at least $5.00 lower than PJM's forecasted NYISO interface price, the transaction would be approved. For 32.7 percent of the approved transactions, the actual, real-time price differentials were in the opposite direction of the forecast differential. The actual, real-time price differentials meant that the transactions would have been economic in the opposite direction. For 67.3 percent of the intervals, the forecast price differentials were consistent with real-time PJM/NYISO and NYISO/PJM price differences.

The MMU does not believe that conclusions should be reached on the effectiveness of the CTS process in improving the scheduling efficiency on the PJM/NYISO interface based on data for eight months. The data for eight months show that ITSCED is not a highly accurate predictor of the real-time PJM/NYIS interface prices. If this remains true, it will limit the effectiveness of CTS in improving the effectiveness of interface pricing.

Reserving Ramp on the PJM/NYISO Interface

Prior to the implementation of CTS, PJM held ramp space for all transactions submitted between PJM and the NYISO as soon as the NERC Tag was approved. At that time, once transactions were evaluated by the NYISO through their real-time market clearing process, any adjustments made to the submitted transactions would be reflected on the NERC Tags and the PJM ramp was adjusted accordingly.

As part of this process, PJM was often required to make further adjustments to transactions on its other interfaces in order to bring total system ramp back to within its limit. For example, if the ramp limit were +/- 1,000 MW, and there were 2,000 MW of imports scheduled from the NYISO to PJM at a given interval, this would allow for 3,000 MW to be exported from PJM on its other interfaces in the same interval (2,000 MW of imports and 3,000 MW of exports net to -1,000 MW of interchange, which is within the +/- 1,000 MW ramp limit in that interval). If, through the NYISO real-time market clearing process, the NYISO only approves 1,000 MW of exports to PJM, the other 1,000 MW of transactions would be curtailed, and PJM would see a ramp of -2,000 MW in that interval (1,000 MW of imports and 3,000 MW of exports net to -2,000 MW of interchange) which violates the +/- 1,000 MW ramp limit. PJM would then be required to curtail an additional 1,000 MW of exports at its other interface to bring the limit back to within the 1,000 MW limit. These curtailments were made on a last-in first-out basis as determined by the timestamp on the NERC Tag.

With the implementation of the CTS product with the NYISO, PJM modified how ramp is handled at the PJM/NYISO interface. Effective November 4, 2014, PJM no longer holds ramp room for any transactions submitted between PJM and the NYISO at the time of submission. Only after the NYISO completes its real-time market clearing process, and communicates the results to PJM, will PJM perform a ramp evaluation on transactions scheduled with the NYISO. If, in the event the NYISO market clearing process violates ramp, PJM would make additional adjustments based on a last-in first-out basis as determined by the timestamp on the NERC Tag. This process prevents the transactions scheduled at the PJM/NYISO interface from holding (or creating) ramp until they have completed their economic evaluation and are approved through the NYISO market clearing process. The MMU has not observed any adverse effects of the new process. The MMU will continue to monitor and evaluate the process moving forward.

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).

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. 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 six months of 2015. Table 9-41 shows that over all 12 forecast ranges, ITSCED predicted the real-time PJM/MISO interface LMP within the range of $0.00 to $5.00 in 39.8 percent of all intervals. In those intervals, the average price difference between the ITSCED forecasted LMP and the actual real-time LMP was $1.72. In 5.8 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 $77.31, and in 4.7 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 $98.59.

Table 9-41 ITSCED real-time LMP - PJM/MISO interface price comparison (all intervals): January through June 2015

Range	Percent of All Intervals	Average Price Difference
> $20	5.8%	$77.31
$10 to $20	6.1%	$14.21
$5 to $10	8.1%	$7.06
$0 to $5	39.8%	$1.72
-$5 to $0	27.7%	$1.52
-$10 to -$5	4.6%	$7.09
-$20 to -$10	3.3%	$14.10
< -$20	4.7%	$98.59

Table 9-42 shows how the accuracy of the ITSCED forecasted LMPs change as the cases approach real-time.

Table 9-42 ITSCED real-time LMP - PJM/MISO interface price comparison (by interval): January through June 2015

	~ 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	7.5%	$53.95	7.1%	$49.13	3.8%	$48.55	3.4%	$57.88
$10 to $20	6.9%	$14.36	7.1%	$14.35	5.7%	$14.07	5.1%	$14.13
$5 to $10	9.0%	$7.07	8.6%	$7.02	8.3%	$7.08	7.3%	$7.04
$0 to $5	39.3%	$1.83	40.6%	$1.82	40.7%	$1.75	41.3%	$1.65
-$5 to $0	25.2%	$1.59	25.0%	$1.56	28.4%	$1.50	29.4%	$1.45
-$10 to -$5	4.3%	$7.06	4.1%	$7.08	4.7%	$7.14	4.9%	$7.11
-$20 to -$10	3.1%	$14.14	3.0%	$14.01	3.3%	$14.22	3.5%	$14.13
< -$20	4.7%	$154.48	4.6%	$126.54	5.0%	$74.48	5.0%	$73.69

Table 9-42 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 70.7 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 64.5 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 8.4 percent of all intervals, the average price difference was $57.88 when the price difference was greater than $20.00, and the average price difference was $73.69 when the price difference was greater than -$20.00.

The data reviewed show that ITSCED is not a highly accurate predictor of the real-time PJM/MISO interface prices. If this remains true, it will limit the effectiveness of CTS in improving the effectiveness of interface pricing between PJM and MISO.

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 9-43 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 9-43 Monthly uncollected congestion charges: January 2010 through June 2015

Month	2010	2011	2012	2013	2014	2015
Jan	$148,764	$3,102	$0	$5	$0	$0
Feb	$542,575	$1,567	($15)	$249	$0	$0
Mar	$287,417	$0	$0	$0	$0	$0
Apr	$31,255	$4,767	($68)	($3,114)	$0	$0
May	$41,025	$0	($27)	$0	$0	$0
Jun	$169,197	$1,354	$78	$0	$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	$0	
Nov	$30,843	($795)	($4,678)	$0	$0	
Dec	$127,176	($659)	($209)	$0	$0	
Total	$3,314,018	($20,955)	($11,789)	($2,860)	$0	$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.[78] 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.

78 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>.

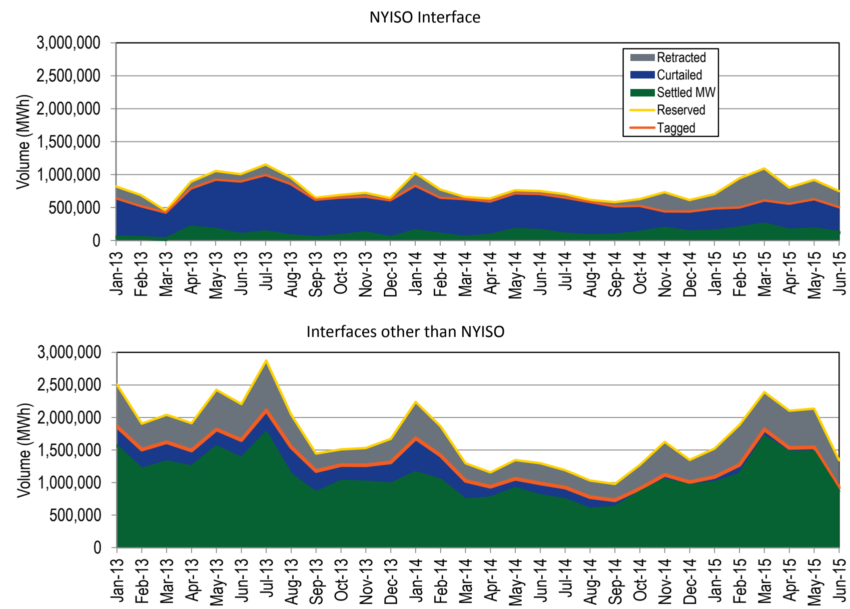
In response to market participant complaints regarding the inability to acquire spot import service after this rule change on April 1, 2007, changes were made to the spot import service effective May 1, 2008.[79] These changes limited spot imports to only hourly reservations and caused spot import service to expire if not associated with a valid NERC Tag within 2 hours when reserved the day prior to the scheduled flow or within 30 minutes when reserved on the day of the scheduled flow.

The new spot import rules provided incentives to hoard spot import capability. In the *2008 State of the Market Report for PJM*, the MMU recommended that PJM reconsider whether a new approach to limiting spot import service is required or whether a return to the prior policy with an explicit system of managing related congestion is preferable. PJM and the MMU jointly addressed this issue through the stakeholder process, recommending that all unused spot import service be retracted if not tagged within 30 minutes from the reservations queued time intraday, and two hours when queued the day prior. On June 23, 2009 PJM implemented the new business rules.

Figure 9-14 shows the spot import service utilization for the NYISO interface, and for all other interfaces, from January 2013, through June 2015. The yellow line shows the total monthly MWh of spot import service reserved and the orange line shows the total monthly MWh of tagged spot import service. The grey shaded area between the yellow and orange lines represents the MWh of retracted spot import service. The blue shaded area between the orange line and green shaded area represents the MWh of curtailed transactions using spot import service, and the green shaded area represents the total settled MWh of spot import service. Figure 9-14 shows that while there are proportionally fewer retracted MWh on the NYISO interface than on all other interfaces, the NYISO has proportionally more curtailed MWh. This is a result of the NYISO market clearing process.

79 See "Regional Transmission and Energy Scheduling Practices" (May 1, 2008) <http://www.pjm.com/markets-and-operations/etools/~/media/etools/oasis/regional-practices-redline-doc.ashx>. (Accessed March 1, 2012)

Figure 9-14 Spot import service utilization: January 2013 through June, 2015



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.

Interchange Optimization

When PJM prices are higher than prices in surrounding balancing authorities, imports will flow into PJM until the prices are approximately equal, given all the identified limitations on the effectiveness of the interchange pricing and transaction process. 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 based on economic dispatch rather than guessing the sensitivity of the transactions to price changes.

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 remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited joint dispatch approach that treats seams between balancing authorizes as a constraint, similar to other constraints 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 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 relatively 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.[80] 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.[81]

On November 12, 2013, PJM submitted its compliance filing to Order 764.[82] 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.[83] PJM concluded that a return to a 15 minute duration rule would cause an increase in imbalance charges/Balancing Operating Reserve

80 *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).
81 Order No. 764 at P 51.
82 See PJM Interconnection L.L.C. filing, Docket No. ER14-383-000 (November 12, 2013).
83 See *Id.* at 5–7.

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.[84] The Commission found that PJM's 45 minute duration rule was inconsistent with Order 764.[85]

Effective May 19, 2014, PJM removed the 45 minute scheduling duration rule to become compliant with Order No. 764.[86,87,88]

PJM and the MMU issued a statement indicating ongoing concern about market participants' scheduling behavior, and a commitment to address any scheduling behavior that raises operational or market manipulation concerns.[89]

Interchange Transaction Credit Screening Process

On November 3, 2014, PJM implemented a credit screening process for export interchange transactions submitted to PJM which requires participants to set aside sufficient credit in the eCredit application to cover their transactions. The amount of credit participants are required to set aside is equal to the MWh of each transaction times a price for each transaction on a rolling two day basis. The price used in the calculation is defined as the export nodal reference price factor for the interface point where the export is scheduled, or the real-time price calculated by PJM's ITSCED model, if higher. The export nodal reference price factor is updated every two months, and is based on nodal prices in the same two months the prior year. For example, if a market participant submits a 100 MW export from PJM to MISO between 0700 and 2300 (16 on-peak hours) in January 2015, and if the ITSCED price does not exceed the export nodal reference price factor, then the credit requirement would be calculated as 100MW * 16 hours/day * 2 days * $318.84 (the MISO on-peak nodal reference price factor for Jan-Feb 2015) or $1,020,288. If this full amount of credit is not set aside for the full two days, the transaction will be curtailed at the next screening.

84 147 FERC ¶ 61,045 (2014).
85 *See Id.* at P 12.
86 *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).
87 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).
88 *See* Letter Order, Docket No. ER14-381-000 (June 30, 2014).
89 *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>.

Marginal Loss Surplus Allocation

The sum of marginal losses is greater than average losses, resulting in a marginal loss surplus. The marginal loss surplus is paid by load and should be returned to load. The allocation of the marginal loss surplus is defined by PJM's marginal loss surplus allocation method.

On February 24, 2009, the Commission issued an Order directing that PJM's marginal loss surplus allocations should be allocated "equitably among all parties that support the fixed cost of the transmission system, without regard to whether such parties serve load, or show cause why such a credit should not be provided to all those who pay transmission charges."[90] On August 18, 2010, PJM filed revisions to the marginal loss surplus allocation.[91] The Commission approved PJM's filing on September 17, 2010.[92] However, the approved allocation method still does not accurately implement the Commission's February 24, 2009, directive. The current marginal loss surplus allocation states:

> The total Transmission Loss Charges accumulated by PJMSettlement in any hour shall be distributed pro-rata to each Network Service User and Transmission Customer in proportion to its ratio shares of the total MWhs of energy delivered to load (net of operating Behind The Meter Generation, but not to be less than zero) in the PJM Region, or the total exports of MWh of energy from the PJM Region (that paid for transmission service during such hour). Exports of energy for which Non-Firm Point-to-Point Transmission Service was utilized and for which the Non-Firm Point-to-Point Transmission Service rate was paid will receive an allocation of the total Transmission Loss Charges based on a percentage of the MWh of energy exported on such service, determined by the ratio of Non-Firm Point-to-Point Transmission Service rate to Firm Point-to-Point Transmission Service rate.[93]

90 126 FERC ¶ 61,164 (2009).
91 See PJM Interconnection L.L.C. filing, Docket No. ER10-2280-000 (August 18, 2010).
92 132 FERC ¶ 61,244 (2010).
93 See OATT Attachment K § 5.5.

The current marginal loss surplus allocation method does not allocate the surplus based on contributions to the fixed costs of the transmission system, but based on the MWh of transmission used instead. For example, if a market participant acquires 100 MWh of transmission, but only schedules 25 MWh, the marginal loss allocation would be based on the 25 MWh of scheduled transmission, ignoring the contribution of the remaining 75 MWh to the fixed costs of the transmission system that were paid for, but not utilized. The use of scheduled energy rather than the contribution to the costs of the grid results in an under allocation of surplus to firm transmission customers. Firm transmission is purchased on an annual, monthly, weekly or daily basis. The load factor, or utilization rate, for firm transmission service is much lower than for non-firm transmission service. The result, in turn, is that an allocation method based on usage rather than the contribution to the fixed costs of the grid under allocates surplus to firm transmission customers and over allocates surplus to non-firm transmission customers. For example, if a market participant wants to schedule energy on daily firm transmission during the on-peak hours, they would be required to acquire, at a minimum, a 24 hour daily firm block. Only the sixteen on-peak hours during which the transmission was used would be eligible for marginal loss surplus allocations. The result is that one third of the total cost of the firm transmission, which the market participant contributes to the fixed costs of the transmission system, is not eligible for any allocation of the marginal loss surplus. This effect is exacerbated for weekly, monthly and annual purchases of firm transmission service.

The current method also inappropriately excludes some transmission service types that contribute to the fixed costs of the transmission system. The method does not allocate any surplus to the purchasers of non-firm or firm point-to-point transmission service that is required to import power to PJM in the PJM Real-Time Market, or to the purchasers of non-firm or firm transmission service required to import or export fixed or dispatchable transactions in the PJM Day-Ahead Market.

The MMU recommends that PJM file revisions to the marginal loss surplus allocation method to fully comply with the February 24, 2009, Order. The MMU recommends that the revised allocation method distribute the marginal loss surplus to each network service user and transmission customer in proportion to its ratio share of the total dollars contributed to the fixed costs of the transmission system, regardless of whether such service is utilized in the PJM Day-Ahead or Real-Time Energy Markets. The MMU recommends that marginal loss surplus allocations be capped such that the marginal loss surplus credits cannot exceed the contributions made to the fixed costs of the transmission system for any reason.

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 January through June 2015.

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

- The Regulation Market structure was evaluated as not competitive for the year because the Regulation Market had one or more pivotal suppliers which failed PJM's three pivotal supplier (TPS) test in 98 percent of the hours in the first six months of 2015.
- Participant behavior in the Regulation Market was evaluated as competitive for the first six months of 2015 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. 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 Tier 2 Synchronized Reserve Market 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	Not 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 not competitive because market participants failed the three pivotal supplier test in 52 hours in the first six months of 2015.
- 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 was raised on January 8, 2015, to 2,175 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 in January through June 2015 was 2,248.8 MW. The actual demand for primary reserve in the MAD subzone in January through June 2015 was 1,708.2 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 counts as part of PJM's primary reserve requirement and is the capability of on-line resources following economic dispatch to ramp up in ten minutes from their current output in response to a synchronized reserve event.

- **Supply.** No offers are made for tier 1 synchronized reserve. The market solution calculates tier 1 synchronized reserve as available 10-minute ramp from the energy dispatch. In the first six months of 2015, there was an average hourly supply of 1,380.8 MW of tier 1 for the RTO synchronized reserve zone, and an average hourly supply of 1,204.2 MW of tier 1 in the Mid-Atlantic Dominion subzone.
- **Demand.** The default hourly required synchronized reserve requirement is 1,450 MW in the RTO Reserve Zone and 1,450 MW for the Mid-Atlantic Dominion Reserve subzone.
- **Tier 1 Synchronized Reserve Event Response.** Tier 1 synchronized reserve is paid when a synchronized reserve event occurs and it responds. The synchronized reserve 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.

  Of tier 1 synchronized reserve eligible for payment in Settlements, 60.5 percent actually responded during the eleven distinct synchronized reserve events in the first six months of 2015. PJM made changes to the way it calculated tier 1 MW for settlements beginning in July 2014. These changes improved the reported response rate by reducing the initial tier 1 estimate.

- **Issues.** The competitive price for tier 1 synchronized reserves is zero, as there is no incremental cost associated with the ability to ramp up from the current economic dispatch point. A tariff change included in the shortage pricing tariff changes (October 1, 2012) added the requirement to pay tier 1 synchronized reserve 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 $26,576,359 to tier 1 resources in 2014, and $25,816,249 in the first six months of 2015.

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 be synchronized, that have an obligation to respond with corresponding penalties, 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 six months of 2015, 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.
- **Demand.** The default hourly required synchronized reserve requirement was 1,450 MW in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone.
- **Market Concentration.** In the first six months of 2015, the weighted average HHI for cleared tier 2 synchronized reserve in the Mid-Atlantic Dominion subzone was 5705 which is classified as highly concentrated. The MMU calculates that 27.1 percent of hours would have failed a three pivotal supplier test in the Mid-Atlantic Dominion subzone.

  In the first six months of 2015, the weighted average HHI for cleared tier 2 synchronized reserve in the RTO Synchronized Reserve Zone was 4886 which is classified as highly concentrated. The MMU calculates that 38.2 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 six months of 2015.

Market Conduct

- **Offers.** Tier 2 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.

Market Performance

- **Price.** The weighted average price (includes all hours when a market was cleared including hours when the SRMCP was $0) for tier 2 synchronized reserve for all cleared hours in the Mid-Atlantic Dominion (MAD) subzone was $13.07 per MW in the first six months of 2015, a decrease of $2.11, 13.9 percent from the first six months of 2014.

  The weighted average price for tier 2 synchronized reserve for all cleared hours in the RTO Synchronized Reserve Zone was $16.76 per MW in the first six months of 2015, a decrease of $1.39 from the first six months of 2014.

Non-Synchronized Reserve Market

Non-synchronized reserve is part of primary reserve and includes the same two markets, the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone (MAD). Non-synchronized reserve is comprised of non-emergency energy resources not currently synchronized to the grid that can provide energy within ten minutes. Non-synchronized reserve is available to fill the primary reserve requirement above the synchronized reserve requirement.

Market Structure

- **Supply.** In the first six months of 2015, the supply of eligible non-synchronized reserve was 1,895.6 MW in MAD and 2,651.9 MW in the RTO. This supply was sufficient to cover the primary reserve requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone.
- **Demand.** Demand for non-synchronized reserve is the remaining primary reserve requirement after tier 1 synchronized reserve is estimated and tier 2 synchronized reserve (if any) is scheduled. In the RTO Zone, the market cleared an hourly average of 460.3 MW of non-synchronized reserve in the first six months of 2015. In the MAD subzone, the market cleared an hourly average of 434.9 MW of non-synchronized reserve.

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.** There are no offers for non-synchronized reserve. The non-synchronized reserve price is determined by the opportunity cost of the marginal non-synchronized reserve unit. The non-synchronized reserve weighted average price for all cleared hours in the RTO Reserve Zone was $1.40 per MW in the first six months of 2015 and in 80.0 percent of hours the market clearing price was $0. The non-synchronized reserve weighted average price for all cleared hours in the Mid-Atlantic Dominion (MAD) subzone was $1.68 and in 80.7 percent of hours the market clearing price was $0.

Secondary Reserve (Day-Ahead Scheduling Reserve)

PJM maintains a day-ahead, offer based market for 30-minute secondary reserve, designed to provide price signals to encourage resources to provide 30-minute reserve.[3] The DASR Market has no performance obligations.

Market Structure

- **Concentration.** In the first six months of 2015, 52 hours in the DASR Market would have failed the three pivotal supplier test. All 52 hours occurred during times when PJM Dispatch increased the DASR requirement.
- **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. In the first six months of 2015, the average available hourly DASR was 36,192 MW.
- **Demand.** The DASR requirement in 2015 is 5.93 percent of peak load forecast, down from 6.27 percent in 2014. The average DASR MW purchased was 4,454 MW per hour in the first six months of 2015.

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 June 30, 2015, 8.0 percent of resources offered DASR at levels above $5 per MW.
- **DR.** Demand resources are eligible to participate in the DASR Market. Six demand resources have entered offers for DASR.

3 See PJM. "Manual 35, Definitions and Acronyms," Revision 23, (April 11, 2014), p. 22.

Market Performance

- **Price.** The weighted average DASR market clearing price in January through March 2015 was $1.54 per MW. This is a decrease from $1.63 per MW in the first six months of 2014.

Regulation Market

The PJM Regulation Market is a single real-time market. Regulation is provided by generation resources and demand response resources that qualify to follow a regulation signal (RegA or RegD). PJM jointly optimizes regulation with synchronized reserve and energy to provide all three services at least cost. The PJM Regulation Market design includes three clearing price components: capability; performance; and lost opportunity cost. The marginal benefit factor and performance score translate a resource's capability (actual) MW into effective MW.

Market Structure

- **Supply.** In the first six months of 2015, the average hourly eligible supply of regulation was 1,237.2 actual MW (907.1 effective MW). This is a decrease of 98.4 actual MW (73.3 effective MW) from the same period of 2014, when the average hourly eligible supply of regulation was 1,335.6 actual MW (980.4 effective MW).
- **Demand.** The average hourly regulation demand was 655.6 actual MW (663.7 effective MW) in the first six months of 2015. This is a 17.9 actual MW (0 effective MW) decrease in the average hourly regulation demand of 673.5 actual MW (663.7 effective MW) from the same period of 2014.
- **Supply and Demand.** The ratio of offered and eligible regulation to regulation required averaged 1.79. This is a 9.84 percent decrease from the same period of 2014 when the ratio was 1.98.
- **Market Concentration.** In the first six months of 2015, the PJM Regulation Market had a weighted average Herfindahl-Hirschman Index (HHI) of 1477 which is classified as moderately concentrated. In the first six months of 2015, the three pivotal supplier test was failed in 98 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-based offer along with cost parameters to verify the offer, and may optionally submit a price-based 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 six months of 2015, there were 265 resources following the RegA signal and 41 resources following the RegD signal.

Market Performance

- **Price and Cost.** The weighted average clearing price for regulation was $41.33 per MW of regulation in the first six months of 2015, a decrease of $20.76 per MW of regulation, or 33.4 percent, from the same period of 2014. The cost of regulation in the first six months of 2015 was $50.04 per MW of regulation, a decrease of $25.16 per MW of regulation, or 33.5 percent, from the same period of 2014. The decreases in regulation price and regulation cost resulted primarily from high prices and costs in the first six months of 2014, particularly in January.
- **RMCP Credits.** RegD resources continue to be incorrectly compensated relative to RegA resources due to an inconsistent application of the marginal benefit factor in the optimization, assignment, pricing, and settlement processes. If the Regulation Market were functioning efficiently, RegD and RegA resources would be paid equally per effective MW.
- **Marginal Benefit Factor Function.** The marginal benefit factor measures the substitutability of RegD resources for RegA resources in satisfying the regulation requirement. The regulation market's effectiveness and efficiency depends on the marginal benefit factor function being properly defined based on the actual tradeoff between RegA and RegD MW in providing regulation. Current regulation performance indicates that the

4 See the *2014 State of the Market Report for PJM*, Volume II, Appendix F "Ancillary Services Markets."

marginal benefit factor function used by PJM is incorrectly describing the operational relationship between RegA and RegD for purposes of providing regulation service.

- **Inconsistent accounting of RegD Effective MW.** The current market design does not correctly account for the amount of effective MW being provided by RegD. Rather than calculating the total effective MW contribution of RegD MW on the basis of the area under the marginal benefit function curve, the current regulation market optimization assigns all RegD resources the lowest marginal benefit factor associated with last RegD MW at that price. This incorrect accounting of effective MW results in the purchase of more than the efficient level of regulation MW necessary to meet PJM's regulation requirement.

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 six months of 2015, total black start charges were $25.0 million with $20.0 million in revenue requirement charges and $5.0 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 to units scheduled in the Day-Ahead Energy Market or committed in real time to provide black start service under the automatic load rejection (ALR) option or for black start testing. Black start zonal charges in the first six months of 2015 ranged from $0.04 per MW-day in the PPL Zone (total charges were $59,801) to $4.35 per MW-day in the BGE Zone (total charges were $5,246,763).

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 six months of 2015, total reactive service charges were $148.5 million, a 8.8 percent decrease from $162.9 million in the first six months of 2014. Revenue requirement charges decreased from $140.7 million to $139.3 million and operating reserve charges fell from $22.2 million to $9.2 million. Total charges in the first six months of 2015 ranged from $1,800 in the RECO Zone to $20.6 million in the AEP Zone. 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.

Ancillary Services Costs per MWh of Load: 2004 through 2015

Table 10-4 shows PJM ancillary services costs for 2004 through 2015, 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. 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.

5 OATT Schedule 1 § 1.3BB.

Table 10-4 History of ancillary services costs per MWh of Load: January through June, 2004 through 2015

Year	Regulation	Scheduling, Dispatch, and System Control	Reactive	Synchronized Reserve	Supplementary Operating Reserve	Total
2004	$0.53	$0.66	$0.26	$0.16	$0.93	$2.53
2005	$0.57	$0.51	$0.27	$0.11	$0.60	$2.05
2006	$0.48	$0.48	$0.29	$0.08	$0.32	$1.65
2007	$0.61	$0.46	$0.30	$0.09	$0.50	$1.95
2008	$0.73	$0.37	$0.30	$0.08	$0.66	$2.14
2009	$0.37	$0.43	$0.37	$0.04	$0.50	$1.71
2010	$0.37	$0.38	$0.36	$0.06	$0.75	$1.92
2011	$0.33	$0.38	$0.41	$0.11	$0.80	$2.03
2012	$0.20	$0.44	$0.47	$0.03	$0.65	$1.79
2013	$0.26	$0.41	$0.65	$0.03	$0.73	$2.09
2014	$0.46	$0.41	$0.42	$0.36	$2.07	$3.71
2015	$0.29	$0.41	$0.38	$0.16	$0.57	$1.81

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. Status: Not adopted.)
- 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. Status: Not adopted. Stakeholder process.)
- The MMU recommends that no payments be made to tier 1 resources if they are deselected in the PJM market solution. (Priority: High. First reported Q3, 2014. Status: Adopted July 2014.)
- The MMU recommends that the tier 2 synchronized reserve must-offer provision of scarcity pricing be enforced. As of the end of December 31, 2014 compliance with the tier 2 must-offer provision was 99.5 percent. (Priority: Medium. First reported 2013. Status: Adopted partially.)
- 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 2012. Status: Not adopted.)
- The MMU recommends 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. Status: Not adopted.)
- 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. Status: Not adopted.)
- The MMU recommends that the three pivotal supplier test be incorporated in the DASR Market. (Priority: Low. First reported 2009. Status: Not adopted.)
- The MMU recommends that a reason code be attached to every hour in which PJM dispatch adds additional DASR MW. The addition of such a code would make the reason explicit, increase transparency and facilitate analysis of the use of PJM's ability to add DASR MW. (Priority: Medium. New recommendation. Status: not adopted.)

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 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 in settlement. This failure to correctly incorporate marginal benefit factor into the current Regulation Market design has resulted in both underpayment and overpayment of RegD resources and in the over procurement of RegD resources in some hours. 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 synchronized reserve events has been an issue. Compliance with the synchronized reserve must-offer requirement has also been an issue.

The shortage pricing rule that requires market participants to pay tier 1 synchronized reserve the tier 2 synchronized reserve price when the nonsynchronized reserve price is greater than zero, is inefficient and results in a windfall payment to the holders of tier 1 synchronized reserve resources. Such tier 1 resources have no obligation to perform and pay no penalties if they do not perform. Such resources are not tier 2 resources, although they have the option to offer as tier 2, to take on tier 2 obligations and to be paid as tier 2. Application of this rule added $80.0 million to the cost of primary reserve in 2014.

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

PJM has an obligation to maintain ten minute reserves (primary reserve) to ensure reliability in the event of disturbances. Primary reserve is PJM's implementation of the NERC 15-minute contingency reserve requirement.[6] 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.[7] PJM implements the NERC requirement conservatively as primary reserve available within ten minutes.

Market Structure

Supply

In 2015, PJM's primary reserve requirement was 2,063 MW for the RTO Zone, and 1,700 MW for the MAD subzone. It is satisfied by tier 1 synchronized reserves, tier 2 synchronized reserves and non-synchronized reserves, subject to the requirement that synchronized reserves equal 100 percent of the largest contingency. Effective January 1, 2015 the synchronized reserve requirement was increased to 1,342 MW in the Mid-Atlantic Dominion subzone, and remained at 1,375 MW in the RTO Zone. Effective January 8, 2015, the synchronized reserve requirement was increased to 1,450 MW in both the Mid-Atlantic Dominion subzone, and the RTO Zone. After the synchronized reserve requirement is satisfied, the remainder of primary reserves can come from non-synchronized reserves.

Estimated tier 1 is credited against PJM's primary reserve requirement. In the MAD subzone an average of 1,204.2 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 146 hours in the first six months of 2015. In the RTO Zone, an average of 1,380.8 MW of tier 1 was

6 PJM. OATT (effective 2/5/2014), p.1740; 1.3.29F Primary Reserve.
7 NERC, IVGTF Task 2.4 Report; Operating Practices, Procedures, and Tools, March 2011, p. 20.

available (Table 10-6). The RTO Zone synchronized reserve requirement was satisfied by tier 1 in 40.1 percent of all hours.

Regardless of online/offline state, all non-emergency generation capacity resources must submit a daily offer for Tier 2 Synchronized Reserve in eMKT prior to the offer submission deadline (1800 the day prior to the operating day). Offer MW and other non-cost offer details can be changed during the operating day. Owners are permitted to make resources unavailable for synchronized reserve daily or hourly but only if they are physically unavailable. Certain unit types including nuclear, wind, solar, and batteries, are expected to have zero MW Tier 2 Synchronized Reserve offer quantities.[8]

There is usually enough tier 2 synchronized reserve to fulfill the synchronized reserve requirement. In the MAD subzone, there was an average of 3,289.0 MW of eligible tier 2 synchronized reserve available (Figure 10-10) to meet the average tier 2 hourly demand of 259.6 MW (Table 10-5). In the RTO Zone, there was an average of 9,497 MW of eligible Tier 2 supply available to meet the average hourly demand of 381.1 MW (Table 10-6).

In the MAD subzone, there was an average of 1,899.2 MW of eligible non-synchronized reserve supply available to meet the average hourly demand of 433.7 MW (Table 10-6). In the RTO Zone, an hourly average of 2,675.5 MW supply was available to meet the average hourly demand of 894.5 MW (Table 10-5).

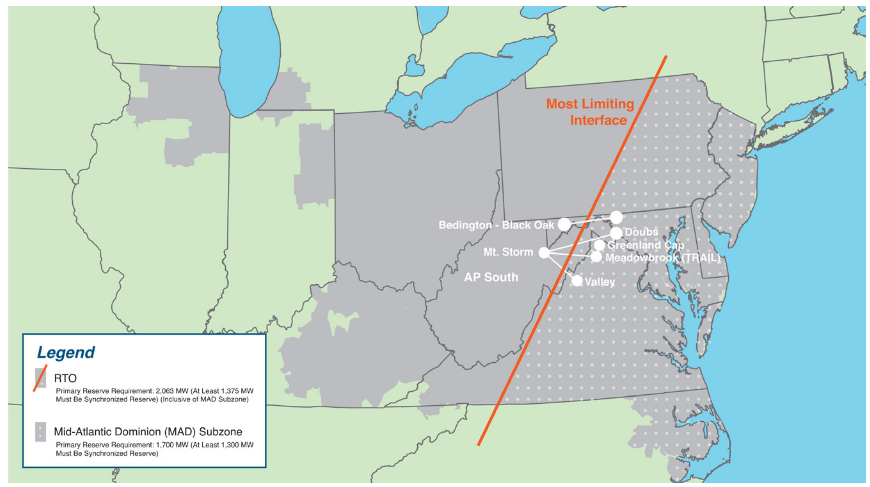
Demand

PJM requires that 150 percent of the largest contingency on the system be maintained as primary reserve. On January 8, 2015, the primary reserve requirement in the RTO Reserve Zone was raised from 2,063 MW to 2,175 MW. Adjustments to this value can occur when grid maintenance or outages change the largest contingency (Figure 10-1).

In 17.4 percent of hours in 2015, PJM increased the primary reserve requirement for the RTO Zone. The actual hourly average RTO primary reserve requirement was 2,247.1 MW in the first six months of 2015. In 38 hours during the first six months of 2015, PJM increased the primary reserve requirement for the MAD subzone. The actual hourly average demand for primary reserve in the MAD subzone in the first six months of 2015 was 1,707.2 MW.

Transmission constraints limit the deliverability of reserves within the RTO, requiring the definition of the Mid-Atlantic Dominion (MAD) subzone.[9] Of the 2,175 MW RTO primary reserve requirement, 1,700 MW (Table 10-15) must be deliverable to the MAD subzone (Figure 10-1).

Figure 10-1 PJM RTO geography and primary reserve requirement: 2015



The Mid-Atlantic Dominion Reserve (MAD) subzone is defined dynamically by the most limiting constraint separating MAD from the PJM RTO Reserve Zone. In 57.7 percent of hours in 2015, that constraint was the Bedington – Black Oak Interface. The AP South transfer interface constraint was the limiting constraint in 36.6 percent of hours.

PJM requires that synchronized reserves equal at least 100 percent of the largest contingency. This means that 1,450 MW of the primary reserve

8 See PJM, "Manual 11, Energy and Ancillary Services Market Operations," Revision 75 (April 9, 2015), p. 65.

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 75 (April 9, 2015), p. 68.

requirement must be synchronized reserve for both RTO Reserve Zone and the Mid Atlantic Dominion Reserve subzone.

Table 10-5 Average monthly tier 1 and tier 2 synchronized reserve, plus non-synchronized reserve used to satisfy the primary reserve requirement, MAD Subzone: January through June 2015

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Non-Synchronized Reserve MW
2015	Jan	1,222.0	206.9	629.7
2015	Feb	1,176.7	305.1	437.4
2015	Mar	1,200.6	288.7	394.6
2015	Apr	1,148.8	302.8	381.3
2015	May	1,217.4	238.5	387.4
2015	Jun	1,258.9	218.7	372.0
2015	Average	1,204.1	260.1	433.7

Table 10-6 Average monthly tier 1 and tier 2 synchronized reserve, and non-synchronized reserve used to satisfy the primary reserve requirement, RTO Zone: January through June 2015

Year	Month	Tier 1 Total MW	Tier 2 Synchronized Reserve MW	Non-Synchronized Reserve MW
2015	Jan	1,582.7	331.7	1,074.4
2015	Feb	1,469.1	415.7	906.3
2015	Mar	1,247.2	424.8	928.5
2015	Apr	1,125.1	438.8	877.1
2015	May	1,245.1	373.1	811.5
2015	Jun	1632,2	303.0	769.0
2015	Average	1,333.8	381.2	894.5

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 reserves (flexibly or inflexibly) 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 tier 2 resources (flexibly or inflexibly) if it forecasts 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 1,450 MW in the MAD subzone. Since the market solution considers tier 1 synchronized reserve to be zero cost, the ASO first estimates how much tier 1 synchronized reserve (green area) is available. If there is 1,450 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 1,450 MW of tier 1 then the remaining synchronized reserve requirement up to 1,450 MW is filled with tier 2 synchronized reserve (dark blue area). After 1,450 MW of synchronized reserve are assigned, the remaining 250 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 than or equal to synchronized reserve, almost all primary reserve between 1,450 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 June 2015

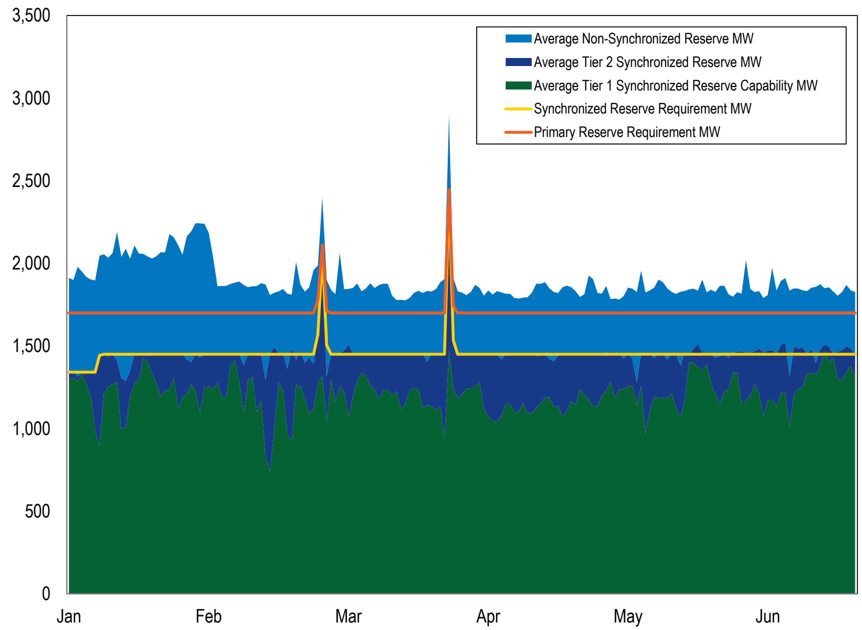
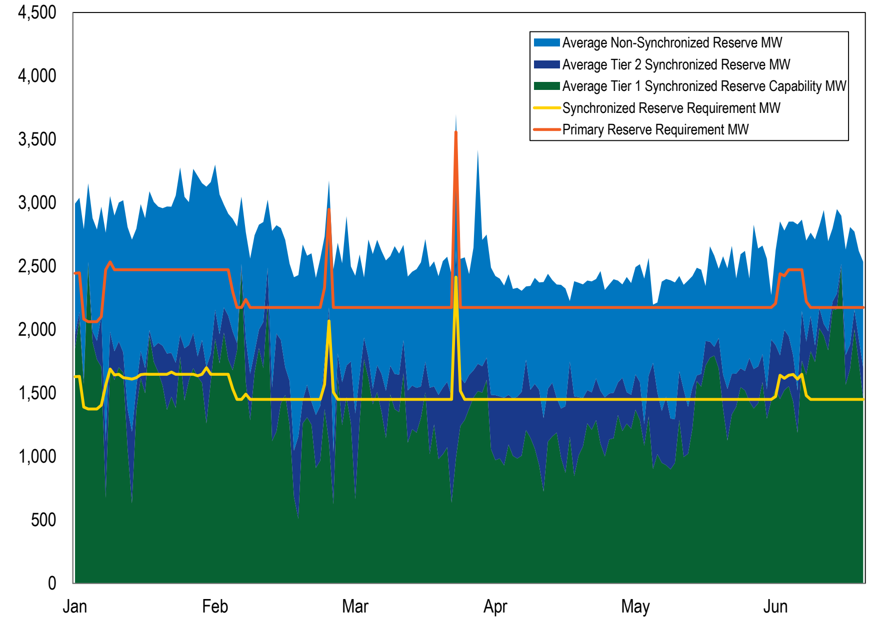


Figure 10-3 RTO subzone primary reserve MW by source (Daily Averages): January through June 2015



The solution methodology is similar for the RTO Reserve Zone (Figure 10-3) except that the required primary reserve MW is 2,175 MW.[10] Figure 10-3 shows how the hour ahead ASO satisfies the primary reserve requirement for the RTO Zone.

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

There is a separate price and cost for each component of primary reserve. In the market solution, the cost of 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 nor is there an obligation to ramp up during a synchronized reserve event. Tier 1 is credited when it responds to a synchronized reserve event. In addition, despite the absence of a performance obligation and an incremental cost to provide tier

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.

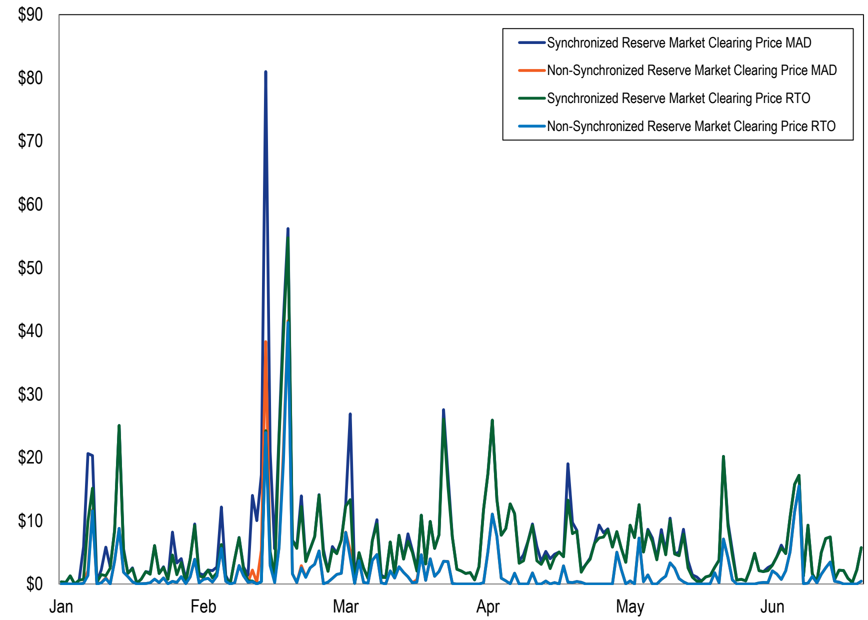
1, PJM's current market rules require that tier 1 synchronized reserves be paid the tier 2 synchronized reserve market price in any hour that the non-synchronized reserve market clears with a price above $0.

Under PJM's current market optimization approach, 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).

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 in the first six months of 2015.

Figure 10-4 Daily average market clearing prices ($/MW) for synchronized reserve and non-synchronized reserve: January through June 2015



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 (light blue area in Figure 10-2 and Figure 10-3) and tier 1 synchronized reserve (green area in Figure 10-2 and 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.

Table 10-7 MW credited, price, cost, and all-in price for primary reserve and its component products, full RTO Reserve Zone, January through June 2015

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	4,460	$193,736	NA	$43.44	$0.00
Tier 1 Synchronized Reserve	21.5%	1,340,635	$25,816,250	$19.26	$19.26	$0.07
Tier 2 Synchronized Reserve	24.0%	1,491,685	$36,438,890	$14.16	$24.43	$0.09
Non-synchronized Reserve	54.5%	3,390,118	$8,242,932	$1.51	$2.43	$0.02
Primary Reserve	100.0%	6,222,438	$70,498,072	$8.36	$11.33	$0.18

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 (green 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 to a synchronized reserve event or unless the non-synchronized reserve market clearing price is above $0.

While PJM relies on tier 1 resources to respond to a synchronized reserve event consistent with Good Utility Practice, tier 1 resources are not financially obligated to provide their tier 1 estimated MW during an event.

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.

In the first six months of 2015, in the RTO Reserve Zone the average hourly estimated tier 1 synchronized reserve was 1,380.8 MW (Table 10-6). In 372 hours (8.6 percent) the estimated tier 1 synchronized reserve was greater than the primary reserve requirement, meaning that the primary reserve requirement was met entirely by tier 1 synchronized reserve.

In the first six months of 2015, in the MAD reserve subzone the average hour ahead estimated tier 1 synchronized reserve was 1,204.2 MW (Table 10-5). In 151 hours the estimated tier 1 synchronized reserve was zero. In 53 hours the estimated tier 1 synchronized reserve was greater than the subzone requirement for synchronized reserve and no tier 2 synchronized reserve market was needed.

Table 10-8 Monthly average market solution Tier 1 Synchronized Reserve (MW) identified hourly, January through June 2015

Mid-Atlantic Dominion Reserve Subzone							
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
2015	Jan	622.8	599.2	1,222.0	410.4	1,450.0
2015	Feb	608.4	568.4	1,176.7	0.0	2,252.6
2015	Mar	483.1	717.5	1,200.6	163.7	2,344.6
2015	Apr	362.0	786.7	1,148.8	495.6	1,385.0
2015	May	533.9	683.5	1,217.4	599.5	2,173.0
2015	Jun	744.1	514.8	1,258.9	515.9	2,573.5
2015	Average	559.1	645.0	1,204.1	364.2	2,029.8

RTO Reserve Zone					
Year	Month	Synchronized Reserve Available from RTO	Average Hourly Tier 1 Used	Minimum Hourly Tier 1 Used	Maximum Hourly Tier 1 Used
2015	Jan	0.0	1,582.7	0.0	3,240.4
2015	Feb	0.0	1,469.1	0.0	2,980.4
2015	Mar	0.0	1,247.2	0.0	2,727.6
2015	Apr	0.0	1,125.1	191.5	2,132.2
2015	May	0.0	1,245.1	0.0	3,408.5
2015	Jun	0.0	1,632.2	0.0	5,547.7
2015	Average	0.0	1,383.6	31.9	3,339.5

Demand

There is no fixed required amount of tier 1 synchronized reserve. The Tier 1 synchronized reserve for each on-line resource is estimated from its synchronized reserve ramp rate 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, even when the non-synchronized reserve market clearing price is above $0.

Beginning January 2015, a new metric, DGP (Degree of Generator Performance), was introduced to improve the accuracy of the tier 1 MW estimate used by the market solution. DGP is calculated for all on-line resources for each market solution. DGP measures how closely the unit has been following economic dispatch for the past thirty minutes. In May 2015, PJM began communicating to generation operators whose tier 1 MW are part of the market solution the latest estimate of units' tier 1 MW and units' current resource specific DGP.[11]

For the first six months of 2015, PJM estimated Tier 1 MW for an average of 159 units as part of the solution each hour. The average DGP was 83.8 percent for those 159 units.

Supply and Demand

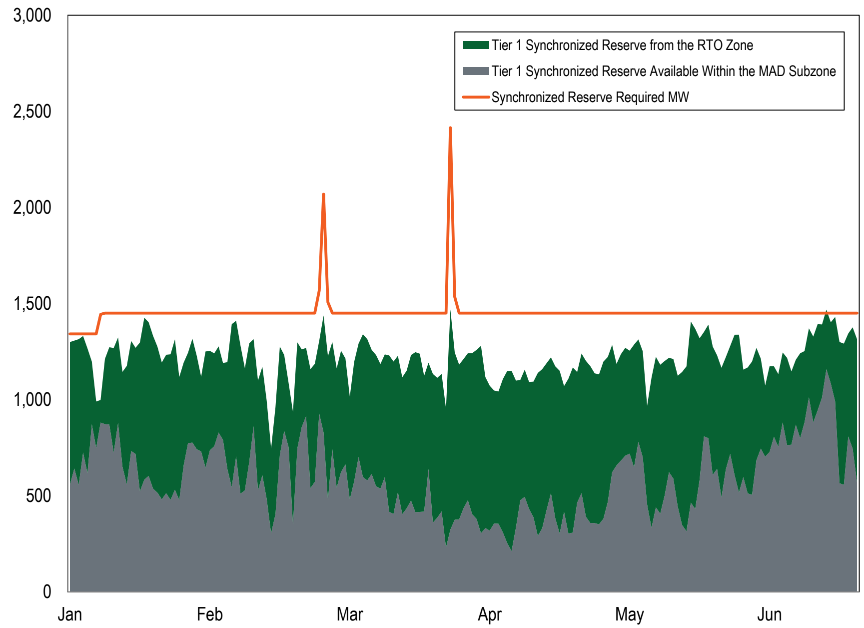
When solving for the synchronized reserve requirement the market solution first subtracts the amount of self-scheduled synchronized reserve from the requirement and then estimates the amount of tier 1. To improve its Tier 1 estimates, PJM routinely deselects certain resources from the tier 1 estimate. Tier 1 deselection is based on unit type, location and daily grid conditions.

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.

11 Communication of Synchronized Reserve Quantities to Resource Owners; <http://www.pjm.com/~/media/markets-ops/ancillary/communication-of-synchronized-reserve-quantities-to-resource-owners.ashx>

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 (MW) in the MAD subzone: January through June 2015[12]



Demand for synchronized reserve in the RTO Zone increased 27.4 percent from the first quarter of 2014 primarily because the hourly synchronized reserve requirement was increased from 1,375 MW to 1,450 MW. In addition, there was a temporary increase to 2,688 MW on February 28, 2015 and to 2,615 MW on March 29, 2015 because of emergency outages. Usually, the synchronized reserve requirement is increased because of planned outages in the spring and fall for periods of 10 to 14 days.

12 Hours in which the tier 1 estimate was biased by PJM dispatch are excluded from this graph.

Tier 1 Synchronized Reserve Event Response

Tier 1 synchronized reserve is awarded credits when a synchronized reserve event occurs and it responds. These synchronized reserve 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 consumption for demand resources) for each five minute interval times the five minute LMP plus $50 per MW.

In the first six months of 2015, tier 1 synchronized reserve synchronized reserve event response credits of $192.736 were paid for 4,460 MW of tier 1 response at a cost per MW of $39.38, for twelve spinning events (Table 10-9).

Table 10-9 Tier 1 synchronized reserve event response costs: January 2014 through June 2015

Year	Month	Synchronized Reserve Event Response Hours	Total Tier 1 Synchronized Reserve Event Response MWh	Total Tier 1 Synchronized Reserve Event Response Credits	Tier 1 Synchronized Reserve Event Response Cost	Average Tier 1 MWh Response Per Event
2014	Jan	12	7,827.8	$965,846	$123.39	521.9
2014	Feb	1	273.2	$11,153	$40.82	273.2
2014	Mar	5	3,029.6	$175,902	$58.06	605.9
2014	Apr	2	389.1	$6,378	$16.39	194.5
2014	May	3	717.1	$34,906	$48.68	239.0
2014	Jun	0	NA	NA	NA	NA
2014	Jul	2	615.6	$35,179	$57.15	307.8
2014	Aug	0	NA	NA	NA	NA
2014	Sep	3	1,936.2	$143,574	$74.15	645.4
2014	Oct	2	1,131.7	$83,901	$74.14	565.8
2014	Nov	4	1,349.8	$38,895	$28.81	337.5
2014	Dec	3	692.0	$35,245	$50.96	230.5
2015	Jan	1	397.3	$8,198	$20.64	397.3
2015	Feb	2	218.3	$9,634	$44.13	109.2
2015	Mar	4	2,445.8	$105,505	$43.14	611.4
2015	Apr	5	1,398.9	$69,399	$49.61	279.8
2015	May	0	NA	NA	NA	NA
2015	Jun	0	NA	NA	NA	NA
All		49	22,422.4	$1,723,715	$76.87	457.6

Paying Tier 1 the Tier 2 Price

The market solutions correctly treat tier 1 synchronized reserve as having zero cost. The price for tier 1 synchronized reserves is zero unless tier 1 is called on to respond, as there is no incremental cost associated with providing the ability to ramp up from the current economic dispatch point. However, 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 541 hours in 2014. For those 541 hours tier 1 synchronized reserve resources were paid a weighted synchronized reserve market clearing price of $30.67 per MW and earned $89,719,045 in credits. (Table 10-10) Of the $89,719,045, $9,687,288 was for tier 1 actually estimated by the PJM market solution and $80,031,757 was mistakenly paid because deselected tier 1 MW were paid when they should not have been. The issue of paying for tier 1 from deselected units was corrected in July 2014. PJM continues however to pay tier 1 synchronized reserve the SRMCP when the non-synchronized reserve market clearing price is above $0. In the first six months of 2015, PJM paid $25,816,249 in credits for tier 1 estimated during the 754 hours when the non-synchronized reserve market clearing price was above $0.

Table 10-10 Weighted price of tier 1 synchronized reserve attributable to a non-synchronized reserve price above zero: January 2014 to June 2015

Year	Month	Total Hours When NSRMCP>$0	Weighted Average SRMCP for Hours When NSRMCP>$0	Total Tier 1 MW Credited for Hours When NSRMCP>$0	Total Tier 1 Credits Paid When NSRMCP>$0	Average Tier 1 MW Paid
2014	Jan	155	$93.26	706,479	$64,956,018	4,557.9
2014	Feb	15	$40.18	65,332	$2,625,303	4,355.4
2014	Mar	67	$44.56	240,625	$10,665,198	3,591.4
2014	Apr	99	$16.07	308,759	$4,959,232	3,118.8
2014	May	61	$15.85	253,076	$4,012,285	4,148.8
2014	Jun	4	$35.46	15,970	$566,292	3,992.4
2014	Jul	5	$17.02	9,150	$155,744	1,829.9
2014	Aug	0	NA	NA	NA	NA
2014	Sep	0	NA	NA	NA	NA
2014	Oct	3	$21.59	2,146	$46,319	715.2
2014	Nov	28	$15.73	38,188	$599,147	1,363.8
2014	Dec	104	$6.93	163,552	$1,133,507	1,739.9
2015	Jan	148	$13.59	274,996	$3,727,945	1,858.1
2015	Feb	194	$24.83	369,111	$9,164,267	1,902.6
2015	Mar	181	$16.33	305,967	$4,985,446	1,690.4
2015	Apr	66	$25.56	102,117	$2,587,076	1,547.2
2015	May	72	$20.35	106,027	$2,158,080	1,472.6
2015	Jun	93	$17.45	182,417	$3,183,436	1,961.0
Total		1295	$29.92	3,143,911	$115,525,295	2,490.3

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 during any spinning event. Tier 1 resources are not obligated to respond to synchronized reserve events. Only 60.5 percent of the market solution's estimated tier 1 resource MWh actually responded during synchronized reserve events in the first three months of 2015. Thus, 39.5 percent of tier 1 resource MWh 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.

When the next MW of non-synchronized reserve (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 increases significantly.

In the first six months of 2015, tier 1 MW were paid $192,736 for responding to synchronized reserve events and were paid $25.8 million simply because the NSRMCP was greater than $0. (Table 10-11)

Table 10-11 Dollar impact of paying Tier 1 Synchronized Reserve the SRMCP when the NSRMCP goes above $0: January 2014 through June 2015

		Synchronized Reserve Events			Hours When NSRMCP > $0		
Year	Month	Total MWh	Total Credits	Average MWh Per Event	Total MW	Total Credits	Average MW Per Hour
2014	Jan	7,828	$965,846	522	706,479	$64,956,018	4,558
2014	Feb	273	$11,153	273	65,332	$2,625,303	4,355
2014	Mar	3,030	$175,902	606	240,625	$10,665,198	3,591
2014	Apr	389	$6,378	195	308,759	$4,959,232	3,119
2014	May	717	$34,906	239	253,076	$4,012,285	4,149
2014	Jun	0	$0	0	15,970	$566,292	3,992
2014	Jul	616	$35,179	308	9,150	$155,744	1,830
2014	Aug	0	$0	0	0	$0	0
2014	Sep	1,936	$143,574	645	0	$0	0
2014	Oct	1,132	$83,901	566	2,146	$46,319	715
2014	Nov	1,350	$38,895	337	38,188	$599,147	1,364
2014	Dec	258	$12,897	129	163,552	$1,133,507	1,740
2015	Jan	397	$8,198	397	274,996	$3,727,945	1,858
2015	Feb	218	$9,634	109	369,111	$9,164,267	1,903
2015	Mar	2,446	$105,505	611	305,967	$4,985,446	1,690
2015	Apr	1,399	$69,399	280	102,117	$2,587,076	1,547
2015	May	0	$0	0	106,027	$2,158,080	1,473
2015	Jun	0	$0	0	182,417	$3,183,436	1,961
Total		21,988	$1,701,367	373	3,143,910	$115,525,295	2,490

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. Tier 1 should be compensated only for a response to synchronized reserve events, as it was before the shortage pricing changes. This compensation requires that when a synchronized reserve event is called, all tier 1 response is paid the average of five-minute LMPs during the event plus $50/MW, termed the Synchronized Energy Premium Price.

A summary of PJM's current tier 1 compensation rules are presented in Table 10-12.

Table 10-12 Tier 1 compensation as currently implemented by PJM

Tier 1 Compensation by Type of Hour as Currently Implemented by PJM		
Hourly Parameters	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWh
NSRMCP>$0	T1 credits = T2 SRMCP * calculated tier 1 MW	T1 credits = T2 SRMCP * min(calculated tier 1 MW, actual response MWh)

The MMU's recommended compensation rules for tier 1 MW are in Table 10-13.

Table 10-13 Tier 1 compensation as recommended by MMU

Tier 1 Compensation by Type of Hour as Recommended by MMU		
Hourly Parameters	No Synchronized Reserve Event	Synchronized Reserve Event
NSRMCP=$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWh
NSRMCP>$0	T1 credits = $0	T1 credits = Synchronized Energy Premium Price * actual response MWh

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.

In 2015, PJM used tier 1 estimate biasing in the MAD subzone ASO and the RTO Zone ASO (Table 10-14). Tier 1 biasing is not used in any IT-SCED solutions.

Table 10-14 MAD subzone ASO tier 1 estimate biasing, January 2014 through June, 2015

Year	Month	Number of Hours Biased Negatively	Average Negative Bias (MW)	Number of Hours Biased Positively	Average Positive Bias (MW)
2014	Jan	13	(1,419.2)	2	250.0
2014	Feb	36	(1,036.1)	1	100.0
2014	Mar	37	(1,281.1)	4	500.0
2014	Apr	32	(1,387.5)	0	NA
2014	May	23	(909.8)	0	NA
2014	Jun	17	(1,179.4)	3	666.7
2014	Jul	36	(1,011.1)	0	NA
2014	Aug	31	(891.9)	1	750.0
2014	Sep	15	(1,206.7)	0	NA
2014	Oct	67	(1,285.8)	1	500.0
2014	Nov	193	(1,125.4)	6	475.0
2014	Dec	163	(1,238.9)	1	300.0
2015	Jan	51	(1,731.4)	6	600.0
2015	Feb	62	(1,641.1)	0	NA
2015	Mar	25	(794.0)	3	1,000.0
2015	Apr	31	(430.7)	0	NA
2015	May	46	(582.6)	8	812.5
2015	Jun	25	(694.0)	1	1,000.0
Total		903	(1,102.6)	37	579.5

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 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.

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 reserve is also provided by demand resources that have offered to reduce load in the event of an synchronized reserve event. Tier 2 synchronized reserves are committed to be available in the event of a synchronized reserve event.

Tier 2 synchronized reserve resources may be inflexible for two reasons, the nature of the resource or if they are committed in the hour ahead for the full operating hour. Some resource types can only be committed by the ASO prior to the operational hour and require an hourly commitment due to physical limitations or market rules. Resources with hour ahead commitment requirements include synchronous condensers operating solely for the purpose of providing synchronized reserves and demand response that has qualified to act as synchronized reserves. Tier 2 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). Due to the hour long commitment that comes with the hour ahead ASO assignment, tier 2 synchronized reserve resources committed by the hour ahead market solution are flagged by the system software as inflexible resources, so they cannot be released for energy for the duration of the operational hour.

During the operating hour, the IT-SCED and the RT-SCED market solutions have the ability to dispatch additional resources 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 within the operational hour.

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.[13] This rule is intended to increase the accuracy of estimates of available synchronized reserve and primary reserve.

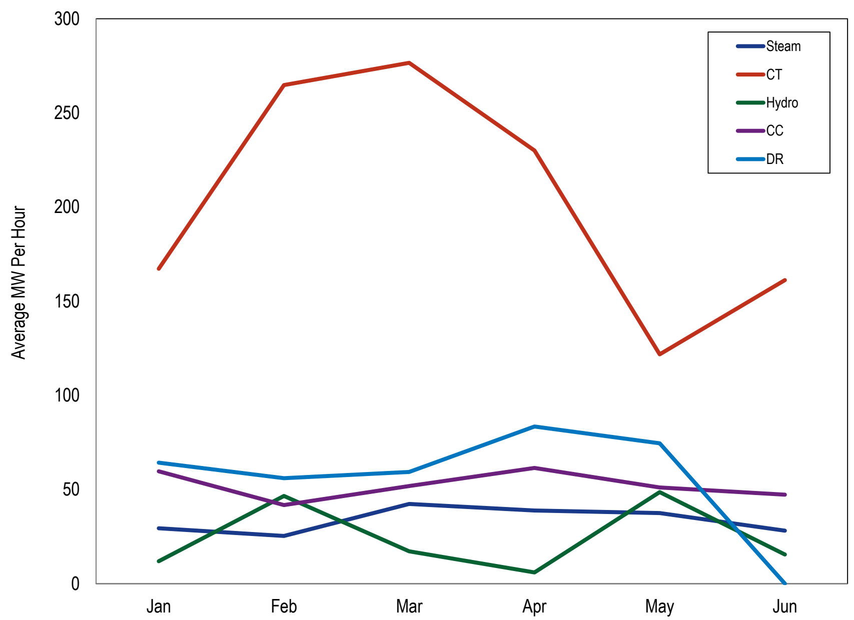
In the first six months of 2015, the Mid Atlantic Dominion subzone averaged 3,289.1 MW in synchronized reserve offers, and the RTO Zone averaged 9,496.6 MW of synchronized reserve offers (Figure 10-10).

The supply of tier 2 synchronized reserve in the first six months of 2015 was sufficient to cover the requirement in both the RTO Reserve Zone and the Mid-Atlantic Dominion Reserve subzone. In addition the availability of on-line resources was sufficient to meet the synchronized reserve requirement and shortage pricing was not reached.

13 See PJM. "Manual 11: Energy and Ancillary Services Market Operations" Revision 75, (April 9, 2015), p. 65.

The largest portion of cleared tier 2 synchronized reserve in the first six months of 2015 is from CTs (Figure 10-6), 54.9 percent of all tier 2 synchronized reserve MW. Demand resources remain a significant part of market scheduled tier 2 synchronized reserve. Although demand resources are limited to 33 percent of the synchronized reserve requirement, the amount of tier 2 synchronized reserve required in any hour is often much less than the full synchronized reserve requirement because so much of it is met with tier 1 synchronized reserve. The DR MW share of the total cleared Tier 2 Synchronized Reserve Market was 15.3 percent in the first six months of 2015.[14] This is a reduction of 12.6 percent from the DR MW share of 17.5 percent of all cleared tier 2 synchronized reserve in the first six months of 2014.

Figure 10-6 Cleared Tier 2 Synchronized Reserve Average Hourly MW per Hour by unit type, full RTO Zone: January through June 2015



14 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.

Demand

Effective January 1, 2015, the synchronized reserve requirement was increased to 1,342 MW in the Mid-Atlantic Dominion subzone, and remained at 1,375 MW in the RTO Zone. Effective January 8, 2015, the synchronized reserve requirement was increased to 1,450 MW in both the Mid-Atlantic Dominion subzone and the RTO Zone (Table 10-15). There are two circumstances in which PJM may alter the synchronized reserve requirement from its default value. When PJM operators anticipate periods of heavy load, they may bring on additional units to account for increased operational uncertainty in meeting load. When a Hot Weather Alert, Cold Weather Alert or an escalating emergency procedure (as defined in Manual 13: Emergency Operations) has been issued for the operating day operators may increase the synchronized reserve requirement up to the full amount of the additional MW brought on-line.[15] In January through March 2015 PJM declared 27 Cold Weather Alerts raising the synchronized reserve requirement from 1,450 MW to 1,700 for 606 hours. In June, hot weather alerts caused the synchronized reserve requirement to be raised to 1,700 MW in 114 hours.

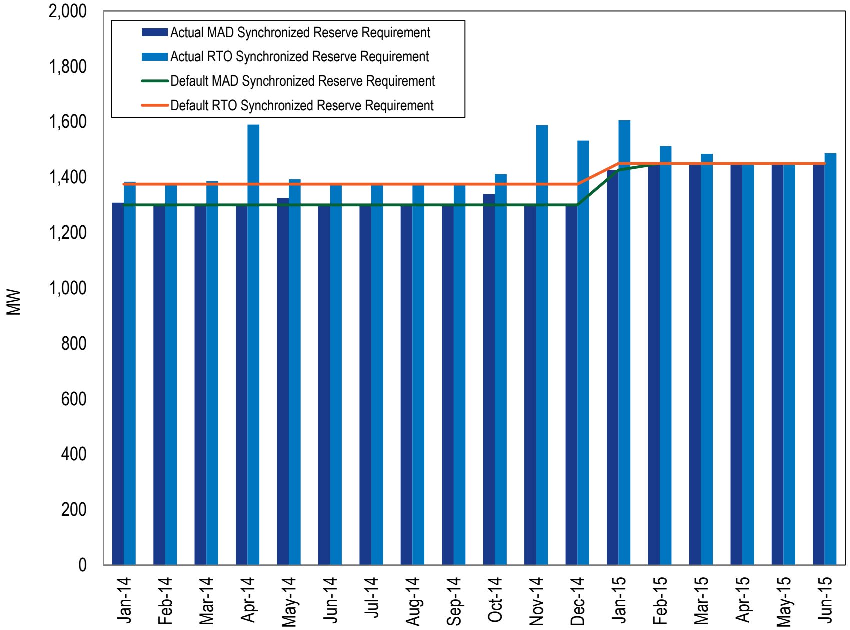
Table 10-15 Default Tier 2 Synchronized Reserve Markets required MW, RTO Zone and Mid-Atlantic Dominion Subzone

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	Jan 1, 2015	1,300	Mar 15, 2010	Nov 12, 2012	1,350
Jan 1, 2015	Jan 8, 2015	1,342	Nov 12, 2012	Jan 8, 2015	1,375
Jan 8, 2015		1,450	Jan 8, 2015		1,450

PJM may also change the synchronized reserve requirement from its default value (Figure 10-1) when grid maintenance or outages change the largest contingency. In the first three months of 2015, PJM increased the synchronized reserve requirement in 38 hours in the RTO Reserve Zone (Figure 10-7) because of grid outages. The average actual synchronized reserve requirement in the MAD subzone was 1,455.2 MW. The average actual synchronized reserve requirement in the RTO Reserve Zone was 1,498.9 MW.

15 PJM Manual 13 Emergency Operations, Rev 57 January 1, 2015, pp. 48, 49.

Figure 10-7 Monthly average actual vs default synchronized reserve requirements, RTO and MAD: January 2014 through June 2015



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.

In the RTO Reserve Zone, 59.9 percent of hours cleared a Tier 2 Synchronized Reserve Market in the first six months of 2015 averaging 381.1 MW. This compares with 44.4 percent of hours averaging 389.9 MW in the first six months of 2014. In the MAD Reserve Subzone, 97.6 percent of hours cleared a Tier 2 Synchronized Reserve Market in the first six months of 2015 averaging 259.6 MW. This compares with 53.6 percent of hours cleared, averaging 265.7 MW in 2014.

Figure 10-8 and Figure 10-9 show the average monthly synchronized reserve required and the average monthly tier 2 synchronized reserve MW scheduled in from January 2014 through June 2015, 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 extreme weather.

Figure 10-8 Mid-Atlantic Dominion Reserve subzone monthly average synchronized reserve required vs. tier 2 synchronized reserve scheduled MW: January 2014 through June 2015

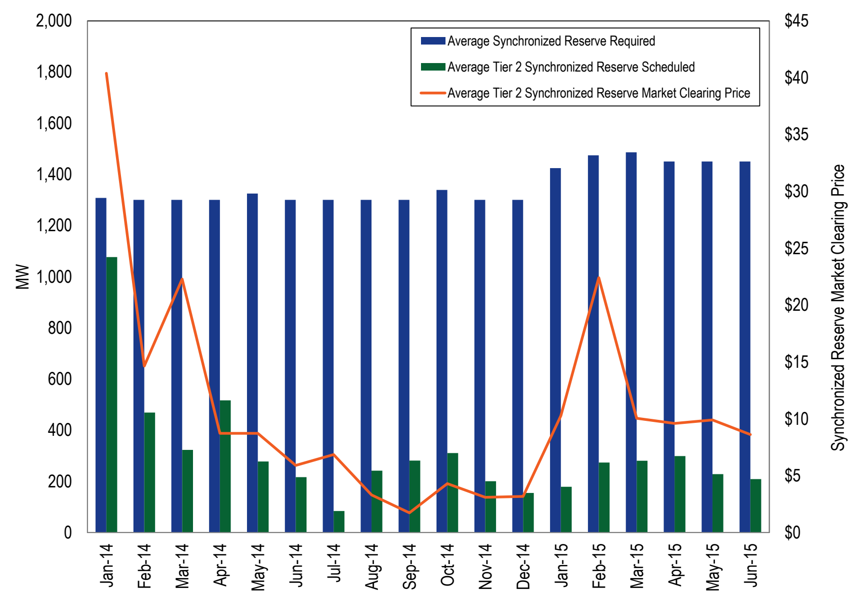
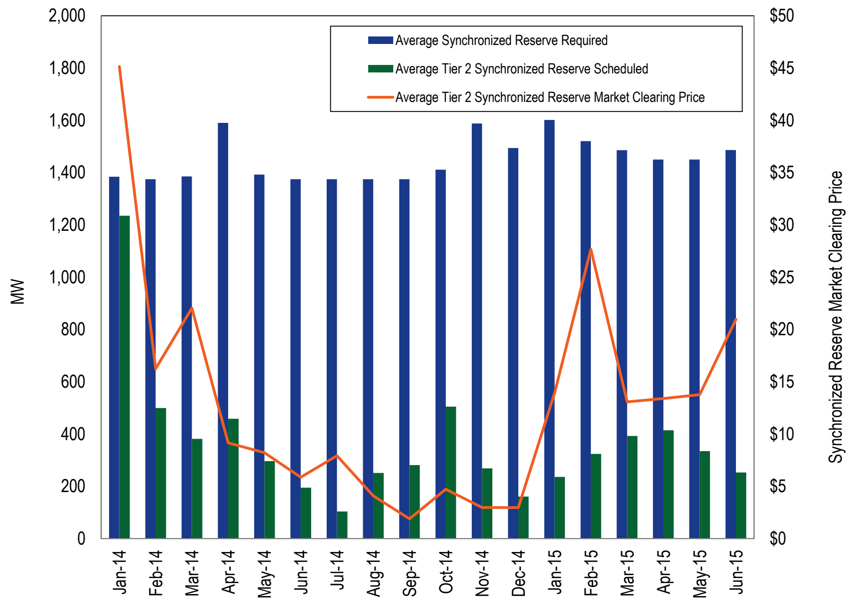


Figure 10-9 RTO Reserve zone monthly average synchronized reserve required vs. tier 2 synchronized reserve scheduled MW: January 2014 through June 2015



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 from the first six months of 2015 was 5705, which is defined as highly concentrated. This is an increase from the 4406 HHI of the first six months of 2014. The largest hourly market share was 100 percent and 81.5 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 six months of 2015 was 4886, which is defined as highly concentrated. The largest hourly market share was 100 percent and 52.3 percent of hours had a maximum market share greater than or equal to 40 percent.

In the MAD subzone, flexible synchronized reserve was 7.0 percent of all tier 2 synchronized reserve in the first six months of 2015. In the RTO Zone, flexible synchronized reserve assigned was 6.5 percent of all tier 2 synchronized reserve in the first six months of 2015.

The MMU calculates that 27.1 percent of hours failed the three pivotal supplier test in the MAD subzone from January through June 2015 for the inflexible synchronized reserve market (excluding self-scheduled synchronized reserve) in the hour ahead market (Table 10-16) and 38.2 percent of hours failed a three pivotal supplier test in the RTO Zone from the first six months of 2015.

Table 10-16 Three Pivotal Supplier Test Results for the RTO Zone and MAD Subzone: January 2014 through June 2015

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	21.2%	17.6%
2014	Sep	25.0%	24.5%
2014	Oct	53.2%	71.8%
2014	Nov	56.4%	51.7%
2014	Dec	37.5%	48.6%
2015	Jan	15.0%	34.2%
2015	Feb	55.7%	29.9%
2015	Mar	14.8%	45.2%
2015	Apr	7.9%	48.4%
2015	May	22.8%	45.3%
2015	Jun	46.6%	26.1%
	Average	36.6%	38.8%

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

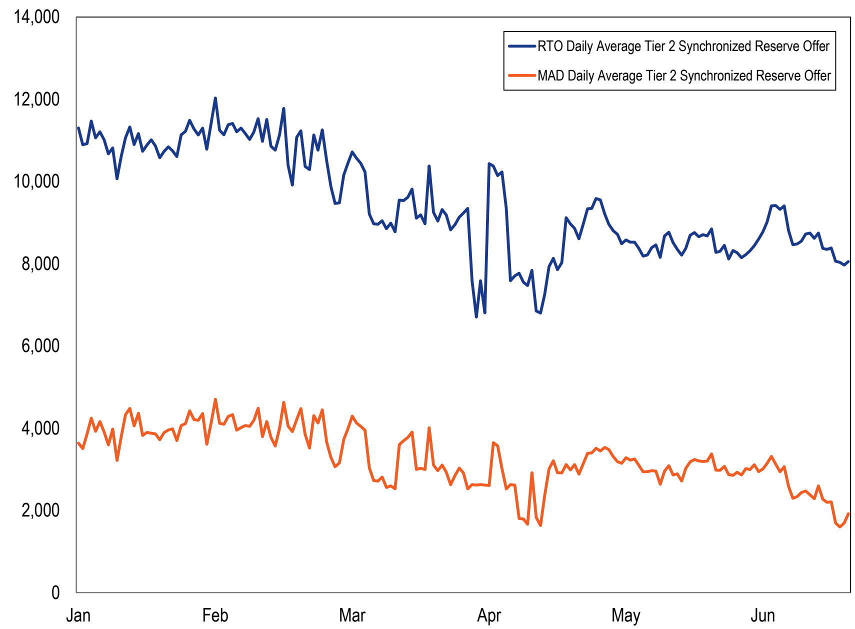
Offers

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 synchronized 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 10-10 shows the daily average of hourly offered tier 2 synchronized reserve MW for both the RTO Synchronized Reserve Zone and the Mid-Atlantic Dominion Synchronized Reserve subzone. In the first six months of 2015, the ratio of on-line and eligible tier 2 synchronized reserve to synchronized reserve required in the Mid-Atlantic Dominion subzone was 3.15 averaged over all hours. For the RTO Synchronized Reserve Zone the ratio was 7.41.

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 10-10 Tier 2 synchronized reserve daily average offer and eligible volume (MW): January through June 2015



Synchronized reserve is offered by steam, CT, CC, hydroelectric and DR resources. Figure 10-11 shows average offer MW volume by market and unit type for the MAD subzone and Figure 10-12 shows average offer MW volume by market and unit type for the RTO Zone.

Figure 10-11 Mid-Atlantic Dominion subzone average daily tier 2 synchronized reserve offer by unit type (MW): January through June, 2012 through 2015

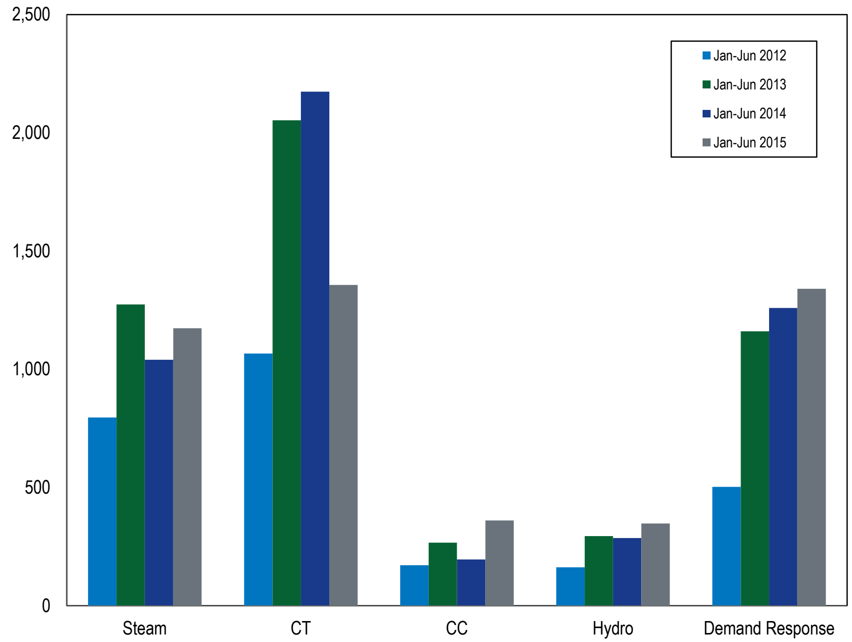
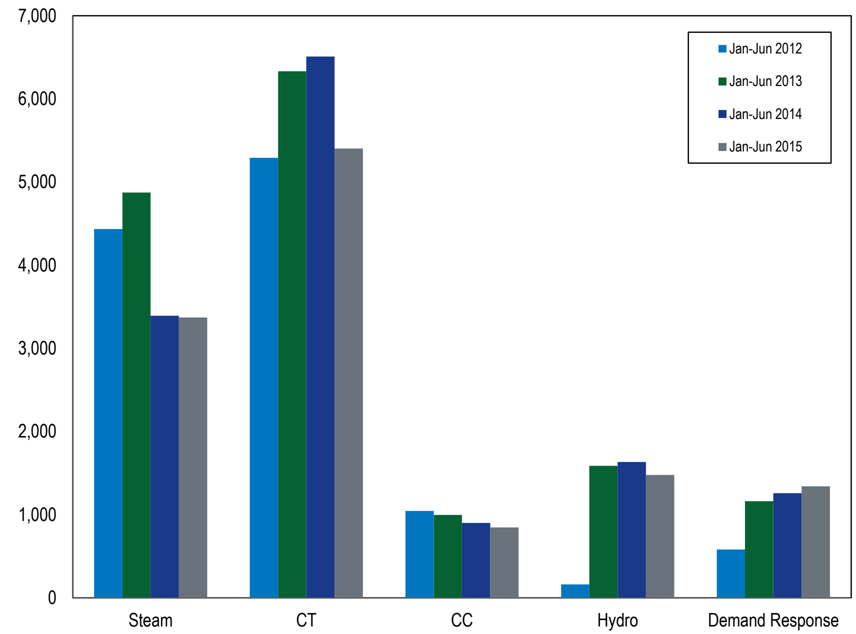


Figure 10-12 RTO Zone average daily tier 2 synchronized reserve offer by unit type (MW): January through June 2012 through 2015



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 averaging 259.6 MW (including self-scheduled) with a price greater than $0 in 97.6 percent of hours in the first six months of 2015, compared to 73.6 percent of hours in the first six months of 2014.

The RTO Zone cleared a Tier 2 Synchronized Reserve Market averaging 381.1 MW (including self-scheduled) with a price greater than $0 in 59.9 percent of hours in the first six months of 2015.

In the first six months of 2015, the weighted average Tier 2 synchronized reserve market clearing price in the MAD subzone for all cleared hours was $13.07. In the first six months of 2014, the weighted average synchronized reserve market clearing price in the MAD subzone was $15.18.

In the first six months of 2015, the weighted average Tier 2 Synchronized Reserve Market clearing price in the full RTO Zone for all cleared hours was $16.76. In the first six months of 2014, the weighted average synchronized reserve market clearing price in the RTO Zone was $18.15.

Supply, performance, and demand are reflected in the price of synchronized reserve (Figure 10-8 and Figure 10-9). In February 2015, cold weather meant that on-line resources which are jointly optimized with synchronized reserve were generating at or near their economic maximum. As a result, tier 2 synchronized reserve was more expensive.

Table 10-17 Mid-Atlantic Dominion Subzone, weighted SRMCP and cleared MW (excludes self-scheduled): January through June 2015

Year	Month	Weighted Average Tier 2 Synchronized Reserve Market Clearing Price	Average Hourly Tier 1 Synchronized Reserve Estimated Hour Ahead (MW)	Average Hourly Demand Response Cleared (MW)	Average Tier 2 Generation Synchronized Reserve Cleared (MW)
2015	Jan	$11.29	1,218.9	63.7	142.8
2015	Feb	$24.12	1,179.5	46.3	224.3
2015	Mar	$11.81	1,196.2	60.8	228.7
2015	Apr	$9.60	1,146.8	85.0	218.1
2015	May	$9.91	1,211.1	76.0	162.9
2015	Jun	$8.16	1,238.0	46.8	165.3

Table 10-18 RTO zone weighted SRMCP and cleared MW (excludes self-scheduled): January through June 2015

Year	Month	Weighted Average Tier 2 Synchronized Reserve Market Clearing Price	Average Hourly Tier 1 Synchronized Reserve Estimated Hour Ahead (MW)	Average Hourly Demand Response Cleared (MW)	Average Tier 2 Generation Synchronized Reserve Cleared (MW)
2015	Jan	$12.24	1,417.5	63.7	123.7
2015	Feb	$24.68	1,618.3	46.3	35.4
2015	Mar	$12.37	1,285.0	60.8	140.0
2015	Apr	$13.40	1,228.6	85.0	136.4
2015	May	$13.77	1,239.8	76.0	134.2
2015	Jun	$19.39	1,337.4	46.8	65.9

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.

In the first six months of 2015, the price to cost ratio of the full RTO Zone Tier 2 Synchronized Reserve Market averaged 58.0 percent (Table 10-19); the price to cost ratio of the RTO Zone excluding MAD averaged 65.4 percent; the price to cost ratio of the MAD subzone averaged 54.7 percent.

Table 10-19 Full RTO, RTO, Mid-Atlantic Subzone Tier 2 synchronized reserve MW, credits, price, and cost: January through June 2015

Tier 2 Synchronized Reserve Market	Year	Month	Total MW	Total Credits	Weighted Synchronized Reserve Market Clearing Price	Cost	Price / Cost Ratio
Full RTO Zone	2015	Jan	225,741	$5,090,077	$12.24	$22.55	54.3%
Full RTO Zone	2015	Feb	272,371	$12,065,569	$24.68	$44.30	55.7%
Full RTO Zone	2015	Mar	301,564	$7,323,630	$12.37	$24.29	50.9%
Full RTO Zone	2015	Apr	278,562	$4,896,351	$11.53	$17.58	65.6%
Full RTO Zone	2015	May	244,947	$4,231,841	$11.22	$17.28	65.0%
Full RTO Zone	2015	Jun	168,501	$2,831,421	$12.93	$16.80	76.9%
Full RTO Zone	2015	Total	1,491,685	$36,438,890	$14.16	$24.43	58.0%
RTO Only	2015	Jan	81,527	$1,635,137	$13.91	$20.06	69.4%
RTO Only	2015	Feb	63,834	$3,324,613	$26.51	$52.08	50.9%
RTO Only	2015	Mar	104,025	$2,835,300	$13.44	$27.26	49.3%
RTO Only	2015	Apr	81,339	$1,312,673	$13.39	$16.14	83.0%
RTO Only	2015	May	72,479	$1,280,635	$13.77	$17.67	77.9%
RTO Only	2015	Jun	48,277	$1,186,044	$19.55	$24.57	79.6%
RTO Only	2015	Total	451,480	$11,574,402	$16.76	$25.64	65.4%
MAD Subzone	2015	Jan	144,214	$3,454,940	$11.29	$23.96	47.1%
MAD Subzone	2015	Feb	208,536	$8,740,957	$24.12	$41.92	57.5%
MAD Subzone	2015	Mar	197,540	$4,488,330	$11.81	$22.72	52.0%
MAD Subzone	2015	Apr	197,223	$3,583,677	$10.76	$18.17	59.2%
MAD Subzone	2015	May	172,468	$2,951,207	$10.16	$17.11	59.3%
MAD Subzone	2015	Jun	120,224	$1,645,377	$10.26	$13.69	75.0%
MAD Subzone	2015	Total	1,040,205	$24,864,488	$13.07	$23.90	54.7%

Compliance

The MMU has identified and quantified the failure of scheduled tier 2 synchronized reserve resources to deliver during synchronized reserve events since 2011.[16] 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 synchronized reserve event. Actual synchronized reserve 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.[17] Tier 2 resources are obligated to sustain their final output for the shorter of the length of the event or 30 minutes.[18]

The MMU has reported the wide range of synchronized reserve event response levels and recommended that PJM take action to increase compliance rates. Penalties can be assessed for any synchronized reserve event greater than 10 minutes during which flexible or inflexible synchronized reserve was scheduled either by the resource owner or by PJM. In 2014, 20 synchronized reserve events occurred that met these criteria. In the first six months of 2015 there were eleven spinning events of which five were longer than 10 minutes.

Table 10-20 Synchronized reserve events greater than 10 minutes, Tier 2 Response Compliance, RTO Reserve Zone: January through June 2015

2015 Qualifying Synchronized Reserve Event (DD-Mon-YYYY HR)	Event Duration (Minutes)	Total Scheduled Tier 2 MW	Tier 2 Response MW	Percent T2 Compliance
03-Mar-2015 17	11	88.1	49.9	56.6%
16-Mar-2015 10	24	99.2	72.1	72.7%
17-Mar-2015 23	17	70.0	66.0	94.3%
23-Mar-2015 23	15	68.4	51.5	75.3%
07-Apr-2015 16	31	485.7	455.5	93.8%

Tier 1 resource owners are credited for the amount of synchronized reserve they provide in response to a synchronized reserve event.[19] Tier 2 resources owner are not credited for synchronized reserve 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. For synchronized reserve events of ten minutes or longer that occurred in the first six months of 2015, 14.3 percent of all scheduled tier 2 synchronized reserve MW were not delivered and were penalized (Table 10-20). 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 synchronized reserve event.[20] Resource owners are permitted to aggregate the response of multiple units to offset an underresponse from one unit with an overresponse from

16 See the *2011 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services" at pg. 250.
17 See PJM, "Manual 11, Energy & Ancillary Services Market Operations," Rev. 75, April 9, 2015 4.2.12 Non-Performance, p. 77.
18 See PJM, "Manual 11, Energy & Ancillary Services Market Operations," Rev. 75, April 9, 2015 4.2.11 Non-Performance, p. 77.
19 See PJM, "Manual 11, Energy & Ancillary Services Market Operations," Rev. 75, April 9, 2015 4.2.12 Non Performance, p. 77.
20 See PJM "M-28 Operating Agreement Accounting," Rev. 71, June 1, 2015, p. 45. See also "Manual 11, Energy & Ancillary Services Market Operations," Rev. 75, April 9, 2015 4.2.12 Non-Performance, p. 77.

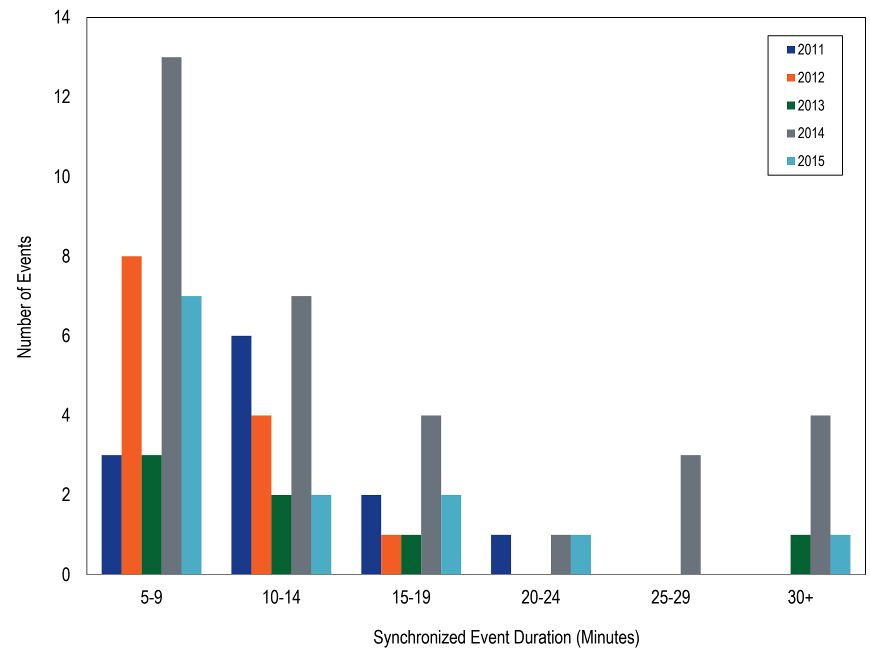
a different unit for the purpose of reducing an underresponse penalty. The average number of days between events calculated by PJM Performance Compliance for 2015 is 13 days.[21]

History of Synchronized Reserve Events

Synchronized reserve is designed to provide relief for disturbances.[22] 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. Five synchronized reserve events were declared during 2014 for low ACE. The 56 minute synchronized reserve event of March 27, 2014 was to supply reactive transfer voltage support. Long spinning events of 49, 56 and 68 minutes in 2014 are indicative of either an inadequate supply of primary reserve or the use of primary reserve when secondary reserve would be more appropriate. The use of synchronized reserve 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 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. Synchronized reserve has a requirement to sustain its output for up to thirty minutes. When the need is for reserve extending past thirty minutes a secondary reserve is the appropriate response.

Synchronized reserve events (Table 10-21) are usually caused by a sudden generation outage or transmission disruption (disturbance) requiring PJM to load synchronized reserve.[23] PJM also calls synchronized reserve events for non-disturbance events, which it characterizes as "low ACE." The reserve remains loaded until system balance is recovered. From January 2010 through June 2015, PJM experienced 163 synchronized reserve events, approximately three events per month. Synchronized reserve events had an average length of 13 minutes.

Figure 10-13 Synchronized reserve events duration distribution curve: 2011 through 2015



21 Report to PJM Operating Committee, "Synchronized Reserve Event Performance and Penalty Days," Dec 3, 2014.
22 2013 State of the Market Report for PJM, Appendix F – PJM's DCS Performance, pp 451-452.
23 See PJM, "Manual 12, Balancing Operations," Revision 31 (August 21, 2014), 4.1.2 Loading Reserves pp. 36.

Table 10-21 Synchronized reserve events, January 2010 through June 2015

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
FEB-18-2010 13:27	Mid-Atlantic	19	JAN-11-2011 15:10	Mid-Atlantic	6	JAN-03-2012 16:51	RFC	9	JAN-22-2013 08:34	RTO	8
MAR-18-2010 11:02	RFC	27	FEB-02-2011 01:21	RFC	5	JAN-06-2012 23:25	RFC	8	JAN-25-2013 15:01	RTO	19
MAR-23-2010 20:14	RFC	13	FEB-08-2011 22:41	Mid-Atlantic	11	JAN-23-2012 15:02	Mid-Atlantic	8	FEB-09-2013 22:55	RTO	10
APR-11-2010 13:12	RFC	9	FEB-09-2011 11:40	Mid-Atlantic	16	MAR-02-2012 19:54	RFC	9	FEB-17-2013 23:10	RTO	13
APR-28-2010 15:09	Mid-Atlantic	8	FEB-13-2011 15:35	Mid-Atlantic	14	MAR-08-2012 17:04	RFC	6	APR-17-2013 01:11	RTO	11
MAY-11-2010 19:57	Mid-Atlantic	9	FEB-24-2011 11:35	Mid-Atlantic	14	MAR-19-2012 10:14	RFC	10	APR-17-2013 20:01	RTO	9
MAY-15-2010 03:03	RFC	6	FEB-25-2011 14:12	RFC	10	APR-16-2012 00:20	Mid-Atlantic	9	MAY-07-2013 17:33	RTO	8
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
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
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
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
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
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
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
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
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
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
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
SEP-15-2010 11:20	RFC	13	MAY-31-2011 16:36	RFC	27	OCT-30-2012 05:12	RTO	14			
SEP-22-2010 15:28	Mid-Atlantic	24	JUN-03-2011 14:23	RFC	7	NOV-25-2012 16:32	RTO	12			
OCT-05-2010 17:20	RFC	10	JUN-06-2011 22:02	Mid-Atlantic	9	DEC-16-2012 07:01	RTO	9			
OCT-16-2010 03:22	Mid-Atlantic	10	JUN-23-2011 23:26	RFC	8	DEC-21-2012 05:51	RTO	7			
OCT-16-2010 03:25	RFCNonMA	7	JUN-26-2011 22:03	Mid-Atlantic	10	DEC-21-2012 10:29	RTO	5			
OCT-27-2010 10:35	RFC	7	JUL-10-2011 11:20	RFC	10						
OCT-27-2010 12:50	Mid-Atlantic	10	JUL-28-2011 18:49	RFC	12						
NOV-26-2010 14:24	RFC	13	AUG-02-2011 01:08	RFC	6						
NOV-27-2010 11:34	RFC	8	AUG-18-2011 06:45	Mid-Atlantic	6						
DEC-08-2010 01:19	RFC	11	AUG-19-2011 14:49	RFC	5						
DEC-09-2010 20:07	RFC	5	AUG-23-2011 17:52	RFC	7						
DEC-14-2010 12:02	Mid-Atlantic	24	SEP-24-2011 15:48	RFC	8						
DEC-16-2010 18:40	Mid-Atlantic	20	SEP-27-2011 14:20	RFC	7						
DEC-17-2010 22:09	Mid-Atlantic	6	SEP-27-2011 16:47	RFC	9						
DEC-29-2010 19:01	Mid-Atlantic	15	OCT-30-2011 22:39	Mid-Atlantic	10						
			DEC-15-2011 14:35	Mid-Atlantic	8						
			DEC-21-2011 14:26	RFC	18						

Table 10-21 Synchronized reserve events, January 2010 through June 2015 (continued)

Effective Time	Region	Duration (Minutes)	Effective Time	Region	Duration (Minutes)
JAN-06-2014 22:01	RTO	68	JAN-07-2015 22:36	RTO	8
JAN-07-2014 02:20	RTO	25	FEB-24-2015 02:51	RTO	5
JAN-07-2014 04:18	RTO	34	FEB-26-2015 15:20	RTO	6
JAN-07-2014 11:27	RTO	11	MAR-03-2015 17:02	RTO	11
JAN-07-2014 13:20	RTO	41	MAR-16-2015 10:25	RTO	24
JAN-10-2014 16:46	RTO	12	MAR-17-2015 23:34	RTO	17
JAN-21-2014 18:52	RTO	6	MAR-23-2015 23:44	RTO	15
JAN-22-2014 02:26	RTO	7	APR-06-2015 14:23	RTO	8
JAN-22-2014 22:54	RTO	8	APR-07-2015 17:11	RTO	31
JAN-25-2014 05:22	RTO	10	APR-15-2015 08:14	RTO	8
JAN-26-2014 17:11	RTO	6	APR-25-2015 03:21	RTO	9
JAN-31-2014 15:05	RTO	13			
FEB-02-2014 14:03	Dominion	8			
FEB-08-2014 06:05	Dominion	18			
FEB-22-2014 23:05	RTO	7			
MAR-01-2014 05:18	RTO	26			
MAR-05-2014 21:25	RTO	8			
MAR-13-2014 20:39	RTO	8			
MAR-27-2014 10:37	RTO	56			
APR-14-2014 01:16	RTO	10			
APR-25-2014 17:33	RTO	6			
MAY-01-2014 14:18	RTO	13			
MAY-03-2014 17:11	RTO	13			
MAY-14-2014 01:36	RTO	5			
JUL-08-2014 03:07	RTO	9			
JUL-25-2014 19:19	RTO	7			
SEP-06-2014 13:32	RTO	18			
SEP-20-2014 23:42	RTO	14			
SEP-29-2014 10:08	RTO	15			
OCT-20-2014 06:35	RTO	15			
OCT-23-2014 11:03	RTO	27			
NOV-01-2014 06:50	RTO	9			
NOV-08-2014 02:08	RTO	8			
NOV-22-2014 05:27	RTO	21			
NOV-22-2014 08:19	RTO	10			
DEC-10-2014 18:58	RTO	8			
DEC-31-2014 21:42	RTO	12			

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 1,450 MW must be synchronized reserve (Figure 10-2), and that 2,175 MW of ten minute primary reserve must be available in the RTO Reserve Zone of which 1,450 MW must be synchronized reserve (Figure 10-3). 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).

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.[24] In the first six months of 2015, an average of 746.6 MW of non-synchronized reserve was scheduled hourly as part of the primary reserve requirement in the Mid-Atlantic Dominion subzone. In the first six months of 2015, an average of 783.0 MW of non-synchronized reserve was scheduled hourly in the RTO Zone.

CTs provided 52.5 percent and hydro 44.1 percent of cleared non-synchronized reserve MW in the first six months of 2015. The remaining 3.3 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 10-22 Non-synchronized reserve market HHIs: January through June 2015

Year	Month	Mid Atlantic Dominion HHI	RTO HHI
2015	Jan	3455	2232
2015	Feb	3749	2201
2015	Mar	3382	3754
2015	Apr	4044	3676
2015	May	3809	5292
2015	Jun	3937	6022
2015	Average	3730	3863

24 See PJM. "Manual 11, Energy & Ancillary Services Market Operations" Revision 75 (April 9, 2015), p. 80.

Table 10-23 Non-synchronized reserve market pivotal supply test: January through June 2015

Year	Month	Mid Atlantic Dominion Three Pivotal Supplier Hours	RTO Three Pivotal Supplier Hours
2015	Jan	100.0%	98.0%
2015	Feb	95.0%	98.9%
2015	Mar	100.0%	95.8%
2015	Apr	100.0%	94.7%
2015	May	98.9%	97.9%
2015	Jun	97.2%	93.7%
2015	Average	98.5%	96.5%

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 10-14 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 759 (17.5 percent) hours in the first six months of 2015, at an average price of $11.73 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 $1.68 per MW. The maximum clearing price was $189.24 per MW on February 20, 2015. Figure 10-15 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 736 (17.0 percent) hours in the first six months of 2015, at an average price of $11.25. The weighted non-synchronized reserve market clearing price for all hours in the RTO Zone including cleared hours when the price was zero, was $1.40.

Figure 10-14 Daily average MAD subzone Non-synchronized Reserve Market clearing price and MW purchased: January through June 2015

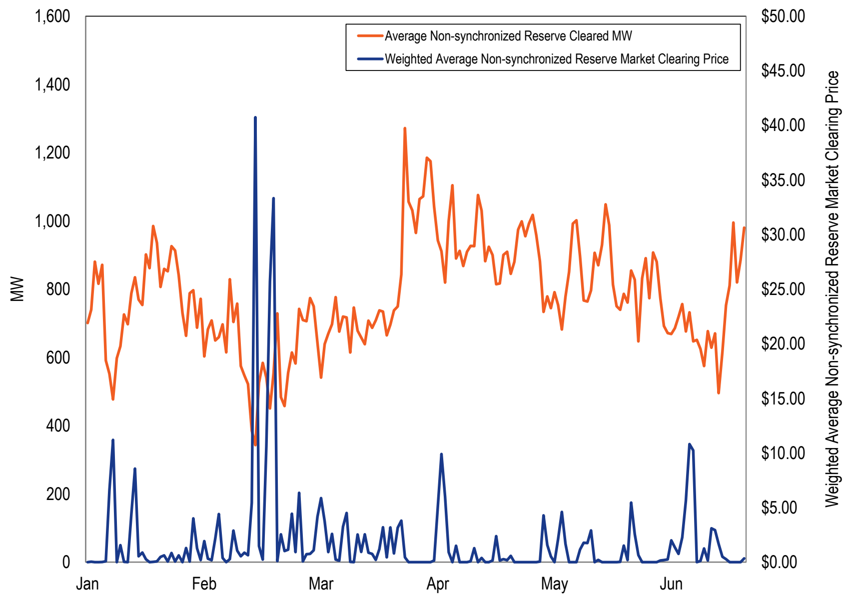
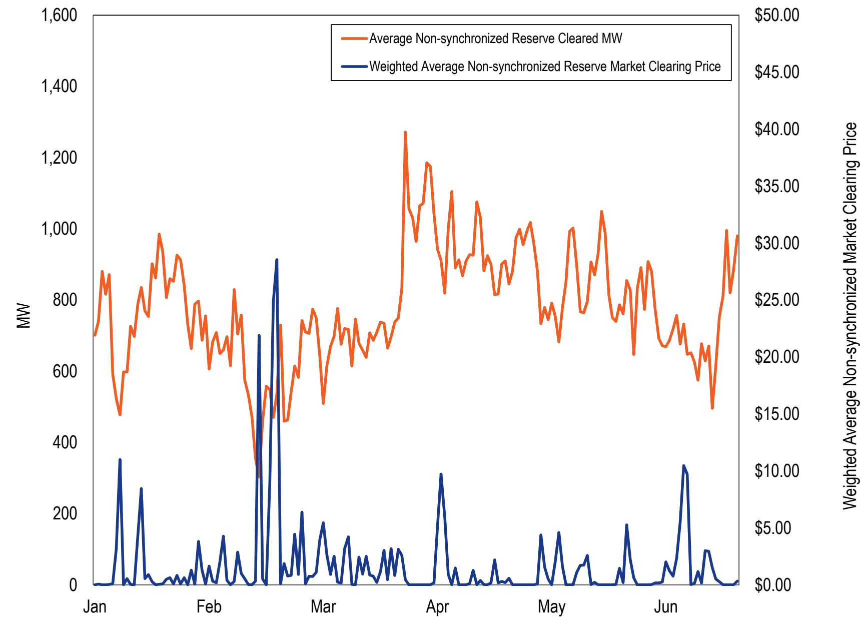


Figure 10-15 Daily average RTO Zone Non-synchronized Reserve Market clearing price and MW purchased: January through June 2015



Price and Cost

In satisfying the primary reserve requirement there is often a large supply of non-synchronized reserve available at zero cost. When the most economic next MW of primary reserve can be met by backing down a resource from its economic operating point for energy, the non-synchronized reserve market price is equal to the LOC of that resource and is greater than zero.

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 NSRMCP 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 10-24). The closer the price to cost ratio comes to one, the more the market price reflects the full cost of non-synchronized reserve.

In the first six months of 2015, the price to cost ratio of the full RTO Zone non-synchronized reserve market averaged 62.0 percent; the price to cost ratio of the RTO Zone excluding MAD averaged 77.9 percent; the price to cost ratio of the MAD subzone averaged 49.3 percent.

Table 10-24 Full RTO, RTO, Mid-Atlantic Subzone non-synchronized reserve MW, credits, price, and cost: January through June 2015

Market	Year	Month	Total Non-synchronized Reserve MW	Total Non-synchronized Reserve Charges	Weighted Non-synchronized Reserve Market Clearing Price	Non-synchronized Reserve Cost	Price Cost Ratio
Full RTO Zone	2015	Jan	576,746	$1,229,436	$1.16	$2.13	54.3%
Full RTO Zone	2015	Feb	415,396	$2,813,595	$4.07	$6.77	60.1%
Full RTO Zone	2015	Mar	548,931	$1,388,380	$1.52	$2.53	60.0%
Full RTO Zone	2015	Apr	688,202	$734,517	$0.90	$1.07	84.2%
Full RTO Zone	2015	May	634,454	$1,061,259	$0.93	$1.67	55.9%
Full RTO Zone	2015	Jun	526,389	$1,015,745	$1.35	$1.93	70.0%
Total	2015	Total	3,390,118	$8,242,932	$1.51	$2.43	62.0%
RTO Only	2015	Jan	347,839	$551,932	$1.10	$1.59	69.4%
RTO Only	2015	Feb	244,284	$1,082,936	$3.51	$4.43	79.3%
RTO Only	2015	Mar	330,187	$790,557	$1.46	$2.39	61.1%
RTO Only	2015	Apr	423,312	$395,999	$0.89	$0.94	94.7%
RTO Only	2015	May	385,646	$401,259	$0.90	$1.04	86.5%
RTO Only	2015	Jun	315,402	$446,968	$1.31	$1.42	92.1%
Total	2015	Total	2,046,670	$3,669,652	$1.40	$1.79	77.9%
MAD Subzone	2015	Jan	228,907	$677,504	$1.24	$2.96	41.9%
MAD Subzone	2015	Feb	171,112	$1,730,659	$4.86	$10.11	48.1%
MAD Subzone	2015	Mar	218,744	$597,823	$1.60	$2.73	58.6%
MAD Subzone	2015	Apr	264,890	$338,518	$0.92	$1.28	71.9%
MAD Subzone	2015	May	248,808	$660,000	$0.99	$2.65	37.2%
MAD Subzone	2015	Jun	210,987	$568,777	$1.42	$2.70	52.6%
Total	2015	Total	1,343,448	$4,573,281	$1.68	$3.40	49.3%

Secondary Reserve (DASR)

PJM maintains a day-ahead, offer based market for 30-minute secondary reserve.[25] The Day Ahead Scheduling Reserves Market (DASR) has no performance obligations. The MMU recommends elimination of the Day-Ahead Scheduling Reserve Market and its replacement with a Real-Time Market for a dispatchable reserve product beyond the 30-minute limit for primary reserves.

Market Structure

Supply

On January 1, 2015, PJM began using economic maximum MW minus dispatch MW to calculate hourly DASR MW by resource. Before January 1, 2015 PJM had used emergency maximum MW minus dispatch MW to calculate hourly DASR MW. The amount of DASR available is the lesser of the energy ramp rate for all on-line units times thirty minutes, or the economic maximum minus the day-ahead dispatch point. For off-line resources capable of being online in thirty minutes, the DASR quantity is the economic maximum. The change in January 2015 reduced the supply of DASR. In the first six months of 2015, the average available hourly DASR was 36,192 MW. This is an 11.2 percent reduction from 40,768 MW of the first six months of 2014. The DASR MW purchased averaged 4,454 MW per hour for all hours in the first six months of 2015, a 14.7 percent decrease from 5,224 MW per hour in the first six months of 2014. 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. Spinning events longer than 30 minutes while rare do occur (September 10, 2013, and March 27, 2014) when secondary reserve was needed but not enough was available in real time.

All generation resources are required to offer DASR.[26] 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 six months of 2015, six demand resources offered into the DASR Market.

25 See PJM. "Manual 35, Definitions and Acronyms," Revision 35, (April 11, 2014), p. 89.
26 See PJM "Manual 11," Revision 75, (April 9, 2015) p. 144 at 11.2.3 Day-Ahead Scheduling Reserve Market Rules.

Demand

DASR 30-minute reserve requirements are determined by PJM for each reliability region.[27] In the Reliability*First* (RFC) region, secondary reserve requirements are calculated based on historical under-forecasted load rates and generator forced outage rates.[28] 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 5.93 percent. The DASR requirement is applicable for all hours of the operating day. If the DASR Market does not procure adequate scheduling reserves, PJM is required to schedule additional operating reserves.[29]

Effective March 1, 2015, the DASR requirement can be increased by PJM dispatch under conditions of "hot weather or cold weather alert or max emergency generation alert or other escalating emergency."[30] The amount of additional DASR MW that may be required is the Adjusted Fixed Demand determined by a Seasonal Conditional Demand Factor.[31] The Seasonal Conditional Demand Factor is calculated separately for the winter (November through March) and summer (April through October) seasons. The Seasonal Conditional Demand Factor is calculated every year based on the top ten peak load days from the prior year. For November 2014 through October 2015, the values for additional percent of peak load are 3.87 percent for winter, 5.36 percent for summer.

On May 26 and 27, 2015, PJM dispatch invoked this authority to adjust DASR for the first time adding an average of 3,626 MW for 44 hours. The authority was again invoked on June 12 and June 13 adding an average 3,263 MW for 46 hours. On June 22 and June 23, the DASR requirement was again raised, this time by an average of 3,016 MW for 48 consecutive hours. The use of this Adjusted Fixed Demand rule impacts the DASR market in several significant ways.

27 See PJM. "Manual 13, Emergency Requirements," Revision 57 (January 1, 2015), p. 11.
28 See PJM. "Manual 13, Emergency Requirements," Revision 57 (January 1, 2015), p. 11.
29 PJM uses the terms "supplemental operating reserves" and "scheduling operating reserves" interchangeably.
30 PJM. "Energy and Reserve Pricing & Interchange Volatility Final Proposal Report," <http://www.pjm.com/~/media/committees-groups/committees/mrc/20141030/20141030-item-04-erpiv-final-proposal-report.ashx>.
31 See PJM "Manual 11," Revision 75, (April 9, 2015) p. 142 at 11.2.1 Day-Ahead Scheduling Reserve Market Requirement.

Market Concentration

Between January 2012 and April 2015, no hours would have failed a three pivotal supplier test in the DASR Market. In May 2015, 13 hours would have failed a three pivotal supplier test. In June 2015, 39 hours would have failed a three pivotal supplier test. All of the hours that would have failed the three pivotal supplier test were hours when PJM Dispatch added MW to the DASR requirement.

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.[32] 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. As of June 30, 2015, 8.0 percent of resources offered DASR at levels above $5 per MW.

Market Performance

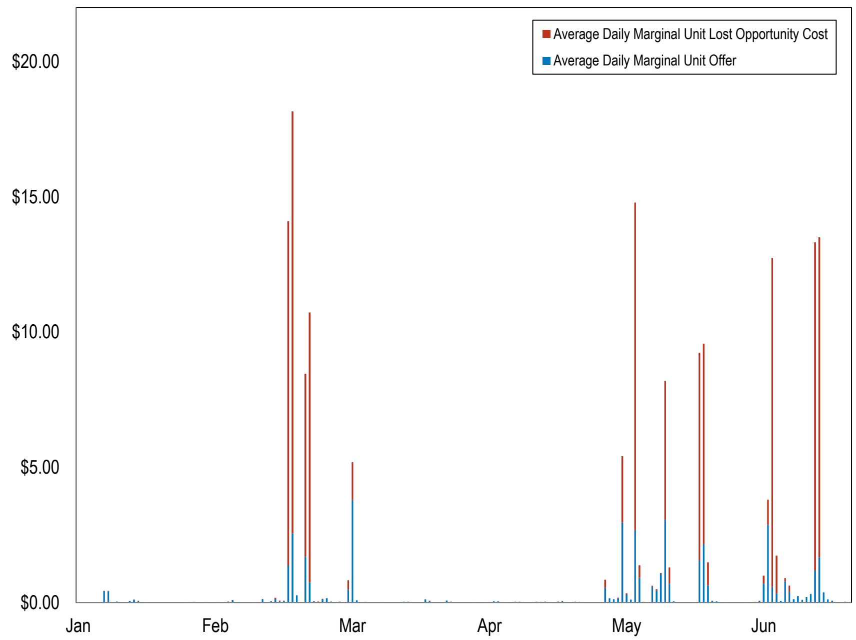
DASR prices are calculated as the sum of the offer price plus the opportunity cost. For 59.6 percent of hours in the first six months of 2015, DASR cleared at a price of $0.00 per MWh (Figure 10-16). This is a significant reduction from the 90.0 percent of hours that the DASR market cleared at $0 in the first six months of 2014. This change in the DASR offer MW from dispatch to emergency maximum to dispatch to economic maximum significantly reduced the amount of DASR offered. In the first six months of 2015, the weighted average DASR price in all hours was $1.54. The average cleared MW in all hours was 4,454 MW. Looking only at the 52 hours when PJM Dispatch added MW, the weighted average DASR price was $12.94 and an average of 8,832 MW was cleared. It is clear that the March 1, 2015, rule change, allowing PJM Dispatch to increase the DASR requirement, had a significant impact on both market prices and market concentration. The highest DASR price was $199.83 on February 19, 2015.

32 See PJM. "Manual 11, Emergency and Ancillary Services Operations," Revision 75 (April 9, 2015), p. 143.

Table 10-25 PJM Day-Ahead Scheduling Reserve Market MW and clearing prices: 2012 through June 2015

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	4,257,558	$35,349,968
2014	Feb	5,804	$0.00	$5.00	$0.05	3,604,087	$188,937
2014	Mar	5,303	$0.00	$3.00	$0.01	3,590,159	$47,749
2014	Apr	4,465	$0.00	$0.05	$0.00	3,304,943	$1,241
2014	May	5,531	$0.00	$0.10	$0.00	3,717,767	$7,386
2014	Jun	6,901	$0.00	$7.80	$0.04	4,236,399	$163,326
2014	Jul	6,865	$0.00	$0.25	$0.00	4,453,376	$9,358
2014	Aug	6,426	$0.00	$0.01	$0.00	1,631,617	$302
2014	Sep	6,596	$0.00	$0.04	$0.00	3,651,911	$2,444
2014	Oct	4,252	$0.00	$0.00	$0.00	3,163,787	$0
2014	Nov	4,803	$0.00	$0.01	$0.00	3,137,595	$577
2014	Dec	4,455	$0.00	$0.01	$0.00	3,314,871	$58
2015	Jan	4,636	$0.00	$10.00	$0.04	3,449,332	$141,561
2015	Feb	4,802	$0.00	$199.83	$1.99	3,226,918	$6,430,235
2015	Mar	3,972	$0.00	$24.82	$0.25	2,954,922	$730,429
2015	Apr	3,760	$0.00	$0.25	$0.02	2,707,467	$46,706
2015	May	4,359	$0.00	$71.40	$2.97	3,243,158	$9,638,772
2015	Jun	5,230	$0.00	$74.17	$3.39	3,765,681	$12,757,661

Figure 10-16 Daily average components of DASR clearing price ($/MW), marginal unit offer and LOC: January through June 2015



When energy demand is high and/or the DASR requirement is increased by PJM dispatch, the reserve requirement cannot be filled without redispatching online resources which significantly affects the price. Figure 10-16 shows the impact of LOC on price when online resources must be redispatched to satisfy the DASR requirement. DASR prices increase very suddenly at peak loads as a result of high LOCs.

DASR is filled by on-line, off-line, and hydro resources in a consistent proportion regardless of price (Figure 10-17).

Figure 10-17 Daily average DASR prices and MW by classification: January through June 2015

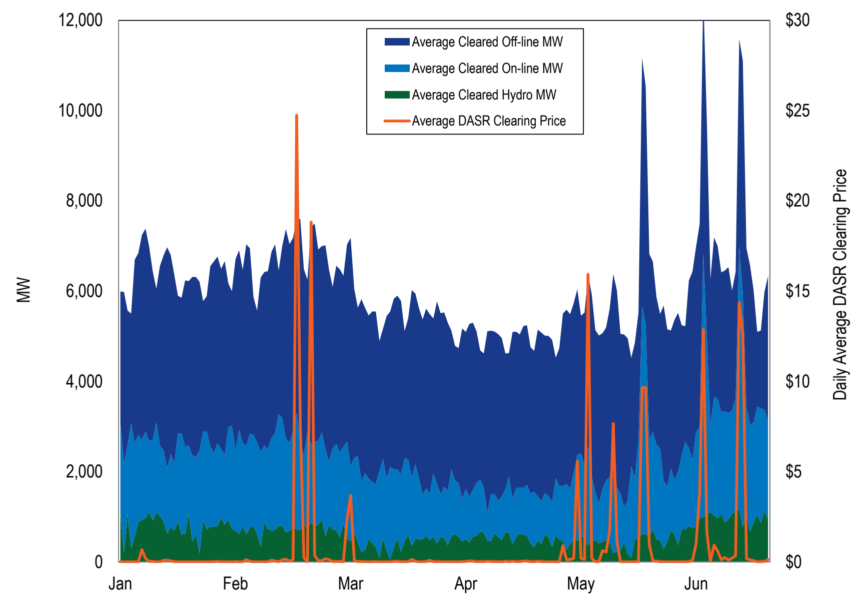


Figure 10-17 illustrates the fact that the 52 hours when additional DASR was scheduled had an impact on both the market price and market concentration. While the new rules allow PJM dispatch to add additional MW under conditions of "hot weather or cold weather alert or max emergency generation alert or other escalating emergency" the rationale for each increase is not always clear. The MMU recommends that a reason code be attached to every hour in which PJM dispatch adds additional DASR MW. The addition of such a code would make the reason explicit, increase transparency and facilitate analysis of the use of PJM's ability to add DASR MW.

The MMU recommends that PJM replace the DASR Market with a real time secondary reserve product that is available and dispatchable in real time. As part of that evaluation, PJM should determine why secondary reserve was either unavailable or not dispatched during the two spinning events greater than thirty minutes on September 10, 2013, and January 6, 2014.

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 real-time market. Significant technical and structural changes were made to the Regulation Market in 2012.[33]

Market Design

The objective of PJM's regulation market design is to minimize the cost to provide regulation using two resource types, RegA and RegD, in a single market. To meet this objective, the marginal benefit factor function defining the substitutability between RegA and RegD must be correctly defined and consistently applied throughout the market construct, from optimization to settlement. That is not the case in PJM's current regulation market design.

The result has been that the Regulation Market has over procured RegD relative to RegA in some hours. This over procurement has begun to degrade the ability of PJM to control ACE in some hours while at the same time increasing the cost of regulation to the PJM market. When the price paid for RegD is above the competitive level defined by an accurate marginal benefit function, there is an artificial incentive for inefficient entry of RegD resources.

The Regulation Market includes resources following two signals: RegA and RegD. Resources responding to either signal help control ACE (area control error). 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 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 marginal benefit factor and performance score translate a resource's capability (actual) MW into effective MW.

33 See the *2012 State of the Market Report for PJM*, Volume II, Section 9, "Ancillary Services," p. 271.

Regulation in PJM is frequently provided by fleets of resources rather than by individual units. A fleet is a set of resources owned or operated by a common entity. The regulation signals (RegA or RegD) are sent every two seconds to the fleet local control centers or, at the option of fleet owners, to their individual resources. Fleet local control centers report to PJM every two seconds the fleet response to the RegA and RegD signals.

Prior to the operating hour, fleet owners are allowed to replace an assigned regulation resource in their fleet with another resource in their fleet as long as that resource is qualified to provide regulation for the originally assigned signal, has an historic performance score close to the originally assigned resource and has notified PJM of the change.

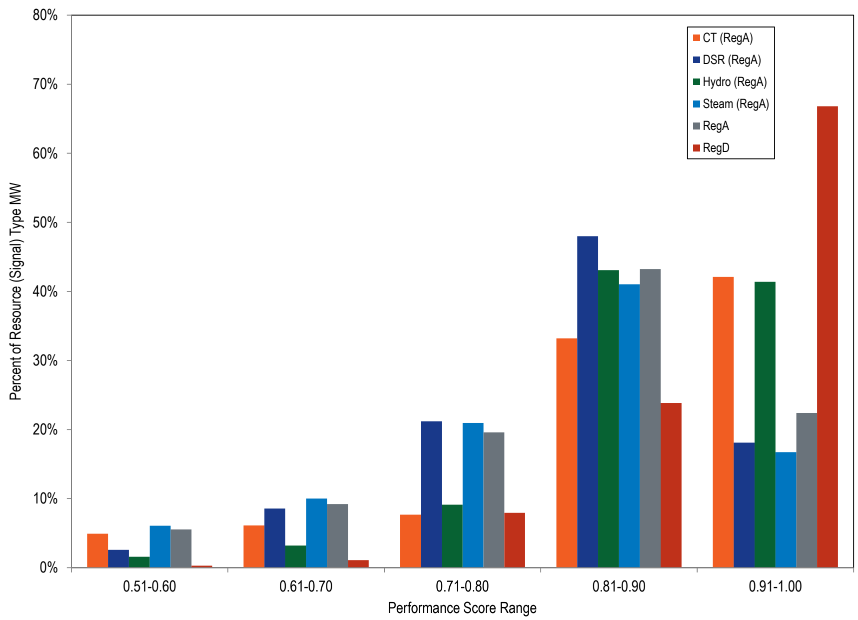
Regulation performance scores (0.0 to 1.0) measure the response of a regulating resource to its assigned regulation signal (RegA or RegD) every ten seconds by measuring: delay, the time delay of the regulation response to a change in the regulation signal; correlation, the correlation between the regulating resource output and the regulation signal; and precision, the difference between the regulation response and the regulation requested.[34]

Figure 10-18 shows the average performance score by resource type and signal followed for the first six months of 2015. 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.[35] Each category (color bar) adds up to 100 percent so that the full performance score distribution for each resource (or signal) type is shown. RegD resources tend to have higher

34 PJM "Manual 12: Balancing Operations" Rev. 31 (August 21, 2014); 4.5.6, p 52.
35 Except where explicitly referred to as effective MW or effective regulation MW, MW means regulation capability MW unadjusted for either marginal benefit factor or performance factor.

performance scores. As the figure shows, 66.8 percent of RegD resources have average performance scores within the 0.91-1.00 range, whereas only 22.4 percent of RegA resources have average performance scores within that range.

Figure 10-18 Hourly average performance score by unit type and regulation signal type: January through June 2015



Performance scores measure the regulating response of individual resources, regardless of whether they were originally assigned or replaced (with notification) by a fleet owner. PJM creates an individual resource's regulation signal proportionately by dividing the assigned regulation of the individual resource by the assigned regulation of the fleet. Then, PJM compares the individual resource's regulation signal to the individual resource's MW output (or, for DR, load) to calculate the performance score based on delay, correlation, and precision. Performance scores are calculated using data every 10 seconds, but are reported on an hourly basis for each individual regulating resource.

While resources following RegA and RegD can both provide regulation service in PJM's regulation market, PJM's joint optimization is intended 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 offers of RegA and RegD resource regulation capability MW into comparable units, termed effective MW and dollars per effective MW.

Resource-specific 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 effective RegA MW. Regulation MW are converted to effective MW by multiplying offered capability MW by the product of resource-specific benefit factor and performance score. The assigned benefit factor of a RegA resource is always 1.0.

Total regulation offers (made up of a $/MW capability offer and a $/mile based performance offer) are converted to dollars per effective MW by dividing the offer by the effective MW.

For example, a 1 MW RegD resource with an total offer price (the sum of the capability and performance offers) of $2/MW with a resource specific benefit factor of 0.5 and a performance score of 100 percent, would be calculated as offering 0.5 effective MW (0.5 Benefit Factor times 1.00 performance score times 1 MW). The total offer price, in terms of dollars per effective MW, would be $4 per effective MW ($2/MW offer divided by the 0.5 effective MW).

36 See the *2013 State of the Market Report for PJM*, Volume II, Section 10, "Issues Related to the Marginal Benefit Factor," pp. 294-8.

Market Design Issues

Marginal Benefit Factor Not Reflected in Market

The marginal benefit factor defines the substitutability between RegA and RegD resources in meeting the regulation requirement. The effectiveness and efficiency of the regulation market depends on the marginal benefit factor function being defined by the actual tradeoff between RegA and RegD MW in providing regulation. If the marginal benefit factor function is incorrectly defined, the resulting combinations of RegA and RegD would not represent the least cost solution.

The absence of the marginal benefit factor from PJM's settlement process is the result of two FERC orders. 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. On October 2, 2013, the FERC directed PJM to eliminate the use of the marginal benefit factor entirely 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]

The result of the current FERC directive is that the marginal benefit factor is used in the optimization to determine the relative value of additional MW of RegD but the marginal benefit factor is not used in the ultimate settlement for RegD. Instead, PJM uses a mileage ratio (RegD/RegA) to adjust the performance component (RMPCP) of price paid to RegD resources.

Resources are paid RMCP credits (the sum of RMCCP credits and RMPCP credits) and lost opportunity cost 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.

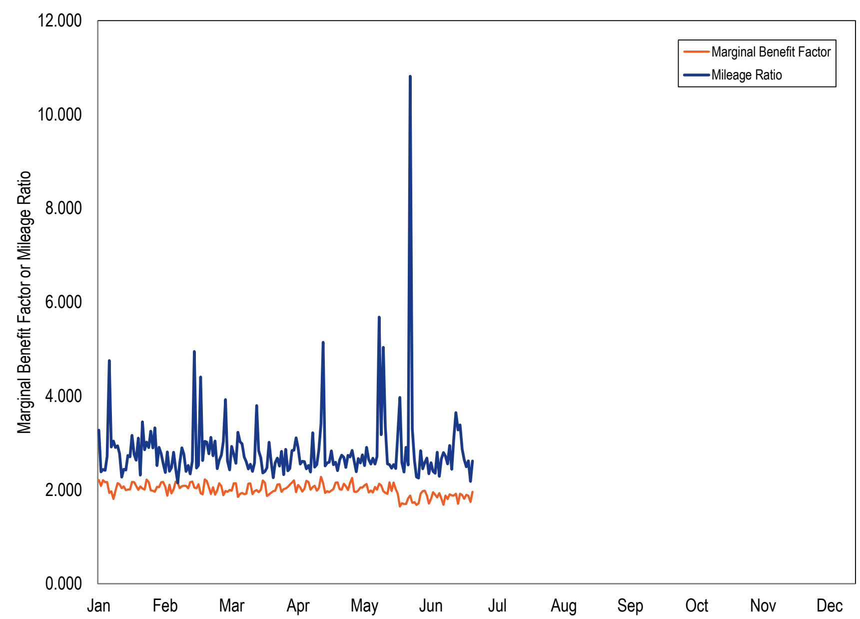
RMCCP (capability related) credits are calculated as MW of regulation capability times performance score times RMCCP (the regulation capability price per effective MW).

37 145 FERC ¶ 61,011 (2013).

The MMU reported that, on average, RegD resources were being underpaid in 2014, relative to their effective MW contributions, relative to RegA resources. This was due to the fact that the average MBF was over 2 for the referenced period and the average mileage ratio multiplier, while higher than the average marginal benefit factor, only applies to the performance credits, which make up a small portion of the regulation credit stream.[38] While overpayment is no longer the case as a result of a much lower MBF, this illustrates clearly that the mileage ratio is not a good substitute for the MBF.

Figure 10-19 compares the daily average marginal benefit factor and the mileage ratio.

Figure 10-19 Daily average marginal benefit factor and mileage ratio: 2015



38 *2014 State of the Market Report for PJM*, Volume II; Section 10:"Ancillary Service Markets."

The current settlement process does not result in RegA and RegD resources being paid a uniform amount per effective MW. Only RegA resources are paid on the basis of dollars per effective MW of RegA. RegD resources are not paid in terms of dollars per effective MW of RegA because the marginal benefit factor is not used. When the marginal benefit factor is above one, this means that RegD resources are generally underpaid on a per effective MW basis relative to RegA resources. When the marginal benefit factor is less than one, this means that RegD resources are generally overpaid on a per effective MW basis relative to RegA resources.

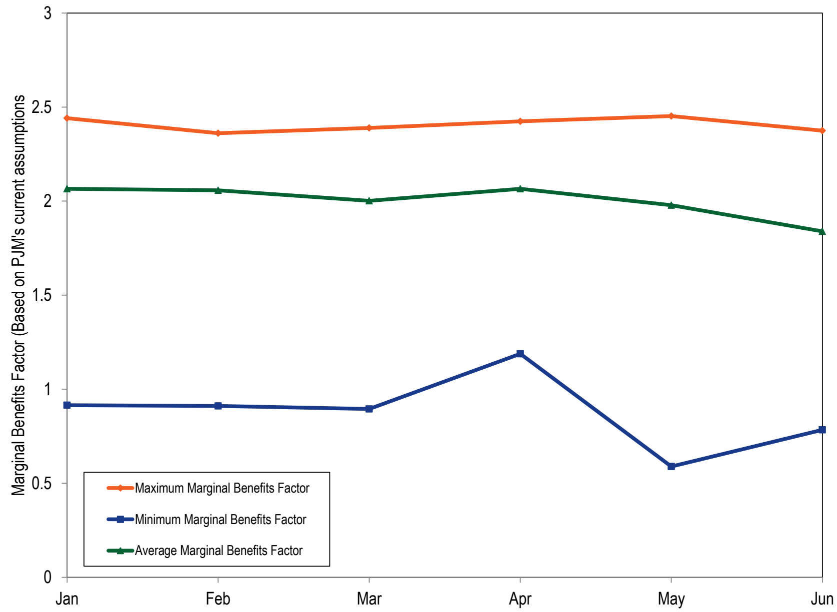
PJM posts clearing prices for the Regulation Market (RMCCP, RMPCP and RMCP) in dollars per effective regulation capability MW. The regulation market clearing price (RMCP) for the hour is the simple average of the twelve five-minute RMCPs within the hour. The RMCP is set in each of the twelve five-minute interval within a market hour, based on the marginal offer (including lost opportunity costs) in each of interval. The five-minute RMCP is the sum of the performance clearing price (RMPCP) and the capability clearing price (RMCCP). The performance clearing price ($/effective MW) is equal to the most expensive performance offer (RMPCP) cleared for the hour. The capability clearing price ($/effective MW) is equal to the difference between the RMCP for the hour and the RMPCP for the hour.

While prices are set on the basis of dollars per effective MW, only RegA receive payments (credits) that are consistent with their effective MW provided.[39] The current market design does not send the correct price signal to the RegD resources as the price realized by RegD resources in settlement is inconsistent with the effective MW based prices used in the optimization. This is due to an inconsistent application of the marginal benefit factor.

Figure 10-20 shows, for the period from January 1, 2015; through June 30, 2015; the maximum, minimum and average PJM calculated marginal benefit factor, based on PJM's incorrect marginal benefit factor curve, by month.

39 This is due to the fact that RegA resources performance adjusted MW are their effective MW.

Figure 10-20 Maximum, minimum, and average PJM calculated marginal benefit factor by month: January through June of 2015



The MMU recommends that the marginal benefit factor function used in the Regulation Market be reviewed as part of incorporating a consistent application of the marginal benefit factor in the Regulation Market and that PJM correct the calculation of effective MW attributed to RegD MW in the regulation market solution.[40]

The Effective MW of Regulation Purchased Are Understated

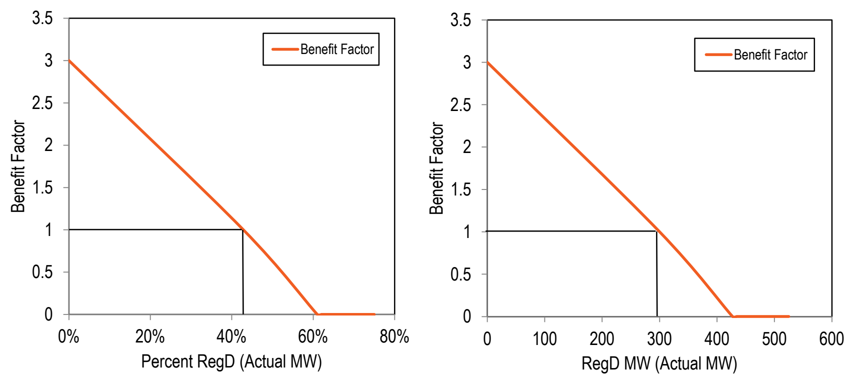
The MMU has determined that the current market optimization/market solution understates the amount of effective MW provided by RegD. Rather than calculating the total effective MW contribution of RegD MW on the basis of the area under the marginal benefit function curve, the current regulation market optimization assigns all RegD resources the lowest marginal benefit

40 See Fast Response Regulation (RegD) Resources Operational Impact Problem Statement and the MMU's Regulation Market Review presentation which were presented at the May 5, 2015 Operating Committee See <http://www.pjm.com/committees-and-groups/committees/oc.aspx>, accessed May 4, 2015.

factor associated with last RegD MW purchased. This has resulted in the purchase of more than the efficient level of regulation MW to meet PJM's defined regulation requirement.

Figure 10-21 shows the marginal benefit curve, in terms of RegD percent (left diagram) and RegD MW (right diagram) in a scenario where 700 MW of effective MW are needed and the market clears 300 MW of RegD (actual MW), all priced at $0.00, and 400 MW of RegA. Figure 10-21 shows that the 300 MW of cleared RegD makes up 42.9 percent of total cleared actual MW and resulting marginal benefit factor of 1.0.

Figure 10-21 Example marginal benefit line in percent RegD and RegD MW terms

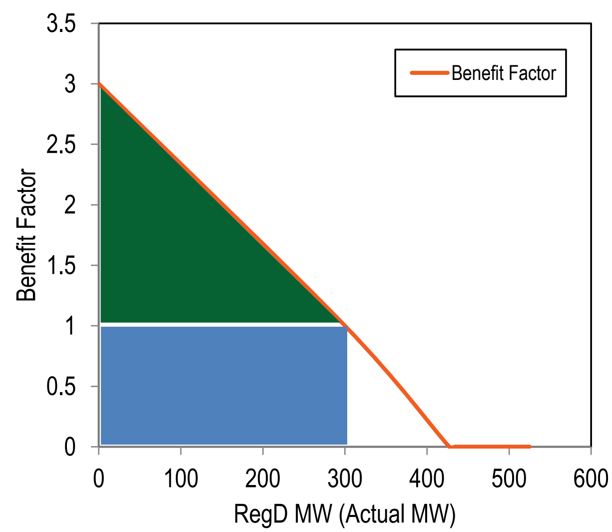


Using PJM's method for the calculation of effective MW from RegD resources, all RegD resources are assigned the lowest marginal benefit factor associated with the last RegD MW purchased. In this example, all 300 MW have an MBF of 1.0 for determining the total effective MW provided by RegD resources. PJM calculates total effective MW from RegD resources to be 300 (300MW x 1.0 = 300 effective MW).

In Figure 10-22, PJM's calculation of total effective MW from RegD is represented by the area of the blue rectangle which is 400 effective MW.

PJM's method is flawed. By assigning a single benefit value to every MW, PJM's methodology undervalues the amount of effective MW provided by RegD MW (assuming the benefit curve is properly defined). This is because the benefit curve represents a marginal rate of substitution between RegD and RegA MW, and the area under the curve, at any RegD amount, represents the total effective MW supplied by RegD at that point. In fact, RegD is providing effective MW equal to area defined by the green triangle and the blue rectangle in Figure 10-22. This corresponds to 600 effective MW being supplied by RegD resources, not 300 effective MW. This means that the actual total effective MW cleared in the market solution is 300 more effective MW than needed to meet the regulation requirement.

Figure 10-22 Illustration of correct method for calculating effective MW

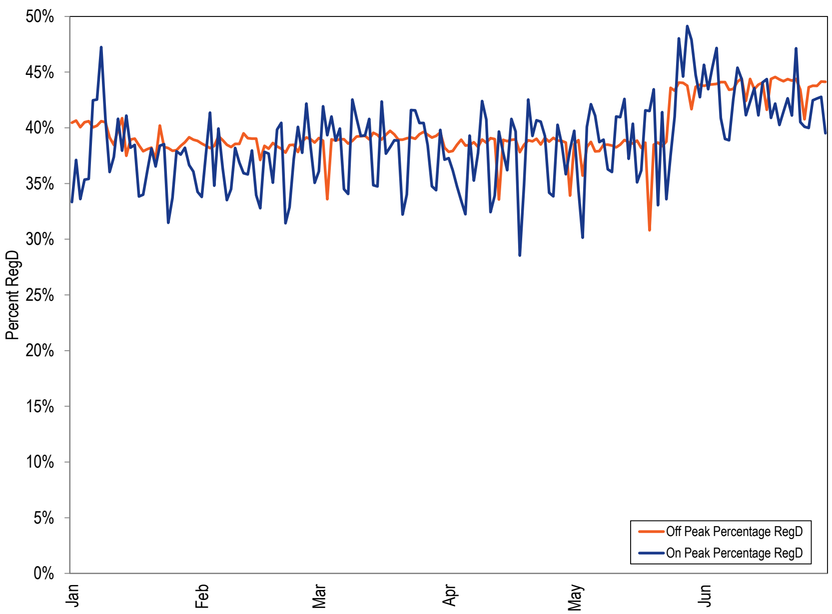


Too Many MW of Regulation (RegD) Purchased

PJM has observed issues with regulation performance when the proportion of effective MW from RegD resources exceeds 42 percent.[41] The system issues are a result of PJM buying too much RegD as a proportion of total regulation. The issues also indicate that the marginal benefit factor function used by PJM is incorrectly describing the operational relationship between RegA and RegD. PJM's current marginal benefit factor function is, at least in some hours, overvaluing RegD as a substitute for RegA in the optimization.

The proportion of RegD resources used to satisfy the on peak (700 MW) and off peak (525 MW) regulation requirements is shown in Figure 10-23.

Figure 10-23 Daily average percent of RegD effective MW by peak: January through June 2015



The effect of the incorrect accounting of effective MW is exacerbated by a marginal benefit factor function that assigns too high a marginal benefit factor to RegD resources. An inflated marginal benefit factor makes incremental effective MW from RegD resources look less expensive than incremental effective MW from RegA resources.

The effect of this market flaw on the amount of Reg D clearing the market has been magnified by the increasing proportion of RegD MW with an effective price of $0.00 per MW. This guarantees that an increasing proportion of RegD MW in the market appears as the cheapest source of incremental effective regulation MW.

Figure 10-24 shows, by month, both an increasing amount and increasing proportion of cleared RegD MW with an effective price of $0.00. The figure also shows a corresponding increase in the total RegD MW clearing the market in the period between January 2014 and June 2015.

As shown in Figure 10-24, self-scheduling or bidding RegD MW at zero has increased significantly.[42] Between May and June of 2015, there was a 5.6 percent increase in the amount of performance adjusted actual RegD MW with an effective cost of $0.00, and a 10.1 percent increase in the amount of performance adjusted actual RegD that is self scheduled.

41 Fast Response Regulation (RegD) Resources Operational Impact Problem Statement, Presented at the May 5, 2015 Operating Committee. See <http://www.pjm.com/committees-and-groups/committees/oc.aspx>, accessed May 4, 2015.

42 See MMU's Regulation Market Review presentation from the May 5, 2015 Operating Committee See <http://www.pjm.com/committees-and-groups/committees/oc.aspx>, accessed May 4, 2015

Figure 10-24 Average cleared RegD MW and average cleared RegD with an effective price of $0.00 by month: January 2014 through June 2015

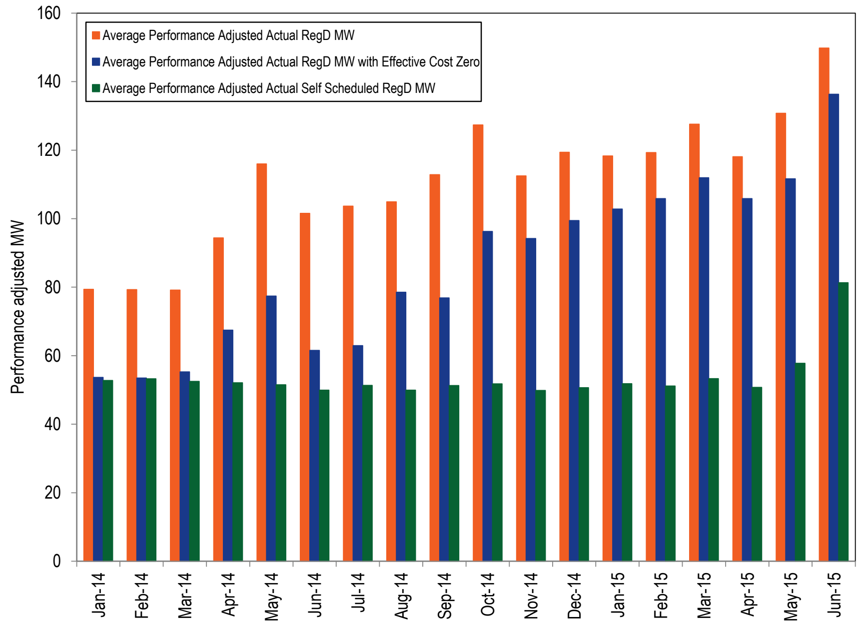


Figure 10-25 Average monthly peak effective MW: PJM market calculated versus benefit factor based

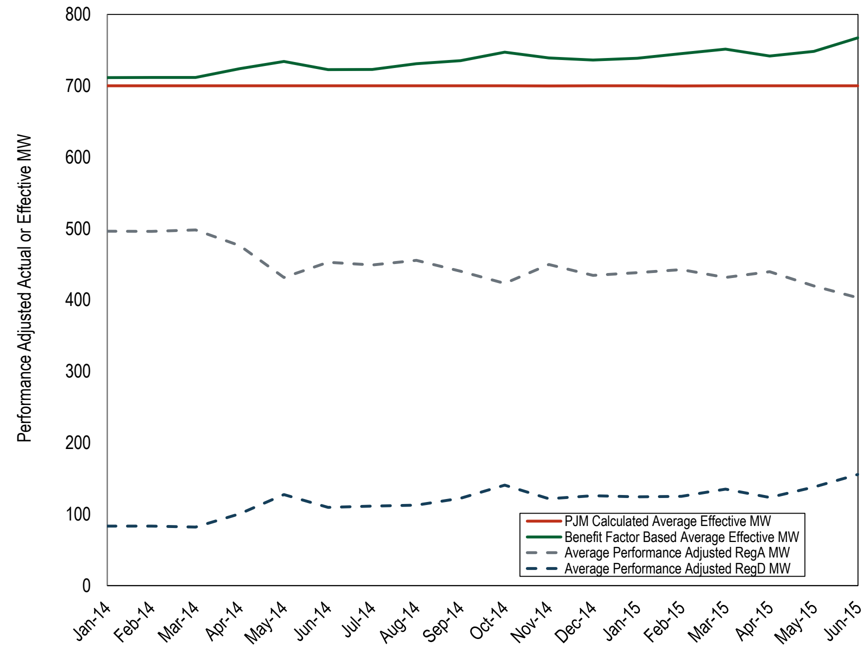
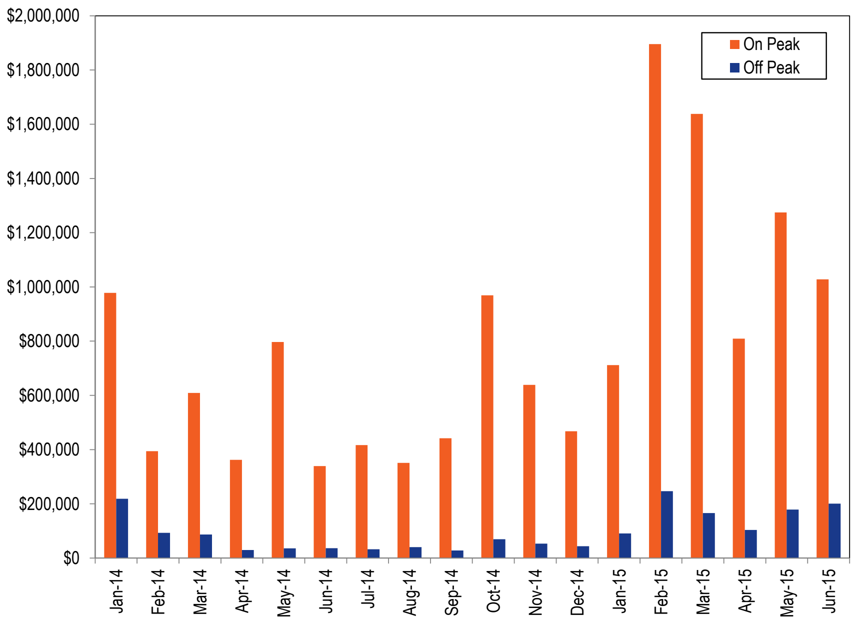


Figure 10-25 shows the average monthly peak total effective MW as calculated by PJM's incorrect accounting method and as calculated by a correctly applied marginal benefit factor for the January 2014 through June 2015 period. The figure also shows the monthly average actual (performance adjusted) RegA MW and RegD cleared in the regulation market for the period. Based on the assumption that the current marginal benefit function is correct, the figure shows that PJM has been clearing an increasing surplus of effective MW. As shown in Figure 10-24, this has been caused by an increasing proportion of RegD MW supply with an effective price of $0.00 in the PJM market.

The Cost of Purchasing Too Many Regulation MW

Figure 10-26 shows the cost of the excess effective MW cleared by month, peak and off peak, from January 1, 2014 through June 30, 2015. In the first six months of 2015, the total cost of excess effective RegD MW during on peak and off peak hours was $7.4 million and $1.0 million.

Figure 10-26 Cost of excess effective MW cleared by month, peak and off peak: January 1, 2014 through June 30, 2015



Market Structure

Supply

Table 10-26 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 the first six months of 2015. 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.[43] 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.

Table 10-26 PJM regulation capability, daily offer and hourly eligible: January through June 2015[44 45]

		By Resource Type		By Signal Type	
Metric	All Regulation	Generating Resources	Demand Resources	RegA Following Resources	RegD Following Resources
Capability MW	8,229.9	8,212.0	17.9	8,109.6	435.4
Offered MW	3,714.1	3,706.9	7.3	3,552.6	161.6
Actual Eligible MW	1,237.2	1,231.9	5.3	1,051.1	186.5
Effective Eligible MW	907.1	899.7	7.4	661.3	245.9
Actual Cleared MW	655.6	652.4	3.2	532.6	122.9
Effective Cleared MW	663.7	657.5	6.2	426.1	237.5

Table 10-27 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 10-27, 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. Total regulation capability MW provided by coal units increased from 294,934.1 MW in the first six months of 2014 to 327,830.2 MW in the first six months of 2015, and the average proportion of regulation provided by coal increased from 14.5 percent of regulation in the first six months of 2014 to 16.7 percent of regulation in the first six months of 2015. Coal unit revenues were $22.7 million in the first six months of 2015, 67.2 percent of the $33.8 million in revenues in the first six months of 2014. The decrease in coal unit revenues was a result of the high regulation market clearing prices and out of market opportunity cost credits in January 2014.

43 Unless otherwise noted, analysis provided in this section uses PJM market data based on PJM's internal calculations of effective MW values, based on PJM's currently incorrect MBF curve. The MMU is working with PJM to correct the MBF curve and future analysis will show the effect of this correction.

44 Average Daily Offer MW excludes units that have offers but are unavailable for the day.

45 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 10-27 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
2014	Jan	109	70,441.3	360,512.5	19.5%	$15,782,562
2014	Feb	102	51,032.8	309,976.1	16.5%	$4,690,694
2014	Mar	101	52,367.8	341,089.2	15.4%	$6,860,625
2014	Apr	76	52,780.3	351,763.3	15.0%	$2,805,943
2014	May	75	36,942.7	324,871.4	11.4%	$2,021,850
2014	Jun	82	31,369.2	330,372.2	9.5%	$1,591,779
2015	Jan	81	49,199.4	343,515.9	14.3%	$2,052,287
2015	Feb	86	72,484.9	308,378.6	23.5%	$6,536,068
2015	Mar	69	54,007.8	342,707.8	15.8%	$4,171,676
2015	Apr	61	50,829.8	337,113.5	15.1%	$3,013,790
2015	May	64	57,520.2	330,008.9	17.4%	$5,000,639
2015	Jun	52	43,788.2	311,010.9	14.1%	$1,922,939

The supply of regulation can be affected by regulating units retiring from service. Table 10-28 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 less than one percent. The MW in Table 10-28 have been adjusted by the actual within-hour performance score.

Table 10-28 Impact on PJM Regulation Market of currently regulating units scheduled to retire through 2015

Current Regulation Units, 2015	Adjusted Settled MW, 2015	Units Scheduled To Retire Through 2015	Adjusted Settled MW of Units Scheduled To Retire Through 2015	Percent Of Regulation MW To Retire Through 2015
272	2,784,129	19	11,477	0.41%

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 six months of 2015, because the average performance score was less than 1.00 For the first six months of 2015, the MW-weighted average RegA performance score was 0.80 and there were 231 resources following the RegA signal.

For RegD resources, the total effective MW vary relative to actual MW because the benefit factor at current participation levels varies from values greater than and less than 1.0. In the first six months of 2015, the marginal benefit factor, based on PJM's current assumed marginal benefit factor curve, for cleared RegD following resources ranged from 0.589 to 2.452 with an average over all hours of 1.969. In the first six months of 2015, the MW-weighted average RegD resource performance score was 0.91 and there were 41 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). In the first six months of 2015, the price and cost of regulation have remained high relative to prior years with the exception of 2014. The weighted average regulation price for the first six months of 2015 was $41.33/MW. The regulation cost for the first six months of 2015 was $50.04/MW. The ratio of price to cost is higher (82.9 percent) than in the same period in 2014 (82.5 percent).

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. The regulation requirement remained 700 effective MW during peak hours and 525 effective MW during off peak hours in the first six months of 2015.

Table 10-29 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 10-27 for every month from January 2011 through May 2015 with the dashed vertical line marking the date (October 1, 2012) of the implementation of the Performance Based Regulation Market design.[46] 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 2014, PJM remained in compliance with the applicable NERC standards.

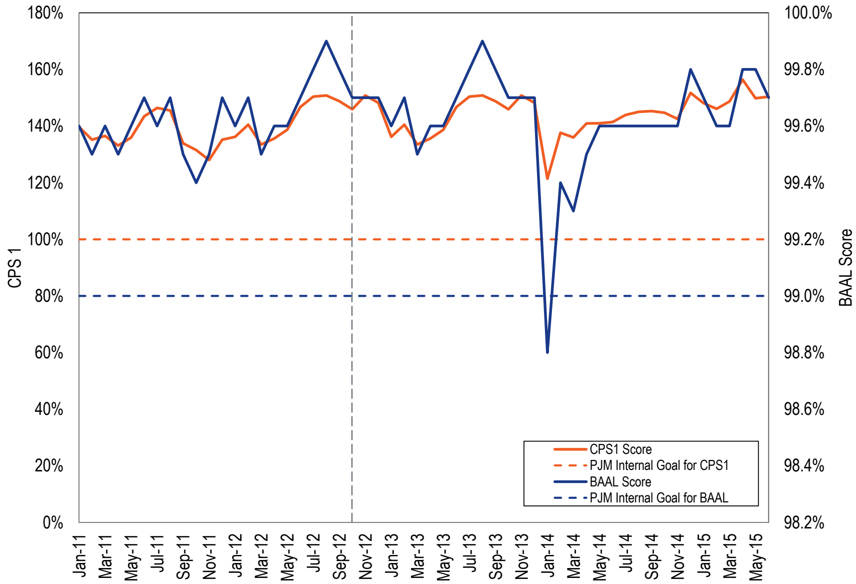
Very cold weather from January 6 through January 8 and from January 17 through January 29, 2014, caused extreme system conditions, including 12 synchronized reserve events, seven RTO-wide shortage pricing events and high forced outage rates. As a result, PJM experienced several frequency excursions of between 10 and 20 minutes which caused PJM's performance on the BAAL metric, a measure of a balancing authority's ability to control ACE and frequency, to decline substantially.

Table 10-29 PJM Regulation Market required MW and ratio of eligible supply to requirement: January through June 2014 and 2015

Month	Average Required Regulation (MW), 2014	Average Required Regulation (MW), 2015	Average Required Regulation (Effective MW), 2014	Average Required Regulation (Effective MW), 2015	Ratio of Supply MW to MW Requirement, 2014	Ratio of Supply MW to MW Requirement, 2015	Ratio of Supply Effective MW to Effective MW Requirement, 2014	Ratio of Supply Effective MW to Effective MW Requirement, 2015
Jan	689.9	638.2	663.6	663.7	2.05	1.86	1.60	1.35
Feb	681.3	656.3	663.6	663.5	2.00	1.75	1.51	1.37
Mar	682.9	649.7	663.8	663.9	1.99	1.73	1.48	1.35
Apr	682.1	646.2	663.7	663.7	2.04	1.83	1.54	1.34
May	658.1	650.3	663.6	663.6	1.93	1.72	1.44	1.32
Jun	646.8	624.3	663.9	655.8	1.89	1.83	1.29	1.31

46 See the *2014 State of the Market Report for PJM*, Appendix F: Ancillary Services.

Figure 10-27 PJM monthly CPS1 and BAAL performance: January 2011 through June 2015



Market Concentration

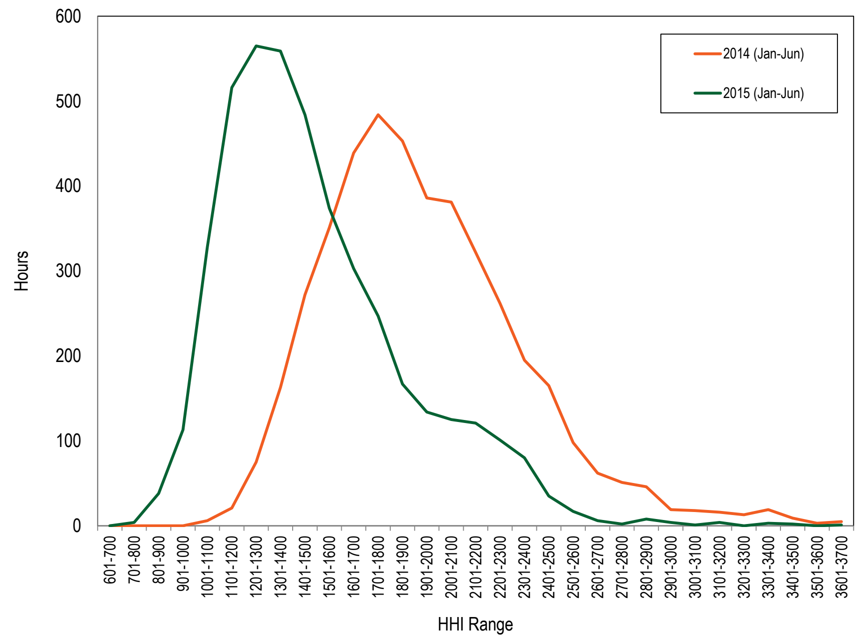
Table 10-30 shows Herfindahl-Hirschman Index (HHI) results for January through June 2014 and 2015, based on market shares of effective MW, defined as regulation capability MW adjusted by performance score and resource-specific benefit factor, consistent with the metrics used to clear the regulation market. The weighted average HHI of 1477 is classified as moderately concentrated and is lower than the HHI for the same period in 2014 of 1922. For the first six months of 2015, the weighted average HHI of RegA resources was 2520 (highly concentrated, but lower than the January through June 2014 value of 2916 and the weighted average HHI of RegD resources was 2865 (highly concentrated, but lower than the January through March 2014 value of 4795). 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 10-30 PJM cleared regulation HHI: 2014 and 2015

Year (Jan-Jun)	Minimum HHI	Weighted Average HHI	Maximum HHI
2014	1034	1922	3943
2015	756	1477	3658

Figure 10-28 compares the frequency distribution of HHI for January through June 2014 and 2015.

Figure 10-28 PJM Regulation Market HHI distribution: 2014 and 2015



The Regulation Market TPS test is calculated for each market hour. If an owner is pivotal, its resources are offer capped at the lower of their cost based or price based regulation offers.

Table 10-31 includes a monthly summary of three pivotal supplier results. In the first six months of 2015, 98 percent of hours had three or fewer pivotal suppliers. The impact of offer capping in the Regulation Market is limited because of the role of LOC in price formation (Figure 10-30). The MMU concludes from these results that the PJM Regulation Market in the first six months of 2015 was characterized by structural market power in 98 percent of hours.

Table 10-31 Regulation market monthly three pivotal supplier results: 2013 through 2015

	2013	2014	2015
Month	Percent of Hours Pivotal	Percent of Hours Pivotal	Percent of Hours Pivotal
Jan	83%	97%	98%
Feb	82%	99%	96%
Mar	97%	95%	97%
Apr	88%	89%	98%
May	93%	96%	99%
Jun	95%	99%	99%
Average	90%	96%	98%

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.[47]

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.[48]

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).[49] Figure 10-29 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.[50] 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 38.7 percent during on peak and 55.6 percent during off peak hours in the first six months of 2015).

47 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 72, (January 16, 2015); para 3.2.1, p 47.
48 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 72, (January 16, 2015); para 3.2.2, pp 48.
49 See PJM. "Manual 28: Operating Agreement Accounting," Revision 68, (January 16, 2015); para 4.1, p 15.
50 See PJM. "Manual 11: Energy & Ancillary Services Market Operations," Revision 72, (January 16, 2015); para 3.2.9, p 59.

Figure 10-29 Off peak and on peak regulation levels: 2015

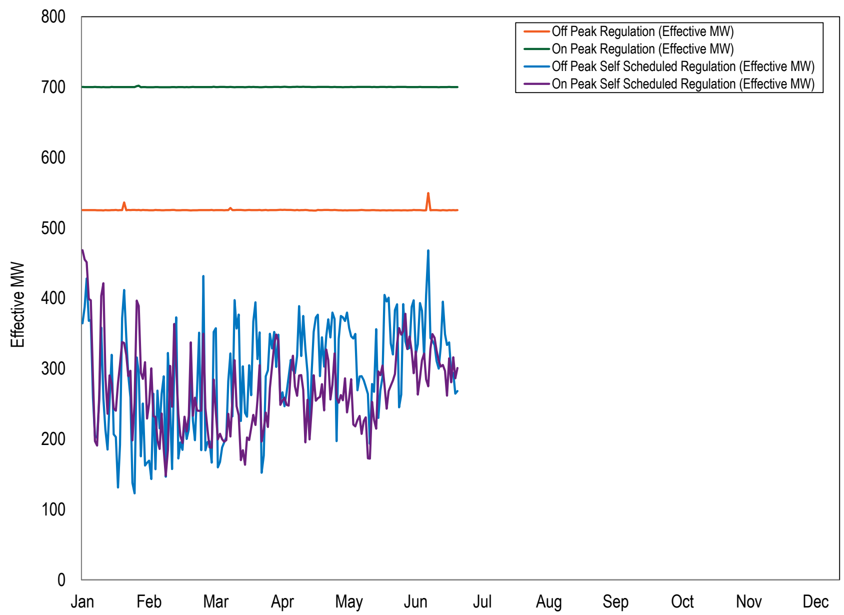


Table 10-32 shows how RegD resources have impacted the Regulation Market. RegD resources are both a growing proportion of the market (11 percent at the start of the Performance Based Regulation Market design in October 2012 versus 43 percent in June 2015) and a growing proportion of resources that self schedule (10 percent in October 2012 versus 24 percent in June 2015). This has resulted in an increase in the proportion of the regulation requirement that is self scheduled.

Table 10-32 RegD self scheduled regulation by month, October 2012 through June 2015

Year	Month	RegD Self Scheduled Effective MW	RegD Effective MW	Total Self Scheduled Effective MW	Total Effective MW	Percent of Total Self Scheduled	RegD Percent of Total Self Scheduled	RegD Percent of Total Effective MW
2012	Oct	66	72	265	658	40%	10%	11%
2012	Nov	74	88	197	716	27%	10%	12%
2012	Dec	83	89	189	701	27%	12%	13%
2013	Jan	36	82	134	720	19%	5%	11%
2013	Feb	85	90	212	724	29%	12%	12%
2013	Mar	80	119	280	681	41%	12%	18%
2013	Apr	82	107	266	594	45%	14%	18%
2013	May	74	109	268	616	44%	12%	18%
2013	Jun	80	123	335	731	46%	11%	17%
2013	Jul	78	120	304	823	37%	9%	15%
2013	Aug	84	128	366	757	48%	11%	17%
2013	Sep	112	152	382	670	57%	17%	23%
2013	Oct	120	164	350	613	57%	20%	27%
2013	Nov	134	176	397	663	60%	20%	26%
2013	Dec	137	181	314	664	47%	21%	27%
2014	Jan	133	194	261	664	39%	20%	29%
2014	Feb	134	193	291	664	44%	20%	29%
2014	Mar	132	194	287	664	43%	20%	29%
2014	Apr	127	212	270	664	41%	19%	32%
2014	May	122	249	265	664	40%	18%	38%
2014	Jun	123	231	366	664	55%	19%	35%
2014	Jul	127	236	352	664	53%	19%	35%
2014	Aug	117	230	369	664	56%	18%	35%
2014	Sep	121	242	394	664	59%	18%	37%
2014	Oct	116	255	353	664	53%	17%	38%
2014	Nov	114	235	348	664	52%	17%	35%
2014	Dec	117	254	352	664	53%	18%	38%
2015	Jan	116	250	306	664	46%	18%	38%
2015	Feb	111	246	242	663	36%	17%	37%
2015	Mar	114	255	231	664	35%	17%	38%
2015	Apr	110	248	283	664	43%	17%	37%
2015	May	122	265	267	664	40%	18%	40%
2015	Jun	154	275	312	643	48%	24%	43%
Average		105	176	298	676	44%	16%	26%

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 six months of 2015, 55.7 percent was purchased in the PJM market, 38.9 percent was self-scheduled, and 5.5 percent was purchased bilaterally (Table 10-33). Table 10-34 shows the total regulation by market regulation, self-scheduled regulation, and bilateral regulation for the first six months of each year. These tables are based on settled (purchased) MW, but are not adjusted for either performance score or benefit factor to maintain consistency with 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: 2014 and 2015

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)
2014	Jan	259,138.4	63.6%	125,621.0	30.8%	22,908.5	5.6%	407,668.0
2014	Feb	218,870.9	59.7%	131,302.2	35.8%	16,356.5	4.5%	366,529.6
2014	Mar	245,924.0	59.8%	147,908.6	36.0%	17,588.5	4.3%	411,421.0
2014	Apr	247,662.9	62.6%	135,878.5	34.4%	11,887.5	3.0%	395,428.9
2014	May	242,065.8	60.9%	141,875.8	35.7%	13,634.5	3.4%	397,576.2
2014	Jun	155,628.6	40.2%	207,331.0	53.6%	23,990.0	6.2%	386,949.6
2014	Jul	171,746.4	43.4%	204,360.7	51.6%	19,820.0	5.0%	395,927.0
2014	Aug	162,805.7	40.5%	221,096.7	55.0%	17,859.5	4.4%	401,761.9
2014	Sep	131,424.4	34.4%	227,891.1	59.6%	22,812.0	6.0%	382,127.5
2014	Oct	165,297.0	41.8%	210,306.7	53.2%	19,439.0	4.9%	395,042.7
2014	Nov	165,812.5	42.9%	200,058.9	51.8%	20,413.0	5.3%	386,284.4
2014	Dec	159,486.0	40.6%	208,365.0	53.1%	24,509.0	6.2%	392,359.9
2015	Jan	198,056.1	50.2%	173,319.4	44.0%	22,975.0	5.8%	394,350.5
2015	Feb	219,652.3	61.6%	116,607.5	32.7%	20,137.6	5.7%	356,397.3
2015	Mar	252,402.2	64.0%	122,001.9	30.9%	20,255.0	5.1%	394,659.1
2015	Apr	197,934.5	52.3%	159,511.3	42.1%	21,236.5	5.6%	378,682.3
2015	May	227,527.5	57.5%	148,998.3	37.7%	19,191.5	4.8%	395,717.3
2015	Jun	186,186.5	48.6%	174,157.4	45.5%	22,613.0	5.9%	382,956.8

Table 10-34 Regulation sources by year: 2011 through 2015

Year (Jan-Jun)	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)
2011	1,502,757	78.9%	338,972	17.8%	62,720	3.3%	1,904,449
2012	1,512,307	73.5%	484,971	23.6%	61,400	3.0%	2,058,678
2013	1,029,412	73.1%	341,164	24.2%	38,432	2.7%	1,409,008
2014	723,432	61.0%	405,781	34.2%	56,790	4.8%	1,186,003
2015	1,281,358	55.6%	895,505	38.9%	126,464	5.5%	2,303,328

In the first six months of 2015, DR provided an average of 3.2 MW of regulation per hour (3.4 MW of regulation per hour in the same period of 2014). Generating units supplied an average of 652.4 MW of regulation per hour (670.1 MW of regulation per hour in the same period of 2014).

Market Performance

Price

The weighted average RMCP for January through June 2015 was $41.33 per MW. This is the average price per unadjusted capability MW. This is a 33.5 percent decrease from the weighted average RMCP of $62.14/MW in the same period of 2014. The decrease in regulation price resulted primarily from very high prices in the first six months of 2014. Figure 10-30 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 10-30 PJM regulation market daily weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2015

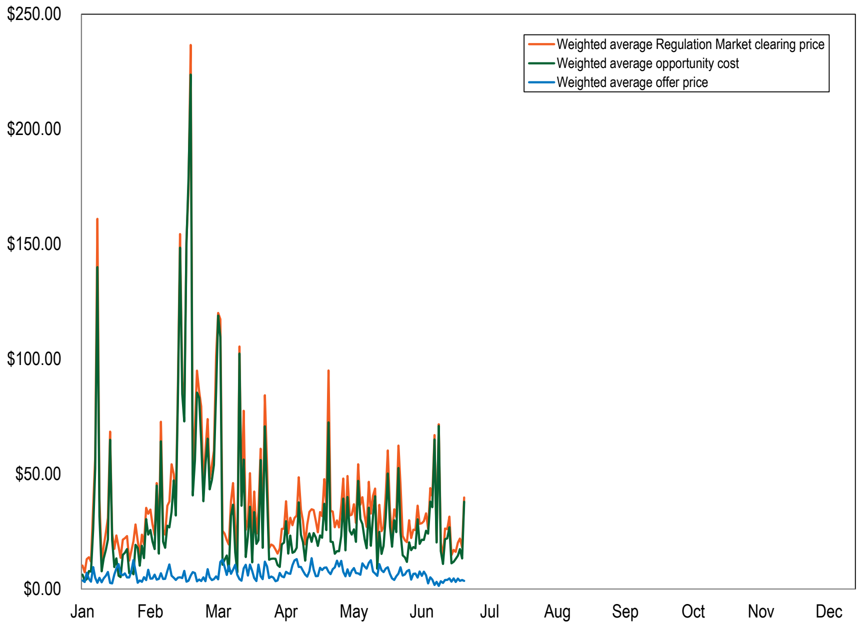


Table 10-35 shows monthly average regulation market clearing price, average marginal unit offer price, and average marginal unit LOC on an unadjusted capability MW basis.

Table 10-35 PJM regulation market monthly weighted average market-clearing price, marginal unit opportunity cost and offer price (Dollars per MW): 2015

Month	Weighted Average Regulation Market Clearing Price	Weighted Average Regulation Marginal Unit Offer	Weighted Average Regulation Marginal Unit LOC
Jan	$27.13	$5.60	$22.67
Feb	$73.24	$5.40	$57.07
Mar	$45.79	$7.09	$41.78
Apr	$32.77	$7.77	$21.60
May	$43.12	$8.24	$27.37
Jun	$25.94	$4.50	$25.96

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. The total of all regulation charges for the first six months of 2015 was $114.2 million, compared to $179.7 million for the same time period in 2014.

Table 10-36 Total regulation charges: January 2014 through June 2015

Year	Month	Scheduled Regulation (MW)	Total Regulation Charges ($)	Weighted Average Regulation Market Price ($/MW)	Cost of Regulation ($/MW)	Price as Percentage of Cost
2014	Jan	407,668	$65,744,697	$132.55	$161.27	82.2%
2014	Feb	366,530	$27,509,975	$63.13	$75.06	84.1%
2014	Mar	411,421	$39,901,162	$80.38	$96.98	82.9%
2014	Apr	395,429	$15,208,374	$31.75	$38.46	82.5%
2014	May	397,576	$16,927,322	$34.40	$42.58	80.8%
2014	Jun	386,950	$14,399,445	$30.65	$37.21	82.4%
2014	Jul	395,927	$14,458,430	$29.75	$36.52	81.5%
2014	Aug	401,762	$9,968,110	$20.45	$24.81	82.4%
2014	Sep	382,128	$11,906,005	$25.10	$31.16	80.5%
2014	Oct	395,043	$15,461,162	$32.96	$39.14	84.2%
2014	Nov	386,284	$12,615,109	$27.50	$32.66	84.2%
2014	Dec	392,360	$9,855,652	$21.25	$25.12	84.6%
2015	Jan	394,351	$13,054,006	$27.13	$33.10	81.9%
2015	Feb	356,397	$31,757,444	$73.24	$89.11	82.2%
2015	Mar	394,659	$21,887,989	$45.79	$55.46	82.6%
2015	Apr	378,682	$14,878,908	$32.77	$39.29	83.4%
2015	May	395,717	$21,030,737	$43.12	$53.15	81.1%
2015	Jun	382,957	$11,550,675	$25.94	$30.16	86.0%

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: 2015

Month	Scheduled Regulation (MW)	Cost of Regulation Capability ($/MW)	Cost of Regulation Performance ($/MW)	Opportunity Cost ($/MW)	Total Cost ($/MW)
Jan	394,350.5	$24.34	$3.82	$4.94	$33.10
Feb	356,397.3	$69.13	$5.98	$14.00	$89.11
Mar	394,659.1	$41.41	$6.19	$7.86	$55.46
Apr	378,682.3	$28.42	$6.07	$4.79	$39.29
May	395,717.3	$39.63	$5.02	$8.50	$53.15
Jun	382,956.8	$23.58	$3.40	$3.17	$30.15

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 remained at 83 percent in the first six months of 2015, from as it was in the same period of 2014.

Table 10-38 Comparison of average price and cost for PJM Regulation, January through June, 2009 through 2015

Year (Jan-Jun)	Weighted Regulation Market Price	Weighted Regulation Market Cost	Regulation Price as Percent Cost
2009	$23.56	$29.87	79%
2010	$18.05	$30.67	59%
2011	$15.31	$31.00	49%
2012	$13.89	$18.34	76%
2013	$32.04	$37.04	87%
2014	$62.70	$75.96	83%
2015	$40.94	$49.57	83%

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.[51] PJM set a September 30, 2013, deadline for resources submitting proposals and requested that resources be able to provide black

51 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.

PJM issued two incremental RFPs in 2014. On April 11, 2014, PJM sought additional black start in the AEP Zone and one proposal was selected. On November 24, 2014, PJM sought additional black start in northeastern Ohio and western Pennsylvania but no proposals have been selected yet.

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 to units scheduled in the Day-Ahead Energy Market or committed in real time to provide black start service under the automatic load rejection (ALR) option or for black start testing. 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 six months of 2015, total black start charges were $25.0 million, a -$0.19 million (0.8 percent) decrease from the same period of 2014 level of $25.2 million. Operating reserve charges for black start service declined from $14.3 million in 2014 to $5.0 million in 2015. Table 10-39 shows total revenue requirement charges from 2010 through 2015. (Prior to December 2012, PJM did not define a black start operating reserve category.)

Table 10-39 Black start revenue requirement charges: January through June, 2010 through 2015

Year (Jan-Jun)	Revenue Requirement Charges
2010	$5,481,206
2011	$5,968,676
2012	$7,873,702
2013	$10,584,683
2014	$10,874,608
2015	$20,012,245

Black start zonal charges in the first six months of 2015 ranged from $0.04 per MW-day in the PPL Zone (total charges were $59,801) to $4.35 per MW-day in the BGE Zone (total charges were $5,246,763). 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 six months of 2015.

Table 10-40 Black start zonal charges for network transmission use: January through June, 2014 and 2015

	2014 (Jan - Jun)					2015 (Jan - Jun)				
Zone	Revenue Requirement Charges	Operating Reserve Charges	Total Charges	Peak Load (MW-day)	Black Start Rate ($/MW-day)	Revenue Requirement Charges	Operating Reserve Charges	Total Charges	Peak Load (MW-day)	Black Start Rate ($/MW-day)
AECO	$311,952	$5,772	$317,725	495,795	$0.64	$225,363	$0	$225,363	442,274	$0.51
AEP	$397,225	$13,317,173	$13,714,398	4,135,180	$3.32	$5,549,130	$4,526,548	$10,075,678	4,417,866	$2.28
APS	$138,802	$3,027	$141,829	1,570,609	$0.09	$136,632	$69,722	$206,354	1,692,223	$0.12
ATSI	$58,250	$0	$58,250	2,378,539	$0.02	$1,276,351	$13,206	$1,289,557	2,237,540	$0.58
BGE	$2,821,475	$5,049	$2,826,524	1,236,284	$2.29	$5,246,763	$2,496	$5,249,259	1,206,401	$4.35
ComEd	$2,074,281	$20,220	$2,094,502	4,030,689	$0.52	$2,178,109	$28,968	$2,207,077	3,569,537	$0.62
DAY	$120,900	$6,511	$127,411	617,083	$0.21	$117,977	$7,929	$125,907	579,888	$0.22
DEOK	$568,211	$15,022	$583,233	931,426	$0.63	$577,766	$12,531	$590,297	924,005	$0.64
Dominion	$500,681	$4,599	$505,280	3,396,103	$0.15	$504,175	$10,434	$514,609	3,580,904	$0.14
DPL	$277,835	$3,255	$281,091	727,385	$0.39	$288,273	$1,417	$289,690	701,375	$0.41
DLCO	$29,187	$0	$29,187	534,222	$0.05	$39,546	$0	$39,546	487,379	$0.08
EKPC	$188,691	$0	$188,691	458,401	$0.41	$205,397	$0	$205,397	619,925	$0.33
JCPL	$245,209	$6,257	$251,466	1,154,581	$0.22	$228,379	$27,382	$255,761	1,020,279	$0.25
Met-Ed	$423,275	$3,816	$427,091	545,226	$0.78	$354,515	$7,698	$362,213	509,841	$0.71
PECO	$734,070	$13,614	$747,684	1,559,930	$0.48	$786,916	$19,741	$806,657	1,494,608	$0.54
PENELEC	$250,552	$0	$250,552	558,801	$0.45	$274,383	$0	$274,383	552,340	$0.50
Pepco	$154,088	$15,053	$169,141	1,182,545	$0.14	$154,999	$1,928	$156,926	1,148,463	$0.14
PPL	$99,043	$0	$99,043	1,337,988	$0.07	$59,801	$0	$59,801	1,454,878	$0.04
PSEG	$811,203	$31,135	$842,339	1,885,006	$0.45	$844,409	$12,058	$856,466	1,722,251	$0.50
RECO	$0	$0	$0	NA	NA	$0	$0	$0	NA	NA
(Imp/Exp/Wheels)	$669,677	$886,317	$1,555,994	1,900,931	$0.82	$963,361	$267,201	$1,230,562	1,427,846	$0.86
Total	$10,874,608	$14,336,821	$25,211,429	30,636,726	$0.82	$20,012,245	$5,009,258	$25,021,503	29,789,822	$0.84

Table 10-41 provides a revenue requirement estimate by zone for the 2015-2016, 2016-2017, and 2017-2018 delivery years. Revenue requirement values are rounded up to the nearest $50,000 to reflect uncertainty about future black start revenue requirement costs. These values are illustrative only. They are based on the best available data (i.e. current black start unit revenue requirements, expected black start unit termination and in-service dates, and owner provided cost estimates of incoming black start units), at the time of publication and may change significantly in either direction as actual costs become known and finalized.

Table 10-41 Black start zonal revenue requirement estimate: 2015/2016 through 2017/2018 delivery years

Zone	2015-2016 Revenue Requirement	2016-2017 Revenue Requirement	2017-2018 Revenue Requirement
AECO	$1,600,000	$2,200,000	$2,150,000
AEP	$17,100,000	$20,600,000	$20,850,000
APS	$4,200,000	$4,400,000	$4,450,000
ATSI	$2,550,000	$2,500,000	$2,500,000
BGE	$8,450,000	$9,300,000	$9,400,000
ComEd	$4,250,000	$3,600,000	$3,750,000
DAY	$250,000	$300,000	$300,000
DEOK	$1,250,000	$1,250,000	$1,250,000
DLCO	$150,000	$100,000	$100,000
Dominion	$4,300,000	$5,700,000	$6,000,000
DPL	$1,750,000	$2,600,000	$2,600,000
EKPC	$450,000	$450,000	$500,000
JCPL	$6,950,000	$7,000,000	$7,000,000
Met-Ed	$850,000	$900,000	$950,000
PECO	$1,800,000	$1,900,000	$2,050,000
PENELEC	$4,700,000	$4,750,000	$4,900,000
Pepco	$2,400,000	$2,650,000	$2,700,000
PPL	$700,000	$800,000	$800,000
PSEG	$7,600,000	$7,800,000	$7,800,000
RECO	$0	$0	$0
Total	$71,300,000	$78,800,000	$80,050,000

Table 10-42 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 10-42 NERC CIP Costs: 2015

Capital Cost Requested	Cost Recovered in Jan-Jun 2015	Number of Units	MW
$1,736,971	$315,260	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).[52] 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 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 six months of 2015, total reactive service charges were $148.5 million, a 8.8 percent decrease from the first six months of 2014 level of $162.9 million.[53] Revenue requirement charges decreased from $140.7 million to $139.3 million and operating reserve charges fell from $22.2 million to $9.2 million. Total charges in the first six months of 2015 ranged from $1.8 thousand in the RECO Zone to $20.6 million in the AEP Zone.

For each zone in the first three months of 2014 and 2015, Table 10-43 shows Reactive Service operating reserve charges, revenue requirement charges and total charges (the sum of operating reserve and revenue requirement charges).

52 PJM OATT. Schedule 2 "Reactive Supply and Voltage Control from Generation Sources Service," (Effective Date: February 18, 2012).
53 See the *2014 State of the Market Report for PJM*, Volume II, Section 4, "Energy Uplift."

Table 10-43 Reactive zonal charges for network transmission use: January through Jun, 2014 and 2015

	2014 (Jan - Jun)			2015 (Jan - Jun)		
Zone	Operating Reserve Charges	Revenue Requirement Charges	Total Charges	Operating Reserve Charges	Revenue Requirement Charges	Total Charges
AECO	$88,275	$2,788,429	$2,876,704	$13,309	$3,922,980	$3,936,289
AEP	$455,938	$19,866,380	$20,322,318	$395,554	$20,197,171	$20,592,725
APS	$282,909	$10,278,004	$10,560,913	$77,563	$8,295,318	$8,372,881
ATSI	$9,617,533	$7,875,173	$17,492,706	$3,815,944	$7,440,696	$11,256,639
BGE	$55,339	$3,830,881	$3,886,220	$51,599	$3,894,668	$3,946,267
ComEd	$146,570	$12,111,130	$12,257,700	$132,500	$12,377,544	$12,510,043
DAY	$29,971	$4,159,163	$4,189,134	$26,244	$4,228,416	$4,254,661
DEOK	$29,413	$2,838,913	$2,868,326	$41,225	$2,564,734	$2,605,960
Dominion	$1,337,912	$14,751,867	$16,089,779	$2,598,813	$14,997,497	$17,596,310
DPL	$6,728,321	$5,334,635	$12,062,956	$1,419,265	$5,464,104	$6,883,369
DLCO	$15,712	$0	$15,712	$19,374	$0	$19,374
EKPC	$12,873	$1,055,006	$1,067,880	$24,773	$1,072,573	$1,097,346
JCPL	$24,412	$3,512,868	$3,537,280	$30,381	$3,571,360	$3,601,741
Met-Ed	$46,087	$3,703,543	$3,749,630	$57,025	$3,847,767	$3,904,793
PECO	$369,729	$8,686,999	$9,056,728	$57,165	$8,831,645	$8,888,809
PENELEC	$2,452,238	$2,881,674	$5,333,913	$264,538	$3,584,470	$3,849,007
Pepco	$50,913	$2,591,709	$2,642,622	$56,586	$2,634,863	$2,691,449
PPL	$45,115	$9,493,188	$9,538,303	$65,415	$9,441,235	$9,506,650
PSEG	$389,325	$13,441,141	$13,830,466	$55,175	$13,664,946	$13,720,121
RECO	$1,679	$0	$1,679	$1,813	$0	$1,813
(Imp/Exp/Wheels)	$0	$11,519,154	$11,519,154	$0	$9,273,059	$9,273,059
Total	$22,180,267	$140,719,857	$162,900,124	$9,204,261	$139,305,045	$148,509,306

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 price of energy for the system, given the current dispatch, at the load weighted reference bus, or LMP net of losses and congestion. SMP is the LMP at the load weighted reference bus. The load weighted reference bus is not a fixed location but is dependent on the distribution of load at system load buses.

CLMP is the incremental price of congestion at each bus, based on the shadow prices associated with the relief of binding constraints in the security constrained optimization. CLMPs are positive or negative depending on location relative to binding constraints and relative to the load weighted reference bus. In an unconstrained system CLMPS will be zero.

MLMP is the incremental price of losses at a bus, based on marginal loss factors in the security constrained optimization. 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.[2]

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. 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.[3] The result is that the price of energy in the constrained area(s) is higher than in the unconstrained area.

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.[4]

Overview

Congestion Cost

- **Total Congestion.** Total congestion costs decreased by $523.6 million or 36.3 percent, from $1,442.3 million in the first six months of 2014 to $918.6 million in the first six months of 2015.
- **Day-Ahead Congestion.** Day-ahead congestion costs decreased by $598.7 million or 35.4 percent, from $1,691.9 million in the first six months of 2014 to $1,093.2 million in the first six months of 2015.

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 2014.

2 See 2014 SOM Technical Appendices for a full discussion of the relationship between marginal, average and total losses.

3 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.

4 The total congestion and marginal losses were calculated as of July 18, 2015, and are subject to change, based on continued PJM billing updates.

- **Balancing Congestion.** Balancing congestion costs increased by $75.1 million or 30.1 percent, from -$249.7 million in the first six months of 2014 to -$174.6 million in the first six months of 2015.
- **Real-Time Congestion.** Real-time congestion costs decreased by $716.8 million or 43.0 percent, from $1,668.4 million in the first six months of 2014 to $951.6 million in the first six months of 2015.
- **Monthly Congestion.** In 2015, 46.8 percent ($429.8 million) of total congestion cost was incurred in February and 22.0 percent ($201.9 million) of total congestion cost was incurred in the months of January and March. Monthly total congestion costs in the first six months of 2015 ranged from $69.5 million in March to $429.8 million in February.
- **Geographic Differences in CLMP.** Differences in CLMP among eastern, southern and western control zones in PJM were primarily a result of congestion on the 5004/5005 Interface, the Bedington - Black Oak Interface, the AEP - DOM Interface, the AP South Interface, and the Bergen - New Milford line.
- **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 six months of 2015. The number of congestion event hours in the Day-Ahead Energy Market was about five times higher than the number of congestion event hours in the Real-Time Energy Market.

  Day-ahead congestion frequency decreased by 57.9 percent from 228,169 congestion event hours in the first six months of 2014 to 95,960 congestion event hours in the first six months of 2015. The day-ahead congestion event hours decreased significantly after September 8, 2014. The reduction was the result of the reduction in UTC activity which was a result of FERC's UTC uplift refund notice, retroactive to September 8, 2014.

  Real-time congestion frequency increased by 2.7 percent from 16,722 congestion event hours in the first six months of 2014 to 17,169 congestion event hours in the first six months of 2015.
- **Congested Facilities.** Day-ahead, congestion-event hours decreased on all types of congestion facilities. Real-time, congestion-event hours increased on line and transformer facilities and decrease on flowgate and interface facilities.

  The 5004/5005 Interface was the largest contributor to congestion costs in the first six months of 2015. With $88.8 million in total congestion costs, it accounted for 9.7 percent of the total PJM congestion costs in the first six months of 2015.
- **Zonal Congestion.** AEP had the largest total congestion costs among all control zones in the first six months of 2015. AEP had $248.8 million in total congestion costs, comprised of -$352.0 million in total load congestion payments, -$621.0 million in total generation congestion credits and -$20.2 million in explicit congestion costs. The AEP - DOM Interface, the Joshua Falls transformer, the 5004/5005 Interface, the Bedington - Black Oak Interface and the Mahans Lane – Tidd line contributed $119.7 million, or 48.1 percent of the total AEP control zone congestion costs.
- **Ownership.** In the first six months of 2015, financial entities as a group were net recipients of congestion credits, and physical entities were net payers of congestion charges. Explicit costs are the primary source of congestion credits to financial entities. In the first six months of 2015, financial entities received $98.8 million in congestion credits, a decrease of $92.3 million or 48.3 percent compared to the first six months of 2014. In the first six months of 2015, physical entities paid $1,017.5 million in congestion charges, a decrease of $615.9 million or 37.7 percent compared to the first six months of 2014. UTCs are in the explicit cost category and comprise most of that category. The total explicit cost is equal to day-ahead explicit cost plus balancing explicit cost. In the first six months of 2015, the total explicit cost is -$107.0 million and 120.3 percent of the total explicit cost is comprised of congestion cost by UTCs, which is -$128.6 million.

Marginal Loss Cost

- **Total Marginal Loss Costs.** Total marginal loss costs decreased by $397.9 million or 39.5 percent, from $1,006.2 million in the first six months of 2014 to $608.3 million in the first six months of 2015. Total marginal loss costs decreased because of the distribution of high load and outages caused by cold weather in January 2014. The loss MW in PJM decreased 17.6 percent, from 9,065.7 GWh in the first six months of 2014 to 7,470.2 GWh in the first six months of 2015. The loss component of LMP remained constant, $0.02 in the first six months of 2014 and $0.02 in the first six months of 2015.

- **Monthly Total Marginal Loss Costs.** Monthly total marginal loss costs in the first six months of 2015 ranged from $52.0 million in April to $220.3 million in February.
- **Day-Ahead Marginal Loss Costs.** Day-ahead marginal loss costs decreased by $469.6 million or 42.9 percent, from $1,095.0 million in the first six months of 2014 to $625.4 million in the first six months of 2015.
- **Balancing Marginal Loss Costs.** Balancing marginal loss costs increased by $71.7 million or 80.7 percent, from -$88.8 million in the first six months of 2014 to -$17.1 million in the first six months of 2015.
- **Marginal Loss Credits.** The marginal loss credits decreased in the first six months of 2015 by $118.3 million or 36.4 percent, from $325.0 million in the first six months of 2014, to $206.7 million in the first six months of 2015.

Energy Cost

- **Total Energy Costs.** Total energy costs increased by $279.5 million or 41.3 percent, from -$677.2 million in the first six months of 2014 to -$397.6 million in the first six months of 2015.
- **Day-Ahead Energy Costs.** Day-ahead energy costs increased by $479.4 million or 50.6 percent, from -$948.3 million in the first six months of 2014 to -$468.9 million in the first six months of 2015.
- **Balancing Energy Costs.** Balancing energy costs decreased by $207.8 million or 75.1 percent, from $276.6 million in the first six months of 2014 to $68.8 million in the first six months of 2015.
- **Monthly Total Energy Costs.** Monthly total energy costs in the first six months of 2015 ranged from -$141.5 million in February to -$36.0 million in April.

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 to congestion. ARR and FTR revenues offset 88.3 percent of the total congestion costs including the Day-Ahead Energy Market and the balancing energy market in PJM for 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.

Locational Marginal Price (LMP)

Components

On June 1, 2007, PJM changed from a single node reference bus to a distributed load reference bus. While the use of a single node reference bus or a distributed load reference bus has no effect on the total LMP, the use of a single node reference bus or a distributed load reference bus will affect the components of LMP. With a distributed load reference bus, the energy component is a load-weighted system price. There are no congestion or losses included in the load weighted reference bus price, unlike the case with a single node reference bus.

LMP at a bus reflects the incremental price of energy at that bus. LMP at any bus is made up of three components: the system marginal price (SMP), marginal loss component of LMP (MLMP), and congestion component of LMP (CLMP).

SMP, MLMP and CLMP are a product of the least cost, security constrained dispatch of system resources to meet system load. SMP is the incremental cost of energy, given the current dispatch and given the choice of reference bus. SMP is LMP net of losses and congestion. Losses refer to energy lost to physical resistance in the transmission and distribution network as power is moved from generation to load. The greater the resistance of the system to flows of energy from generation to loads, the greater the losses of the system and the greater the proportion of energy needed to meet a given level of load. Marginal losses are the incremental change in system power losses caused by changes in the system load and generation patterns.[5] The first derivative of total losses with respect to the power flow equals marginal losses. Congestion cost reflects the incremental cost of relieving transmission constraints while maintaining system power balance. Congestion occurs when available, least-cost energy cannot be delivered to all loads because transmission facilities are not adequate to deliver that energy. When the least-cost available energy cannot be delivered to load in a transmission-constrained area, higher cost units in the constrained area must be dispatched to meet that load.[6] The result is that the price of energy in the constrained area is higher than in the unconstrained area because of the combination of transmission limitations and the cost of local generation.

Table 11-1 shows the PJM real-time, load-weighted average LMP components January through June of 2009 through 2015.[7]

The load-weighted average real-time LMP decreased $27.62 or 39.5 percent from $69.92 in the first six months of 2014 to $42.30 in the first six months of 2015. The load-weighted average congestion component increased $0.09 or 161.3 percent from -$0.06 in the first six months of 2014 to $0.03 in the first six months of 2015. The load-weighted average loss component ($0.02) did not change in the first six months of 2015 from the first six months of 2014. The load-weighted average energy component decreased $27.71 or 39.6 percent from $69.95 in the first six months of 2014 to $42.24 in the first six months of 2015.

Table 11-1 PJM real-time, load-weighted average LMP components (Dollars per MWh): January through June of 2009 through 2015[8]

(Jan - Jun)	Real-Time LMP	Energy Component	Congestion Component	Loss Component
2009	$42.48	$42.40	$0.05	$0.03
2010	$45.75	$45.65	$0.06	$0.04
2011	$48.47	$48.40	$0.05	$0.03
2012	$31.21	$31.17	$0.04	$0.01
2013	$37.96	$37.92	$0.02	$0.02
2014	$69.92	$69.95	($0.06)	$0.02
2015	$42.30	$42.24	$0.03	$0.02

Table 11-2 shows the PJM day-ahead, load-weighted average LMP components for the first six months of 2009 through 2015.[9]

The load-weighted average day-ahead LMP decreased $27.40 or 38.8 percent from $70.66 in the first six months of 2014 to $43.26 in the first six months of 2015. The load-weighted average congestion component increased $0.04 or 12.3 percent from $0.30 in the first six months of 2014 to $0.33 in the first six months of 2015. The load-weighted average loss component decreased $0.01 or 80.8 percent from -$0.01 in the first six months of 2014 to -$0.02 in the first six months of 2015. The load-weighted average energy component decreased $27.43 or 39.0 percent from $70.37 in the first six months of 2014 to $42.95 in the first six months of 2015.

5 For additional information, see the *MMU Technical Reference for PJM Markets*, at "Marginal Losses," <http://www.monitoringanalytics.com/reports/Technical_References/docs/2010-som-pjm-technical-reference.pdf>.
6 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.
7 The PJM real-time, load-weighted price is weighted by accounting load, which differs from the state-estimated load used in determination of the energy component (SMP). In the Real-Time Energy Market, the distributed load reference bus is weighted by state-estimated load in real time. When the LMP is calculated in real time, the energy component equals the system load-weighted price. But real-time bus-specific loads are adjusted, after the fact, based on updated load information from meters. This meter adjusted load is accounting load that is used in settlements and is used to calculate reported PJM load weighted prices. This after the fact adjustment means that the Real-Time Energy Market energy component of LMP (SMP) and the PJM real-time load-weighted LMP are not equal. The difference between the real-time energy component of LMP and the PJM-wide real-time load-weighted LMP is a result of the difference between state-estimated and metered loads used to weight the load-weighted reference bus and the load-weighted LMP.
8 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.
9 In the Real-Time Energy Market, the energy component (SMP) equals the system load-weighted price, with the caveat about state-estimated versus metered load. However, in the Day-Ahead Energy Market the day-ahead energy component of LMP (SMP) and the PJM day-ahead load-weighted LMP are not equal. The difference between the day-ahead energy component of LMP and the PJM day-ahead load-weighted LMP is a result of the difference in the types of load used to weight the load-weighted reference bus and the load-weighted LMP. In the Day-Ahead Energy Market, the distributed load reference bus is weighted by fixed-demand bids only and the day-ahead SMP is, therefore, a system fixed demand weighted price. The day-ahead load-weighted LMP calculation uses all types of demand, including fixed, price-sensitive and decrement bids.

Table 11-2 PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through June of 2009 through 2015

(Jan - Jun)	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
2009	$42.21	$42.47	($0.14)	($0.12)
2010	$46.12	$46.04	$0.08	($0.00)
2011	$47.12	$47.32	($0.10)	($0.11)
2012	$31.84	$31.76	$0.10	($0.02)
2013	$38.23	$38.14	$0.09	$0.00
2014	$70.66	$70.37	$0.30	($0.01)
2015	$43.26	$42.95	$0.33	($0.02)

The real-time components of LMP for each control zone are presented in Table 11-3 for the first six months of 2014 and the first six months of 2015. In the first six months of 2015, BGE had the highest congestion component of all control zones and ComEd had the lowest congestion component.

Table 11-3 Zonal and PJM real-time, load-weighted average LMP components (Dollars per MWh): January through June of 2014 and 2015

	2014 (Jan - Jun)				2015 (Jan - Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AECO	$76.31	$68.12	$5.29	$2.90	$45.10	$41.51	$1.81	$1.78
AEP	$59.99	$70.20	($8.35)	($1.86)	$37.76	$42.23	($3.24)	($1.24)
AP	$69.31	$71.06	($2.03)	$0.28	$44.73	$42.69	$1.73	$0.31
ATSI	$60.96	$67.95	($7.74)	$0.75	$37.75	$41.40	($3.85)	$0.20
BGE	$92.61	$72.13	$17.11	$3.37	$54.57	$43.15	$9.11	$2.30
ComEd	$50.82	$67.28	($12.64)	($3.82)	$31.54	$41.06	($6.72)	($2.80)
DAY	$58.75	$69.74	($10.82)	($0.17)	$37.79	$41.93	($3.86)	($0.29)
DEOK	$55.90	$69.54	($10.03)	($3.61)	$36.50	$41.91	($3.23)	($2.17)
DLCO	$53.86	$67.61	($11.52)	($2.22)	$34.87	$41.45	($5.67)	($0.91)
Dominion	$86.92	$72.63	$13.72	$0.57	$49.19	$43.51	$4.93	$0.75
DPL	$88.47	$72.89	$10.90	$4.68	$52.35	$43.55	$6.00	$2.80
EKPC	$60.73	$76.26	($11.83)	($3.70)	$36.36	$44.49	($5.76)	($2.37)
JCPL	$77.00	$68.45	$5.33	$3.21	$45.14	$41.82	$1.49	$1.82
Met-Ed	$77.14	$70.12	$5.20	$1.82	$45.80	$42.30	$2.31	$1.19
PECO	$77.01	$69.41	$5.35	$2.24	$44.65	$42.07	$1.19	$1.39
PENELEC	$67.58	$68.94	($2.16)	$0.80	$43.29	$41.79	$0.70	$0.80
Pepco	$90.86	$71.29	$17.29	$2.27	$50.34	$42.84	$5.98	$1.52
PPL	$78.54	$71.03	$5.96	$1.56	$46.08	$42.64	$2.42	$1.01
PSEG	$80.35	$67.47	$9.71	$3.17	$48.14	$41.29	$5.07	$1.78
RECO	$77.97	$67.10	$7.91	$2.96	$48.24	$41.03	$5.53	$1.69
PJM	$69.92	$69.95	($0.06)	$0.02	$42.30	$42.24	$0.03	$0.02

The day-ahead components of LMP for each control zone are presented in Table 11-4 for the first six months of 2014 and the first six months of 2015.

Table 11-4 Zonal and PJM day-ahead, load-weighted average LMP components (Dollars per MWh): January through June of 2014 and 2015

	2014 (Jan - Jun)				2015 (Jan - Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AECO	$79.81	$68.07	$9.20	$2.54	$46.67	$42.29	$3.31	$1.06
AEP	$61.61	$71.90	($8.59)	($1.71)	$38.25	$43.13	($4.03)	($0.84)
AP	$68.10	$71.32	($3.08)	($0.14)	$44.58	$43.38	$1.25	($0.04)
ATSI	$62.64	$68.79	($6.75)	$0.60	$38.48	$42.12	($3.99)	$0.35
BGE	$92.46	$72.27	$17.50	$2.70	$55.75	$43.59	$10.61	$1.54
ComEd	$53.08	$68.78	($13.09)	($2.62)	$31.09	$42.03	($9.02)	($1.92)
DAY	$61.59	$71.38	($9.85)	$0.06	$37.90	$42.87	($5.12)	$0.14
DEOK	$57.81	$69.49	($8.81)	($2.88)	$37.03	$43.09	($4.45)	($1.62)
DLCO	$55.14	$68.09	($10.46)	($2.49)	$35.40	$42.18	($5.65)	($1.14)
Dominion	$80.84	$72.75	$8.25	($0.16)	$52.25	$44.23	$7.33	$0.69
DPL	$91.52	$72.47	$15.05	$4.00	$53.99	$43.97	$8.04	$1.98
EKPC	$62.21	$76.90	($11.12)	($3.57)	$36.96	$45.59	($6.37)	($2.26)
JCPL	$83.74	$69.70	$10.74	$3.30	$47.29	$42.65	$3.36	$1.28
Met-Ed	$79.90	$69.62	$8.90	$1.37	$45.90	$42.52	$3.00	$0.37
PECO	$80.63	$69.47	$9.13	$2.03	$46.26	$42.53	$3.08	$0.65
PENELEC	$68.36	$67.74	($0.30)	$0.92	$42.42	$42.10	$0.01	$0.32
Pepco	$87.92	$70.61	$15.55	$1.76	$52.23	$43.03	$8.20	$1.00
PPL	$82.51	$71.14	$10.25	$1.12	$47.17	$43.17	$3.74	$0.26
PSEG	$87.36	$68.61	$15.50	$3.25	$48.87	$42.18	$5.32	$1.37
RECO	$83.55	$67.27	$13.24	$3.04	$48.71	$42.06	$5.27	$1.38
PJM	$70.66	$70.37	$0.30	($0.01)	$43.26	$42.95	$0.33	($0.02)

Hub Components

The real-time components of LMP for each hub are presented in Table 11-5 for the first six months of 2014 and the first six months of 2015.

Table 11-5 Hub real-time, load-weighted average LMP components (Dollars per MWh): January through June of 2014 and 2015

	2014 (Jan - Jun)				2015 (Jan - Jun)			
	Real-Time LMP	Energy Component	Congestion Component	Loss Component	Real-Time LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$51.71	$67.56	($11.32)	($4.53)	$34.98	$43.39	($5.58)	($2.83)
AEP-DAY Hub	$56.18	$68.67	($10.34)	($2.14)	$36.83	$42.75	($4.37)	($1.55)
ATSI Gen Hub	$60.06	$69.03	($8.62)	($0.34)	$37.06	$42.79	($5.02)	($0.71)
Chicago Gen Hub	$48.05	$66.39	($13.61)	($4.74)	$29.74	$39.97	($7.00)	($3.22)
Chicago Hub	$51.46	$67.86	($12.67)	($3.73)	$32.12	$41.81	($6.89)	($2.80)
Dominion Hub	$88.75	$75.51	$13.52	($0.29)	$49.31	$44.33	$4.71	$0.28
Eastern Hub	$81.17	$68.31	$8.73	$4.14	$49.77	$41.89	$5.25	$2.62
N Illinois Hub	$49.75	$66.93	($13.00)	($4.17)	$30.78	$40.16	($6.52)	($2.87)
New Jersey Hub	$77.85	$67.43	$7.34	$3.07	$46.14	$41.35	$3.05	$1.75
Ohio Hub	$56.55	$68.91	($10.38)	($1.98)	$36.16	$42.07	($4.45)	($1.45)
West Interface Hub	$64.40	$66.31	($0.84)	($1.07)	$40.54	$44.09	($2.63)	($0.93)
Western Hub	$74.44	$70.80	$3.54	$0.10	$46.79	$44.10	$2.26	$0.43

The day-ahead components of LMP for each hub are presented in Table 11-6 for the first six months of 2014 and the first six months of 2015.

Table 11-6 Hub day-ahead, load-weighted average LMP components (Dollars per MWh): January through June of 2014 and 2015

	2014 (Jan - Jun)				2015 (Jan - Jun)			
	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component	Day-Ahead LMP	Energy Component	Congestion Component	Loss Component
AEP Gen Hub	$47.47	$56.10	($5.64)	($2.98)	$33.94	$40.49	($4.57)	($1.98)
AEP-DAY Hub	$55.55	$64.73	($7.80)	($1.38)	$36.21	$42.21	($5.07)	($0.93)
ATSI Gen Hub	$56.03	$59.25	($3.39)	$0.17	$38.17	$41.52	($3.33)	($0.02)
Chicago Gen Hub	$49.04	$66.12	($13.66)	($3.42)	$28.51	$38.80	($8.13)	($2.16)
Chicago Hub	$49.45	$63.08	($11.46)	($2.18)	$30.95	$41.43	($8.68)	($1.80)
Dominion Hub	$78.56	$72.06	$7.49	($0.99)	$51.67	$44.14	$7.16	$0.37
Eastern Hub	$84.02	$68.10	$12.05	$3.87	$52.94	$43.50	$7.46	$1.98
N Illinois Hub	$49.88	$65.09	($12.45)	($2.76)	$30.24	$40.99	($8.73)	($2.02)
New Jersey Hub	$80.07	$65.88	$11.29	$2.90	$47.64	$42.24	$4.13	$1.27
Ohio Hub	$56.19	$65.53	($8.20)	($1.14)	$36.05	$42.00	($5.15)	($0.79)
West Interface Hub	$55.68	$56.82	($0.33)	($0.81)	$40.38	$42.03	($1.25)	($0.39)
Western Hub	$69.10	$65.84	$3.26	($0.00)	$44.39	$42.15	$2.45	($0.21)

Component Costs

Table 11-7 shows the total energy, loss and congestion component costs and the total PJM billing for the first six months of 2009 through 2015. These totals are actually net energy, loss and congestion costs. Total congestion and marginal loss costs decreased in the first six months of 2015 compared to the first six months of 2014. Total congestion and marginal loss costs in the first six months of 2014 were unusually high because of the distribution of high load and outages caused by cold weather in January 2014.

Table 11-7 Total PJM costs by component (Dollars (Millions)): January through June of 2009 through 2015[10,11]

	Component Costs (Millions)					
(Jan - Jun)	Energy Costs	Loss Costs	Congestion Costs	Total Costs	Total PJM Billing	Total Costs Percent of PJM Billing
2009	($344)	$705	$408	$769	$13,457	5.7%
2010	($373)	$751	$644	$1,022	$16,314	6.3%
2011	($394)	$701	$570	$878	$18,685	4.7%
2012	($262)	$445	$263	$446	$13,991	3.2%
2013	($333)	$494	$306	$468	$15,571	3.0%
2014	($677)	$1,006	$1,442	$1,771	$31,060	5.7%
2015	($398)	$608	$919	$1,129	$23,400	4.8%

10 The energy costs, loss costs and congestion costs include net inadvertent charges.
11 Total PJM billing is provided by PJM. The MMU is not able to verify the calculation.

Congestion

Congestion Accounting

Congestion occurs in the Day-Ahead and Real-Time Energy Markets.[12] 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.[13]

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 six months of 2015 were $918.6 million, which was comprised of load congestion payments of $439.2 million, generation credits of -$586.4 million and explicit congestion of -$107.0 million. Total congestion costs in PJM in the first six months of 2014 were $1,422.3 million, which was comprised of load congestion payments of $456.9 million, generation credits of -$1,133.7 million and explicit congestion of -$148.3 million. The decrease in total congestion cost from the first six months of 2014 to the first six months of 2015 is primarily a result of the decrease in generation credits.

Total Congestion

Table 11-8 shows total congestion for the first six months of 2008 through 2015. 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.[14,15]

12 When the term *congestion charge* is used in documents by PJM's Market Settlement Operations, it has the same meaning as the term *congestion costs* as used here.
13 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.
14 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (December 11, 2008) Section 6.1 <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed January 16, 2015).
15 See "Joint Operating Agreement Among and Between the New York Independent System Operator Inc. and PJM Interconnection, L.L.C.," (January 17, 2013) Section 35.12.1 <http://www.pjm.com/~/media/documents/agreements/nyiso-pjm.ashx> (Accessed January 16, 2015).

Table 11-8 Total PJM congestion (Dollars (Millions)): January through June of 2008 through 2015

	Congestion Costs (Millions)			
(Jan - Jun)	Congestion Cost	Percent Change	Total PJM Billing	Percent of PJM Billing
2008	$1,166	NA	$16,549	7.0%
2009	$408	(65.0%)	$13,457	3.0%
2010	$644	57.8%	$16,314	3.9%
2011	$570	(11.5%)	$18,685	3.1%
2012	$263	(53.8%)	$13,991	1.9%
2013	$306	16.3%	$15,571	2.0%
2014	$1,442	371.3%	$31,060	4.6%
2015	$919	(36.3%)	$23,400	3.9%

Table 11-9 shows the congestion costs by accounting category by market for the first six months of 2015. In the first six months of 2015, PJM total congestion costs were comprised of $439.2 million in load congestion payments, -$586.4 million in generation congestion credits, and -$107.0 million in explicit congestion costs.

Table 11-9 Total PJM congestion costs by accounting category by market (Dollars (Millions)): January through June of 2008 through 2015

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
(Jan - Jun)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2008	$727.6	($589.4)	$86.7	$1,403.8	($102.4)	$68.2	($67.1)	($237.7)	$0.0	$1,166.1
2009	$159.3	($299.4)	$63.1	$521.7	($17.0)	($2.4)	($99.0)	($113.6)	$0.0	$408.2
2010	$151.5	($544.1)	$38.1	$733.8	($7.3)	$18.6	($63.9)	($89.8)	($0.0)	$644.0
2011	$256.0	($420.3)	$25.6	$701.9	$31.1	$56.0	($107.0)	($131.9)	$0.0	$570.0
2012	$56.8	($267.4)	$65.4	$389.6	($5.0)	$19.5	($101.8)	($126.4)	$0.0	$263.3
2013	$133.2	($306.1)	$87.8	$527.1	($8.4)	$90.4	($122.3)	($221.1)	($0.0)	$306.0
2014	$392.5	($1,353.6)	($54.1)	$1,691.9	$64.4	$219.9	($94.2)	($249.7)	$0.0	$1,442.3
2015	$428.5	($655.2)	$9.6	$1,093.2	$10.7	$68.8	($116.5)	($174.6)	$0.0	$918.6

Table 11-10 and Table 11-11 show that the decrease in total congestion cost from the first six months of 2014 to the first six months of 2015 is mainly due to the decrease in negative generation credits incurred by generation in Day-Ahead Market. Congestion costs incurred by generation in the Day-Ahead Market decreased by $673.5 million or 41.8 percent, from $1,612.0 million in the first six months of 2014 to $938.5 million in the first six months of 2015.

Table 11-10 Total PJM congestion costs by transaction type by market (Dollars (Millions)): January through June of 2015

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	$46.6	$0.0	$0.0	$46.6	($60.5)	$0.0	$0.0	($60.5)	$0.0	($13.9)
Demand	$89.6	$0.0	$0.0	$89.6	$50.8	$0.0	$0.0	$50.8	($0.0)	$140.4
Demand Response	($0.2)	$0.0	$0.0	($0.2)	$0.2	$0.0	$0.0	$0.2	($0.0)	($0.0)
Explicit Congestion Only	$0.0	$0.0	$2.3	$2.3	$0.0	$0.0	$0.0	$0.0	$0.0	$2.3
Export	($13.8)	$0.0	$0.6	($13.2)	($0.5)	$0.0	$1.1	$0.6	$0.0	($12.6)
Generation	$0.0	($938.5)	$0.0	$938.5	$0.0	$116.3	$0.0	($116.3)	$0.0	$822.2
Grandfathered Overuse	$0.0	$0.0	($2.7)	($2.7)	$0.0	$0.0	$0.5	$0.5	$0.0	($2.2)
Import	$0.0	($35.7)	$1.1	$36.8	$0.0	($65.4)	$0.3	$65.8	($0.0)	$102.5
INC	$0.0	$12.7	$0.0	($12.7)	$0.0	($2.8)	$0.0	$2.8	$0.0	($10.0)
Internal Bilateral	$270.0	$270.0	$0.0	$0.0	$21.2	$21.2	$0.0	($0.0)	$0.0	($0.0)
Up-to Congestion	$0.0	$0.0	($10.7)	($10.7)	$0.0	$0.0	($117.9)	($117.9)	$0.0	($128.6)
Wheel In	$0.0	$36.3	$19.1	($17.2)	$0.0	($0.5)	($0.6)	($0.0)	$0.0	($17.3)
Wheel Out	$36.3	$0.0	$0.0	$36.3	($0.5)	$0.0	$0.0	($0.5)	$0.0	$35.8
Total	$428.5	($655.2)	$9.6	$1,093.2	$10.7	$68.8	($116.5)	($174.6)	$0.0	$918.6

Table 11-11 Total PJM congestion costs by transaction type by market (Dollars (Millions)): January through June of 2014

	Congestion Costs (Millions)									
	Day Ahead				Balancing					
Transaction Type	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
DEC	$64.9	$0.0	$0.0	$64.9	($45.1)	$0.0	$0.0	($45.1)	$0.0	$19.8
Demand	$58.2	$0.0	$0.0	$58.2	$141.0	$0.0	$0.0	$141.0	$0.0	$199.2
Demand Response	($1.0)	$0.0	$0.0	($1.0)	$1.0	$0.0	$0.0	$1.0	$0.0	($0.0)
Explicit Congestion Only	$0.0	$0.0	$1.2	$1.2	$0.0	$0.0	$0.3	$0.3	$0.0	$1.5
Export	($60.4)	$0.0	($1.2)	($61.6)	($38.8)	$0.0	$4.8	($34.0)	$0.0	($95.6)
Generation	$0.0	($1,612.0)	$0.0	$1,612.0	$0.0	$283.4	$0.0	($283.4)	$0.0	$1,328.6
Grandfathered Overuse	$0.0	$0.0	($4.1)	($4.1)	$0.0	$0.0	$0.3	$0.3	$0.0	($3.8)
Import	$0.0	($42.6)	$6.7	$49.3	$0.0	($114.4)	$4.0	$118.4	$0.0	$167.7
INC	$0.0	($30.6)	$0.0	$30.6	$0.0	$44.5	$0.0	($44.5)	$0.0	($13.9)
Internal Bilateral	$267.0	$267.8	$0.8	$0.0	$8.4	$8.4	$0.0	($0.0)	$0.0	$0.0
Up-to Congestion	$0.0	$0.0	($77.1)	($77.1)	$0.0	$0.0	($102.1)	($102.1)	$0.0	($179.2)
Wheel In	$0.0	$63.8	$19.6	($44.2)	$0.0	($2.1)	($1.5)	$0.6	$0.0	($43.6)
Wheel Out	$63.8	$0.0	$0.0	$63.8	($2.1)	$0.0	$0.0	($2.1)	$0.0	$61.7
Total	$392.5	($1,353.6)	($54.1)	$1,691.9	$64.4	$219.9	($94.2)	($249.7)	$0.0	$1,442.3

Monthly Congestion

Table 11-12 shows that monthly total congestion costs ranged from $69.5 million to $429.8 million in the first six months of 2015. Table 11-12 shows that congestion costs in January of 2014 were substantially higher than congestion costs in January of 2015, due to weather related load and outages in January of 2014.

Table 11-12 Monthly PJM congestion costs by market (Dollars (Millions)): January through June of 2014 and 2015

	Congestion Costs (Millions)							
	2014				2015			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$922.5	($97.4)	$0.0	$825.1	$156.7	($24.4)	$0.0	$132.3
Feb	$203.5	($38.3)	$0.0	$165.2	$476.3	($46.4)	($0.0)	$429.8
Mar	$307.3	($61.5)	$0.0	$245.8	$140.9	($71.4)	$0.0	$69.5
Apr	$66.3	($12.0)	($0.0)	$54.3	$76.3	($4.9)	($0.0)	$71.4
May	$84.9	($21.9)	$0.0	$63.1	$128.9	($19.9)	$0.0	$109.0
Jun	$107.4	($18.6)	$0.0	$88.8	$114.1	($7.5)	($0.0)	$106.6
Total	$1,691.9	($249.7)	$0.0	$1,442.3	$1,093.2	($174.6)	$0.0	$918.6

Figure 11-1 shows PJM monthly total congestion cost for 2009 through the first six months of 2015.

Figure 11-1 PJM monthly total congestion cost (Dollars (Millions)): 2009 through June of 2015

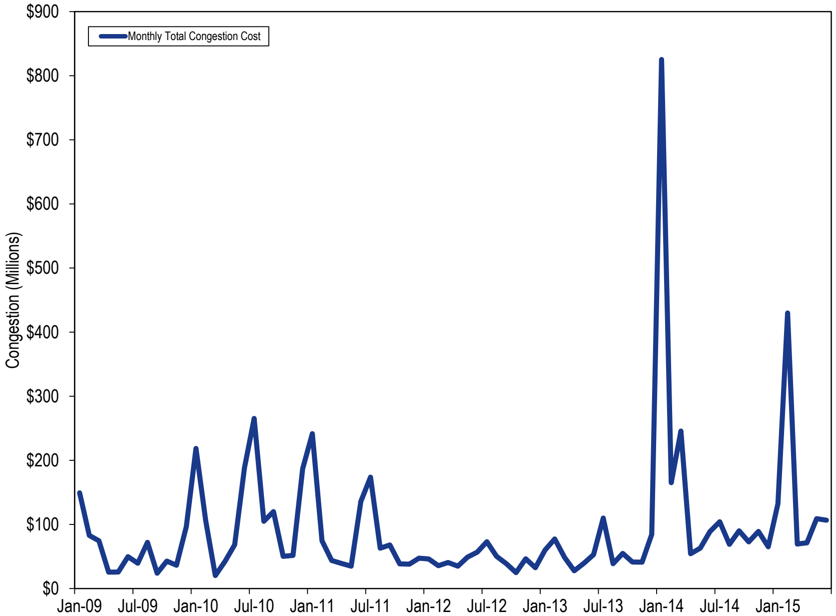


Table 11-13 shows the monthly total congestion costs for each virtual transaction type in the first six months of 2015 and Table 11-14 shows the monthly total congestion costs for each virtual transaction type in the first six months of 2014. Virtual transaction congestion costs, when positive, measure the total congestion cost to the virtual transaction and when negative, measure the total congestion credit to the virtual transaction. Table 11-13 and Table 11-14 shows that UTCs were paid both day-ahead congestion credits and balancing congestion credits in the first six months of 2014 and in the first six months of 2015. Total day-ahead congestion payments to UTCs decreased by $66.4 million from the first six months of 2014 to the first six months of 2015, from $77.1 million in the first six months of 2014 to $10.7 million in the first six months of 2015. Over the same period balancing congestion payments to UTCs increased from $102.1 million in the first six months of 2014 to $117.9 million in the first six months of 2015. Overall, total congestion payments to UTC decreased by 28.2 percent between the first six months of 2014 and the first six months of 2015. UTCs were paid $179.2 million in congestion in the first six months of 2014 and $128.6 million in the first six months of 2015. UTCs were paid $132.9 million in January 2014 alone due to emergency conditions in that month. The significant reduction in UTC activity that started September 8, 2014, is reflected in the changes in day-ahead and balancing congestion related revenues attributed to UTCs between the two periods. The reduction in UTC activity was a result of FERC's UTC uplift refund notice, effective September 8, 2014.[16]

Table 11-13 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): January through June of 2015

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
	DEC	INC	Up-to Congestion	Virtual Total	DEC	INC	Up-to Congestion	Virtual Total	Virtual Grand Total
Jan	$7.4	($3.2)	($3.4)	$0.8	($7.1)	$1.1	($11.3)	($17.4)	($16.6)
Feb	$11.1	$0.1	($37.6)	($26.4)	($15.4)	($0.6)	($13.0)	($29.0)	($55.4)
Mar	$9.6	($0.1)	$12.5	$22.0	($17.7)	$0.5	($55.1)	($72.3)	($50.3)
Apr	$4.3	($2.5)	$5.3	$7.1	($5.8)	$3.7	($10.0)	($12.2)	($122.3)
May	$5.1	($3.7)	$5.9	$7.3	($4.8)	($2.1)	($21.7)	($28.6)	($228.1)
Jun	$9.0	($3.2)	$6.6	$12.4	($9.5)	$0.2	($6.9)	($16.2)	($400.8)
Total	$46.6	($12.7)	($10.7)	$23.1	($60.5)	$2.8	($117.9)	($175.6)	($751.2)

16 See 18 CFR § 385.213 (2014).

Table 11-14 Monthly PJM congestion costs by virtual transaction type and by market (Dollars (Millions)): January through June of 2014

	Congestion Costs (Millions)								
	Day Ahead				Balancing				
	DEC	INC	Up-to Congestion	Virtual Total	DEC	INC	Up-to Congestion	Virtual Total	Virtual Grand Total
Jan	$51.0	$27.1	($109.4)	($31.4)	($31.8)	($26.7)	($23.5)	($82.0)	($113.3)
Feb	$7.4	$1.5	($5.8)	$3.1	($8.1)	($6.5)	($11.1)	($25.7)	($22.6)
Mar	$2.2	$4.9	$3.1	$10.2	($2.3)	($11.0)	($33.3)	($46.6)	($36.4)
Apr	($2.2)	($0.2)	$12.7	$10.3	$0.8	($0.3)	($9.5)	($9.0)	$1.3
May	$3.8	($1.6)	$10.7	$12.9	($3.5)	$0.4	($9.2)	($12.3)	$0.7
Jun	$2.7	($1.0)	$11.6	$13.2	($0.1)	($0.5)	($15.5)	($16.1)	($2.9)
Total	$64.9	$30.6	($77.1)	$18.3	($45.1)	($44.5)	($102.1)	($191.7)	($173.4)

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 six months of 2015, there were 95,960 day-ahead, congestion-event hours compared to 228,169 day-ahead congestion-event hours in the first six months of 2014. In the first six months of 2015, there were 17,169 real-time, congestion-event hours compared to 16,722 real-time, congestion-event hours in the first six months of 2014.

During the first six months of 2015, there were 9,295 real-time congestion-event hours, 9.7 percent of day-ahead energy congestion-event hours, when the same facilities also constrained in the Real-Time Energy Market. During the first six months of 2015, there were 9,286 day-ahead congestion-event hours, 54.1 percent of real-time congestion-event hours, when the same facilities were also constrained in the Day-Ahead Energy Market.

The 5004/5005 Interface was the largest contributor to total congestion costs in the first six months of 2015. With $88.8 million in total congestion costs, it accounted for 9.7 percent of the total PJM congestion costs in the first six months of 2015. The top five constraints in terms of congestion costs contributed $227.2 million, or 24.7 percent, of the total PJM congestion costs in the first six months of 2015. The top five constraints were the 5004/5005 Interface, the Bedington - Black Oak Interface, the AEP - DOM Interface, the AP South Interface, and the Bergen – New Milford line.

Congestion by Facility Type and Voltage

In the first six months of 2015, day-ahead, congestion-event hours decreased on all types of congestion facilities. Real-time, congestion-event hours increased on line and transformer facilities and decrease on flowgate and interface facilities.

Day-ahead congestion costs decreased on all types of facilities except transformers in the first six months of 2015 compared to the first six months of 2014. Balancing congestion costs increased on all types of facilities except transmission lines in the first six months of 2015 compared to the first six months of 2014.

Table 11-15 provides congestion-event hour subtotals and congestion cost subtotals comparing the first six months of 2015 results by facility type: line, transformer, interface, flowgate and unclassified facilities.[17,18] Table 11-16 presents this information for the first six months of 2014.

17 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.

18 The term flowgate refers to MISO reciprocal coordinated flowgates and NYISO M2M flowgates.

Table 11-15 Congestion summary (By facility type): January through June of 2015

	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	$54.6	($116.6)	($25.5)	$145.7	$2.2	($0.1)	($13.1)	($10.8)	$134.9	15,172	3,249
Interface	$59.1	($307.4)	($29.2)	$337.3	$10.6	$28.2	$2.9	($14.8)	$322.5	6,784	1,988
Line	$212.6	($144.3)	$65.4	$422.3	($7.2)	$28.0	($111.0)	($146.2)	$276.1	53,941	10,054
Other	$0.1	($0.4)	$0.3	$0.9	$0.0	$0.1	$0.1	$0.0	$0.9	974	26
Transformer	$102.1	($86.0)	($1.5)	$186.6	$5.8	$11.0	($2.3)	($7.5)	$179.0	19,089	1,852
Unclassified	($0.1)	($0.5)	$0.1	$0.4	($0.6)	$1.6	$7.0	$4.8	$5.2	NA	NA
Total	$428.5	($655.2)	$9.6	$1,093.2	$10.7	$68.8	($116.5)	($174.6)	$918.6	95,960	17,169

Table 11-16 Congestion summary (By facility type): January through June 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	($81.9)	($332.4)	($14.0)	$236.5	$1.9	$13.3	($35.7)	($47.1)	$189.4	21,331	4,577
Interface	$322.7	($587.9)	($97.3)	$813.4	$61.9	$142.5	$21.4	($59.1)	$754.2	11,013	2,421
Line	$85.3	($347.0)	$24.7	$457.0	($13.3)	$47.1	($40.9)	($101.3)	$355.7	118,134	8,175
Other	$0.0	($1.0)	$0.6	$1.7	$0.0	$0.0	$0.0	$0.0	$1.7	4,543	0
Transformer	$65.1	($76.1)	$20.1	$161.3	$8.7	$15.7	($47.2)	($54.3)	$107.1	73,148	1,549
Unclassified	$1.1	($9.2)	$11.7	$22.1	$5.2	$1.3	$8.3	$12.2	$34.2	NA	NA
Total	$392.5	($1,353.6)	($54.1)	$1,691.9	$64.4	$219.9	($94.2)	($249.7)	$1,442.3	228,169	16,722

Table 11-17 and Table 11-18 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 11-17. In the first six months of 2015, there were 95,960 congestion-event hours in the Day-Ahead Energy Market. Among those day-ahead congestion-event hours, only 9,295 (9.7 percent) were also constrained in the Real-Time Energy Market. In the first six months of 2014, among the 228,169 day-ahead congestion-event hours, only 8,150 (3.6 percent) were binding in the Real-Time Energy Market.[19]

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 11-18. In the first six months of 2015, there were 17,169 congestion-event hours in the Real-Time Energy Market. Among these real-time congestion-event hours, 9,286 (54.1 percent) were also constrained in the Day-Ahead Energy Market. In the first six months of 2014, among the 16,722 real-time congestion-event hours, 8,607 (51.5 percent) were also in the Day-Ahead Energy Market.

19 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 11-17 Congestion event hours (Day-Ahead against Real-Time): January through June of 2014 and 2015

	Congestion Event Hours					
	2014 (Jan - Jun)			2015 (Jan - Jun)		
Type	Day Ahead Constrained	Corresponding Real Time Constrained	Percent	Day Ahead Constrained	Corresponding Real Time Constrained	Percent
Flowgate	21,331	2,521	11.8%	15,172	1,741	11.5%
Interface	11,013	1,519	13.8%	6,784	1,467	21.6%
Line	118,134	3,641	3.1%	53,941	5,219	9.7%
Other	4,543	0	0.0%	974	0	0.0%
Transformer	73,148	469	0.6%	19,089	868	4.5%
Total	228,169	8,150	3.6%	95,960	9,295	9.7%

Table 11-18 Congestion event hours (Real-Time against Day-Ahead): January through June of 2014 and 2015

	Congestion Event Hours					
	2014 (Jan - Jun)			2015 (Jan - Jun)		
Type	Real Time Constrained	Corresponding Day Ahead Constrained	Percent	Real Time Constrained	Corresponding Day Ahead Constrained	Percent
Flowgate	4,577	2,647	57.8%	3,249	1,753	54.0%
Interface	2,421	1,852	76.5%	1,988	1,497	75.3%
Line	8,175	3,664	44.8%	10,054	5,216	51.9%
Other	0	0	0.0%	26	0	0.0%
Transformer	1,549	444	28.7%	1,852	820	44.3%
Total	16,722	8,607	51.5%	17,169	9,286	54.1%

Table 11-19 shows congestion costs by facility voltage class for the first six months of 2015. Congestion costs in the first six months of 2015 decreased for facilities rated at 500 kV, 345 kV, 230 kV and 138 kV compared to the first six months of 2014 (Table 11-20).

Table 11-19 Congestion summary (By facility voltage): January through June of 2015

	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	$17.8	($54.0)	($5.2)	$66.6	$3.2	$4.3	$0.6	($0.5)	$66.1	1,569	136
500	$75.1	($317.2)	($27.8)	$364.5	$12.5	$28.5	($0.7)	($16.7)	$347.8	8,121	1,046
460	($0.0)	($3.6)	$0.3	$4.0	$0.0	$0.0	$0.0	$0.0	$4.0	1,360	0
345	($6.4)	($100.8)	$5.8	$100.2	$7.0	$5.4	($15.7)	($14.1)	$86.2	12,571	1,636
230	$197.6	($2.1)	$16.8	$216.6	($3.0)	$6.4	($41.1)	($50.5)	$166.1	16,815	4,450
161	($9.7)	($26.8)	($0.8)	$16.3	$0.3	$0.7	($2.0)	($2.5)	$13.8	2,005	873
138	$109.6	($126.9)	$15.5	$251.9	($5.9)	$22.8	($61.6)	($90.3)	$161.6	39,359	6,890
115	$14.3	($20.9)	$6.2	$41.4	$1.9	$0.8	($3.3)	($2.2)	$39.2	7,872	1,369
69	$30.3	($2.3)	($1.4)	$31.2	($4.7)	($1.8)	$0.3	($2.6)	$28.6	5,585	730
34	$0.0	$0.0	$0.1	$0.1	($0.0)	$0.0	$0.0	$0.0	$0.2	683	39
13	$0.0	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	19	0
12	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	1	0
Unclassified	($0.1)	($0.5)	$0.1	$0.4	($0.6)	$1.6	$7.0	$4.8	$5.2	NA	NA
Total	$428.5	($655.2)	$9.6	$1,093.2	$10.7	$68.8	($116.5)	($174.6)	$918.6	95,960	17,169

Table 11-20 Congestion summary (By facility voltage): January through June 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	$21.3	($35.4)	$2.1	$58.7	$0.3	$1.7	($2.7)	($4.1)	$54.6	7,723	223
500	$329.9	($584.7)	($97.1)	$817.4	$71.2	$158.6	$7.6	($79.8)	$737.6	14,504	2,119
345	($65.1)	($286.0)	($2.8)	$218.1	$3.7	$14.6	($23.8)	($34.7)	$183.4	44,669	2,157
230	$35.8	($202.8)	($15.2)	$223.4	$0.8	($0.7)	$1.5	$2.9	$226.3	34,885	3,057
161	($16.9)	($34.6)	($1.6)	$16.1	($1.9)	$0.0	($1.4)	($3.4)	$12.8	3,563	779
138	$48.2	($193.1)	$44.1	$285.4	($3.6)	$39.5	($80.0)	($123.1)	$162.2	97,054	6,879
115	($0.7)	($16.6)	$3.4	$19.3	($6.0)	$2.2	($2.6)	($10.7)	$8.6	12,708	1,003
69	$38.9	$8.8	$1.1	$31.3	($5.2)	$2.6	($1.1)	($8.9)	$22.3	10,372	505
34	$0.0	($0.0)	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.1	2,669	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	$1.1	($9.2)	$11.7	$22.1	$5.2	$1.3	$8.3	$12.2	$34.2	NA	NA
Total	$392.5	($1,353.6)	($54.1)	$1,691.9	$64.4	$219.9	($94.2)	($249.7)	$1,442.3	228,169	16,722

Constraint Duration

Table 11-21 lists the constraints in the first six months of 2014 and the first six months of 2015 that were most frequently binding and Table 11-22 shows the constraints which experienced the largest change in congestion-event hours from the first six months of 2014 to the first six months of 2015.

Table 11-21 Top 25 constraints with frequent occurrence: January through June of 2014 and 2015

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2014	2015	Change	2014	2015	Change	2014	2015	Change	2014	2015	Change
1	Bergen - New Milford	Line	2,958	2,580	(378)	291	795	504	34%	29%	(4%)	3%	9%	6%
2	Oak Grove - Galesburg	Flowgate	3,563	2,005	(1,558)	690	872	182	41%	23%	(18%)	8%	10%	2%
3	East Danville - Banister	Line	0	2,704	2,704	3	126	123	0%	31%	31%	0%	1%	1%
4	Easton	Transformer	812	2,662	1,850	0	0	0	9%	30%	21%	0%	0%	0%
5	Bunsonville - Eugene	Flowgate	1,551	1,914	363	490	456	(34)	18%	22%	4%	6%	5%	(0%)
6	Maywood - Saddlebrook	Line	1,459	1,811	352	183	448	265	17%	21%	4%	2%	5%	3%
7	Bedington - Black Oak	Interface	1,613	1,911	298	253	282	29	18%	22%	3%	3%	3%	0%
8	SENECA	Interface	382	938	556	469	1,182	713	4%	11%	6%	5%	13%	8%
9	Bagley - Graceton	Line	1,717	1,352	(365)	457	621	164	20%	15%	(4%)	5%	7%	2%
10	Michigan City - Laporte	Flowgate	927	1,855	928	0	0	0	11%	21%	11%	0%	0%	0%
11	East Bend	Transformer	3,090	1,582	(1,508)	0	0	0	35%	18%	(17%)	0%	0%	0%
12	Breed - Wheatland	Flowgate	1,925	1,358	(567)	456	148	(308)	22%	15%	(7%)	5%	2%	(4%)
13	Tidd	Transformer	362	1,401	1,039	2	92	90	4%	16%	12%	0%	1%	1%
14	Mahans Lane - Tidd	Line	49	1,038	989	0	394	394	1%	12%	11%	0%	4%	4%
15	Person - Halifax	Flowgate	125	1,412	1,287	0	6	6	1%	16%	15%	0%	0%	0%
16	Brucea	Transformer	0	1,360	1,360	0	0	0	0%	15%	15%	0%	0%	0%
17	Sayreville - Sayreville	Line	1,891	1,281	(610)	0	0	0	22%	15%	(7%)	0%	0%	0%
18	Conastone - Northwest	Line	55	687	632	35	510	475	1%	8%	7%	0%	6%	5%
19	Glenarm - Windy Edge	Line	121	709	588	36	366	330	1%	8%	7%	0%	4%	4%
20	Burlington - Croydon	Line	2,972	859	(2,113)	386	214	(172)	34%	10%	(24%)	4%	2%	(2%)
21	Rising	Flowgate	386	652	266	105	372	267	4%	7%	3%	1%	4%	3%
22	5004/5005 Interface	Interface	362	661	299	313	321	8	4%	8%	3%	4%	4%	0%
23	AEP - DOM	Interface	1,514	939	(575)	55	42	(13)	17%	11%	(7%)	1%	0%	(0%)
24	Bergen - Leonia	Line	1,693	947	(746)	0	0	0	19%	11%	(9%)	0%	0%	0%
25	Belmont	Transformer	11	830	819	49	94	45	0%	9%	9%	1%	1%	1%

Table 11-22 Top 25 constraints with largest year-to-year change in occurrence: January through June of 2014 and 2015

			Event Hours						Percent of Annual Hours					
			Day Ahead			Real Time			Day Ahead			Real Time		
No.	Constraint	Type	2014	2015	Change	2014	2015	Change	2014	2015	Change	2014	2015	Change
1	Tanners Creek	Transformer	6,020	676	(5,344)	0	0	0	69%	8%	(61%)	0%	0%	0%
2	Miami Fort	Transformer	5,413	215	(5,198)	21	3	(18)	62%	2%	(59%)	0%	0%	(0%)
3	Monticello - East Winamac	Flowgate	3,041	0	(3,041)	1,377	0	(1,377)	35%	0%	(35%)	16%	0%	(16%)
4	Braidwood	Transformer	5,253	915	(4,338)	0	0	0	60%	10%	(50%)	0%	0%	0%
5	Kendall Co. Energy Ctr.	Transformer	3,906	44	(3,862)	0	0	0	45%	1%	(44%)	0%	0%	0%
6	Sunbury	Transformer	3,839	29	(3,810)	0	0	0	44%	0%	(43%)	0%	0%	0%
7	AP South	Interface	3,703	846	(2,857)	879	42	(837)	42%	10%	(33%)	10%	0%	(10%)
8	Clinch River	Transformer	3,664	296	(3,368)	0	0	0	42%	3%	(38%)	0%	0%	0%
9	Keeney	Transformer	2,909	9	(2,900)	57	0	(57)	33%	0%	(33%)	1%	0%	(1%)
10	Mardela - Vienna	Line	3,141	312	(2,829)	44	1	(43)	36%	4%	(32%)	1%	0%	(0%)
11	East Danville - Banister	Line	0	2,704	2,704	3	126	123	0%	31%	31%	0%	1%	1%
12	Cook - Palisades	Flowgate	2,316	0	(2,316)	308	0	(308)	26%	0%	(26%)	4%	0%	(4%)
13	Nelson - Cordova	Line	2,814	414	(2,400)	227	45	(182)	32%	5%	(27%)	3%	1%	(2%)
14	Sporn	Transformer	2,530	34	(2,496)	0	0	0	29%	0%	(28%)	0%	0%	0%
15	Wolf Creek	Transformer	3,264	710	(2,554)	97	171	74	37%	8%	(29%)	1%	2%	1%
16	Beckjord	Transformer	2,492	52	(2,440)	0	0	0	28%	1%	(28%)	0%	0%	0%
17	Huntington Junction - Huntington	Line	2,394	25	(2,369)	0	0	0	27%	0%	(27%)	0%	0%	0%
18	Burlington - Croydon	Line	2,972	859	(2,113)	386	214	(172)	34%	10%	(24%)	4%	2%	(2%)
19	Fort Robinson - Wolf Hills	Line	2,101	0	(2,101)	0	0	0	24%	0%	(24%)	0%	0%	0%
20	Gould Street - Westport	Line	2,669	606	(2,063)	0	14	14	30%	7%	(24%)	0%	0%	0%
21	Argenta - Greenup	Line	2,047	90	(1,957)	0	0	0	23%	1%	(22%)	0%	0%	0%
22	Loretto - Cayuga	Line	1,954	0	(1,954)	0	0	0	22%	0%	(22%)	0%	0%	0%
23	West Moulton-City Of St. Marys	Line	2,105	189	(1,916)	0	0	0	24%	2%	(22%)	0%	0%	0%
24	Easton	Transformer	812	2,662	1,850	0	0	0	9%	30%	21%	0%	0%	0%
25	Tanners Creek	Transformer	1,679	95	(1,584)	0	0	0	19%	1%	(18%)	0%	0%	0%

Constraint Costs

Table 11-23 and Table 11-24 present the top constraints affecting congestion costs by facility for the periods the first six months of 2015 and the first six months of 2014.

Table 11-23 Top 25 constraints affecting PJM congestion costs (By facility): January through June of 2015

				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	2015 (Jan - Jun)
1	5004/5005 Interface	Interface	500	($22.9)	($134.6)	($9.2)	$102.4	$7.0	$22.5	$1.9	($13.6)	$88.8	9.7%
2	Bedington - Black Oak	Interface	500	$40.7	($42.0)	($7.1)	$75.5	$2.3	$1.7	$3.2	$3.8	$79.3	8.6%
3	AP South	Interface	500	$34.8	($21.4)	($5.1)	$51.1	$0.3	$0.2	$0.6	$0.7	$51.9	5.6%
4	AEP - DOM	Interface	500	$27.2	($27.6)	($1.0)	$53.8	$0.9	$1.6	($1.9)	($2.6)	$51.2	5.6%
5	Bergen - New Milford	Line	PSEG	$24.7	$18.1	$17.6	$24.2	($7.6)	$9.3	($51.2)	($68.1)	($44.0)	(4.8%)
6	Joshua Falls	Transformer	AEP	$9.6	($35.6)	($4.9)	$40.2	$0.7	($0.1)	$2.3	$3.1	$43.4	4.7%
7	Bagley - Graceton	Line	BGE	$36.8	$0.0	$1.3	$38.1	($0.3)	($5.7)	($0.7)	$4.7	$42.8	4.7%
8	Person - Halifax	Flowgate	MISO	$79.7	$29.2	($10.4)	$40.1	$0.0	($0.0)	($0.1)	($0.1)	$40.0	4.4%
9	Conastone - Northwest	Line	BGE	$27.7	($1.5)	$0.0	$29.2	$0.2	($1.9)	($1.1)	$1.0	$30.2	3.3%
10	Maywood - Saddlebrook	Line	PSEG	$7.9	$3.9	$6.3	$10.3	($4.8)	$8.7	($21.0)	($34.5)	($24.1)	(2.6%)
11	East	Interface	500	($12.1)	($35.5)	($1.9)	$21.5	($0.1)	$0.3	$0.5	$0.1	$21.6	2.4%
12	Easton	Transformer	DPL	$28.1	$6.4	($0.8)	$20.9	$0.0	$0.0	$0.0	$0.0	$20.9	2.3%
13	Mahans Lane - Tidd	Line	AEP	$7.7	($13.3)	($1.6)	$19.4	$0.4	$1.1	$0.9	$0.2	$19.6	2.1%
14	Glenarm - Windy Edge	Line	BGE	$2.8	($11.9)	$0.9	$15.7	$1.8	($1.7)	($0.5)	$3.1	$18.7	2.0%
15	East Danville - Banister	Line	AEP	$7.7	($7.4)	$1.8	$16.9	$0.5	($1.5)	($0.6)	$1.4	$18.3	2.0%
16	49th Street - Hoboken	Line	PSEG	$0.0	$0.0	$0.0	$0.0	($2.8)	$2.2	($13.1)	($18.1)	($18.1)	(2.0%)
17	Valley	Transformer	Dominion	$15.6	($0.5)	($0.0)	$16.1	$0.0	$0.0	$0.0	$0.0	$16.1	1.7%
18	Breed - Wheatland	Flowgate	MISO	($1.7)	($15.5)	$0.6	$14.4	$0.1	($0.6)	($0.7)	($0.0)	$14.4	1.6%
19	Oak Grove - Galesburg	Flowgate	MISO	($9.7)	($26.8)	($0.8)	$16.3	$0.3	$0.7	($2.0)	($2.5)	$13.8	1.5%
20	Cloverdale	Transformer	AEP	$5.9	($9.3)	($1.6)	$13.6	$0.0	$0.0	$0.0	$0.0	$13.6	1.5%
21	Central	Interface	500	($15.5)	($32.7)	($3.9)	$13.3	$0.1	$1.0	$0.3	($0.7)	$12.6	1.4%
22	West	Interface	500	($1.7)	($14.8)	($0.8)	$12.2	$0.2	$1.0	$0.1	($0.6)	$11.7	1.3%
23	BCPEP	Interface	Pepco	$8.0	($1.6)	$0.3	$9.9	$0.0	$0.0	$0.0	$0.0	$9.9	1.1%
24	Rising	Flowgate	MISO	$0.5	($11.7)	($6.6)	$5.6	$0.3	($0.1)	$3.7	$4.1	$9.7	1.1%
25	Dravosburg - West Mifflin	Line	DLCO	$15.9	$3.4	($0.7)	$11.8	$0.4	$2.7	($0.1)	($2.3)	$9.5	1.0%

Table 11-24 Top 25 constraints affecting PJM congestion costs (By facility): January through June 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 - Jun)
1	AP South	Interface	500	$307.4	($190.7)	($9.9)	$488.3	$31.1	$73.2	$9.1	($32.9)	$455.4	31.6%
2	West	Interface	500	($19.9)	($284.5)	($78.1)	$186.5	$16.7	$47.7	$16.7	($14.3)	$172.2	11.9%
3	Breed - Wheatland	Flowgate	MISO	($14.4)	($80.8)	($8.8)	$57.7	$2.1	$1.2	$5.7	$6.6	$64.3	4.5%
4	Bedington - Black Oak	Interface	500	$25.3	($32.4)	($1.1)	$56.6	$2.9	$3.6	($1.7)	($2.4)	$54.2	3.8%
5	Cloverdale	Transformer	AEP	$22.0	($26.1)	($0.3)	$47.8	$0.0	$0.0	$0.0	$0.0	$47.8	3.3%
6	Benton Harbor - Palisades	Flowgate	MISO	($11.2)	($65.5)	($7.1)	$47.1	($0.2)	$0.6	($0.9)	($1.8)	$45.3	3.1%
7	BCPEP	Interface	Pepco	$11.2	($14.7)	($1.8)	$24.1	($1.7)	($14.1)	$1.4	$13.8	$37.8	2.6%
8	Bagley - Graceton	Line	BGE	$29.5	($1.8)	$2.8	$34.1	$1.4	$0.3	($0.3)	$0.8	$34.9	2.4%
9	Unclassified	Unclassified	Unclassified	$1.1	($9.2)	$11.7	$22.1	$5.2	$1.3	$8.3	$12.2	$34.2	2.4%
10	Cook - Palisades	Flowgate	MISO	($12.6)	($55.3)	($5.3)	$37.4	($1.5)	$1.6	($6.2)	($9.3)	$28.1	1.9%
11	Monticello - East Winamac	Flowgate	MISO	($3.3)	($41.9)	$0.9	$39.5	$2.5	$4.1	($9.8)	($11.5)	$28.1	1.9%
12	Readington - Roseland	Line	PSEG	($8.9)	($46.1)	($12.2)	$25.1	$0.9	$5.4	$5.8	$1.3	$26.4	1.8%
13	Wolf Creek	Transformer	AEP	$3.3	$0.4	$3.4	$6.2	$3.0	$5.9	($27.5)	($30.3)	($24.1)	(1.7%)
14	Brambleton - Loudoun	Line	Dominion	($11.2)	($35.1)	($1.3)	$22.6	$0.6	$0.0	$0.1	$0.6	$23.2	1.6%
15	Cloverdale	Transformer	AEP	$18.5	($5.0)	($2.4)	$21.1	$0.0	$0.0	$0.0	$0.0	$21.1	1.5%
16	Wescosville	Transformer	PPL	$17.5	($0.8)	$2.7	$21.0	($0.0)	$0.0	$0.0	($0.0)	$21.0	1.5%
17	Bridgewater - Middlesex	Line	PSEG	$0.1	($22.1)	($3.0)	$19.2	($1.5)	$0.1	$1.4	($0.2)	$19.0	1.3%
18	East	Interface	500	($6.5)	($25.9)	($3.1)	$16.3	$0.3	$0.7	$0.5	$0.1	$16.4	1.1%
19	Atlantic - Larrabee	Line	JCPL	$2.0	($14.8)	($0.7)	$16.1	$0.0	$1.3	$1.2	($0.1)	$16.0	1.1%
20	Nelson - Cordova	Line	ComEd	($21.1)	($39.6)	$2.6	$21.1	($0.7)	$0.9	($3.5)	($5.1)	$16.0	1.1%
21	Oak Grove - Galesburg	Flowgate	MISO	($16.9)	($34.6)	($1.6)	$16.1	($0.5)	($0.0)	($0.4)	($0.9)	$15.2	1.1%
22	Rising	Flowgate	MISO	($5.1)	($3.8)	$1.4	$0.2	($3.9)	$1.2	($9.3)	($14.3)	($14.1)	(1.0%)
23	Bergen - New Milford	Line	PSEG	$19.6	$11.2	$9.7	$18.1	($1.6)	$2.2	($0.7)	($4.5)	$13.6	0.9%
24	5004/5005 Interface	Interface	500	$0.5	($17.9)	($2.7)	$15.7	$7.7	$17.5	$7.1	($2.7)	$13.0	0.9%
25	Cloverdale	Transformer	AEP	$0.0	$0.0	$0.0	$0.0	$2.6	$4.6	($10.9)	($12.9)	($12.9)	(0.9%)

Figure 11-2 shows the locations of the top 10 constraints by PJM total congestion costs in the first six months of 2015. Figure 11-3 shows the locations of the top 10 constraints by PJM day-ahead congestion costs in the first six months of 2015. Figure 11-4 shows the locations of the top 10 constraints by PJM balancing congestion costs in the first six months of 2015.

Figure 11-2 Location of the top 10 constraints by PJM total congestion costs: January through June of 2015

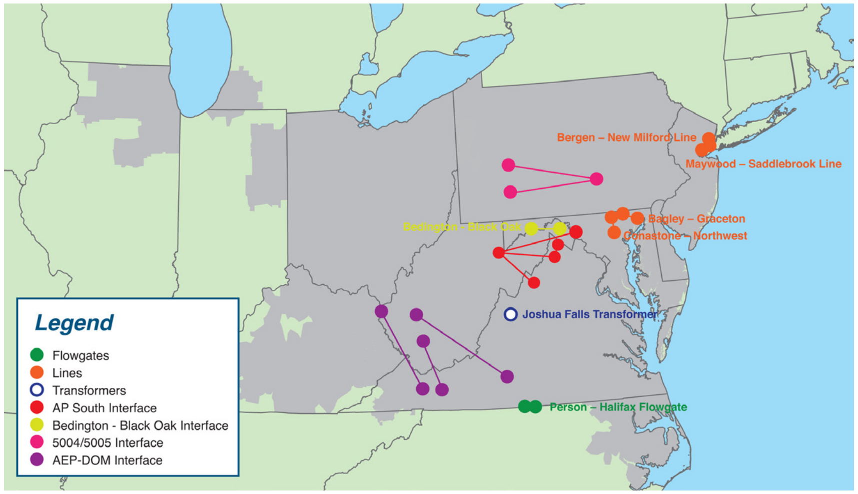


Figure 11-3 Location of the top 10 constraints by PJM day-ahead congestion costs: January through June of 2015

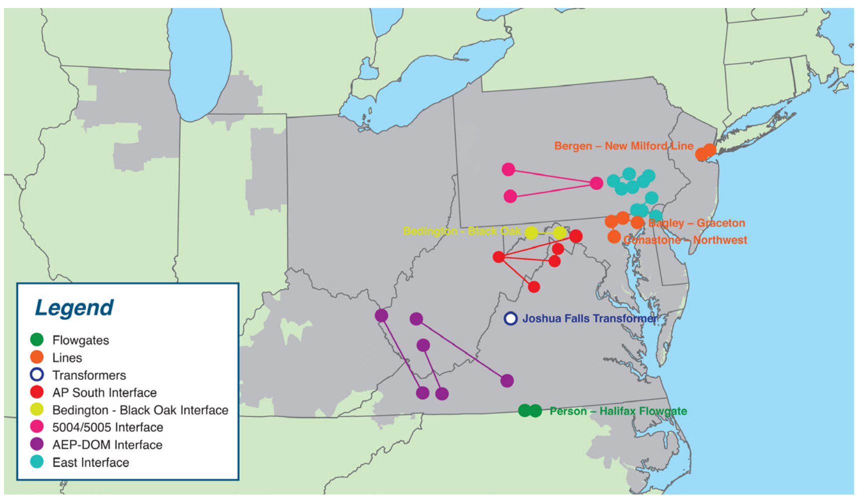
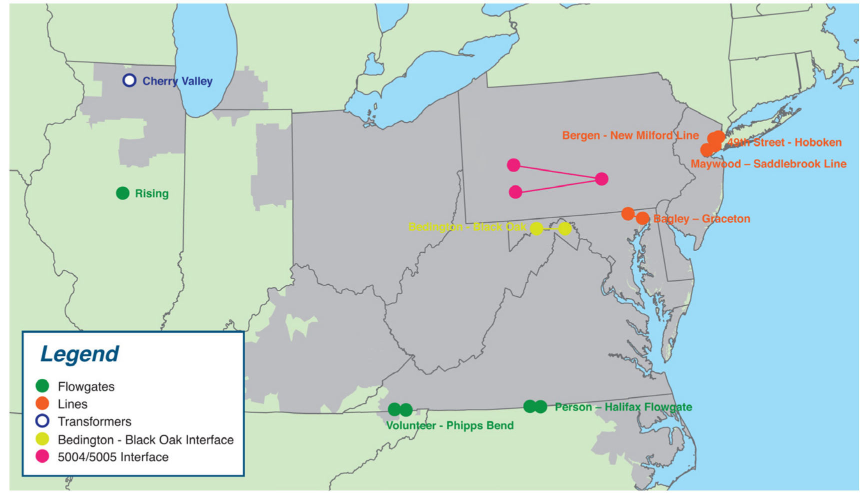


Figure 11-4 Location of the top 10 constraints by PJM balancing congestion costs: January through June of 2015



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.[20] A flowgate is a facility or group of facilities that may act as constraint points on the regional system.[21] PJM models these coordinated flowgates and controls for them in its security-constrained, economic dispatch.

As of June 30, 2015, PJM had 110 flowgates eligible for M2M (Market to Market) coordination and MISO had 268 flowgates eligible for M2M coordination.

Table 11-25 and Table 11-26 show the MISO flowgates which PJM and/or MISO took dispatch action to control during the first six months of 2015 and

20 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (September 17, 2010), Section 6.1 <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed July 25, 2015).

21 See "Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C.," (February 26, 2014), Section 2.2.24 <http://pjm.com/documents/agreements/~/media/documents/agreements/joa-complete.ashx> (Accessed July 25, 2015).

the first six months of 2014, and which had the greatest congestion cost impact on PJM. Total congestion costs associated with a given constraint may be positive or negative in value. The top congestion cost impacts for MISO flowgates affecting PJM and MISO dispatch are presented by constraint, in descending order of the absolute value of total congestion costs. Among MISO flowgates in the first six months of 2015, the Person - Halifax flowgate made the most significant contribution to positive congestion while the Klondcin - Purdue flowgate made the most significant contribution to negative congestion.

Table 11-25 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through June of 2015

		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	Person - Halifax	$79.7	$29.2	($10.4)	$40.1	$0.0	($0.0)	($0.1)	($0.1)	$40.0	1,412	6
2	Breed - Wheatland	($1.7)	($15.5)	$0.6	$14.4	$0.1	($0.6)	($0.7)	($0.0)	$14.4	1,358	148
3	Oak Grove - Galesburg	($9.7)	($26.8)	($0.8)	$16.3	$0.3	$0.7	($2.0)	($2.5)	$13.8	2,005	872
4	Rising	$0.5	($11.7)	($6.6)	$5.6	$0.3	($0.1)	$3.7	$4.1	$9.7	652	372
5	Michigan City - Laporte	$1.0	($6.8)	($0.4)	$7.3	$0.0	$0.0	$0.0	$0.0	$7.3	1,855	0
6	Monroe - Bayshore	($3.8)	($12.9)	($2.5)	$6.6	($0.1)	($0.8)	($0.1)	$0.6	$7.2	572	209
7	Burnham - Munster	$0.0	($5.8)	$0.3	$6.2	$0.0	$0.0	$0.0	$0.0	$6.2	786	0
8	Bunsonville - Eugene	($2.0)	($13.3)	($7.0)	$4.4	$0.1	($0.2)	$1.1	$1.4	$5.8	1,914	456
9	Nelson	($1.7)	($6.4)	$0.7	$5.3	$0.0	$0.0	$0.0	$0.0	$5.3	451	0
10	Braidwood - East Frankfurt	($0.1)	($5.1)	($0.0)	$5.0	$0.0	$0.0	$0.0	$0.0	$5.0	54	0
11	Marysville - Tangy	($0.4)	($5.1)	($0.2)	$4.5	$0.0	$0.0	$0.0	$0.0	$4.5	118	0
12	Cherry Valley - Silver Lake	($0.9)	($4.5)	$0.1	$3.7	$0.0	$0.0	$0.0	$0.0	$3.7	184	0
13	Dixon - McGirr Rd	($1.0)	($4.3)	($0.4)	$3.0	$0.0	$0.0	$0.0	$0.0	$3.0	273	0
14	Klondcin - Purdue	$0.0	($0.1)	$0.0	$0.1	$0.0	$0.4	($2.5)	($2.9)	($2.8)	40	53
15	Crete - St Johns Tap	($0.1)	($2.8)	$0.0	$2.7	$0.0	$0.0	$0.0	$0.0	$2.7	205	0
16	Volunteer - Phipps Bend	$0.1	($1.3)	$0.1	$1.5	$0.0	($0.3)	($4.5)	($4.1)	($2.6)	43	49
17	Byron - Cherry Valley	($0.2)	($2.5)	$0.4	$2.6	$0.0	$0.0	$0.0	$0.0	$2.6	157	0
18	Quad Cities	($1.1)	($2.2)	$0.8	$1.9	$0.0	$0.0	$0.0	$0.0	$1.9	278	0
19	Reynolds - Magnetation	($0.2)	($3.6)	$0.2	$3.7	$0.1	$0.2	($1.7)	($1.8)	$1.9	509	151
20	Powerton Jct - Lilly	($1.5)	($2.6)	$0.6	$1.6	$0.3	($0.3)	($0.4)	$0.2	$1.9	274	147

Table 11-26 Top 20 congestion cost impacts from MISO flowgates affecting PJM dispatch (By facility): January through June 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	($14.4)	($80.8)	($8.8)	$57.7	$2.1	$1.2	$5.7	$6.6	$64.3	1,925	456
2	Benton Harbor - Palisades	($11.2)	($65.5)	($7.1)	$47.1	($0.2)	$0.6	($0.9)	($1.8)	$45.3	1,252	129
3	Cook - Palisades	($12.6)	($55.3)	($5.3)	$37.4	($1.5)	$1.6	($6.2)	($9.3)	$28.1	2,316	308
4	Monticello - East Winamac	($3.3)	($41.9)	$0.9	$39.5	$2.5	$4.1	($9.8)	($11.5)	$28.1	3,041	1,377
5	Oak Grove - Galesburg	($16.9)	($34.6)	($1.6)	$16.1	($0.5)	($0.0)	($0.4)	($0.9)	$15.2	3,563	690
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	($4.7)	($10.2)	$2.1	$7.6	$0.0	$0.0	$0.0	$0.0	$7.6	927	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	Todd Hunter	($0.7)	($3.0)	$0.7	$2.9	$0.0	$0.0	$0.0	$0.0	$2.9	867	0
12	Beaver Channel - Albany	$0.0	$0.0	$0.0	$0.0	($1.4)	$0.0	($1.0)	($2.5)	($2.5)	0	73
13	Paddock - Townline	$0.1	($2.4)	($0.3)	$2.2	$0.0	$0.0	$0.1	$0.1	$2.3	670	38
14	Nelson	($2.7)	($5.1)	($0.4)	$2.0	$0.0	$0.0	$0.0	$0.0	$2.0	165	0
15	Edwards - Kewanee	($1.6)	($3.4)	$0.0	$1.8	$0.0	$0.0	$0.0	$0.0	$1.8	1,448	0
16	Bunsonville - Eugene	($4.1)	($6.8)	$0.4	$3.0	($0.1)	($0.1)	($1.2)	($1.3)	$1.7	1,551	490
17	Magnetation - Monticello	($0.0)	($1.0)	$0.4	$1.3	$0.3	$0.3	$0.4	$0.4	$1.7	112	59
18	Pana North	$0.1	($0.1)	$0.1	$0.3	$0.0	$0.2	($1.8)	($1.9)	($1.6)	157	48
19	Batesville - Hubble	($0.7)	($2.3)	($0.5)	$1.1	($0.0)	($0.0)	$0.1	$0.1	$1.2	48	18
20	Rantoul - Rantoul Jct	($2.8)	($3.3)	$0.7	$1.1	$0.0	$0.0	$0.0	$0.0	$1.1	312	63

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.[22] 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.[23]

Table 11-27 shows the NYISO flowgates which PJM and/or NYISO took dispatch action to control during the first six months of 2015, and which had the greatest congestion cost impact on PJM.

22 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 July 16, 2015).
23 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 July 16, 2015).

Table 11-27 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): January through June of 2015

				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	$0.0	$0.4	($0.1)	($0.5)	($0.5)	0	149
2	Dysinger East	Flowgate	NYISO	$0.0	$0.0	$0.0	$0.0	$0.0	($0.1)	$0.1	$0.2	$0.2	0	25

Table 11-28 Top two congestion cost impacts from NYISO flowgates affecting PJM dispatch (By facility): January through June 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	121
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

Congestion-Event Summary for the 500 kV System

Constraints on the 500 kV system generally have a regional impact. Table 11-29 and Table 11-30 show the 500 kV constraints affecting congestion costs in PJM for the first six months of 2015 and the first six 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 11-29 Regional constraints summary (By facility): January through June of 2015

				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	5004/5005 Interface	Interface	500	($22.9)	($134.6)	($9.2)	$102.4	$7.0	$22.5	$1.9	($13.6)	$88.8	661	321
2	Bedington - Black Oak	Interface	500	$40.7	($42.0)	($7.1)	$75.5	$2.3	$1.7	$3.2	$3.8	$79.3	1,911	282
3	AP South	Interface	500	$34.8	($21.4)	($5.1)	$51.1	$0.3	$0.2	$0.6	$0.7	$51.9	846	42
4	AEP - DOM	Interface	500	$27.2	($27.6)	($1.0)	$53.8	$0.9	$1.6	($1.9)	($2.6)	$51.2	939	42
5	East	Interface	500	($12.1)	($35.5)	($1.9)	$21.5	($0.1)	$0.3	$0.5	$0.1	$21.6	461	16
6	Central	Interface	500	($15.5)	($32.7)	($3.9)	$13.3	$0.1	$1.0	$0.3	($0.7)	$12.6	291	41
7	West	Interface	500	($1.7)	($14.8)	($0.8)	$12.2	$0.2	$1.0	$0.1	($0.6)	$11.7	273	49
8	Nagel - Phipps Bend	Line	500	($0.1)	($0.4)	$1.0	$1.3	$0.0	$0.0	$0.0	$0.0	$1.3	260	0
9	Juniata	Transformer	500	$0.2	($0.7)	$0.1	$0.9	$0.4	$0.3	($0.1)	($0.0)	$0.9	62	21

Table 11-30 Regional constraints summary (By facility): January through June 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	$307.4	($190.7)	($9.9)	$488.3	$31.1	$73.2	$9.1	($32.9)	$455.4	3,703	879
2	West	Interface	500	($19.9)	($284.5)	($78.1)	$186.5	$16.7	$47.7	$16.7	($14.3)	$172.2	1,202	345
3	Bedington - Black Oak	Interface	500	$25.3	($32.4)	($1.1)	$56.6	$2.9	$3.6	($1.7)	($2.4)	$54.2	1,613	253
4	East	Interface	500	($6.5)	($25.9)	($3.1)	$16.3	$0.3	$0.7	$0.5	$0.1	$16.4	1,395	17
5	5004/5005 Interface	Interface	500	$0.5	($17.9)	($2.7)	$15.7	$7.7	$17.5	$7.1	($2.7)	$13.0	362	313
6	AEP - DOM	Interface	500	$8.6	($10.0)	$3.7	$22.3	$5.5	$13.3	($9.6)	($17.3)	$5.0	1,514	55
7	Central	Interface	500	($5.1)	($13.7)	($3.8)	$4.8	$0.2	$0.5	$0.0	($0.3)	$4.5	315	10
8	Branchburg - Elroy	Line	500	($0.0)	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	10	0
9	Juniata	Transformer	500	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	15	0
10	Conemaugh - Hunterstown	Line	500	$0.0	$0.0	$0.0	$0.0	($0.0)	$0.0	$0.0	$0.0	$0.0	0	1

Congestion Costs by Physical and Financial Participants

In order to evaluate the recipients and payers of congestion, the MMU categorized all participants in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

In the first six months of 2015, financial entities as a group were net recipients of congestion credits, and physical entities were net payers of congestion charges. Explicit costs are the primary source of congestion credits to financial entities. UTCs are in the explicit cost category and comprise most of that category. Total explicit cost is equal to day-ahead explicit cost plus balancing explicit cost. In the first six months of 2015, the total explicit cost was -$107.0 million (indicating net credits to participants), of which -$128.6 million (120.3 percent) was credited to UTCs. In the first six months of 2014, the total explicit cost was -$148.3 million, of which -$179.2 million (120.8 percent) was credited to UTCs. In the first six months of 2015, financial entities received $98.8 million in net congestion credits, a decrease of $92.3 million or 48.3 percent compared to the first six months of 2014. In the first six months of 2015, physical entities paid $1,017.5 million in congestion charges, a decrease of $615.9 million or 37.7 percent compared to the first six months of 2014.

Table 11-31 Congestion cost by type of participant: January through June of 2015

	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	$83.6	$46.4	($20.4)	$16.8	($29.9)	($6.9)	($92.6)	($115.6)	$0.0	($98.8)
Physical	$344.9	($701.6)	$29.9	$1,076.4	$40.7	$75.7	($23.9)	($58.9)	$0.0	$1,017.5
Total	$428.5	($655.2)	$9.6	$1,093.2	$10.7	$68.8	($116.5)	($174.6)	$0.0	$918.6

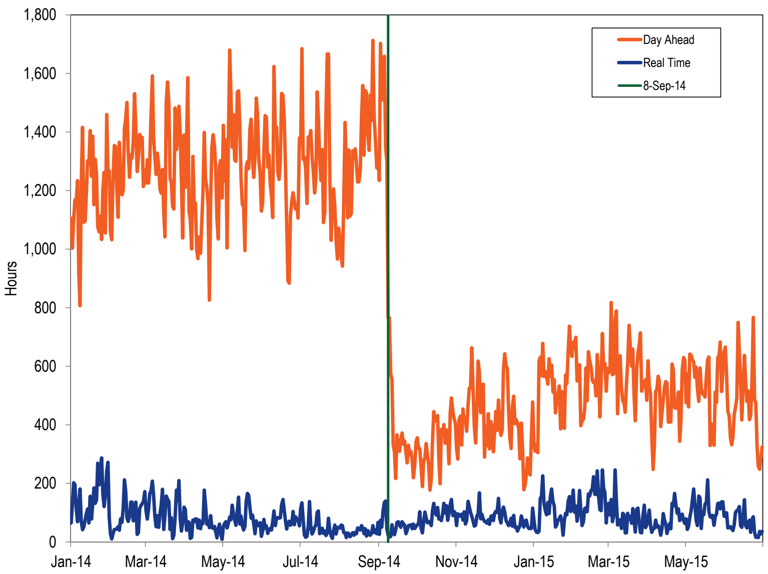
Table 11-32 Congestion cost by type of participant: January through June of 2014

	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	$65.9	$69.2	($103.1)	($106.5)	($26.5)	($0.3)	($58.4)	($84.6)	$0.0	($191.1)
Physical	$326.6	($1,422.8)	$49.0	$1,798.4	$90.9	$220.2	($35.7)	($165.0)	$0.0	$1,633.4
Total	$392.5	($1,353.6)	($54.1)	$1,691.9	$64.4	$219.9	($94.2)	($249.7)	$0.0	$1,442.3

Congestion-Event Summary before and after September 8, 2014

The day-ahead congestion event hours decreased significantly after September 8, 2014. The reduction in UTC activity was a result of FERC's UTC uplift refund notice, effective September 8, 2014.[24] Figure 11-5 shows the daily day-ahead and real-time congestion event hours for 2014 through June of 2015.

Figure 11-5 Daily congestion event hours: 2014 through June of 2015



24 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.

Total marginal loss costs equal net implicit marginal loss costs plus net explicit marginal loss costs plus net inadvertent loss charges. Net implicit marginal loss costs equal load loss payments minus generation loss credits. Net explicit marginal loss costs are the net marginal loss costs associated with point-to-point energy transactions. Net inadvertent loss charges are the losses associated with the hourly difference between the net actual energy flow and the net scheduled energy flow into or out of the PJM control area.[25] Unlike the other categories of marginal loss accounting, inadvertent loss charges are common costs not directly attributable to specific participants. Inadvertent loss charges are assigned to load on a load ratio share basis. Each of these categories of marginal loss costs is comprised of day-ahead and balancing 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.

25 OA. Schedule 1 (PJM Interchange Energy Market) §3.7

Day-ahead marginal loss costs are based on day-ahead MWh priced at the marginal loss price component of LMP. Balancing marginal loss costs are based on the load or generation deviations between the Day-Ahead and Real-Time Energy Markets priced at the marginal loss price component of LMP in the Real-Time Energy Market. If a participant has real-time generation or load that is greater than its day-ahead generation or load then the deviation will be positive. If there is a positive load deviation at a bus where the real-time LMP has a positive marginal loss component, positive balancing marginal loss costs will result. Similarly, if there is a positive load deviation at a bus where real-time LMP has a negative marginal loss component, negative balancing marginal loss costs will result. If a participant has real-time generation or load that is less than its day-ahead generation or load then the deviation will be negative. If there is a negative load deviation at a bus where real-time LMP has a positive marginal loss component, negative balancing marginal loss costs will result. Similarly, if there is a negative load deviation at a bus where real-time LMP has a negative marginal loss component, positive balancing marginal loss costs will result.

Marginal loss credits or loss surplus is the remaining loss amount from collection of marginal losses, after accounting for total energy costs and net residual market adjustments, that is paid back in full to load and exports on a load ratio basis. Payment to load is appropriate as load is the source of the surplus.

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 six months of 2015 was $608.3 million, which was comprised of load loss payments of -$15.4 million, generation loss credits of -$635.5 million, explicit loss costs of -$11.9 million and inadvertent loss charges of $0.0 million. Monthly marginal loss costs in the first six months of 2015 ranged from $52.0 million in April to $220.3 million in February. Marginal loss credits decreased in the first six months of 2015 by $118.3 million or 36.4 percent from the first six months of 2014, from $325.0 million to $206.7 million.

Total Marginal Loss Costs

Table 11-33 shows the total marginal loss component costs for the first six months of 2009 through 2015.

Table 11-33 Total marginal loss component costs (Dollars (Millions)): January through June of 2009 through 2015[26]

(Jan - Jun)	Loss Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	$705	NA	$13,457	5.2%
2010	$751	6.5%	$16,314	4.6%
2011	$701	(6.6%)	$18,685	3.8%
2012	$445	(36.6%)	$13,991	3.2%
2013	$494	11.2%	$15,571	3.2%
2014	$1,006	103.5%	$31,060	3.2%
2015	$608	(39.5%)	$23,400	2.6%

26 The loss costs include net inadvertent charges.

Total marginal loss costs for the first six months of 2009 through 2015 are shown in Table 11-34 and Table 11-35. Table 11-34 shows PJM total marginal loss costs by accounting category for the first six months of 2009 through 2015. Table 11-35 shows PJM total marginal loss costs by accounting category by market for the first six months 2009 through 2015.

Table 11-34 Total PJM marginal loss costs by accounting category (Dollars (Millions)): January through June of 2009 through 2015

Marginal Loss Costs (Millions)					
(Jan - Jun)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	($42.2)	($726.4)	$20.7	$0.0	$704.8
2010	($15.7)	($750.5)	$16.2	($0.0)	$750.9
2011	($70.6)	($755.3)	$16.8	$0.0	$701.5
2012	($17.9)	($473.4)	($10.6)	$0.0	$444.9
2013	$8.6	($512.4)	($26.6)	($0.0)	$494.5
2014	($35.7)	($1,083.3)	($41.4)	$0.0	$1,006.2
2015	($15.4)	($635.5)	($11.9)	$0.0	$608.3

Table 11-35 Total PJM marginal loss costs by accounting category by market (Dollars (Millions)): January through June of 2009 through 2015

Marginal Loss Costs (Millions)										
	Day Ahead				Balancing					
(Jan - Jun)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	($43.8)	($723.3)	$44.6	$724.1	$1.5	($3.1)	($23.9)	($19.3)	$0.0	$704.8
2010	($27.2)	($751.6)	$33.5	$757.9	$11.4	$1.2	($17.3)	($7.0)	($0.0)	$750.9
2011	($90.4)	($774.1)	$44.3	$728.1	$19.8	$18.8	($27.5)	($26.6)	$0.0	$701.5
2012	($30.4)	($481.4)	$15.5	$466.5	$12.5	$8.0	($26.1)	($21.6)	$0.0	$444.9
2013	($7.2)	($528.2)	$25.0	$546.0	$15.9	$15.8	($51.6)	($51.6)	($0.0)	$494.5
2014	($75.4)	($1,118.8)	$51.6	$1,095.0	$39.7	$35.6	($93.0)	($88.8)	$0.0	$1,006.2
2015	($33.2)	($643.0)	$15.6	$625.4	$17.8	$7.4	($27.5)	($17.1)	$0.0	$608.3

Monthly Marginal Loss Costs

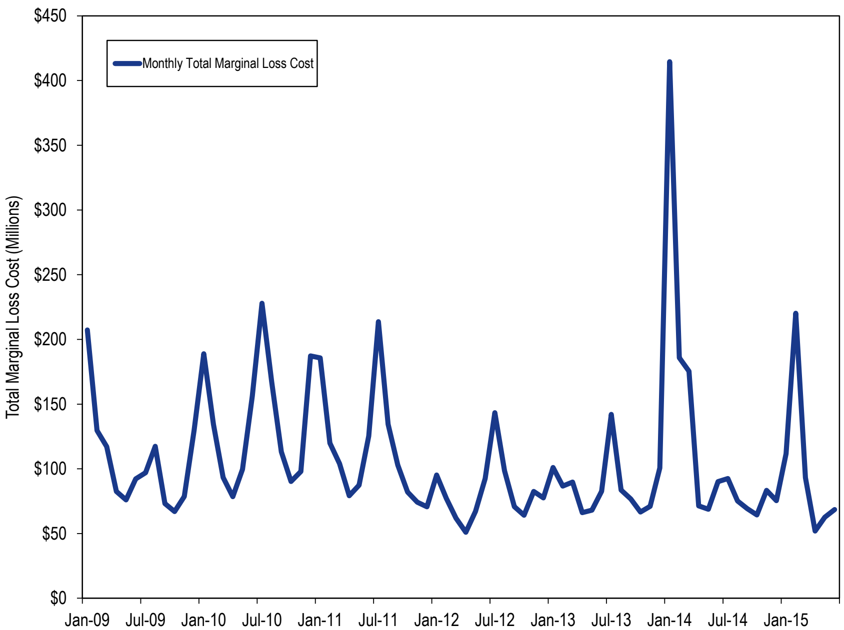
Table 11-36 shows a monthly summary of marginal loss costs by market type for the first six months of 2014 and the first six months of 2015. Total marginal loss costs decreased because of the distribution of high load and outages related to the cold weather in January, but marginal loss costs were also lower in March 2015 than in March 2014.

Table 11-36 Monthly marginal loss costs by market (Dollars (Millions)): January through June of 2014 and 2015

Marginal Loss Costs (Millions)								
	2014				2015			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	$431.1	($16.5)	$0.0	$414.6	$115.9	($4.2)	$0.0	$111.7
Feb	$202.1	($16.3)	$0.0	$185.8	$218.2	$2.0	$0.0	$220.3
Mar	$198.0	($22.6)	($0.0)	$175.4	$97.9	($4.7)	($0.0)	$93.2
Apr	$83.2	($11.8)	($0.0)	$71.4	$54.0	($2.0)	($0.0)	$52.0
May	$80.3	($11.5)	$0.0	$68.7	$66.2	($3.6)	$0.0	$62.6
Jun	$100.4	($10.2)	$0.0	$90.2	$73.2	($4.6)	($0.0)	$68.6
Total	$1,095.0	($88.8)	$0.0	$1,006.2	$625.4	($17.1)	$0.0	$608.3

Figure 11-6 shows PJM monthly marginal loss costs for 2009 through June of 2015.

Figure 11-6 PJM monthly marginal loss costs (Dollars (Millions)): 2009 through June of 2015



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 11-37 shows the total energy costs, the total marginal loss costs collected, the net residual market adjustments and total marginal loss credits redistributed for the first six months of 2009 through 2015. The total marginal loss credits decreased $118.3 million in the first six months of 2015 from the first six months of 2014.

Table 11-37 Marginal loss credits (Dollars (Millions)): January through June of 2009 through 2015[27]

	Loss Credit Accounting (Millions)			
(Jan - Jun)	Total Energy Charges	Total Marginal Loss Charges	Adjustments	Loss Credits
2009	($343.6)	$704.8	$1.3	$362.5
2010	($372.8)	$750.9	($0.6)	$377.5
2011	($393.9)	$701.5	$0.8	$308.4
2012	($262.0)	$444.9	($0.8)	$182.1
2013	($332.6)	$494.5	($0.7)	$161.3
2014	($677.2)	$1,006.2	($4.1)	$325.0
2015	($397.6)	$608.3	($3.9)	$206.7

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

27 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.

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.

Total Energy Costs

The total energy cost for the first six months of 2015 was -$397.6 million, which was comprised of load energy payments of $24,267.0 million, generation energy credits of $24,667.1 million, explicit energy costs of $0.0 million and inadvertent energy charges of $2.5 million. The monthly energy costs for the first six months of 2015 ranged from -$141.5 million in February to -$36.0 million in April.

Table 11-38 shows total energy component costs and total PJM billing, for the first six months of 2009 through 2015. The total energy component costs are net energy costs.

Table 11-38 Total PJM costs by energy component (Dollars (Millions)): January through June of 2009 through 2015[28]

(Jan - Jun)	Energy Costs	Percent Change	Total PJM Billing	Percent of PJM Billing
2009	($344)	NA	$13,457	(2.6%)
2010	($373)	8.5%	$16,314	(2.3%)
2011	($394)	5.7%	$18,685	(2.1%)
2012	($262)	(33.5%)	$13,991	(1.9%)
2013	($333)	26.9%	$15,571	(2.1%)
2014	($677)	103.6%	$31,060	(2.2%)
2015	($398)	(41.3%)	$23,400	(1.7%)

Energy costs for the first six months of 2009 through 2015 are shown in Table 11-39 and Table 11-40. Table 11-39 shows PJM energy costs by accounting category for the first six months of 2009 through 2015 and Table 11-40 shows PJM energy costs by market category for the first six months of 2009 through 2015. These energy costs are the actual total energy costs rather than the net energy costs in Table 11-38.

Table 11-39 Total PJM energy costs by accounting category (Dollars (Millions)): January through June of 2009 through 2015

	Energy Costs (Millions)				
(Jan - Jun)	Load Payments	Generation Credits	Explicit Costs	Inadvertent Charges	Total
2009	$22,815.7	$23,162.1	$0.0	$2.9	($343.6)
2010	$25,040.9	$25,406.7	$0.0	($7.1)	($372.8)
2011	$23,524.8	$23,932.1	$0.0	$13.3	($393.9)
2012	$16,823.4	$17,092.7	$0.0	$7.2	($262.0)
2013	$20,488.2	$20,819.3	$0.0	($1.5)	($332.6)
2014	$39,885.0	$40,556.7	$0.0	($5.4)	($677.2)
2015	$24,267.0	$24,667.1	$0.0	$2.5	($397.6)

28 The energy costs include net inadvertent charges.

Table 11-40 Total PJM energy costs by market category (Dollars (Millions)): January through June of 2009 through 2015

	Energy Costs (Millions)									
	Day Ahead				Balancing					
(Jan - Jun)	Load Payments	Generation Credits	Explicit Costs	Total	Load Payments	Generation Credits	Explicit Costs	Total	Inadvertent Charges	Grand Total
2009	$22,893.0	$23,278.1	$0.0	($385.1)	($77.3)	($116.0)	$0.0	$38.7	$2.9	($343.6)
2010	$25,072.6	$25,450.1	$0.0	($377.5)	($31.6)	($43.4)	$0.0	$11.8	($7.1)	($372.8)
2011	$23,685.6	$24,076.3	$0.0	($390.6)	($160.8)	($144.1)	$0.0	($16.7)	$13.3	($393.9)
2012	$16,907.0	$17,148.9	$0.0	($241.9)	($83.6)	($56.2)	$0.0	($27.4)	$7.2	($262.0)
2013	$20,543.4	$20,895.6	$0.0	($352.2)	($55.1)	($76.3)	$0.0	$21.2	($1.5)	($332.6)
2014	$39,831.7	$40,780.0	$0.0	($948.3)	$53.3	($223.3)	$0.0	$276.6	($5.4)	($677.2)
2015	$24,389.1	$24,858.0	$0.0	($468.9)	($122.1)	($190.9)	$0.0	$68.8	$2.5	($397.6)

Monthly Energy Costs

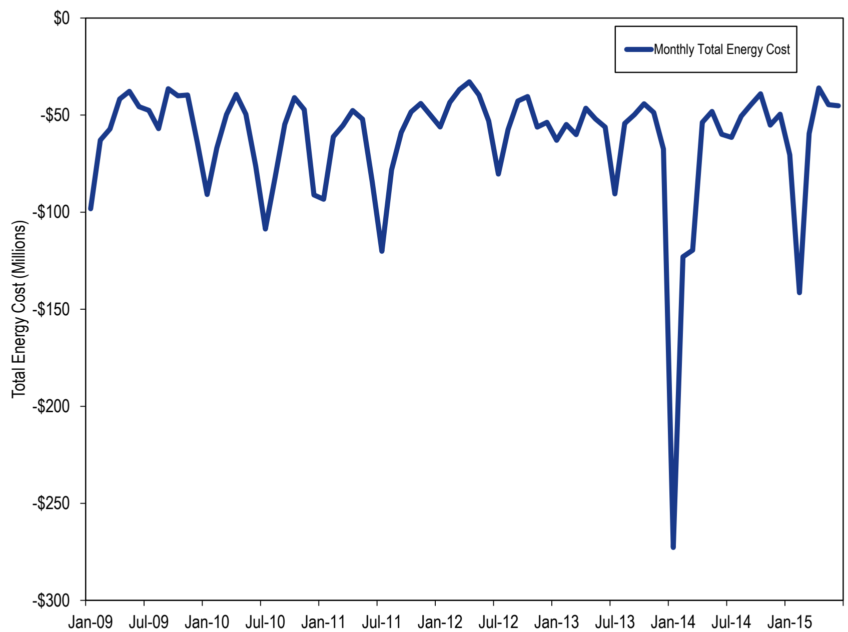
Table 11-41 shows a monthly summary of energy costs by market type for the first six months of 2014 and the first six months of 2015. Marginal total energy costs in the first six months of 2015 decreased from 2014. Monthly total energy costs in the first six months of 2015 ranged from -$141.5 million in February to -$36.0 million in April.

Table 11-41 Monthly energy costs by market type (Dollars (Millions)): January through June of 2014 and 2015

	Energy Costs (Millions)							
	2014 (Jan - Jun)				2015 (Jan - Jun)			
	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total	Day-Ahead Total	Balancing Total	Inadvertent Charges	Grand Total
Jan	($339.8)	$68.1	($1.0)	($272.7)	($84.6)	$13.3	$0.9	($70.5)
Feb	($163.7)	$43.5	($2.8)	($123.0)	($150.5)	$6.2	$2.8	($141.5)
Mar	($167.3)	$50.8	($3.1)	($119.6)	($77.6)	$19.0	($1.0)	($59.6)
Apr	($90.4)	$36.7	($0.1)	($53.7)	($45.4)	$9.5	($0.1)	($36.0)
May	($92.4)	$44.0	$0.3	($48.1)	($57.1)	$12.2	$0.2	($44.7)
Jun	($94.7)	$33.4	$1.3	($59.9)	($53.8)	$8.7	($0.1)	($45.2)
Total	($948.3)	$276.6	($5.4)	($677.2)	($468.9)	$68.8	$2.5	($397.6)

Figure 11-7 shows PJM monthly energy costs for January 2009 through June 2015.

Figure 11-7 PJM monthly energy costs (Dollars (Millions)): January 2009 through June 2015



Generation and Transmission Planning

Overview

Planned Generation and Retirements

- **Planned Generation.** As of June 30, 2015, 77,461.3 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 192,864.9 MW as of June 30, 2015. Of the capacity in queues, 8,242.9 MW, or 10.6 percent, are uprates and the rest are new generation. Wind projects account for 15,297.5 MW of nameplate capacity or 19.7 percent of the capacity in the queues. Combined-cycle projects account for 49,851.5 MW of capacity or 64.4 percent of the capacity in the queues.
- **Generation Retirements.** As shown in Table 12-6, 26,967.6 MW have been, or are planned to be, retired between 2011 and 2019. Of that, 3,203.3 MW are planned to retire after 2015. In the first two quarters of 2015, 9,717.0 MW were retired, of which 7,537.8 MW were coal units. The coal unit retirements were a result of the EPA's Mercury and Air Toxics Standards (MATS) and low gas prices.
- **Generation Mix.** A significant shift in the distribution of unit types within the PJM footprint continues as natural gas fired units enter the queue and steam units retire. While only 1,936.0 MW of coal fired steam capacity are currently in the queue, 53,050.5 MW of gas fired capacity are in the queue. The replacement of coal 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 at least in part as a result 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. Excluding currently active projects and projects currently under construction, 2,182 projects, representing 262,424 MW, have completed the queue process since its inception. Of those, 566 projects, 32,622 MW, went into service. Of the projects that have completed the queue process, 87.6 percent of the MW that entered the queue withdrew at some point in the process. 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 the backlog of incomplete 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 the parent company of the transmission owner or the interconnection requirements of a merchant transmission developer which is a competitor of the transmission owner. 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 as the transmission owner.

Regional Transmission Expansion Plan (RTEP)

- Artificial Island is an area in southern New Jersey that includes nuclear units at Salem and at Hope Creek in the PSEG Zone. 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

1 See PJM, OATT Parts IV & VI.

criteria violations in this area. PJM staff announced on April 28, 2015, that they will recommend that the Board approve the Artificial Island project being designated to LS Power, PSEG, and PHI with a total cost estimate between $263M and $283M.[2]

Backbone Facilities

- PJM baseline transmission projects are implemented to resolve reliability criteria violations. PJM backbone transmission projects are a subset of significant baseline projects, which are intended to resolve multiple 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.

Transmission Facility Outages

- PJM maintains a list of reportable transmission facilities. When the reportable transmission facilities need to be taken out of service, PJM transmission owners are required to report planned transmission facility outages as early as possible. PJM processes the transmission facility outages according to rules in PJM's Manual 3 to decide if the outage is on time, late, or past its deadline.[3]

Recommendations

The MMU recommends improvements to the planning process.

- The MMU recommends the creation of a mechanism to permit a direct comparison, or competition, between transmission and generation alternatives, including which alternative is less costly and who bears the risks associated with each alternative. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that rules be implemented to permit competition to provide financing for 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. Status: Not adopted.)
- 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.[4] (Priority: Low. First reported 2013. Status: Not adopted.)
- 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. Status: Not adopted.)
- 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. Status: Not Adopted.)
- 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. Status: Partially adopted, 2014.)
- The MMU recommends that PJM enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. (Priority: Medium. New recommendation. Status: Not adopted.)

2 See PJM. "Artificial Island Recommendations," at <http://www.pjm.com/~/media/committees-groups/committees/teac/20150428-ai/20150428-artificial-island-recommendations.ashx>

3 PJM. "Manual 03: Transmission Operations," Revision 46 (December 1, 2014), Section 4.

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

- The MMU recommends that PJM establish fair terms of access to rights of way and property, such as at substations, in order to remove any barriers to entry and permit competition between incumbent transmission providers and merchant transmission providers in the Regional Transmission Expansion Plan. (Priority: Medium. First reported 2014. Status: Not adopted.)
- The MMU recommends that PJM reevaluate all transmission outage tickets as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages. (Priority: Low. First reported 2014. Status: Not adopted.)

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 transparent, robust and clearly defined mechanism to permit competition to build transmission projects, to ensure that competitors provide total project cost cap, 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, whether there is more risk associated with the generation or transmission alternatives, 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 for new generation investments 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.

The PJM rules for competitive transmission development through the Regional Transmission Expansion Plan should build upon Order No. 1000 to create real competition between incumbent transmission providers and merchant transmission providers. PJM should enhance the transparency and queue management process for merchant transmission investment. Issues related to data access and complete explanations of cost impacts should be addressed. The goal should be to remove barriers to competition from merchant transmission. Another element of opening competition would be to consider transmission owners' ownership of property and rights of way at or around transmission substations. In many cases, the land acquired included property intended to support future expansion of the grid. Incumbents have included the costs of the property in their rate base. Because PJM now has the responsibility for planning the development of the grid under its RTEP process, property bought to facilitate future expansion should be a part of that process and be made available to all providers on equal terms.

The process for the submission of planned transmission outages needs to be carefully reviewed and redesigned to limit the ability of transmission owners to submit transmission outages that are late for FTR Auction bid submission dates and are late for the Day Ahead Energy Market. The submission of late transmission outages can inappropriately affect market outcomes when market participants do not have the ability to modify market bids and offers.

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 time lag 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 June 30, 2015, 77,461.3 MW of capacity were in generation request queues for construction through 2024, compared to an average installed capacity of 192,864.9 MW as of June 30, 2015. 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 six months of 2015, 2,505.8 MW of nameplate capacity went into service in PJM.

Table 12-1 Year-to-year capacity additions from PJM generation queue: Calendar years 2000 through June 30, 2015

	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	2,659.0
2015	2,505.8

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 reset to six months, starting with Queue Y2. Queue AB1 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. 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.[5] When a project is suspended, PJM extends the scheduled milestones by the duration of the suspension. If, at any time, a milestone is not met, PJM will initiate the termination of the Interconnection Service Agreement (ISA) and the corresponding cancellation costs must be paid by the customer.

Table 12-2 shows MW in queues by expected completion date and MW changes in the queues between March 31, 2015, and June 30, 2015, for ongoing projects, i.e. projects with the status active, under construction or suspended.[6] Projects that are already in service are not included here. The total MW in queues increased by 10,193.3 MW, or 15.2 percent, from 67,268.0 MW at the end of the first quarter of 2015. The change was the result of 15,803.5 MW in new projects entering the queue, 3,087.0 MW in existing projects withdrawing, and 1,827.0 MW going into service. The remaining difference is the result of projects adjusting their expected MW.

5 See PJM. Manual 14C. "Generation and Transmission Interconnection Process," Revision 8 (December 20, 2012), Section 3.7, <http://www.pjm.com/~/media/documents/manuals/m14c.ashx>.

6 Expected completion dates are entered when the project enters the queue. Actual completion dates are generally different than expected completion dates.

Table 12-2 Queue comparison by expected completion year (MW): March 31, 2015 vs. June 30, 2015[7]

Year	As of 3 /31/2015	As of 6/30/2015	Quarterly Change MW	Quarterly Change Percent
2015	15,609.4	12,632.6	(2,976.8)	(19.1%)
2016	17,453.7	16,466.5	(987.2)	(6.0%)
2017	12,878.1	13,821.4	943.3	6.8%
2018	14,139.0	14,603.1	464.1	3.2%
2019	4,191.8	12,274.8	8,083.0	65.9%
2020	1,152.0	4,442.0	3,290.0	74.1%
2021	250.0	1,377.0	1,127.0	81.8%
2022	0.0	250.0	250.0	100.0%
2024	1,594.0	1,594.0	0.0	0.0%
Total	67,268.0	77,461.3	10,193.3	15.2%

Table 12-3 shows the yearly project status changes in more detail and how scheduled queue capacity has changed between March 31, 2015, and June 30, 2015. For example, 27,814.9 MW entered the queue in the second quarter of 2015, 15,803.5 MW of which are currently active and 12,011.5 MW of which were withdrawn before the quarter ended. Of the total 39,974.8 MW marked as active at the beginning of the quarter, 3,034.0 MW were withdrawn, 1,745.3 MW started construction, and 225.1 MW went into service by the end of the second quarter. The Under Construction column shows that 964.0 MW came out of suspension and 1,745.3 MW began construction in the second quarter of 2015, in addition to the 20,254.1 MW of capacity that maintained the status under construction from the previous quarter.

Table 12-3 Change in project status (MW): March 31, 2015 vs. June 30, 2015

Status at 3/31/2015	Total at 3/31/2015	Status at 6/30/2015 Active	Suspended	Under Construction	In Service	Withdrawn
(Entered in Q2 2015)		15,803.5	0.0	0.0	0.0	12,011.5
Active	39,974.8	34,288.1	0.0	1,745.3	225.1	3,034.0
Suspended	5,224.8	0.0	4,036.8	964.0	200.0	24.0
Under Construction	22,068.4	0.0	369.5	20,254.1	1,401.8	29.0
In Service	38,975.3	0.0	0.0	0.0	38,969.6	0.0
Withdrawn	277,444.8	0.0	0.0	0.0	0.0	265,939.1
Total at 6/30/2015		50,091.6	4,406.3	22,963.4	40,796.5	281,037.5

7 Wind and solar capacity in Table 12-2 through Table 12-5 have not been adjusted to reflect derating.

Table 12-4 shows the amount of capacity active, in-service, under construction, suspended, or withdrawn for each queue since the beginning of the 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 June 30, 2015, there are 77,461.3 MW of capacity in queues that are not yet in service, of which 5.7 percent are suspended, 29.6 percent are under construction and 64.7 percent have not begun construction.

Table 12-4 Capacity in PJM queues (MW): At June 30, 2015[8]

Queue	Active	In Service	Under Construction	Suspended	Withdrawn	Total
A Expired 31-Jan-98	0.0	8,103.0	0.0	0.0	17,347.0	25,450.0
B Expired 31-Jan-99	0.0	4,465.0	0.0	0.0	14,620.7	19,085.7
C Expired 31-Jul-99	0.0	531.0	0.0	0.0	3,470.7	4,001.7
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	778.2	0.0	0.0	8,021.8	8,800.0
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	1,189.6	0.0	0.0	17,962.3	19,151.9
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	200.0	0.0	0.0	2,425.4	2,625.4
L Expired 31-Jan-04	0.0	252.5	0.0	0.0	4,033.7	4,286.2
M Expired 31-Jul-04	0.0	477.8	150.0	0.0	3,705.6	4,333.4
N Expired 31-Jan-05	0.0	2,382.8	38.0	0.0	8,090.3	10,511.0
O Expired 31-Jul-05	0.0	1,668.2	437.0	0.0	5,466.8	7,572.0
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	0.0	2,046.4	988.3	300.0	19,420.6	22,755.3
S Expired 31-Jul-07	0.0	3,536.3	458.3	420.0	12,706.5	17,121.0
T Expired 31-Jan-08	675.0	1,911.0	2,011.8	428.0	22,488.3	27,514.1
U Expired 31-Jan-09	1,410.0	1,072.8	401.9	300.0	30,119.6	33,304.3
V Expired 31-Jan-10	1,249.2	1,812.8	1,774.3	148.0	12,016.4	17,000.7
W Expired 31-Jan-11	2,018.0	1,159.6	1,603.7	1,564.0	17,942.6	24,287.9
X Expired 31-Jan-12	3,045.5	359.0	8,993.9	383.8	17,586.0	30,368.2
Y Expired 30-Apr-13	3,623.5	474.0	3,910.9	630.8	17,336.3	25,975.3
Z Expired 30-Apr-14	8,392.7	220.3	457.5	21.7	5,579.9	14,672.0
AA1 Expired 31-Oct-14	10,919.6	5.3	81.5	0.0	1,243.8	12,250.2
AA2 Expired 30-Apr-15	15,661.8	0.0	0.0	0.0	1,383.8	17,045.6
AB1 Through 30-Jun-15	2,991.3	0.0	0.0	0.0	1.5	2,992.8
Total	50,091.6	40,796.5	22,963.4	4,406.3	281,037.5	399,295.4

8 Projects listed as partially in-service are counted as in-service for the purposes of this analysis.

Table 12-5 Queue capacity by control zone and fuel (MW) at June 30, 2015[9]

Zone	CC	CT	Diesel	Hydro	Nuclear	Solar	Steam	Storage	Wind	Total Queue Capacity	Planned Retirements
AECO	1,276.0	295.3	0.0	0.0	0.0	73.2	0.0	20.0	373.0	2,037.5	8.0
AEP	6,111.0	51.0	17.8	46.5	102.0	118.4	209.0	72.0	7,312.0	14,039.7	0.0
AP	4,767.4	0.0	119.5	68.2	0.0	184.3	1,724.2	31.0	723.6	7,618.2	0.0
ATSI	4,052.0	0.8	21.6	0.0	0.0	0.0	0.0	0.0	518.0	4,592.4	6.3
BGE	0.0	0.0	30.3	0.4	0.0	23.1	132.0	0.0	0.0	185.8	209.0
ComEd	1,720.8	603.3	15.3	22.7	0.0	14.0	27.0	140.6	3,562.0	6,105.7	0.0
DAY	0.0	0.0	1.9	112.0	0.0	23.4	12.0	20.0	300.0	469.3	0.0
DEOK	513.0	0.0	6.4	0.0	0.0	125.0	50.0	18.0	0.0	712.4	0.0
DLCO	205.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	205.0	124.0
Dominion	5,465.3	0.0	3.6	0.0	1,594.0	1,571.4	62.5	128.0	1,322.1	10,146.9	323.0
DPL	901.0	17.0	2.0	0.0	0.0	455.5	0.0	20.0	250.0	1,645.5	34.0
EKPC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	149.0
JCPL	3,034.0	0.0	0.0	0.0	0.0	574.1	0.0	180.0	0.0	3,788.1	614.5
Met-Ed	1,250.0	86.6	0.0	0.0	16.8	3.0	401.0	0.0	0.0	1,757.4	0.0
PECO	4,229.5	0.0	3.7	0.0	330.0	0.0	0.0	0.0	0.0	4,563.2	50.8
PENELEC	3,841.0	592.3	181.2	40.0	0.0	13.5	0.0	68.4	413.3	5,149.7	0.0
Pepco	2,725.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,725.6	1,204.0
PPL	6,100.0	0.0	5.0	0.0	0.0	129.0	16.0	30.0	523.5	6,803.5	0.0
PSEG	3,659.9	1,096.1	13.6	0.0	0.0	145.9	0.0	0.0	0.0	4,915.5	611.0
RECO	0.0	0.0	0.0	0.0	0.0	0.0		0.0	0.0	0.0	0.0
Total	49,851.5	2,742.4	421.9	289.8	2,042.8	3,453.8	2,633.7	728.0	15,297.5	77,461.3	3,333.6

Distribution of Units in the Queues

Table 12-5 shows the projects under construction, suspended, or active, by unit type, and control zone.[10] As of June 30, 2015, 77,461.3 MW of capacity were in generation request queues for construction through 2024, compared to 67,268.0 MW at March 31, 2015.[11] Table 12-5 also shows the planned retirements for each zone. 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. A significant shift in the distribution of unit types within the PJM footprint continues as natural gas fired units enter the queue and steam units retire. While 53,050.5 MW of gas fired capacity are in the queue, only 1,936.0 MW of coal fired steam capacity are in the queue. The only new coal project since the second quarter a year ago is the new Hatfield unit, with 1,710 MW of capacity. This project entered the queue in October, 2014 and is intended to replace three coal units retired in October 2013 at the same location. With respect to retirements, 1,935.0 MW of coal fired steam capacity and 1,572.0 MW of natural gas capacity are slated for deactivation. The replacement of coal 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.

Planned Retirements

As shown in Table 12-6, 26,967.6 MW have been, or are planned to be, retired between 2011 and 2019. Of that, 3,203.3 MW are planned to retire after 2015.

9 This data includes only projects with a status of active, under-construction, or suspended.
10 Unit types designated as reciprocating engines are classified as diesel.
11 Since wind resources cannot be dispatched on demand, PJM rules previously required that the unforced capacity of wind resources be derated to 20 percent of installed capacity until actual generation data are available. Beginning with Queue U, PJM derates wind resources to 13 percent of installed capacity 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 15,297.5 MW of wind resources and 3,453,8 MW of solar resources, the 77,461.3 MW currently active in the queue would be reduced to 62,011.1 MW.

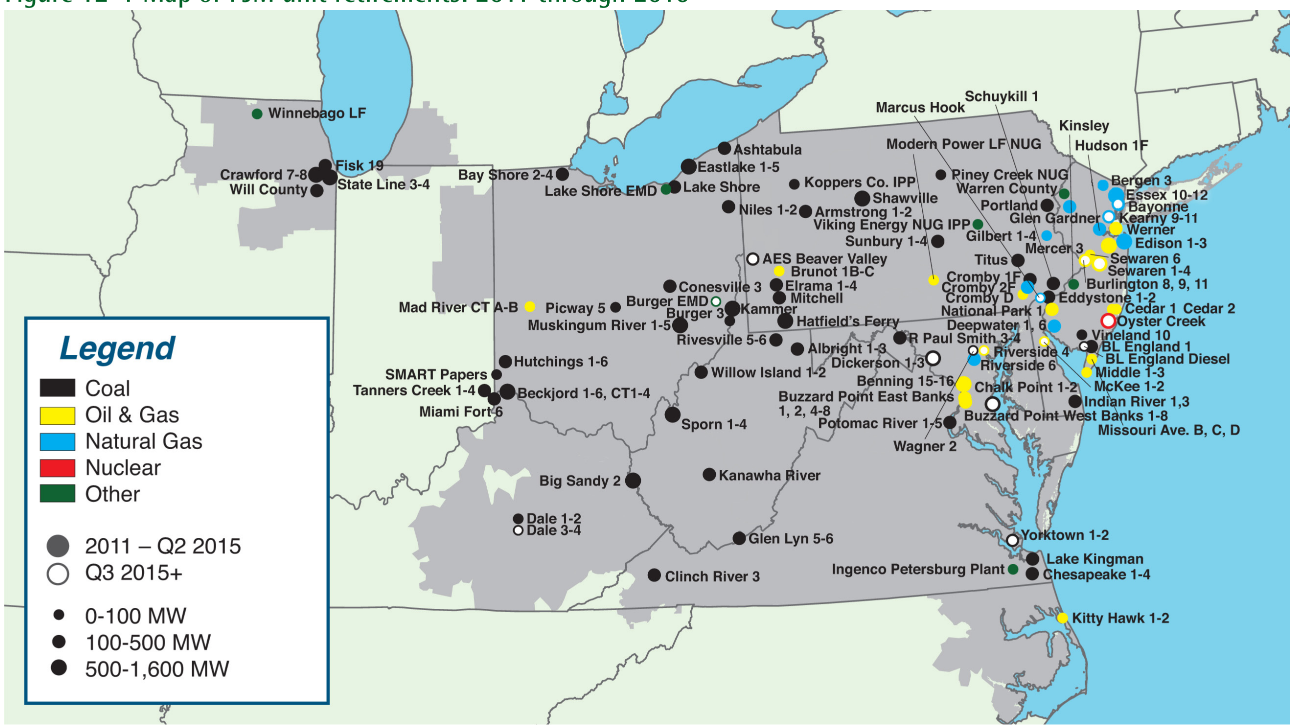
In the first two quarters of 2015, 9,717.0 MW were retired, of which 7,537.8 MW were coal units. The coal unit retirements were a result of the EPA's Mercury and Air Toxics Standards (MATS) and low gas prices.

Table 12-6 Summary of PJM unit retirements by fuel (MW): 2011 through 2019

	Coal	Diesel	Heavy Oil	Kerosene	Landfill Gas	Light Oil	Natural Gas	Nuclear	Wood Waste	Total
Retirements 2011	543.0	0.0	0.0	0.0	0.0	63.7	522.5	0.0	0.0	1,129.2
Retirements 2012	5,907.9	0.0	0.0	0.0	0.0	788.0	250.0	0.0	16.0	6,961.9
Retirements 2013	2,589.9	2.9	166.0	0.0	3.8	85.0	0.0	0.0	8.0	2,855.6
Retirements 2014	2,427.0	50.0	0.0	184.0	15.3	0.0	294.0	0.0	0.0	2,970.3
Retirements 2015	7,537.8	4.0	0.0	644.2	0.0	212.0	1,319.0	0.0	0.0	9,717.0
Planned Retirements 2015	124.0	6.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	130.3
Planned Retirements Post-2015	1,811.0	8.0	108.0	0.0	0.0	0.0	661.8	614.5	0.0	3,203.3
Total	20,940.6	71.2	274.0	828.2	19.1	1,148.7	3,047.3	614.5	24.0	26,967.6

A map of these retirements between 2011 and 2019 is shown in Figure 12-1.

Figure 12-1 Map of PJM unit retirements: 2011 through 2019



The list of pending deactivations is shown in Table 12-7.

Table 12-7 Planned deactivations of PJM units, as of June 30, 2015

Unit	Zone	MW	Fuel	Unit Type	Projected Deactivation Date
AES Beaver Valley	DLCO	124.0	Coal	Steam	01-Sep-15
Burger EMD	ATSI	6.3	Diesel	Diesel	18-Sep-15
Yorktown 1-2	Dominion	323.0	Coal	Steam	31-Mar-16
Dale 3-4	EKPC	149.0	Coal	Steam	16-Apr-16
BL England Diesels	AECO	8.0	Diesel	Diesel	31-May-16
Riverside 4	BGE	74.0	Natural gas	Steam	01-Jun-16
McKee 1-2	DPL	34.0	Heavy Oil	Combustion Turbine	31-May-17
Sewaren 1-4	PSEG	453.0	Kerosene	Combustion Turbine	01-Nov-17
Bayonne Cogen Plant (CC)	PSEG	158.0	Natural gas	Steam	01-Nov-18
MH50 Marcus Hook Co-gen	PECO	50.8	Natural gas	Steam	13-May-19
Chalk Point 1-2	Pepco	667.0	Coal	Steam	31-May-19
Dickerson 1-3	Pepco	537.0	Coal	Steam	31-May-19
Oyster Creek	JCPL	614.5	Nuclear	Nuclear	31-Dec-19
Wagner 2	BGE	135.0	Coal	Steam	01-Jun-20
Total		3,333.6			

Table 12-8 shows the capacity, average size, and average age of units retiring in PJM, from 2011 through 2019, while Table 12-9 shows these retirements by state. The majority, 77.5 percent of all MW retiring during this period are coal steam units. These units have an average age of 56.2 years and an average size of 165.9 MW. More than half of them, 51.6 percent, are located in either Ohio or Pennsylvania. Retirements have generally 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	126	165.9	56.2	20,909.6	77.5%
Diesel	6	11.9	42.5	71.2	0.3%
Heavy Oil	4	68.5	57.5	274.0	1.0%
Kerosene	20	41.4	45.5	828.2	3.1%
Landfill Gas	4	4.8	14.8	19.1	0.1%
Light Oil	15	76.6	43.8	1,148.7	4.3%
Natural Gas	51	59.8	46.3	3,047.3	11.3%
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	230	117.3	50.8	26,967.6	100.0%

Table 12-9 Retirements (MW) by fuel type and state, 2011 through 2019

State	Coal	Diesel	Heavy Oil	Kerosene	Landfill Gas	Light Oil	Natural Gas	Nuclear	Wood Waste	Total
Delaware	254.0	0.0	34.0	0.0	0.0	0.0	0.0	0.0	0.0	288.0
Illinois	1,624.0	0.0	0.0	0.0	6.4	0.0	0.0	0.0	0.0	1,630.4
Indiana	982.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	982.0
Kentucky	995.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	995.0
Maryland	1,454.0	0.0	74.0	0.0	0.0	0.0	115.0	0.0	0.0	1,643.0
Michigan	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New Jersey	136.0	8.0	0.0	828.2	4.7	212.0	2,680.5	614.5	0.0	4,483.9
North Carolina	0.0	0.0	0.0	0.0	0.0	31.0	0.0	0.0	0.0	31.0
Ohio	5,658.6	60.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5,718.9
Pennsylvania	5,145.0	0.0	166.0	0.0	8.0	117.7	251.8	0.0	24.0	5,712.5
Tennessee	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Virginia	2,051.0	2.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,053.9
West Virginia	2,641.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2,641.0
Washington, DC	0.0	0.0	0.0	0.0	0.0	788.0	0.0	0.0	0.0	788.0
Total	20,940.6	71.2	274.0	828.2	19.1	1,148.7	3,047.3	614.5	24.0	26,967.6

Actual Generation Deactivations in 2015

Table 12-10 shows the units that were deactivated in 2015.

Table 12-10 Unit deactivations in 2015

Company	Unit Name	ICAP (MW)	Primary Fuel	Zone Name	Average Age (Years)	Retirement Date
Calpine Corporation	Cedar 1	44.0	Kerosene	AECO	43	28-Jan-15
First Energy	Eastlake 2	109.0	Coal	ATSI	62	06-Apr-15
First Energy	Eastlake 1	109.0	Coal	ATSI	62	09-Apr-15
First Energy	Eastlake 3	109.0	Coal	ATSI	61	10-Apr-15
First Energy	Ashtabula 5	210.0	Coal	ATSI	57	11-Apr-15
First Energy	Lake Shore 18	190.0	Coal	ATSI	53	13-Apr-15
First Energy	Lake Shore EMD	4.0	Diesel	ATSI	49	15-Apr-15
NRG Energy	Will County	251.0	Coal	Comed	58	15-Apr-15
EKPC	Dale 1-2	46.0	Coal	EKPC	61	16-Apr-15
Calpine Corporation	Cedar 2	21.6	Kerosene	AECO	43	01-May-15
NRG Energy	Gilbert 1-4	98.0	Natural gas	JCPL	45	01-May-15
NRG Energy	Glen Gardner 1-8	160.0	Natural gas	JCPL	44	01-May-15
Calpine Corporation	Middle 1-3	74.7	Kerosene	AECO	45	01-May-15
Calpine Corporation	Missouri Ave B, C, D	57.9	Kerosene	AECO	46	01-May-15
NRG Energy	Werner 1-4	212.0	Light oil	JCPL	43	01-May-15
PSEG	Bergen 3	21.0	Natural gas	PSEG	48	01-Jun-15
AEP	Big Sandy 2	800.0	Coal	AEP	46	01-Jun-15
PSEG	Burlington 8, 11	205.0	Kerosene	PSEG	48	01-Jun-15
AEP	Clinch River 3	230.0	Coal	AEP	54	01-Jun-15
PSEG	Edison 1-3	504.0	Natural gas	PSEG	44	01-Jun-15
PSEG	Essex 10-11	352.0	Natural gas	PSEG	44	01-Jun-15
PSEG	Essex 12	184.0	Natural gas	PSEG	43	01-Jun-15
AEP	Glen Lyn 5-6	325.0	Coal	AEP	65	01-Jun-15
AES Corporation	Hutchings 1-3, 5-6	271.8	Coal	DAY	65	01-Jun-15
AEP	Kammer 1-3	600.0	Coal	AEP	57	01-Jun-15
AEP	Kanawha River 1-2	400.0	Coal	AEP	62	01-Jun-15
PSEG	Mercer 3	115.0	Kerosene	PSEG	48	01-Jun-15
Duke Energy Kentucky	Miami Fort 6	163.0	Coal	DEOK	55	01-Jun-15
AEP	Muskingum River 1-5	1,355.0	Coal	AEP	60	01-Jun-15
PSEG	National Park 1	21.0	Kerosene	PSEG	46	01-Jun-15
AEP	Picway 5	95.0	Coal	AEP	60	01-Jun-15
PSEG	Sewaren 6	105.0	Kerosene	PSEG	50	01-Jun-15
AEP	Sporn 1-4	580.0	Coal	AEP	64	01-Jun-15
AEP	Tanners Creek 1-4	982.0	Coal	AEP	60	01-Jun-15
NRG Energy	Shawville 4	175.0	Coal	PENELEC	55	02-Jun-15
NRG Energy	Shawville 3	175.0	Coal	PENELEC	56	07-Jun-15
NRG Energy	Shawville 1	122.0	Coal	PENELEC	61	12-Jun-15
NRG Energy	Shawville 2	125.0	Coal	PENELEC	61	14-Jun-15
Portsmouth Genco	Lake Kingman	115.0	Coal	Dominion	27	19-Jun-15
Total		9,717.0				

Generation Mix

As of June 30, 2015, PJM had an installed capacity of 192,864.9 MW (Table 12-11). This measure differs from capacity market installed capacity because it includes energy-only units and uses non-derated values for solar and wind resources.

Table 12-11 Existing PJM capacity: At June 30, 2015 (By zone and unit type (MW))[12]

Zone	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
AECO	901.9	507.7	22.6	0.0	0.0	0.0	41.7	815.9	0.0	7.5	2,297.3
AEP	4,900.0	3,682.2	77.1	0.0	1,071.9	2,071.0	0.0	18,897.8	4.0	1,953.2	32,657.2
AP	1,129.0	1,214.9	47.9	0.0	86.0	0.0	36.1	5,409.0	27.4	1,058.5	9,008.8
ATSI	685.0	1,617.4	74.0	0.0	0.0	2,134.0	0.0	5,813.0	0.0	0.0	10,323.4
BGE	0.0	840.0	18.4	0.0	0.0	1,716.0	0.0	2,995.5	0.0	0.0	5,569.9
ComEd	3,146.1	7,244.0	93.8	0.0	0.0	10,473.5	9.0	5,166.1	4.5	2,431.9	28,568.9
DAY	0.0	1,368.5	47.5	0.0	0.0	0.0	1.1	2,908.0	40.0	0.0	4,365.1
DEOK	47.2	654.0	0.0	0.0	0.0	0.0	0.0	3,730.0	2.0	0.0	4,433.2
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	5,493.6	3,874.8	153.8	0.0	3,589.3	3,581.3	22.7	7,890.0	0.0	0.0	24,605.5
DPL	1,498.5	1,820.4	96.1	30.0	0.0	0.0	4.0	1,620.0	0.0	0.0	5,069.0
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	5,253.5	0.0	0.0	7,304.0
JCPL	1,692.5	763.1	19.9	0.0	400.0	614.5	96.3	10.0	0.0	0.0	3,596.3
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	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
PPL	1,807.9	616.2	55.5	0.0	706.6	2,520.0	15.0	5,169.9	20.0	219.7	11,130.8
PSEG	3,091.3	1,132.0	11.1	0.0	5.0	3,493.0	124.8	2,050.1	2.0	0.0	9,909.3
RECO	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	31,658.0	29,163.8	817.7	30.0	8,378.0	33,744.6	353.7	82,016.5	100.9	6,601.7	192,864.9

Figure 12-2 and Table 12-12 show the age of PJM generators by unit type. Units older than 40 years comprise 69,760.2 MW, or 36.2 percent, of the total capacity of 192,864.9 MW.

Table 12-12 PJM capacity (MW) by age (years): At June 30, 2015

Age (years)	CC	CT	Diesel	Fuel Cell	Hydroelectric	Nuclear	Solar	Steam	Storage	Wind	Total
Less than 20	27,279.5	21,754.9	557.0	30.0	189.6	0.0	353.7	5,212.9	100.9	6,601.7	62,080.2
20 to 40	3,936.5	2,913.9	88.8	0.0	3,557.2	22,906.4	0.0	27,621.7	0.0	0.0	61,024.5
40 to 60	442.0	4,495.0	169.9	0.0	3,010.0	10,838.2	0.0	47,545.4	0.0	0.0	66,500.5
More than 60	0.0	0.0	2.0	0.0	1,621.2	0.0	0.0	1,636.5	0.0	0.0	3,259.7
Total	31,658.0	29,163.8	817.7	30.0	8,378.0	33,744.6	353.7	82,016.5	100.9	6,601.7	192,864.9

12 The capacity described in this section refers to all non-derated installed capacity in PJM, regardless of whether the capacity entered the RPM auction.

Figure 12-2 PJM capacity (MW) by age (years): At June 30, 2015

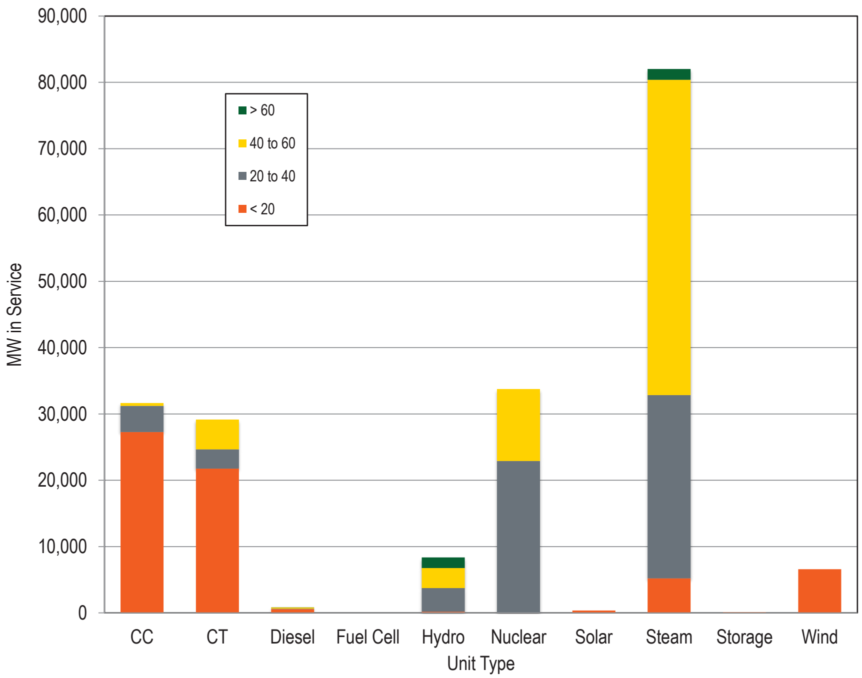


Table 12-13 shows the effect that expected retirements and new generation in the queues would have on the existing generation mix five years from now. Even though 69,760.2 MW of the total capacity are more than 40 years old, only 3,333.6 MW are planned to retire within the next five years. The expected role of gas-fired generation depends on projects in the queues and retirement of coal-fired generation. Existing capacity is 42.5 percent steam, which will be reduced to 31.9 percent by 2020 as a result of the addition of 44,498.5 MW of planned CC capacity. The percentage of CC capacity would increase from 16.4 percent to 29.7 percent of total capacity in PJM in 2020.

Table 12-13 Expected capacity (MW) in five years, as of June 30, 2015[13]

Unit Type	Current Generator Capacity	Percent of Area Total	Planned Additions	Planned Retirements	Estimated Capacity in 5 Years	Percent of Area Total
Combined Cycle	31,658.0	16.4%	44,498.5	0.0	76,156.5	29.7%
Combustion Turbine	29,163.8	15.1%	2,742.4	0.0	31,906.2	12.4%
Diesel	817.7	0.4%	415.5	14.3	1,218.9	0.5%
Fuel Cell	30.0	0.0%	0.0	0.0	30.0	0.0%
Hydroelectric	8,378.0	4.3%	154.7	0.0	8,532.7	3.3%
Nuclear	33,744.6	17.5%	448.8	614.5	33,578.9	13.1%
Solar	353.7	0.2%	3,170.8	0.0	3,524.5	1.4%
Steam	82,016.5	42.5%	2,633.7	2,704.8	81,945.4	31.9%
Storage	100.9	0.1%	311.6	0.0	412.5	0.2%
Wind	6,601.7	3.4%	12,657.4	0.0	19,259.1	7.5%
Total	192,864.9	100.0%	67,033.3	3,333.6	256,564.6	100.0%

13 Percentages shown in Table 12-12 are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

Generation and Transmission Interconnection Planning Process

PJM made changes to the queue process in May 2012.[14] These changes included 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). PJM staff reported on June 11, 2015, that the study backlog has been significantly reduced.[15]

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 12-14 is an overview of PJM's study process. System impact and facilities studies are often redone when a project is withdrawn in order to determine the impact on the projects remaining in the queue.

Table 12-14 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

14 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>.
15 See PJM. Planning Committee "PJM Interconnection Queue Status & Statistics Update, Database Snapshot on 5/27/2015," at <http://www.pjm.com/~/media/committees-groups/committees/pc/20150611/20150611-item-09-queue-status-update.ashx>

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.[16] The impact and facilities studies are performed using the full amount of planned generation in the queues. The actual withdrawal rate is shown in Table 12-15. Disregarding projects still active or under construction, Table 12-15 shows the rate at which projects drop out of the queue as they move through the process. Out of 262,424 MW that entered the queue, 32,622 went into service, while the remaining 229,801 MW withdrew at some point. Of the withdrawals, 53.9 percent happened after the Feasibility study was completed, before proceeding to the next milestone.

Table 12-15 Completed (withdrawn or in service) queue MW (January 1, 1997 through June 30, 2015)

Milestone Completed	MW in Queue	Percent of Total in Queue	MW Withdrawn	Percent of Total Withdrawn
Enter Queue	262,424.1	100.0%	20,335.5	8.8%
Feasibility Study	242,088.6	92.3%	123,973.5	53.9%
System Impact Study	118,115.1	45.0%	48,040.5	20.9%
Facility Study	70,074.7	26.7%	22,860.8	9.9%
ISA/WMPA	47,213.9	18.0%	8,151.5	3.5%
CSA	39,062.4	14.9%	6,439.8	2.8%
In Service	32,622.6	12.4%	0.0	0.0%

Table 12-16 shows the milestone due when projects were withdrawn, for all withdrawn projects. Of the projects withdrawn, 48.1 percent were withdrawn before the Impact Study was completed. Once an Interconnection Service Agreement (ISA), or a Wholesale Market Participation Agreement (WMPA), is executed, the financial obligation for any necessary transmission upgrades cannot be retracted.[17] [18] As expected, withdrawing at or beyond this point is uncommon; 201 projects, or 12.4 percent, of all projects withdrawn were withdrawn after reaching this milestone.

16 See PJM Manual 14B. "PJM Region Transmission Planning Process," Revision 30 (February 26, 2015), p.70.
17 "Generators planning to connect to the local distribution systems at locations that are not under FERC jurisdiction and wish to participate in PJM's market need to execute a PJM Wholesale Market Participation Agreement (WMPA)..." instead of an ISA. See PJM Manual 14C. "Generation and Transmission Interconnection Facility Construction," Revision 08 (December 20, 2012), p.8.
18 See PJM Manual 14C. "Generation and Transmission Interconnection Facility Construction," Revision 08 (December 20, 2012), p.22.

Table 12-16 Last milestone completed at time of withdrawal (January 1, 1997 through June 30, 2015)

Milestone Completed	Projects Withdrawn	Percent
Never Started	171	10.6%
Feasibility Study	607	37.6%
Impact Study	532	32.9%
Facilities Study	105	6.5%
Interconnection Service Agreement (ISA)	37	2.3%
Wholesale Market Participation Agreement (WMPA)	110	6.8%
Construction Service Agreement (CSA) or beyond	54	3.3%
Total	1,616	100.0%

Table 12-17 and Table 12-18 show the time spent at various stages in the queue process and the completion time for the studies performed. For completed projects, there is an average time of 937 days, or 2.6 years, between entering a queue and going into service. Nuclear, hydro, and wind projects tend to take longer to go into service. The average time to go into service for all other fuel types is 700 days. For withdrawn projects, there is an average time of 658 days between entering a queue and withdrawing.

Table 12-17 Average project queue times (days): At June 30, 2015

Status	Average (Days)	Standard Deviation	Minimum	Maximum
Active	976	687	15	3,890
In Service	937	683	1	4,024
Suspended	1,987	765	509	4,149
Under Construction	1,787	906	428	6,380
Withdrawn	658	656	1	4,249

Table 12-18 presents information on the time in the stages of the queue for those projects not yet in service. Of the 577 projects in the queue as of June 30, 2015, 68 had a completed feasibility study and 191 were under construction.

Table 12-18 PJM generation planning summary: At June 30, 2015

Milestone Completed	Number of Projects	Percent of Total Projects	Average Days	Maximum Days
Not Started	130	22.5%	713	2,555
Feasibility Study	68	11.8%	780	2,223
Impact Study	85	14.7%	1,366	3,890
Facilities Study	21	3.6%	1,773	3,291
Interconnection Service Agreement (ISA)	13	2.3%	780	1,858
Wholesale Market Participation Agreement (WMPA)	1	0.2%	427	427
Construction Service Agreement (CSA)	1	0.2%	1,554	1,554
Under Construction	191	33.1%	1,787	6,380
Suspended	67	11.6%	1,987	4,149
Total	577	100.0%		

The time it takes to complete a study depends on the backlog and the number of projects in the queue. The time it takes to complete a study does not necessarily depend on the size of the project. Renewable projects (solar, hydro, storage, biomass, wind) account for 61.4 percent of the total number of projects in the queue but only 25.6 percent of the non-derated MW. See Table 12-19.

Table 12-19 Queue details by fuel group: At June 30, 2015

Fuel Group	Number of Projects	Percent of Projects	MW	Percent MW
Nuclear	6	1.0%	2,042.8	2.6%
Renewable	354	61.4%	19,806.5	25.6%
Traditional	217	37.6%	55,612.0	71.8%
Total	577	100.0%	77,461.3	100.0%

Role of Transmission Owners in Transmission Planning Study Phase

According to PJM Manual 14A, PJM, in coordination with the TOs, conducts the feasibility, system impact and facilities studies for every interconnection queue project. It is clear that the TOs perform the studies.[19] The coordination begins with PJM identifying transmission issues resulting from the generation projects. The TOs perform the studies and provide the mitigation requirements for each issue. A facilities study is required only for new generation and significant generation additions and is the study in which the TO is most involved. For a facilities study, the interconnected TO (ITO), as well as any other affected TOs, is required to conduct their own facilities study and provide a summary and results to PJM. PJM compiles these results, along with inputs from the developer, into PJM's models to confirm that the TOs' defined upgrades will resolve the issue. PJM writes the final facilities report, which includes the inputs, a description of the issues to be resolved, and the findings of all contributing TOs.[20]

Of 577 active projects analyzed, the developer and TO are part of the same company for 41 of the projects, or 11,390.5 MW of a total 59,225.2 MW, 19.2 percent of the MW. Where the TO is a vertically integrated company that also owns generation, there is a potential conflict of interest when the TO evaluates the interconnection requirements of new generation which is part of the same company. There is also 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.

Table 12-20 is a summary of the number of projects and total MW, by transmission owner parent company, which identifies the number of projects for which the developer and transmission owner are part of the same company. The Dominion Zone has eight related projects which account for 5,881.3 MW, 58.0 percent of the total MW currently in the queue in the Dominion Zone. Renewable projects comprise 3,075.6 MW, 72.1 percent, of unrelated projects in the queue in the Dominion Zone while natural gas projects total 5,465.3 MW, 53.9 percent of total MW in the queue. In contrast, the AEP Zone has 12 related projects, but they account for only 2.6 percent of its total MW currently in the queue.

19 See PJM, OATT, Part VI, § 210

20 See PJM. "Manual 14A, "Generation and Transmission Interconnection Process," Revision 17, (January 22, 2015),< http://www.pjm.com/documents/manuals.aspx>

Table 12-20 Summary of project developer relationship to transmission owner

	Number of Projects			Total MW		
Parent Company	Related	Unrelated	Percent Related	Related	Unrelated	Percent Related
AEP	12	73	14.1%	369.7	13,670.0	2.6%
AES	2	6	25.0%	32.0	437.3	6.8%
DLCO	0	1	0.0%		205.0	0.0%
Dominion	8	53	13.1%	5,881.3	4,265.6	58.0%
Duke	2	6	25.0%	52.0	660.4	7.3%
Exelon	7	66	9.6%	3,100.0	7,754.7	28.6%
First Energy	2	198	1.0%	1,736.0	21,169.8	7.6%
Pepco	0	80	0.0%		6,408.5	0.0%
PPL	0	26	0.0%		6,803.5	0.0%
PSEG	11	24	31.4%	1,923.1	2,992.4	39.1%
Total	44	533	7.6%	13,094.1	64,367.2	16.9%

These projects are shown by fuel type in Table 12-21. Natural gas generators comprise 69.6 percent of the total related MW in this table. Developers of coal and nuclear projects are almost entirely related to the TO, with 95.2 percent and 99.1 percent of MW. Developers are related to the TO for 17.2 percent of the natural gas project MW in the queue and 12.2 percent of the coal project MW. Wind and solar projects have no more than 1.0 percent of MW in development related to the TO.

Table 12-21 Developer-transmission owner relationship by fuel type

				MW by Fuel Type											
Parent Company	Transmission Owner	Related to Developer	Number of Projects	Biomass	Coal	Hydro	Landfill Gas	Natural Gas	Nuclear	Oil	Other	Solar	Storage	Wind	Total MW
AEP	AEP	Related	12		72.0	34.0		137.0	102.0			14.7	10.0		369.7
		Unrelated	73	45.0	92.0	12.5	23.8	6,019.0				103.7	62.0	7,312.0	13,670.0
AES	DAY	Related	2		12.0								20.0		32.0
		Unrelated	6	1.9		112.0						23.4		300.0	437.3
DLCO	DLCO	Unrelated	1					205.0							205.0
Dominion	Dominion	Related	8					4,275.3	1,594.0					12.0	5,881.3
		Unrelated	53	62.5			3.6	1,190.0				1,571.4	128.0	1,310.1	4,265.6
Duke	DEOK	Related	2		50.0								2.0		52.0
		Unrelated	6				6.4	513.0				125.0	16.0		660.4
Exelon	BGE	Related	1									20.0			20.0
		Unrelated	7	25.0		0.4	4.0	1.3			132.0	3.1			165.8
	ComEd	Unrelated	48			22.7	28.6	2,337.8				10.0	144.6	3,562.0	6,105.7
	PECO	Related	6					2,750.0	330.0						3,080.0
		Unrelated	11				3.2	1,480.0							1,483.2
First Energy	APS	Related	2		1,710.0			26.0							1,736.0
		Unrelated	55			68.2	9.2	4,865.9				184.3	31.0	723.6	5,882.2
	ATSI	Unrelated	12				2.5	4,071.9						518.0	4,592.4
	JCPL	Unrelated	83					3,034.0				574.1	180.0		3,788.1
	Met-Ed	Unrelated	8					1,336.6	16.8	401.0		3.0			1,757.4
	PENELEC	Unrelated	40			40.0	4.0	4,610.5				13.5	68.4	413.3	5,149.7
Pepco	AECO	Unrelated	22				0.3	1,571.0				73.2	20.0	373.0	2,037.5
	DPL	Unrelated	50				2.0	918.0				455.4	20.0	250.0	1,645.4
	Pepco	Unrelated	8					2,725.6							2,725.6
PPL	PPL	Unrelated	26	16.0			5.0	6,213.0				16.0	30.0	523.5	6,803.5
PSEG	PSEG	Related	11					1,922.1				1.0			1,923.1
		Unrelated	24					2,847.5				144.9			2,992.4
Total		Related	44		1,844.0	34.0		9,110.4	2,026.0			15.7	32.0	12.0	13,074.1
		Unrelated	533	150.4	92.0	255.8	92.6	43,940.1	16.8	401.0	132.0	3,321.1	700.0	15,285.5	64,387.2

Regional Transmission Expansion Plan (RTEP)

PJM's Transmission Expansion Advisory Committee (TEAC), made up of PJM staff, is responsible for the Regional Transmission Expansion Plan (RTEP).[21] Transmission upgrades can be divided into three categories: network, supplemental, and baseline. Network upgrades are initiated by generation queue projects and are funded by the developers of the generation projects. Supplemental upgrades are initiated and funded by the TOs. Baseline upgrades are initiated by the TEAC to resolve reliability criteria violations not addressed in other ways. The costs of the baseline projects are allocated proportionally to all TOs who will benefit from the upgrade. The TEAC solicits proposals via fixed proposal windows to address these needs. The TEAC evaluates the proposals and recommends proposals to the PJM Board of Managers for approval. The TEAC typically makes these recommendations three times a year: in February, mid-summer and late fall.

On February 17, 2015, baseline projects with an estimated cost of $551.4 million were presented to and approved by the Board. New projects account

21 See PJM Manual 14B. "PJM Region Transmission Planning Process," Revision 30 (February 26, 2015), Section 2, p.14

for $474.4 million of this amount and adjustments to previously approved baseline projects were $77.0 million.[22] Table 12-22 shows a summary of the new baseline upgrade costs for each TO.

Table 12-22 2015 Board approved new baseline upgrades by transmission owner

Transmission Owner	Baseline Upgrades ($ millions)
AEP	312.6
AP	1.7
ComEd	0.7
Dominion	118.0
EKPC	2.1
JCPL	14.8
Met-Ed	1.0
PECO	1.5
PENELEC	5.8
PPL	0.8
PSEG	15.6
Total	474.4

The 2015 RTEP Proposal Window 1 opened on June 19, 2015, and will close on July 20, 2015. The scope for these proposals includes baseline N-1, generation deliverability and common mode outage, N-1-1, and load deliverability.[23]

Artificial Island Update

Artificial Island is an area in the PSEG Zone 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, PSEG, and from non-incumbents. PJM staff announced on April 28, 2015, that they will recommend that the Board approve the assignment of the Artificial Island project to LS Power, a non-incumbent, PSEG, and PHI with a total cost estimate between $263M and $283M. Table 12-23 shows the details of the project allocation.

22 See PJM Staff Whitepaper,"Transmission Expansion Advisory Committee (TEAC) Recommendations to the PJM Board," <http://www.pjm.com/~/media/committees-groups/committees/teac/20150409/20150409-february-2015-board-approval-of-rtep-whitepaper.ashx>

23 See TEAC webcast, June 24, 2015 at <http://mediastream.pjm.com/2015/0624/teac/2015-rtep-proposal/index.htm>

Table 12-23 Artificial Island recommended work and cost allocation

Project Task	Designated Developer	Cost Estimate ($ million)
230kV transmission line under the Delaware River from Salem to a new substation near the 230kV transmission RoW in Delaware utilizing HDD under the river	LS Power	146.0 (cost cap)
Associated substation work at Salem	PSEG	61.0-74.0
Associated work on the 230kV RoW	PHI	
SVC at New Freedom	PSEG	31.0-38.0
OPGW upgrades designated to PSEG and PHI & Artificial Island GSU tap settings upgrade	PSEG	25.0
Total		263.0-283.0

PJM received comments from PSEG & PSEG Nuclear, contesting the selection of LS Power for the construction of a 230kV line over the PSEG proposal. They argued that the PSEG proposal was inappropriately modified, resulting in a higher cost and a lower score and that several performance factors, including stability, installation complexity, long term maintenance and operational costs, and operational complexity were excluded. PSEG also argued that LS Power's cost cap is misleading and was misinterpreted by PJM staff to be more robust than it actually is. Atlantic Grid Holdings also questioned the robustness of the recommended design. The Delaware Riverkeeper Network raised environmental concerns.

On July 30, 2105, the PJM Board of Managers accepted PJM's recommendation.[24]

The inclusion of a cost cap in some of the offers and the inclusion of a cost cap in the decision criteria is an important step in the development of meaningful competition to build transmission projects. Such cost caps should include minimum exceptions and be enforceable.

Cost Estimates and Allocations

Con Edison and Linden VFT

Following the RTEP Baseline upgrade filings, ER14-972-000 on January 10, 2014, and ER14-1485-000 on March 13, 2014, Con Edison and Linden VFT took issue with their cost allocations for two specific upgrades (Bergen-Linden

24 See PJM, "Artificial Island Project," July 29, 2015 <http://www.pjm.com/~/media/documents/reports/board-statement-on-artificial-island-project.ashx>.

Corridor and Sewaren.) Both filed complaints (ConEd on November 7, 2014, and Linden on May 22, 2015) that the allocations violated Schedule 12 of the tariff and Schedule 6 of the PJM Operating Agreement, which address unreasonable cost allocations. Schedule 12 of the tariff states "If Transmission Provider determines in its reasonable engineering judgment that, as a result of applying the provisions of this Section (b)(iii), the DFAX analysis cannot be performed or that the results of such DFAX analysis are objectively unreasonable, the Transmission Provider may use an appropriate substitute proxy for the Required Transmission Enhancement in conducting the DFAX analysis." Schedule 6 of the PJM Operating Agreement requires PJM to avoid an allocation of unreasonable costs in the RTEP project selection process.[25] [26] Finally, Order 1000 states that "costs must be allocated in a way that is roughly commensurate with benefits."[27]

ConEd argued, using the tariff language, that the cost allocation is "objectively unreasonable" and requested "an appropriate substitute proxy." ConEd's complaint was not that the solution-based DFAX method was necessarily faulty, but that the assumptions and inputs that PJM used to model ConEd were inaccurate and resulted in an over allocation to ConEd, Linden VFT, and Hudson Transmission Partners (HTP), and an under allocation to PSEG. PJM's response was that the substitute proxy was to be used when a DFAX could not otherwise be calculated, which did not apply in this case.[28] PJM also argued that ConEd had a chance to question the cost allocation during numerous TEAC meetings. ConEd replied that detailed information was not made available and thus ConEd was not aware of the significant allocation at that point. PSEG commented in support of the allocation. The FERC decision on June 18, 2015, accepted the PJM allocation and found that the DFAX method, as applied, was not faulty.[29]

Linden VFT commented in support of ConEd's complaint and filed a separate complaint on May 22, 2015.[30] In addition to the two upgrades that were the focus of the ConEd complaint, Linden added a third (Edison Rebuild).

25 See PJM, Intra-PJM Tariffs, OATT, Schedule 12 § (b)(iii)(G)
26 See PJM Operating Agreement, § 1.4(d)(ii)
27 See FERC Order 1000-B, §3, Paragraph 66
28 See PJM, Intra-PJM Tariffs, OATT, Schedule 12 § (b)(iii)(I)
29 See 151 FERC ¶ 61,227 (2015). <http://www.pjm.com/~/media/documents/ferc/2015-orders/20150618-er14-972-002.ashx>.
30 See "Motion for Leave to Answer and Limited Answer of Linden VFT, LLC," Docket No. EL15-18-000 (November 19, 2014)

The allocations in dispute were a result of a new approach to transmission upgrade cost allocation, applied for the first time to the transmission costs resulting from the 2013 RTEP.[31] Linden VFT argued that the DFAX calculations assume peak conditions and therefore maximum firm transmission withdrawal rights (FTWRs), but during peak periods, Linden VFT is least likely to use its full FTWRs because the flow is going in the other direction.[32]

Artificial Island

After the Artificial Island recommendation was presented by PJM Staff on April 28, 2015, Delaware Public Service Commission, Delaware Division of the Public Advocate, Old Dominion Electric Cooperative (ODEC), the Maryland Public Service Commission (MD PSC), and Delaware Governor Jack Markell raised concerns regarding the allocation of 99.9 percent of the costs for the 230kV line portion of the Artificial Island project to PHI.[33]

TransSource

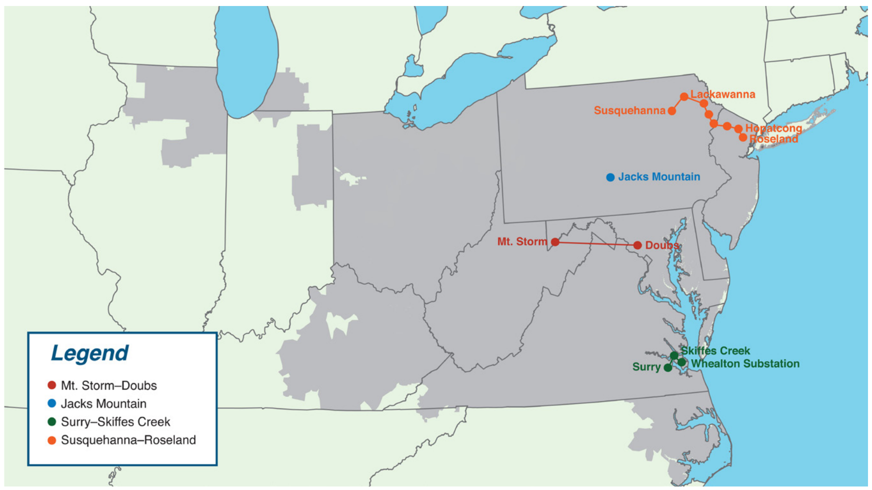
TransSource LLC stated, in a complaint filed on June 23, 2015, that PJM is not being transparent with respect to the development of its cost estimates in the System Impact Study (SIS) phase of three TransSource queue projects. TransSource seeks an order directing PJM to provide data and working papers related to the SIS sufficient to fully evaluate the basis of cost estimates that TransSource considers excessive. PJM responded that it has provided all work papers relevant to the SIS and objects to the complaint on procedural grounds.[34]

31 See *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 (2013)
32 See "Complaint and Request for Fast Track Processing of Linden VFT, LLC," Docket no. EL15-67-000 (May 22, 2015)
33 See PJM Board Communications. Responses at <http://www.pjm.com/about-pjm/who-we-are/pjm-board/public-disclosures.aspx>
34 See Motion to Dismiss Complaint and Answer to Complaint Submitted on Behalf of PJM Interconnection, L.L.C., Docket No. EL15-79-000 (July 10, 2015).

Backbone Facilities

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.

Figure 12-3 PJM Backbone 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. The first two phases, the line rebuild and the energizing of the Mount Storm switchyard, are complete. Construction plans for Phase 3, consisting of additional upgrades to the Mount Storm switchyard, are under development. Completion of this phase is expected by the end of 2015.[35]

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. This project is currently in the engineering and design phase. 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.[36]

The Susquehanna-Roseland project is required to resolve reliability criteria violations starting June 1, 2012. Susquehanna-Roseland is a new 101-mile 500 kV transmission line connecting the Susquehanna, Lackawanna, Hopatcong, and Roseland buses. PPL is responsible for the first two legs and PSEG for the third. The Susquehanna-Lackawanna portion went into service on September 23, 2014, and the Lackawanna–Hopatcong portion was energized on May 11, 2015. The Hopatcong – Roseland leg was placed in service on April 1, 2014.[37] This project is now complete.

The Surry Skiffes Creek 500kV was initiated in the fall of 2014 to relieve the overload of the James River Crossing Double Circuit Towerline anticipated to result from the retirement of Chesapeake units 1-4, which occurred in December 2014, and Yorktown 1, which is pending. It will include 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. PJM's required in service date for the 500kv portion was June 1, 2015. This project has been delayed by legal challenges. BASF Corporation raised environmental concerns with the siting and the design. James City County and James River Association (JCC) argued that the switching station is not part of the transmission line and therefore should be subject to local zoning ordinances. In an April 16, 2015, ruling, the Supreme Court of Virginia rejected BASF's claim but agreed with JCC.[38] On April 30, 2015, Dominion filed a petition for rehearing and will wait for the follow-

35 See Dominion "*Mt. Storm-Doubs*," which can be accessed at: <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/mount-storm-doubs.aspx

36 See "Jacks Mountain," which can be accessed at: <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/jacks-mountain.aspx>.

37 See "Susquehanna-Roseland," which can be accessed at: <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/susquehanna-roseland.aspx>.

38 BASF Corporation v SCC, et al., Record No. 141009 et al.

up ruling before they will begin construction but they are proceeding with the planning.[39] Dominion anticipates beginning construction in the summer of 2015 and expects to energize both the 230kV line and the 500kV line by January 31, 2017.[40]

Transmission Facility Outages

Scheduling Transmission Facility Outage Requests

PJM designates some transmission facilities as reportable. A transmission facility is reportable if a change in its status can affect a transmission constraint on any Monitored Transmission Facility or could impede free-flowing ties within the PJM RTO and/or adjacent areas. If a transmission facility is not modeled in the PJM EMS or the facility is not expected to significantly impact PJM system security or congestion management, it is not reportable.[41] When one of the reportable transmission facilities needs to be taken out of service, the TO is required to submit an outage request as early as possible. The outages are categorized by duration: greater than 30 calendar days; less than or equal to 30 calendar days and greater than five calendar days; or less than or equal to five calendar days. Table 12-24 shows that 78.5 percent of the requested outages were planned for five days or shorter and 5.3 percent of requested outages were planned for longer than 30 days in the first six months of 2015. All of the outage data in this section are for outages scheduled to occur in the first six months of 2015, regardless of when they were initially submitted.

Table 12-24 Transmission facility outage request summary by planned duration: January through June of 2014 and 2015

	2014 (Jan - Jun)		2015 (Jan - Jun)	
Planned Duration (Days)	Outage Requests	Percent	Outage Requests	Percent
<=5	8,039	79.8%	8,279	78.5%
>5 & <=30	1,537	15.3%	1,705	16.2%
>30	493	4.9%	564	5.3%
Total	10,069	100.0%	10,548	100.0%

After receiving a transmission facility outage request from a TO, PJM assigns a received status to the request, based on its submission date, outage planned starting and ending date, and outage planned duration. The received status can be on time, late or past deadline, as defined in Table 12-25.[42] The purpose of the rules is to require the TOs to submit transmission facility outages prior to the Financial Transmission Right ("FTR") auctions so that market participants have complete information on which to base their FTR bids.[43]

Table 12-25 PJM transmission facility outage request received status definition

Planned Duration (Days)	Ticket Submission Date	Received Status
<=5	Before the 1st of the month one month prior to the starting month of the outage	On Time
	After or on the 1st of the month one month prior to the starting month of the outage	Late
	After 8:00AM three days prior to the outage	Past Deadline
> 5 & <=30	Before the 1st of the month six months prior to the starting month of the outage	On Time
	After or on the 1st of the month six months prior to the starting month of the outage	Late
	After 8:00AM three days prior to the outage	Past Deadline
>30	The earlier of either February 1st or the 1st of the month six months prior to the starting month of the outage	On Time
	After or on the earlier of either February 1st or the 1st of the month six months prior to the starting month of the outage	Late
	After 8:00AM three days prior to the outage	Past Deadline

Table 12-26 shows a summary of requests by received status. In the first six months of 2015, 52.8 percent of outage requests received were late.

Table 12-26 Transmission facility outage request summary by received status: January through June of 2014 and 2015

	2014 (Jan - Jun)				2015 (Jan - Jun)			
Planned Duration (Days)	On Time	Late	Total	Percent Late	On Time	Late	Total	Percent Late
<=5	4,214	3,825	8,039	52.4%	4,545	3,734	8,279	54.9%
>5 & <=30	771	766	1,537	50.2%	846	859	1,705	49.6%
>30	172	321	493	34.9%	183	381	564	32.4%
Total	5,157	4,912	10,069	51.2%	5,574	4,974	10,548	52.8%

39 See "Surry-Skiffes Creek 500kV," which can be accessed at: <http://www.pjm.com/planning/rtep-upgrades-status/backbone-status/surry-skiffes-creek.aspx>

40 See "Surry-Skiffes Creek 500kV and Skiffes Creek-Whealton 230kV Projects,"which can be accessed at: <https://www.dom.com/corporate/what-we-do/electricity/transmission-lines-and-projects/surry-skiffes-creek-500kv-and-skiffes-creek-whealton-230kv-projects>.

41 See PJM. "Manual 3a: Energy Management System (EMS) Model Updates and Quality Assurance (QA), Revision 9 (January 22, 2015).

42 See "PJM. "Manual 3: Transmission Operations," Revision 46 (December 1, 2014), p.58.

43 See 97 FERC ¶ 61,010 (October 3, 2001).

Once received, PJM processes the request according to its priority, which is determined by its submission date. If a request has an emergency flag, it has the highest priority and will be approved even if submitted past its deadline. Table 12-27 is a summary of outage requests by emergency status. Of all outage requests submitted in the first six months of 2015, 13.0 percent were for emergency outages.

Table 12-27 Transmission facility outage request summary by emergency: January through June of 2014 and 2015

	2014 (Jan - Jun)				2015 (Jan - Jun)			
Planned Duration (Days)	Emergency	Non Emergency	Total	Percent Emergency	Emergency	Non Emergency	Total	Percent Emergency
<=5	1,238	6,801	8,039	15.4%	1,069	7,210	8,279	12.9%
>5 & <=30	200	1,337	1,537	13.0%	237	1,468	1,705	13.9%
>30	89	404	493	18.1%	63	501	564	11.2%
Total	1,527	8,542	10,069	15.2%	1,369	9,179	10,548	13.0%

A late outage request may be denied or cancelled by PJM if it is expected to cause congestion based on PJM's analysis. Table 12-28 is a summary of outage requests by congestion status. Of all outage requests submitted in the first six months of 2015, 9.6 percent were expected to cause congestion and the percentage of outage requests flagged for congestion is similar across the categories of planned duration.

Table 12-28 Transmission facility outage request summary by congestion: June of 2014 and 2015

	2014 (Jan - Jun)				2015 (Jan - Jun)			
Planned Duration (Days)	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Total	Percent Congestion Expected
<=5	679	7,360	8,039	8.4%	766	7,513	8,279	9.3%
>5 & <=30	148	1,389	1,537	9.6%	188	1,517	1,705	11.0%
>30	44	449	493	8.9%	57	507	564	10.1%
Total	871	9,198	10,069	8.7%	1,011	9,537	10,548	9.6%

Table 12-29 shows the outage requests summary by received status, congestion status and emergency status. In the first six months of 2015, 72.6 percent of late requests were non-emergency outages while 4.8 percent of late non-emergency outage requests were expected to cause congestion in the first six months of 2015.

Table 12-29 Transmission facility outage requests that by received status, congestion and emergency: January through June of 2014 and 2015

		2014 (Jan - Jun)				2015 (Jan - Jun)			
Submission Status		Congestion Expected	No Congestion Expected	Total	Percent Congestion	Congestion Expected	No Congestion Expected	Total	Percent Congestion
Late	Emergency	44	1,475	1,519	2.9%	55	1,308	1,363	4.0%
	Non Emergency	167	3,226	3,393	4.9%	172	3,439	3,611	4.8%
On Time	Emergency	0	8	8	0.0%	0	6	6	0.0%
	Non Emergency	660	4,489	5,149	12.8%	784	4,784	5,568	14.1%
	Total	871	9,198	10,069	8.7%	1,011	9,537	10,548	9.6%

Once PJM processes an outage request, the outage request is labelled as submitted, received, denied, approved, cancelled by company, revised, active or complete according to the processed stage of a request.[44] Table 12-30 shows the detailed process status for outage requests only for the outage requests that are expected to cause congestion. All process status categories except cancelled, complete or denied are in the In Process category in Table 12-30. Table 12-30 shows that 62.8 percent of late, non-emergency, outage requests which were expected to cause congestion were approved and completed and 6.6 (67 out of 1,011) percent of the outage requests which were expected to cause congestion were denied in the first six months of 2015.

Table 12-30 Transmission facility outage requests that might cause congestion status summary: January through June of 2014 and 2015

		2014 (Jan - Jun)						2015 (Jan - Jun)					
Submission Status		Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete	Cancelled	Complete	In Process	Denied	Congestion Expected	Percent Complete
Late	Emergency	2	41	1	0	44	93.2%	7	47	0	1	55	85.5%
	Non Emergency	29	117	1	20	167	70.1%	38	108	2	24	172	62.8%
On Time	Non Emergency	133	485	1	41	660	73.5%	223	516	3	42	784	65.8%
	Total	164	643	3	61	871	73.8%	268	671	5	67	1,011	66.4%

Rescheduling Transmission Facility Outage Requests

A TO can reschedule or cancel an outage after initial submission. Table 12-31 is a summary of all the outage requests planned for the first six months of 2014 and 2015 which were approved and then cancelled or revised by TOs at least once. In the first six months of 2015, 2.7 percent of transmission outage requests were approved by PJM and then revised by the TOs, and 12.9 percent of the transmission outages were approved by PJM and subsequently cancelled by the TOs.

Table 12-31 Rescheduled transmission outage request summary: January through June of 2014 and 2015

	2014 (Jan - Jun)					2015 (Jan - Jun)				
Days	Outage Requests	Approved and Revised	Percent Approved and Revised	Approved and Cancelled	Percent Approved and Cancelled	Outage Requests	Approved and Revised	Percent Approved and Revised	Approved and Cancelled	Percent Approved and Cancelled
<=5	8,039	270	3.4%	1,173	14.6%	8,279	207	2.5%	1,186	14.3%
>5 & <=30	1,537	68	4.4%	116	7.5%	1,705	54	3.2%	129	7.6%
>30	493	14	2.8%	30	6.1%	564	25	4.4%	50	8.9%
Total	10,069	352	3.5%	1,319	13.1%	10,548	286	2.7%	1,365	12.9%

All late rescheduled outages are reevaluated by PJM. An on-time transmission outage ticket with duration of five days or less with an on-time status can retain its on-time status if the outage is rescheduled within the original scheduled month.[45] This rule allows a TO to move an outage to an earlier date than originally requested within the same month with very little notice.

An on-time transmission outage ticket with duration exceeding five days can retain its on-time status if the outage is moved to a future month, and the revision is submitted by the first of the month prior to the month in which new proposed outage will occur.[46] This rescheduling rule is much less strict than the rule that

44 PJM. Markets and Operations. "Outage Information,"<http://www.pjm.com/markets-and-operations/etools/oasis/system-information/outage-info.aspx>
45 PJM. "Manual 3: Transmission Outages," Revision 46 (December 1, 2014), p. 63.
46 PJM. "Manual 3: Transmission Outages," Revision: 46 (December 1, 2014), p. 64.

applies to the first submission of outage requests with similar duration. When first submitted, the outage request planned to last longer than five days needs to be submitted the first of the month six months prior to the month in which the outage was expected to occur.

These rules mean that an outage, once approved, acts as a reservation that does not require further review and allows rescheduling without review.

The MMU recommends that PJM reevaluate all transmission outage tickets as if they were new requests when an outage is rescheduled and apply the standard rules for late submissions to any such outages.

Transmission Facility Outage Analysis for the FTR Market

Transmission facility outages affect the price and quantity outcomes of FTR auctions. It is critical that outages are known with enough lead time prior to FTR auctions both so that market participants can understand market conditions and so that PJM can accurately model market conditions. Outage requests must be submitted according to rules based on planned outage duration (Table 12-25). The rules defining when an outage is late are based on the timing of FTR auctions. When an outage request is submitted late, the outage will be marked as late and may be denied if it is expected to cause congestion.

There are Long Term, Annual and Monthly Balance of Planning Period auctions in the FTR market. When modeling transmission outages in the annual ARR allocation and FTR auction, PJM does not consider outages with planned duration shorter than two weeks, does consider some outages with planned duration longer than two weeks but shorter than two months, and does consider all outages with planned duration longer than or equal to two months. PJM posts an FTR outage list to the FTR web page usually at least one week before the auction bidding opening day.[47]

47 PJM. 2015-2016 Annual ARR Allocation and FTR Auction Transmission Outage Modeling <http://www.pjm.com/~/media/markets-ops/ftr/annual-ftr-auction/2015-2016/2015-2016-annual-outage-modeling.ashx>

Table 12-32 shows that 89.9 percent of the outage requests for outages expected to occur during the planning period 2014 to 2015 were planned for less than two weeks and that 47.7 percent of all outage requests for the planning period were submitted late according to outage submission rules.

Table 12-32 Transmission facility outage requests by received status: Planning period 2014 to 2015

Planned Duration	On Time	Late	Total	Percent Late
<2 weeks	9,300	8,346	17,646	47.3%
>=2 weeks & <2 months	805	821	1,626	50.5%
>=2 months	155	192	347	55.3%
Total	10,260	9,359	19,619	47.7%

Once received, PJM processes outage requests in the following priority order: emergency transmission outage request, transmission outage requests submitted On Time, and transmission submitted Late. If two outage requests submitted by different transmission owners are expected to occur during the same period, the outage submitted first is processed first by PJM. If a request has an emergency flag, it has the highest priority and will be approved even if submitted past its deadline after PJM determines that the outage does not result in Emergency Procedures.[48] Table 12-33 shows outage requests summary by emergency status. Of all outage requests submitted late in the 2014 to 2015 planning year, 72.7 percent were for non-emergency outages.

Table 12-33 Transmission facility outage requests by received status and emergency: Planning period 2014 to 2015

	On Time			Late		
Planned Duration	Emergency	Non Emergency	Percent Non Emergency	Emergency	Non Emergency	Percent Non Emergency
<2 weeks	13	9,287	99.9%	2,363	5,983	71.7%
>=2 weeks & <2 months	0	805	100.0%	155	666	81.1%
>=2 months	0	155	100.0%	35	157	81.8%
Total	13	10,247	99.9%	2,553	6,806	72.7%

48 PJM. "Manual 3: Transmission Outages," Revision: 46 (December 1, 2014), p. 67 and p.68.

PJM analyzes expected congestion for both on time and late outage requests. A late outage request may be denied or cancelled if it is expected to cause congestion. Table 12-34 shows a summary of requests by congestion flag and received status. Overall, 5.3 percent of all tickets submitted late in the 2014 to 2015 planning year were requests that might cause congestion.

Table 12-34 Transmission facility outage requests by received status and congestion: Planning period 2014 to 2015

	On Time			Late		
Planned Duration	Congestion Expected	No Congestion Expected	Percent Congestion Expected	Congestion Expected	No Congestion Expected	Percent Congestion Expected
<2 weeks	1,334	7,966	14.3%	445	7,901	5.3%
>=2 weeks & <2 months	160	645	19.9%	43	778	5.2%
>=2 months	32	123	20.6%	6	186	3.1%
Total	1,526	8,734	14.9%	494	8,865	5.3%

Table 12-35 shows that 86.5 percent of late outage requests with a duration of two weeks or longer but shorter than two months were completed and that 86.5 percent of late outage requests with a duration of two months or longer were completed.

Table 12-35 Transmission facility outage requests by received status and processed status: Planning period 2014 to 2015

Planned Duration	Processed Status	On Time	Percent	Late	Percent
<2 weeks	In Process	23	0.2%	166	2.0%
	Denied	106	1.1%	91	1.1%
	Cancelled by Company	2,766	29.7%	1,193	14.3%
	Completed	6,405	68.9%	6,895	82.6%
Total		9,300	100.0%	8,345	100.0%
>=2 weeks & <2 months	In Process	1	0.1%	9	1.1%
	Denied	0	0.0%	2	0.2%
	Cancelled by Company	194	24.1%	100	12.2%
	Completed	610	75.8%	710	86.5%
Total		805	100.0%	821	100.0%
>=2 months	In Process	0	0.0%	7	3.6%
	Denied	0	0.0%	0	0.0%
	Cancelled by Company	38	24.5%	19	9.9%
	Completed	117	75.5%	166	86.5%
Total		155	100.0%	192	100.0%

Table 12-36 shows outage requests in more detail. It shows that there were 821 outage requests with a duration of two weeks or longer but shorter than two months were submitted late, of which 40 were non-emergency and expected to cause congestion in the 2014 to 2015 planning year. Of the 40 such requests, 33 were approved and completed. For the outages planned for two months or longer, there are 347 total outages, of which 192 requests were late. The six outages that were non-emergency and expected to cause congestion were all approved and completed.

Table 12-36 Transmission facility outage requests by received status, processed status, emergency and congestion: Planning period 2014 to 2015

		On time					Late				
		Emergency Congestion Expected		Non Emergency Congestion Expected			Emergency Congestion Expected		Non Emergency Congestion Expected		
Planned Duration	Processed Status	Yes	No	Yes	No	Total	Yes	No	Yes	No	Total
<2 weeks	In Progress	0	0	2	21	23	0	77	3	86	166
	Denied	0	0	72	34	106	1	8	39	43	91
	Cancelled by Company	1	1	362	2,402	2,766	9	133	75	977	1,194
	Completed	0	11	897	5,497	6,405	96	2,039	222	4,538	6,895
Total Submission		1	12	1,333	7,954	9,300	106	2,257	339	5,644	8,346
>=2 weeks & <2 months	In Progress	0	0	1	0	1	0	4	0	5	9
	Denied	0	0	0	0	0	0	0	2	0	2
	Cancelled by Company	0	0	30	164	194	0	5	5	90	100
	Completed	0	0	129	481	610	3	143	33	531	710
Total Submission		0	0	160	645	805	3	152	40	626	821
>=2 months	In Progress	0	0	0	0	0	0	1	0	6	7
	Denied	0	0	0	0	0	0	0	0	0	0
	Cancelled by Company	0	0	3	35	38	0	1	0	18	19
	Completed	0	0	29	88	117	0	33	6	127	166
Total Submission		0	0	32	123	155	0	35	6	151	192

If an outage request were submitted after the Annual FTR Auction bidding opening date, the outage would not be considered in the FTR model. If an outage were submitted on-time according to the transmission outage rules, it may not be modeled in the FTR model if it is submitted after the Annual FTR Auction bidding opening date. Table 12-38 shows that 84.0 percent of outage requests labelled on time according to rules were submitted after the annual FTR bidding opening date.

Table 12-37 Transmission facility outage requests by submission status and bidding opening date: Planning period 2014 to 2015

	On Time			Late		
Planned Duration	Before Bidding Opening Date	After Bidding Opening Date	Percent After	Before Bidding Opening Date	After Bidding Opening Date	Percent After
<2 weeks	1,040	8,260	88.8%	78	8,267	99.1%
>=2 weeks & <2 months	475	330	41.0%	77	744	90.6%
>=2 months	127	28	18.1%	18	174	90.6%
Total	1,642	8,618	84.0%	173	9,185	98.2%

Table 12-38 shows that 83.1 percent of late outage requests which were submitted after the Annual FTR Auction bidding opening date were approved and complete.

Thus, although the definition of late outages was developed in order to prevent outages for the planning period being submitted after the Annual FTR Auction bidding opening date, the rules have not worked to prevent this.

Table 12-38 Late transmission facility outage requests that are submitted after annual bidding opening date: Planning period 2014 to 2015

Planned Duration	Completed Outages	Total	Percent
<2 weeks	6,837	8,267	82.7%
>=2 weeks & <2 months	650	744	87.4%
>=2 months	150	174	86.2%
Total	7,637	9,185	83.1%

Transmission Facility Outage Analysis in the Day-Ahead Market

Transmission facility outages also affect the energy market. Just as with the FTR market, it is critical that outages that affect the operating day are known prior to the submission of offers in the Day-Ahead Energy Market both so that market participants can understand market conditions and so that PJM can accurately model market conditions.

There may be more than one instance for each outage request due to the change of the processed status. PJM maintains all the history of outage requests including all the processed status changes and all the starting or ending date changes. For example, if an outage requested were submitted, received, approved and completed, the four occurrences, termed instances, of the outage request will be stored in the database. In the day-ahead market transmission outage analysis, all instances of the outages planned in the 2014/2015 planning year are included. Table 12-39 shows that 14.6 percent of non-emergency outage request instances were submitted late for the day-ahead market and were expected to cause congestion.

Table 12-39 Transmission facility outage request instance summary by congestion and emergency: Planning period 2014 to 2015

For Day-ahead Market	Submission Status	Congestion Expected	No Congestion Expected	Total	Percent Congestion
Late	Emergency	310	3,916	4,226	7.3%
	Non Emergency	2,677	15,682	18,359	14.6%
On Time	Emergency	816	11,101	11,917	6.8%
	Non Emergency	15,197	88,362	103,559	14.7%
	Total	19,000	119,061	138,061	13.8%

Table 12-40 shows that there were 22,585 instances related to outage requests which were expected to occur in the planning period 2014 to 2015 , of which 3,043 (13.5 percent) had the status submitted, cancelled by company or revised and 205 (0.9 percent) had the status submitted, cancelled by company or revised and were expected to cause congestion.

Table 12-40 Transmission facility outage request instance status summary by congestion and emergency: Planning period 2014 to 2015

	Late For Day-ahead Market					On Time For Day-ahead Market				
	Emergency		Non Emergency			Emergency		Non Emergency		
	Congestion Expected		Congestion Expected			Congestion Expected		Congestion Expected		
Processed Status	Yes	No	Yes	No	Total	Yes	No	Yes	No	Total
Submitted	24	984	71	668	1,747	113	1,515	2,292	15,835	19,755
Cancelled by Company	8	41	86	703	838	8	132	593	4,273	5,006
Revised	14	131	48	265	458	215	3,649	2,678	13,927	20,469
Total	46	1,156	205	1,636	3,043	336	5,296	5,563	34,035	45,230
Other	264	2,760	2,472	14,046	19,542	480	5,805	9,634	54,327	70,246
Total	310	3,916	2,677	15,682	22,585	816	11,101	15,197	88,362	115,476

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 *2015 Quarterly State of the Market Report for PJM: January through June* focuses on the 2015 to 2016 Annual FTR Auction, which occurs from March 2015 through April 2015, Monthly Balance of Planning Period FTR Auctions during the 2014 to 2015 and 2015 to 2016 planning periods, covering January 1, 2015, through June 30, 2015 and summarizes FTR auction results for the 2014 to 2015 planning period.

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 2015 to 2016 Annual FTR Auction, total participant FTR sell offers were 378,744 MW, up from 271,368 MW in the 2014 to 2015 planning period. In the Monthly Balance of Planning Period FTR Auctions for the 2014 to 2015 planning period, total participant FTR sell offers were 3,583,085 MW, down from 5,010,437 MW for the same period during the 2013 to 2014 planning period.
- **Demand.** The total FTR buy and self-scheduled bids from the 2015 to 2016 Annual FTR Auction dcreased 24.7 percent from 3,270,331 MW, for the 2014 to 2015 planning period, to 2,461,662 MW. The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the 2014 to 2015 planning period increased 1.0 percent from 25,088,655 MW for the same time period of the prior planning period, 25,346,226 MW.
- **Patterns of Ownership.** For the 2015 to 2016 Annual FTR Auction, financial entities purchased 56.3 percent of prevailing flow FTRs and 75.0 percent of counter flow FTRs. For the Monthly Balance of Planning Period Auctions, financial entities purchased 76.4 percent of prevailing flow and 80.1 percent of counter flow FTRs for January through June of 2015. Financial entities owned 69.9 percent of all prevailing and counter flow FTRs, including 61.7 percent of all prevailing flow FTRs and 83.2 percent of all counter flow FTRs during the period from January through June 2015.

Market Behavior

- **FTR Forfeitures.** Total forfeitures for the 2014 to 2015 planning period were $3.5 million for Increment Offers, Decrement Bids and UTC Transactions.
- **Credit Issues.** There were two collateral defaults and seven payment defaults for the first six months of 2015. The two collateral defaults totaled $710,300 and the seven payment defaults totaled $1,726,641. All of these default events were from Intergrid Mideast Group, LLC.

  PJM terminated Intergrid's membership as of April 23, 2015, and FERC approved PJM's termination as of June 23, 2015. Some of Intergrid's invoices were paid through Intergrid, a guarantor or cash collateral posted with PJM. Intergrid held FTRs at the time they were declared in default. PJM will liquidate Intergrid's FTR positions in accordance with Section 7.3.9 of the Operating Agreement.[3] The amount of revenue generated by these liquidated FTRs will impact the default allocation assessments that may be billed in accordance with Section 15.2.2 of the Operating Agreement.[4] PJM liquidated 500.8 MW of Intergrid's FTRs in the June Monthly Balance of Planning Period Auction for a net of $509,732 in revenue. PJM also liquidated 417.2 MW of Long Term FTRs for various planning periods for a net of $230,318 in cost. The net revenue result of Intergrid's FTR liquidation so far is $279,414.

Market Performance

- **Volume.** In the Annual FTR Auction for the 2015 to 2016 planning period, 378,328 (15.4 percent) of buy and self-scheduled bids cleared. In the 2014 to 2015 planning period Monthly Balance of Planning Period FTR Auctions 2,256,736 MW (8.9 percent) of FTR buy bids and 813,870 MW (22.7 percent) of FTR sell offers cleared.
- **Price.** The weighted-average buy-bid FTR price for the 2015 to 2016 Annual FTR Auction was $0.31 per MW, up from $0.29 per MW in the 2014 to 2015 planning period. The weighted-average buy-bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for the 2014 to 2015 planning period was $0.15, up from $0.17 per MW in the 2013 to 2014 planning period.
- **Revenue.** The 2015 to 2016 Annual FTR Auction generated $936.3 million in net revenue, up from $748.6 million from the 2014 to 2015 Annual FTR Auction. The Monthly Balance of Planning Period FTR Auctions generated $19.3 million in net revenue for all FTRs for the 2014 to 2015

3 *See* PJM OATT. Liquidation of Financial Transmission Rights in the Event of Member Default. § 7.3.9.
4 *See* PJM OATT. Default Allocation Assessment § 15.2.2.

planning period, down from $29.8 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 2014 to 2015 planning period. This high level of revenue adequacy was primarily due to actions taken by PJM to address prior low levels of revenue adequacy. PJM's actions included PJM's assumption of higher outage levels and PJM's decision to include additional constraints (closed loop interfaces) both of which reduced system capability in the FTR auction model. PJM's actions led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs.
- **ARR and FTR Offset.** ARRs and FTRs served as an effective, but not total, offset to congestion. ARR and FTR revenues offset 88.3 percent of the total congestion costs including the Day-Ahead Energy Market and the balancing energy market in PJM for 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. In 2015, FTRs were profitable overall, with $339.3 million in profits for physical entities, of which $229.1 million was from self-scheduled FTRs, and $191.0 million for financial entities.

Auction Revenue Rights

Market Structure

- **ARR Allocations.** PJM's actions to address prior low levels of revenue adequacy included PJM's assumption of higher outage levels and PJM's decision to include additional constraints (closed loop interfaces) both of which reduced system capability in the FTR auction model. PJM's actions led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs. ARR allocation quantities were significantly reduced from historic levels for both the 2014 to 2015 and 2015 to 2016 planning periods. 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. For the 2015 to 2016 planning period, Stage 1B and Stage 2 ARR allocations were reduced 79.7 percent from the 2013 to 2014 planning period.
- **Residual ARRs.** If ARR allocations are reduced as the result of a modeled transmission outage and the transmission outage ends during the relevant planning year, the result is that residual ARRs may be available. These residual ARRs are automatically assigned to eligible participants the month before the effective date. Residual ARRs are only available on paths prorated in Stage 1 of the annual ARR allocation, are only effective for single, whole months and cannot be self scheduled. Residual ARR clearing prices are based on monthly FTR auction clearing prices.

  In the 2014 to 2015 planning period planning period, PJM allocated a total of 22,532.9 MW of residual ARRs, up from 15,417.5 MW in the 2013 to 2014 planning period, with a total target allocation of $8.2 million for the 2014 to 2015 planning period, up from $4.7 million for the 2013 to 2014 planning period. This 46.2 percent increase in residual ARR volume was primarily a result of PJM's significant reductions in Annual ARR Stage 1B allocations. The assumed outages did not materialize resulting in more available ARRs which were distributed as residual ARRs.
- **ARR Reassignment for Retail Load Switching.** There were 64,086 MW of ARRs associated with $338,100 of revenue that were reassigned in the 2013 to 2014 planning period. There were 57,270 MW of ARRs associated with $506,000 of revenue that were reassigned for the 2014 to 2015 planning period.

Market Performance

- **Revenue Adequacy.** For the 2014 to 2015 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $735.3 million while PJM collected $767.9 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. The increase in ARR target allocations and auction revenue, despite decreased volume, is a result of increased prices resulting from the reduced allocation of Stage 1B and Stage 2 ARRs.

- **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 ARR holders across the Day-Ahead Energy Market and balancing energy market for the 2014 to 2015 planning period and for the 2013 to 2014 planning period. Individual participants may not have a 100 percent offset.

Recommendations

- 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. Status: Not adopted.)
- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR marketplace participants. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM 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. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models. (Priority: Low. First reported 2013. Status: Adopted partially, 14/15 planning period.)
- The MMU recommends that PJM 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. Status: Adopted partially, 14/15 planning period.)
- The MMU recommends that PJM implement a seasonal ARR and FTR allocation system to better represent outages. (Priority: Medium. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM eliminate overallocation requirement of ARRs in the Annual ARR Allocation process. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM 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. Status: Not adopted. (Pending before FERC.)
- 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. Status: Not adopted.)

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 repeatedly.[5] 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 adequacy 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 2014 to 2015 planning period, total day-ahead congestion was $1,624.0 million while total day-ahead plus balancing congestion was $1,390.2 million, compared to target allocations of $1,254.4 million in the same time period.

Clearing prices fell and cleared quantities increased from the 2010 to 2011 planning period through the 2013 to 2014 planning period. The market response to lower revenue adequacy was to reduce bid prices and to increase bid volumes and offer volumes.

PJM's actions to address prior low levels of revenue adequacy included PJM's assumption of higher outage levels and PJM's decision to include additional constraints (closed loop interfaces) both of which reduced system capability in the FTR auction model. PJM's actions led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs from the 2013 to 2014 planning period, and a corresponding reduction in the available quantity of FTRs, an increase in FTR prices and an increase in ARR target allocations. The market response to the reduced supply of FTRs was increased bid prices, increased clearing prices and reduced clearing quantities.

5 See "FirstEnergy Solutions Corp. Allegheny Energy Supply Company, LLC v PJM Interconnection, LLC," Docket No. EL13-47-000 (February 15, 2013).

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. For the 2014 to 2015 planning period the payout ratio was 100 percent. The MMU recommends that counter flow and prevailing flow FTRs be treated symmetrically with respect to the application of a payout ratio.

The overallocation of Stage 1A ARRs results in FTR overallocations on the same facilities. Stage 1A ARR overallocation is a source of revenue inadequacy and cross subsidy. While prorating the Stage 1A ARR allocations based on actual system capability would address the issue, Stage 1A ARRs cannot be prorated under current market rules.

The MMU recommends that Stage 1A allocations be prorated to match actual system capability and that PJM commit to building the transmission capability required to provide all defined Stage 1A allocations. If Stage 1A overallocations are addressed, Stage 1B and Stage 2 allocations would not need to be reduced as they were for the 2014 to 2015 and 2015 to 2016 planning periods.

The result of removing portfolio netting, applying a payout ratio to counter flow FTRs and eliminating Stage 1A ARR overallocation in the 2013 to 2014 planning period would have increased the payout ratio to 94.6 percent without reducing ARR allocations in Stage 1B and Stage 2.

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.

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 eligible pricing nodes on the system. For the Long Term FTR Auction a list of available hubs, control zones, aggregates, generator buses and interface pricing points is available. For the Annual FTR Auction and FTRs bought for a quarterly period in the monthly auction the available FTR source and sink points include hubs, control zones, aggregates, generator buses, load buses and interface pricing points. An FTR bought in the Monthly FTR Auction for the single calendar month following the auction may include any bus for which an LMP is calculated in the FTR model used. 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.

Table 13-2 shows the date of first availability and final closing date for all annual ARR and FTR products.

Table 13-2 Annual FTR product dates

Auction	Initial Open Date	Final Close Date
2016/2019 Long Term	6/1/2015	12/3/2015
2015/2016 ARR	3/2/2015	3/31/2015
2015/2016 Annual	4/7/2015	4/30/2015

Supply and Demand

PJM oversees the process of selling and buying FTRs through ARR Allocations and FTR Auctions. Market participants purchase FTRs by participating in Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.[6] 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, as modeled in the Annual ARR Allocation. Stage 1A ARR requests must be granted, which artificially increases the capacity of the model on those facilities affected by the over allocated Stage 1A ARR requests. The capacity modeled in the Annual ARR Allocation is used as the capacity for the Annual FTR Auction to simultaneously accommodate the requested FTRs and the various combinations of requested FTRs. Depending on assumptions used in the auction transmission model, the total FTR supply can be greater than or less than system capability in aggregate and/or on an element by element basis. When FTR supply is greater than system capability, FTR target allocations will be greater than congestion revenues, contributing to FTR revenue inadequacy. Where FTR supply is less than system capability, FTR target allocations will be less than congestion revenues, contributing to FTR revenue surplus.

PJM can also make further adjustments to the auction model to address expected revenue inadequacies. PJM can assume higher outage levels and PJM can decide to include additional constraints (closed loop interfaces) both of which reduce system capability in the auction model. These PJM actions reduce the supply of available Stage 1B and Stage 2 ARRs, which in turn reduce the number of FTRs available for purchase. PJM made such adjustments in the 2014 to 2015 and 2015 to 2016 planning year auction model.

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.[7]

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. To address this issue, the MMU has recommended that PJM use probabilistic outage modeling and seasonal ARR/FTR markets to better align the supply of ARRs and FTRs with actual system capabilities.

Annual FTR Auctions

After the Long Term FTR Auction, residual capability on the PJM transmission system is auctioned in the Annual FTR Auction. Annual FTRs are effective beginning June 1 of the planning period through May 31. Outages expected to last two or more months are included in the determination of the simultaneous feasibility for the Annual FTR Auction. ARR holders who wish to self schedule must inform PJM prior to round one of this auction. Any self-scheduled ARR requests clear 25 percent of the requested volume in each round of the Annual FTR Auction as price takers. This auction consists of four rounds that allow any transmission service customers or PJM members to bid for any FTR or to offer for sale any FTR that they currently hold. FTRs in this auction can be obligations or options for peak, off peak or 24-hour periods. FTRs purchased in one round of the Annual FTR Auction can be sold in later rounds or in the Monthly Balance of Planning Period FTR Auctions.

Table 13-3 shows the top 10 binding constraints for the 2015 to 2016 Annual FTR Auction based on the marginal value of on peak hours.

6 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p. 38.

7 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p. 55.

Table 13-3 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2015 to 2016

			Severity Ranking by Auction Round			
Constraint	Type	Control Zone	1	2	3	4
Bush - Lafayette	Flowgate	MISO	NA	NA	1	NA
Oakgrove - Galesburg	Flowgate	MISO	NA	1	2	2
Kenney - Stockton	Line	DPL	NA	2	3	1
Kenney - Mount Olive	Line	DPL	1	NA	NA	NA
South Akron - Moore Park Tap	Line	ATSI	2	6	75	NA
Wempletown	Transformer	ComEd	3	527	55	4
Bush - Lafayette	Flowgate	MISO	24	3	NA	NA
Lancaster - Maryland	Line	ComEd	4	23	NA	12
Bagley - Raphael Rd.	Line	BGE	6	4	4	3
Hopatcon - Ramapo Tie	Line	PSEG	5	5	5	5

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.[8]

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 2015 to 2016 Annual FTR Auction were 2,437,964 MW. The total FTR buy bids in the Monthly Balance of Planning Period FTR Auctions for the 2014 to 2015 planning period were 25,346,227 MW.

Patterns of Ownership

The overall ownership structure of FTRs and the ownership of prevailing flow and counter flow FTRs is descriptive and is not necessarily a measure of actual or potential FTR market structure issues, as the ownership positions result from competitive auctions.

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 13-4 presents the Annual FTR Auction cleared FTRs for the 2015 to 2016 planning period by trade type, organization type and FTR direction. In the Annual FTR Auction for the 2015 to 2016 planning period, financial entities purchased 56.3 percent of prevailing flow FTRs, down 1.2 percent, and 75.0 percent of counter flow FTRs, down 5.0 percent, with the results that financial entities purchased 62.3 percent, down 2.1 percent, of all Annual FTR Auction cleared buy bids for the 2015 to 2016 planning period.

8 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p. 39.

Table 13-4 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2015 to 2016

			FTR Direction		
Trade Type	Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	8.8%	0.9%	6.3%
		No	34.9%	24.1%	31.4%
		Total	43.7%	25.0%	37.7%
	Financial	No	56.3%	75.0%	62.3%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		22.9%	23.5%	23.2%
	Financial		77.1%	76.5%	76.8%
	Total		100.0%	100.0%	100.0%

Table 13-5 presents the Monthly Balance of Planning Period FTR Auction cleared FTRs for 2015 by trade type, organization type and FTR direction. Financial entities purchased 76.4 percent of prevailing flow, down 1.1 percent, and 85.7 percent, down 1.5 percent, of counter flow FTRs for the year, with the result that financial entities purchased 80.1 percent, down 1.5 percent, of all prevailing and counter flow FTR buy bids in the Monthly Balance of Planning Period FTR Auction cleared FTRs for 2015.

Table 13-5 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: 2015

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	23.6%	14.3%	19.9%
	Financial	76.4%	85.7%	80.1%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	36.7%	37.5%	36.9%
	Financial	63.3%	62.5%	63.1%
	Total	100.0%	100.0%	100.0%

Table 13-6 presents the average daily net position ownership for all FTRs for 2015, by FTR direction.

Table 13-6 Daily FTR net position ownership by FTR direction: 2015

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	38.3%	16.8%	30.1%
Financial	61.7%	83.2%	69.9%
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

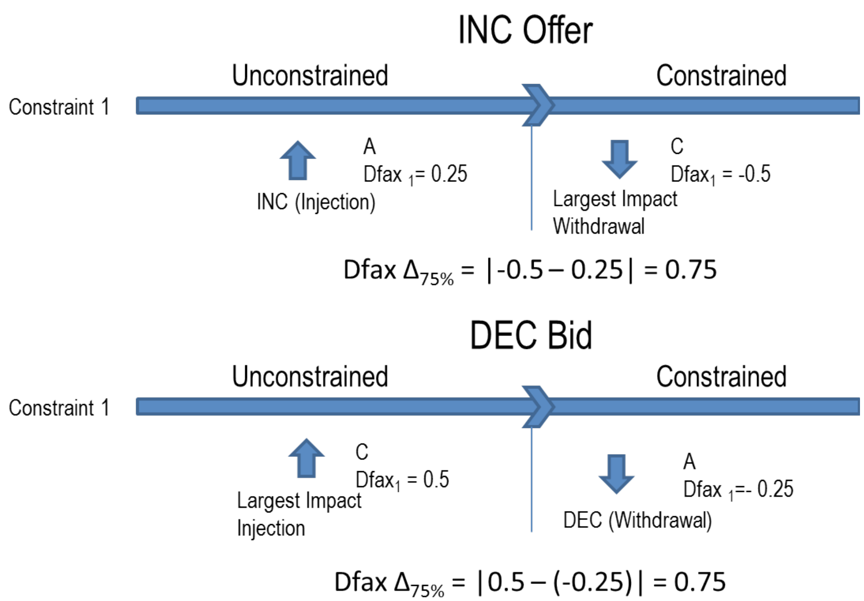


Figure 13-2 shows the FTR forfeiture values for both physical and financial participants for each month of June 2010 through May 2015. Currently, counter flow FTRs are not subject to forfeiture regardless of INC or DEC positions. Total forfeitures for the 2014 to 2015 planning period were $3.5 million (0.3 percent of total FTR target allocations).

Figure 13-2 Monthly FTR forfeitures for physical and financial participants: June 2010 through May 2015

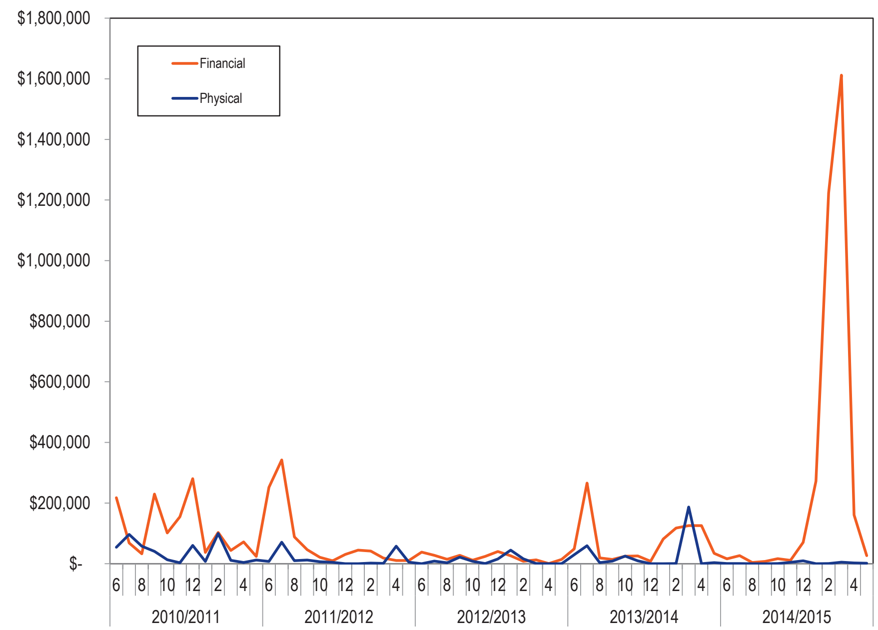
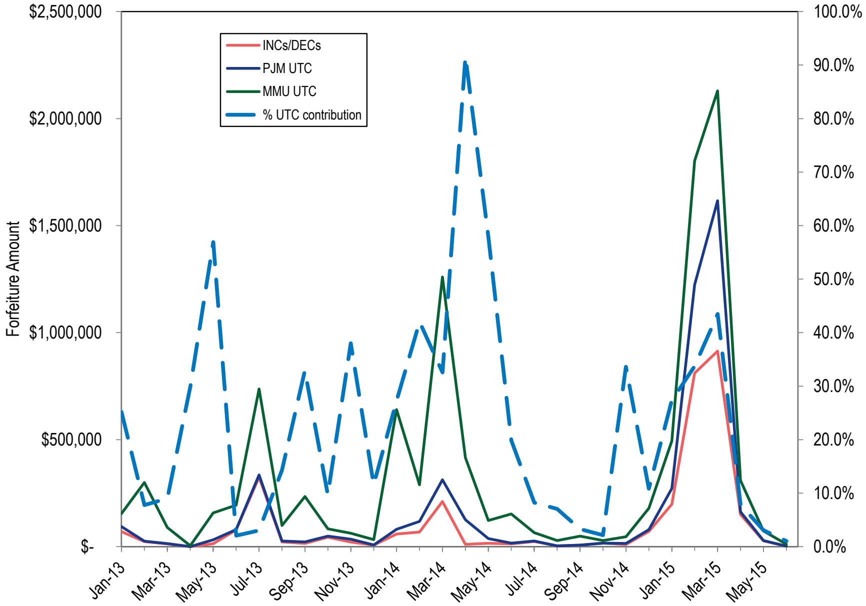


Figure 13-3 shows the FTR forfeitures on just INCs and DECs, FTR forfeitures on INCs, DECs and UTCs using the method proposed by PJM and FTR forfeitures on INCs, DECs and UTCs using the method proposed by the MMU from January 2013 through June 2015. The method proposed by PJM for calculating forfeitures 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. The dotted line indicates the percentage of forfeitures caused by UTC transactions using PJM's method, excluding INCs and DECs.

Figure 13-3 FTR forfeitures for INCs/DECs and INCs/DECs/UTCs for both the PJM and MMU methods: January 2013 through June 2015



Up-to-Congestion Transaction FTR Forfeitures

The current implementation of the FTR forfeiture rule submitted by PJM is not consistent with the application of the forfeiture rule for INCs and DECs. Under PJM's method the simple net dfax of the UTC transaction is the only consideration for forfeiture, representing the contract path of the UTC transaction. Under this method, the net dfax is the sink dfax of the UTC minus the source dfax of the UTC. The net dfax alone cannot be used as an indication of helping or hurting a constraint, rather, the direction of the constraint must also be considered. In addition, the PJM method only considers UTC transactions whose net dfax is positive. This logic not only passes transactions that should fail the forfeiture test, but fails transactions that should pass the forfeiture test.

PJM's logic also does not hold when one of the points of the UTC is far from the constraint. In this case, one side of the UTC would have a dfax of zero, indicating no connection to the constraint being considered. If a point of the UTC transaction has no connection to the constraint, there can be no power flow directly between the two UTC points, so the simple net dfax, cannot logically be used in this case to indicate whether a UTC is eligible for forfeiture. Under the MMU method this UTC would be treated as an INC or DEC and follow the same rules as the current INC/DEC FTR forfeiture rule.

Figure 13-4 shows an example of the two proposed FTR forfeiture rules for UTC transactions. In both cases, the net dfax of the UTC is taken. Under the PJM method the net dfax of the UTC is calculated by subtracting the dfax of the sink bus A (0.2) from the dfax of the source bus B (0.5) to get a net dfax of -0.3. If this net dfax value is greater than 0.75 the UTC is subject to forfeiture. Under the MMU method, the net dfax is calculated by subtracting the dfax of sink A (0.2) from the dfax of source bus B (0.5) to get a net dfax of 0.3. This net dfax is then compared to the withdrawal point with the largest impact on the constraint. The MMU method compares the net UTC dfax to a withdrawal because the UTC is a net injection on this constraint. In this example, the net dfax is 0.3 and it is compared to the largest withdrawal dfax at C (-0.5). The absolute value of the difference is calculated from these two points to determine if the UTC fails the FTR forfeiture rule. In this case, the absolute value of the difference is the dfax of bus C (-0.5) minus the net UTC dfax (0.3) for a total impact of 0.8, which is over the 0.75 threshold for the FTR forfeiture rule. The result is that this UTC fails the FTR forfeiture rule. The MMU proposes to apply the same rules to UTC transactions as is applied to INCs and DECs, treat the UTC as equivalent to an INC or a DEC depending on its net impact on a given constraint. A UTC transaction is essentially a paired INC/DEC, it has a net impact on the flow across a constraint, as an INC or DEC does. While total system power balance is maintained by a UTC, local flows may change based on the UTC's net impact on a constraint. The MMU method captures this impact.

Figure 13-4 Illustration of UTC FTR forfeiture rule

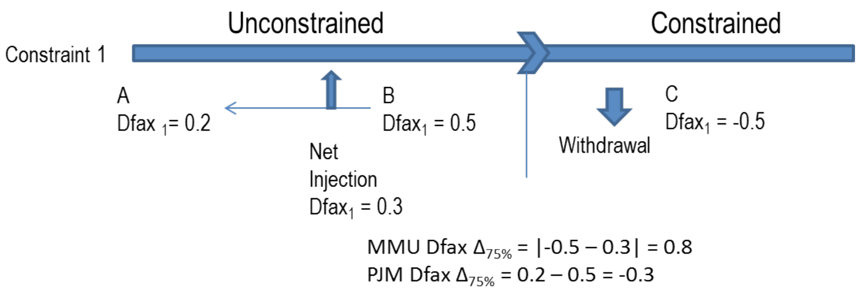
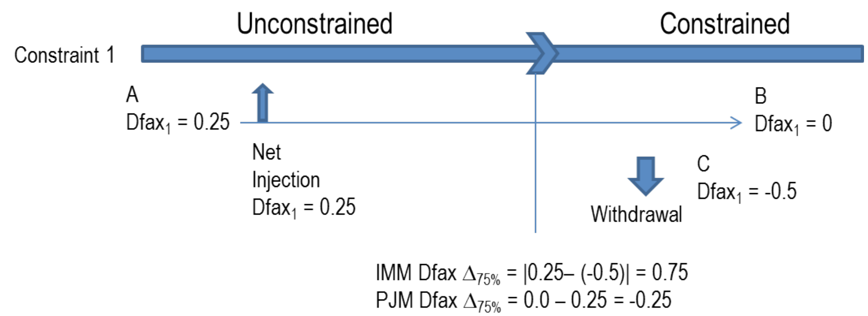


Figure 13-5 demonstrates where the assumption of contract path for UTCs in PJM's method does not hold with actual system conditions when either the source or sink of the UTC does not have any impact on the constraint being considered. In this case, the UTC is effectively an INC or a DEC relative to the constraint, as the other end of the UTC has no impact on the constraint. However, the PJM approach would not treat the UTC as an INC or DEC, despite the effective absence of the other end of the UTC. This is a flawed result.

As demonstrated in Figure 13-5, the UTC is no different than an INC on the constraint being considered. Using the PJM method this UTC would pass the FTR forfeiture rule. The net dfax would be calculated as the dfax of bus B (0) minus the dfax of bus A (0.25) for a net dfax of -0.25, with no comparison to any withdrawal bus. Since the dfax is negative, it would pass the PJM FTR forfeiture rule. Under the MMU's method, the net dfax is calculated as an injection with a dfax of 0.25, and then the absolute value of the difference is calculated between that injection and the dfax of the largest withdrawal on the constraint. In this example that is bus C, with a dfax of -0.5. The result is an absolute value of the dfax difference of 0.75, meaning that this UTC fails the FTR forfeiture test.

Figure 13-5 Illustration of UTC FTR Forfeiture rule with one point far from constraint



The MMU recommends that the FTR forfeiture rule be applied to UTCs in the same way it is applied to INCs and DECs.

Credit Issues

There were two collateral defaults and seven payment defaults for the first six months of 2015. The two collateral defaults totaled $710,300 and the seven payment defaults totaled $1,726,641. All of these default events were from Intergrid Mideast Group, LLC.

PJM terminated Intergrid's membership as of April 23, 2015 and FERC approved PJM's termination as of June 23, 2015. Some of Intergrid's invoices were paid through Intergrid, a guarantor or cash collateral posted with PJM. Intergrid held FTRs at the time they were declared in default. PJM will liquidate Intergrid's FTR positions in accordance with Section 7.3.9 of the Operating Agreement.[9] The amount of revenue generated by these liquidated FTRs will impact the default allocation assessments that may be billed in accordance with Section 15.2.2 of the Operating Agreement.[10] PJM liquidated 500.8 MW of Intergrid's FTRs in the June Monthly Balance of Planning Period Auction for a net of $509,732 in revenue. PJM also liquidated 417.2 MW of Long Term FTRs for various planning periods for a net of $230,318 in cost. The net revenue result of Intergrid's FTR liquidation so far is $279,414.

9 *See* PJM OATT. Liquidation of Financial Transmission Rights in the Event of Member Default. § 7.3.9.
10 *See* PJM OATT. Default Allocation Assessment § 15.2.2.

Market Performance

Volume

In an effort to address reduced FTR payout ratios, PJM may use normal transmission limits in the FTR auction model. 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 for counter flow FTRs.[11]

In another 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 counter flow auction bids available to reduce the infeasibilities.[12]

Table 13-7 provides the Annual FTR Auction market volume for the 2015 to 2016 planning period. Total FTR buy bids were 2,461,662 MW, down 24.7 percent from 3,270,311 MW for the previous planning period. For the 2015 to 2016 planning period 354,630 MW (14.5 percent) of buy bids cleared, down 3.1 percent from 365,843 MW for the previous planning period. There were 378,744 MW of sell offers with 63,983 MW (16.9 percent) clearing for the 2015 to 2016 planning period. The total volume of cleared buy and self-scheduled bids was 378,328 MW, up 3.4 percent from 365,843 in the previous Annual FTR Auction.

11 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013,) p. 56.
12 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013,) p. 56.

Table 13-7 Annual FTR Auction market volume: Planning period 2015 to 2016

Trade Type	Type	FTR Direction	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Obligations	Counter Flow	98,979	406,755	120,598	29.6%	286,157	70.4%
		Prevailing Flow	321,737	1,650,128	211,385	12.8%	1,438,742	87.2%
		Total	420,716	2,056,883	331,984	16.1%	1,724,899	83.9%
	Options	Counter Flow	86	17,253	21	0.1%	17,231	99.9%
		Prevailing Flow	31,107	363,829	22,625	6.2%	341,204	93.8%
		Total	31,193	381,081	22,646	5.9%	358,435	94.1%
	Total	Counter Flow	99,065	424,007	120,619	28.4%	303,388	71.6%
		Prevailing Flow	352,844	2,013,956	234,011	11.6%	1,779,946	88.4%
		Total	451,909	2,437,964	354,630	14.5%	2,083,334	85.5%
Self-scheduled bids	Obligations	Counter Flow	63	1,045	1,045	100.0%	0	0.0%
		Prevailing Flow	2,629	22,654	22,654	100.0%	0	0.0%
		Total	2,692	23,699	23,699	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	99,042	407,800	121,643	29.8%	286,157	70.2%
		Prevailing Flow	324,366	1,672,781	234,039	14.0%	1,438,742	86.0%
		Total	423,408	2,080,581	355,682	17.1%	1,724,899	82.9%
	Options	Counter Flow	86	17,253	21	0.1%	17,231	99.9%
		Prevailing Flow	31,107	363,829	22,625	6.2%	341,204	93.8%
		Total	31,193	381,081	22,646	5.9%	358,435	94.1%
	Total	Counter Flow	99,128	425,052	121,664	28.6%	303,388	71.4%
		Prevailing Flow	355,473	2,036,610	256,664	12.6%	1,779,946	87.4%
		Total	454,601	2,461,662	378,328	15.4%	2,083,334	84.6%
Sell offers	Obligations	Counter Flow	53,483	162,830	23,986	14.7%	138,844	85.3%
		Prevailing Flow	70,454	205,920	39,619	19.2%	166,301	80.8%
		Total	123,937	368,750	63,605	17.2%	305,144	82.8%
	Options	Counter Flow	2	15	0	0.0%	15	100.0%
		Prevailing Flow	3,462	9,979	378	3.8%	9,601	96.2%
		Total	3,464	9,994	378	3.8%	9,616	96.2%
	Total	Counter Flow	53,485	162,845	23,986	14.7%	138,859	85.3%
		Prevailing Flow	73,916	215,899	39,997	18.5%	175,902	81.5%
		Total	127,401	378,744	63,983	16.9%	314,761	83.1%

Figure 13-6 shows the bid volumes of the Annual FTR Auctions from the 2009 to 2010 planning period through the 2015 to 2016 planning period and the associated planning period payout ratios, represented by the background bars. The payout ratio for the current planning period is shown as dotted background because it is not yet final. Bid volume has not changed significantly with payout ratio, with the exception of on and off peak prevailing flow products. For on and off peak prevailing flow products, the 2012 to 2013 planning period the bid volume decreased 24.3 percent from the 2011 to 2012 planning period, but then increased 30.5 percent for the 2013 to 2014 planning period despite an only slightly improved payout ratio.

Figure 13-6 Annual Bid FTR Auction volume: Planning period 2009 to 2010 through 2015 to 2016

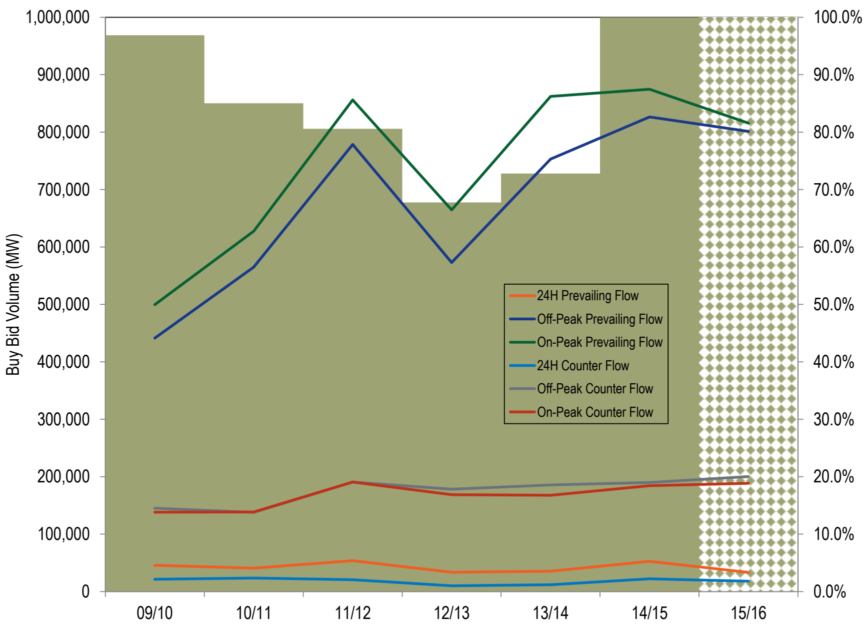


Figure 13-7 shows the cleared volumes of the Annual FTR Auctions from planning period 2009 to 2010 through the 2015 to 2016 planning period and the associated planning period payout ratios, represented by the background bars. The payout ratio for the current planning period is shown as dotted background because it is not yet final. The cleared MW increased from the 2009 to 2010 planning period through the 2013 to the 2014 planning period, as a market response to lower payout ratios compared to target allocations. The 2014 to 2015 planning period volume was 19.1 percent lower than the 2013 to 2014 planning period, while the 2015 to 2016 planning period was 16.3 percent lower than the 2013 to 2014 volume, as a result of PJM's more restrictive modeling of Stage 1B and Stage 2 ARRs, leading to fewer available FTRs in the Annual FTR Auction and higher prices.

Figure 13-7 Annual Cleared FTR Auction volume: Planning period 2009 to 2010 through 2015 to 2016

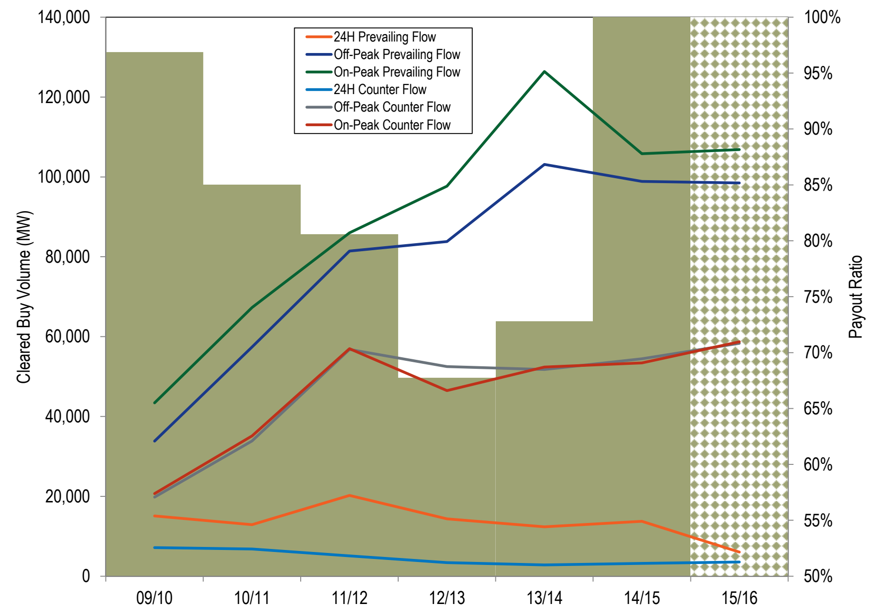


Table 13-8 shows the proportion of ARRs self-scheduled as FTRs for the last six planning periods. The maximum possible level of self-scheduled FTRs includes all ARRs, including RTEP ARRs. Eligible participants self-scheduled 23,699 MW (30.4 percent) of ARRs as FTRs for the 2015 to 2016 planning period, down from 26,964 MW (36.7 percent) in the previous planning period. This reduction was a market response to the relative values of ARRs and FTRs.

Table 13-8 Comparison of self-scheduled FTRs: Planning periods 2009 to 2010 through 2015 to 2016

Planning Period	Self-Scheduled FTRs (MW)	Maximum Possible Self-Scheduled FTRs (MW)	Percent of ARRs Self-Scheduled as FTRs
2009/2010	68,589	109,613	62.6%
2010/2011	55,669	102,046	54.6%
2011/2012	46,017	103,660	44.4%
2012/2013	41,351	99,115	41.7%
2013/2014	29,289	94,097	31.1%
2014/2015	26,964	73,504	36.7%
2015/2016	23,699	77,872	30.4%

Table 13-9 provides the Monthly Balance of Planning Period FTR Auction market volume for the entire 2014 to 2015 planning period and the first month of the 2015 to 2016 planning period. There were 2,017,412 MW of FTR obligation buy bids and 553,702 MW of FTR obligation sell offers for all bidding periods in the first month of the 2015 to 2016 planning period. The monthly balance of planning period auction cleared 187,357 MW (9.3 percent) of FTR obligation buy bids and 102,726 MW (18.6 percent) of FTR obligation sell offers.

There were 352,799 MW of FTR option buy bids and 57,100 MW of FTR option sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the first month of the 2015 to 2016 planning period. The monthly auctions cleared 7,999 (2.3 percent) of FTR option buy bids, and 57,100 MW (26.6 percent) of FTR option sell offers.

Table 13-9 Monthly Balance of Planning Period FTR Auction market volume: 2015

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-15	Obligations	Buy bids	252,024	1,586,427	144,179	9.1%	1,442,248	90.9%
		Sell offers	99,255	247,626	61,026	24.6%	186,600	75.4%
	Options	Buy bids	10,732	263,464	2,787	1.1%	260,678	98.9%
		Sell offers	2,886	15,735	4,571	29.1%	11,164	70.9%
Feb-15	Obligations	Buy bids	266,009	1,417,759	161,646	11.4%	1,256,112	88.6%
		Sell offers	96,236	237,844	51,752	21.8%	186,091	78.2%
	Options	Buy bids	12,280	284,062	6,106	2.1%	277,956	97.9%
		Sell offers	3,281	16,999	5,332	31.4%	11,667	68.6%
Mar-15	Obligations	Buy bids	254,361	1,467,192	151,571	10.3%	1,315,621	89.7%
		Sell offers	97,054	259,360	54,239	20.9%	205,121	79.1%
	Options	Buy bids	7,894	216,952	8,671	4.0%	208,281	96.0%
		Sell offers	4,158	28,822	8,783	30.5%	20,039	69.5%
Apr-15	Obligations	Buy bids	195,242	1,239,939	133,675	10.8%	1,106,263	89.2%
		Sell offers	67,401	211,198	53,998	25.6%	157,200	74.4%
	Options	Buy bids	6,529	189,448	6,364	3.4%	183,084	96.6%
		Sell offers	3,049	23,932	7,442	31.1%	16,490	68.9%
May-15	Obligations	Buy bids	118,504	696,460	81,864	11.8%	614,596	88.2%
		Sell offers	35,828	104,822	36,911	35.2%	67,910	64.8%
	Options	Buy bids	3,709	120,692	2,524	2.1%	118,169	97.9%
		Sell offers	1,366	12,379	4,778	38.6%	7,600	61.4%
Jun-15	Obligations	Buy bids	384,766	2,017,412	187,357	9.3%	1,830,054	90.7%
		Sell offers	180,141	553,702	102,726	18.6%	450,976	81.4%
	Options	Buy bids	12,429	352,799	7,999	2.3%	344,800	97.7%
		Sell offers	11,041	57,100	15,172	26.6%	41,928	73.4%
2014/2015*	Obligations	Buy bids	3,360,128	21,777,160	2,201,036	10.1%	19,576,124	89.9%
		Sell offers	1,348,860	3,357,375	742,612	22.1%	2,614,762	77.9%
	Options	Buy bids	151,829	3,569,067	55,700	1.6%	3,513,367	98.4%
		Sell offers	35,890	225,710	71,258	31.6%	154,452	68.4%
2015/2016**	Obligations	Buy bids	384,766	2,017,412	187,357	9.3%	1,830,054	90.7%
		Sell offers	180,141	553,702	102,726	18.6%	450,976	81.4%
	Options	Buy bids	12,429	352,799	7,999	2.3%	344,800	97.7%
		Sell offers	11,041	57,100	15,172	26.6%	41,928	73.4%

* Shows twelve months for 2014/2015; ** Shows one month ended for 2015/2016

Table 13-10 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 2015 was 140,090.5 MW. The average monthly cleared volume for 2014 was 224,036.6 MW.

Table 13-10 Monthly Balance of Planning Period FTR Auction buy-bid, bid and cleared volume (MW per period): 2015

Monthly Auction	MW Type	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-15	Bid	971,818	380,246	165,248				332,579	1,849,891
	Cleared	90,259	25,220	7,982				23,505	146,966
Feb-15	Bid	930,310	230,137	204,195				337,179	1,701,821
	Cleared	103,322	16,683	14,472				33,276	167,753
Mar-15	Bid	926,146	248,594	275,292				234,112	1,684,143
	Cleared	105,252	23,524	20,266				11,200	160,242
Apr-15	Bid	1,039,343	390,043						1,429,386
	Cleared	113,418	26,621						140,039
May-15	Bid	817,152							817,152
	Cleared	84,387							84,387
Jun-15	Bid	766,478	314,523	305,243				273,146	1,659,391
	Cleared	81,472	22,796	20,096				16,792	141,156

Figure 13-8 shows cleared auction volumes as a percent of the total FTR cleared volume by calendar months for June 2004 through June 2015, 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 13-8 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through June 2015

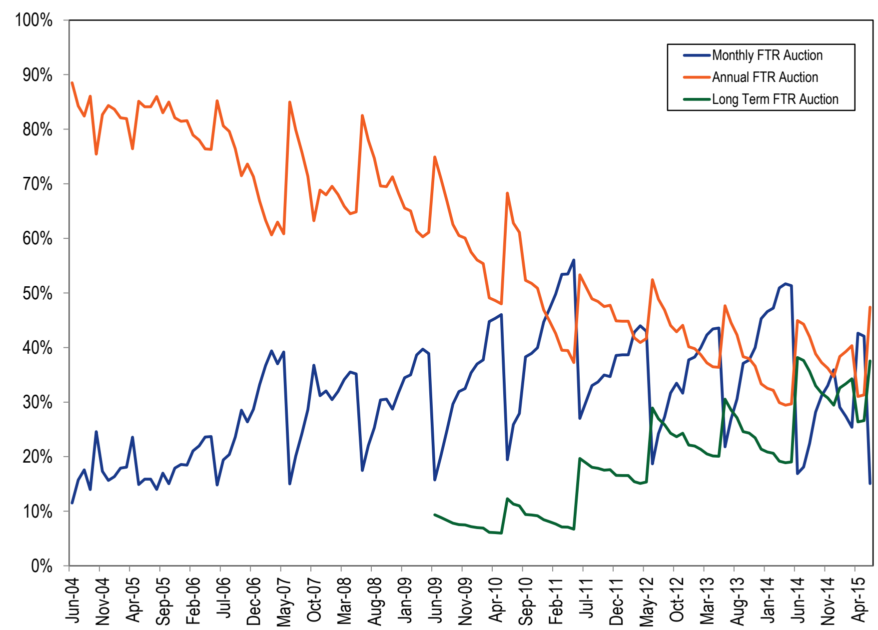


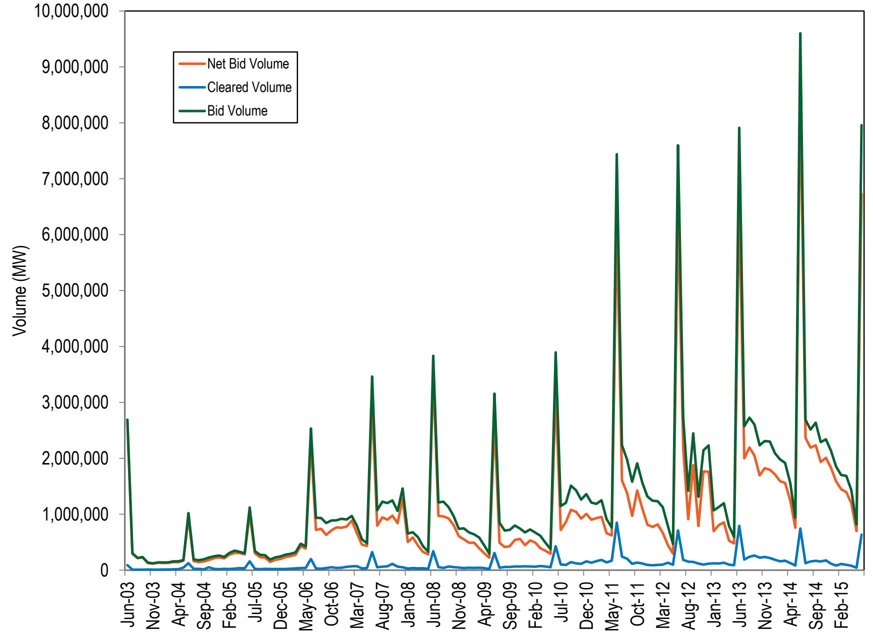
Table 13-11 provides the secondary bilateral FTR market volume for the entire 2013 to 2014 and 2014 to 2015 planning periods.

Table 13-11 Secondary bilateral FTR market volume: Planning periods 2013 to 2014 and 2014 to 2015[13]

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	203
		On Peak	1,535
		Off Peak	1,141
		Total	2,879
	Option	24-Hour	0
		On Peak	0
		Off Peak	0
		Total	0

Figure 13-9 shows the FTR bid, cleared and net bid volume from June 2003 through June 2015 for Long Term, Annual and Monthly Balance of Planning Period Auctions.[14] 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.

Figure 13-9 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through June 2015



13 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.
14 The data for this table are available in *2014 State of the Market Report for PJM*, Volume 2, Appendix H.

Price

Figure 13-10 shows the volume-weighted average buy bid price for the Annual FTR Auctions from the 2009 to 2010 through the 2015 to 2016 planning periods and the associated planning period payout ratios, represented by the background bars. The payout ratio for the 2015 to 2016 planning period is shown as dotted background because it is not yet final. From the 2010 to 2011 planning period to the 2013 to 2014 planning period FTR prices decreased. The 2014 to 2015 and 2015 to 2016 planning periods 24 hour obligation prices increased 142.5 percent and 210.8 percent. This large price increase was driven by the significant decrease in FTR supply volume during the Annual FTR Auction which was a result of PJM's decisions to use a more constrained model and its impact on Stage 1B and Stage 2 ARR allocations. The increased price due to decreased volume has led to an increase in ARR target allocations for the planning period.

Figure 13-10 Annual FTR Auction volume-weighted average buy bid price: Planning period 2009 to 2010 through 2015 to 2016

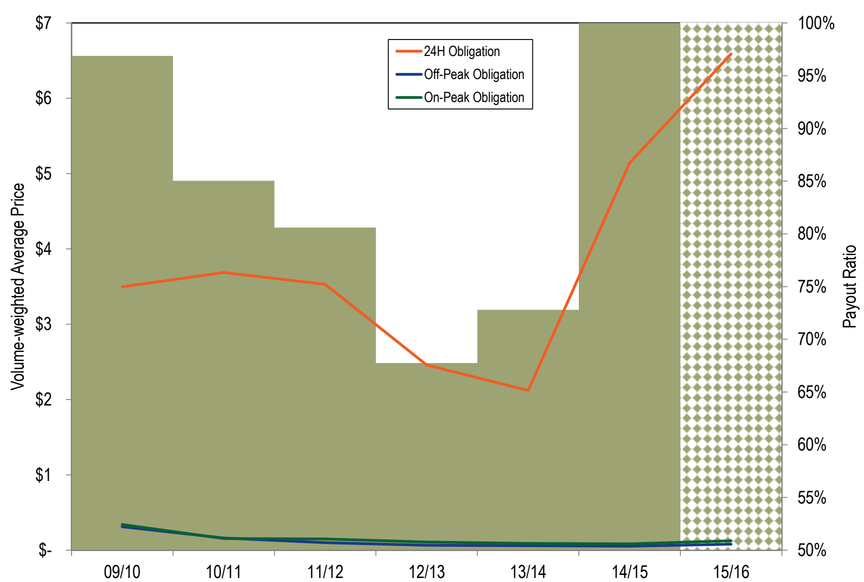


Table 13-12 shows the weighted-average cleared buy-bid prices by trade type, FTR product, FTR direction and class type for the Annual FTR Auction for the 2015 to 2016 planning period. The weighted-average cleared buy bid price in the 2015 to 2016 Annual FTR Auction was $0.31 per MW, up from $0.29 per MW in the 2014 to 2015 planning period.

Table 13-12 Annual FTR Auction weighted-average cleared prices (Dollars per MW): Planning period 2015 to 2016

			Class Type			
Trade Type	Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.74)	($0.48)	($0.30)	($0.40)
		Prevailing Flow	$1.33	$1.00	$0.62	$0.83
		Total	$0.57	$0.47	$0.28	$0.39
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$3.01	$0.50	$0.32	$0.43
		Total	$3.01	$0.50	$0.32	$0.43
Self-scheduled bids	Obligations	Counter Flow	($0.09)	NA	NA	($0.09)
		Prevailing Flow	$1.65	NA	NA	$1.65
		Total	$1.58	NA	NA	$1.58
Buy and self-scheduled bids	Obligations	Counter Flow	($0.59)	($0.48)	($0.30)	($0.40)
		Prevailing Flow	$1.59	$1.00	$0.62	$0.98
		Total	$1.29	$0.47	$0.28	$0.53
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$3.01	$0.50	$0.32	$0.43
		Total	$3.01	$0.50	$0.32	$0.43
Sell offers	Obligations	Counter Flow	($2.00)	($0.58)	($0.50)	($0.60)
		Prevailing Flow	$0.69	$0.50	$0.33	$0.42
		Total	($0.85)	$0.12	$0.02	$0.04
	Options	Counter Flow	NA	NA	NA	NA
		Prevailing Flow	$0.00	$0.33	$0.12	$0.18
		Total	$0.00	$0.33	$0.12	$0.18

Table 13-13 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2015 through June 2015. For example, for the January 2015 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 2015 Monthly Balance of Planning Period FTR Auction.

Table 13-13 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MW): January through June 2015

Monthly Auction	Prompt Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-15	$0.38	$0.57	$0.16				$0.19	$0.33
Feb-15	$0.21	$0.30	$0.21				$0.11	$0.17
Mar-15	$0.27	$0.27	$0.20				$0.13	$0.24
Apr-15	$0.17	$0.20					$0.00	$0.18
May-15	$0.20						$0.00	$0.20
Jun-15	$0.25	$0.38	$0.32	$0.29	$0.27	$0.63	$0.34	$0.36

The cleared weighted-average price paid in the Monthly Balance of Planning Period FTR Auctions for January through June 2015 was $0.25 per MW, up from $0.15 per MW in the same time last year, a 66.7 percent increase in FTR prices. The cleared weighted-average price for the current planning period was $0.36, up 140.0 percent from $0.15 for the same time period during the previous planning period.

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 13-14 lists FTR profits by organization type and FTR direction for the period from January through June 2015. 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 $339.3 million in profits for physical entities, of which $229.1 million was from self-scheduled FTRs, and $191.0 million for financial entities. In the first six months of 2014, FTRs were more profitable, with an overall profit of $1,215.4 million. The large profit last year was mainly due to January 2014, which experienced unusually high congestion prices.

Table 13-14 FTR profits by organization type and FTR direction: 2015

	FTR Direction				
Organization Type	Prevailing Flow	Self Scheduled Prevailing Flow	Counter Flow	Self Scheduled Counter Flow	All
Physical	$146,734,712	$229,067,950	($36,477,115)	$9,805	$339,335,351
Financial	$217,894,814	NA	($26,943,958)	NA	$190,950,856
Total	$364,629,526	$229,067,950	($63,421,073)	$9,805	$530,286,207

Table 13-15 lists the monthly FTR profits in 2015 by organization type.

Table 13-15 Monthly FTR profits by organization type: 2015

	Organization Type			
Month	Physical	Self Scheduled Physical FTRs	Financial	Total
Jan	$12,061,474	$34,995,565	$31,637,412	$78,694,451
Feb	$76,959,226	$97,372,186	$103,812,757	$278,144,168
Mar	$5,881,768	$27,967,818	$35,574,450	$69,424,036
Apr	($6,468,547)	$16,657,504	$8,362,429	$18,551,386
May	$17,605,952	$29,353,275	$8,298,743	$55,257,970
Jun	$4,217,724	$22,731,406	$3,265,064	$30,214,195
Total	$110,257,597	$229,077,755	$190,950,856	$530,286,207

Revenue

Annual FTR Auction Revenue

Table 13-16 shows the Annual FTR Auction revenue by trade type, type, FTR direction and class type. The Annual FTR Auction for the 2015 to 2016 planning period generated $936.3 million, up 25.1 percent from $748.6 million in the 2014 to 2015 planning period, and up 67.7 percent from $558.4 in the 2013 to 2014 planning period. Counter flow FTR holders received $157.1 million, up 10.5 percent from the previous planning period and prevailing flow FTR holders paid $1,093.4 million, up 22.7 percent from the previous planning period.

Table 13-16 Annual FTR Auction revenue: Planning period 2015 to 2016

			Class Type			
Trade Type	Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($22,998,708)	($115,833,322)	($79,872,792)	($218,704,822)
		Prevailing Flow	$70,921,369	$440,928,707	$283,846,269	$795,696,345
		Total	$47,922,661	$325,095,385	$203,973,477	$576,991,523
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$3,412,228	$23,054,249	$17,051,001	$43,517,479
		Total	$3,412,228	$23,054,249	$17,051,001	$43,517,479
	Total	Counter Flow	($22,998,708)	($115,833,322)	($79,872,792)	($218,704,822)
		Prevailing Flow	$74,333,597	$463,982,956	$300,897,271	$839,213,824
		Total	$51,334,889	$348,149,634	$221,024,478	$620,509,002
Self-scheduled bids	Obligations	Counter Flow	($803,134)	NA	NA	($803,134)
		Prevailing Flow	$328,924,705	NA	NA	$328,924,705
		Total	$328,121,572	NA	NA	$328,121,572
Buy and self-scheduled bids	Obligations	Counter Flow	($23,801,841)	($115,833,322)	($79,872,792)	($219,507,955)
		Prevailing Flow	$399,846,074	$440,928,707	$283,846,269	$1,124,621,050
		Total	$376,044,233	$325,095,385	$203,973,477	$905,113,095
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$3,412,228	$23,054,249	$17,051,001	$43,517,479
		Total	$3,412,228	$23,054,249	$17,051,001	$43,517,479
	Total	Counter Flow	($23,801,841)	($115,833,322)	($79,872,792)	($219,507,955)
		Prevailing Flow	$403,258,302	$463,982,956	$300,897,271	$1,168,138,529
		Total	$379,456,461	$348,149,634	$221,024,478	$948,630,574
Sell offers	Obligations	Counter Flow	($8,864,388)	($26,951,089)	($26,599,078)	($62,414,555)
		Prevailing Flow	$2,292,837	$42,440,354	$29,751,044	$74,484,235
		Total	($6,571,551)	$15,489,266	$3,151,965	$12,069,680
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$0	$141,030	$158,316	$299,346
		Total	$0	$141,030	$158,316	$299,346
	Total	Counter Flow	($8,864,388)	($26,951,089)	($26,599,078)	($62,414,555)
		Prevailing Flow	$2,292,837	$42,581,384	$29,909,360	$74,783,581
		Total	($6,571,551)	$15,630,295	$3,310,282	$12,369,026
Total			$386,028,012	$332,519,339	$217,714,197	$936,261,548

Monthly Balance of Planning Period FTR Auction Revenue

Table 13-17 shows Monthly Balance of Planning Period FTR Auction revenue by trade type, type and class type for January through June 2015. The Monthly Balance of Planning Period FTR Auction for the 2015 to 2016 planning period netted $5.3 million in revenue, with buyers paying $44.9 million and sellers receiving $39.6 million for the first month of the 2015 to 2016 planning period. For the entire 2014 to 2015 planning period, the Monthly Balance of Planning Period FTR Auctions netted $19.3 million in revenue with buyers paying $214.3 million and sellers receiving $195.0 million.

Table 13-17 Monthly Balance of Planning Period FTR Auction revenue: 2015

			Class Type			
Monthly Auction	Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-15	Obligations	Buy bids	($618,302)	$13,581,853	$10,015,068	$22,978,619
		Sell offers	$635,745	$10,914,326	$7,928,853	$19,478,925
	Options	Buy bids	$0	$256,008	$168,789	$424,797
		Sell offers	$8,592	$1,047,368	$1,259,073	$2,315,033
Feb-15	Obligations	Buy bids	($147,453)	$7,611,995	$6,052,270	$13,516,812
		Sell offers	$114,483	$5,945,620	$4,885,777	$10,945,879
	Options	Buy bids	$5,211	$498,896	$432,335	$936,443
		Sell offers	$26	$1,332,728	$1,345,070	$2,677,824
Mar-15	Obligations	Buy bids	$47,778	$8,735,038	$6,313,585	$15,096,401
		Sell offers	$1,543	$6,293,269	$4,485,916	$10,780,728
	Options	Buy bids	$0	$408,180	$399,129	$807,309
		Sell offers	$23	$1,419,352	$1,351,464	$2,770,839
Apr-15	Obligations	Buy bids	($285,836)	$5,243,669	$3,185,097	$8,142,930
		Sell offers	$131,098	$3,852,576	$2,136,076	$6,119,750
	Options	Buy bids	$8,726	$560,959	$381,773	$951,458
		Sell offers	$17	$1,062,303	$934,036	$1,996,356
May-15	Obligations	Buy bids	($1,534,332)	$4,116,947	$3,375,795	$5,958,410
		Sell offers	($67,511)	$2,225,577	$1,600,569	$3,758,635
	Options	Buy bids	$0	$224,867	$72,334	$297,201
		Sell offers	$23	$777,796	$694,570	$1,472,389
Jun-15	Obligations	Buy bids	$974,245	$25,819,492	$15,835,242	$42,628,980
		Sell offers	$852,490	$18,479,372	$12,329,257	$31,661,119
	Options	Buy bids	$0	$1,400,901	$849,366	$2,250,267
		Sell offers	$7,166	$4,818,452	$3,094,994	$7,920,611
2014/2015*	Obligations	Buy bids	$14,690,243	$114,510,024	$74,009,738	$203,210,005
		Sell offers	$10,416,134	$96,121,532	$63,750,015	$170,287,681
	Options	Buy bids	$163,116	$6,269,159	$4,616,812	$11,049,087
		Sell offers	$39,972	$13,570,524	$11,100,778	$24,711,274
	Net Total		$4,397,253	$11,087,127	$3,775,756	$19,260,137
2015/2016**	Obligations	Buy bids	$974,245	$25,819,492	$15,835,242	$42,628,980
		Sell offers	$852,490	$18,479,372	$12,329,257	$31,661,119
	Options	Buy bids	$0	$1,400,901	$849,366	$2,250,267
		Sell offers	$7,166	$4,818,452	$3,094,994	$7,920,611
	Net Total		$114,590	$3,922,570	$1,260,357	$5,297,517

* Shows Twelve Months; ** Shows one month

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 13-11 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 38.5 percent of total positive target allocations during the 2014 to 2015 planning period with the Northern Illinois Hub accounting for 6.4 percent of all positive target allocations. The top 10 sinks that created liability accounted for 7.3 percent of total negative target allocations with the Western Hub accounting for 1.1 percent of all negative target allocations.

Figure 13-11 Ten largest positive and negative FTR target allocations summed by sink: 2014 to 2015 planning period

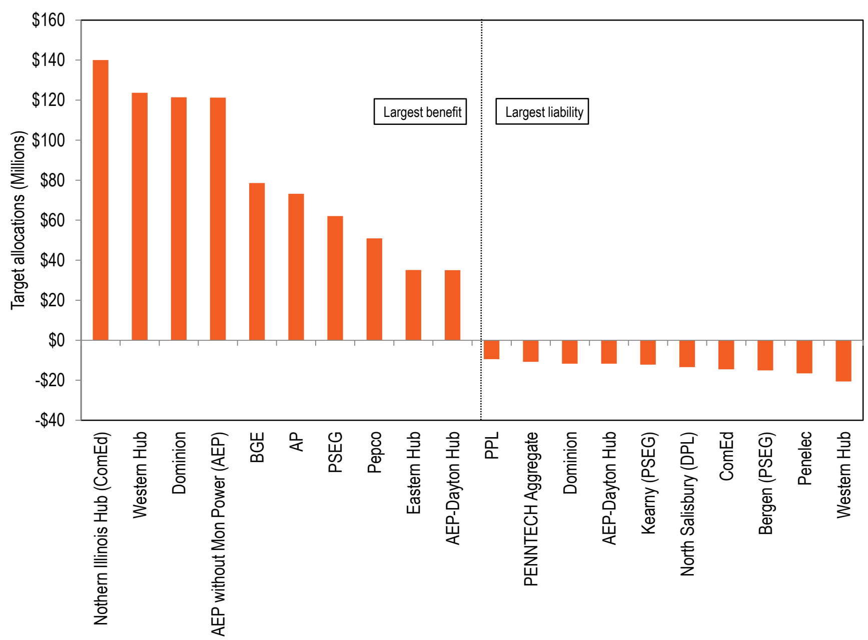
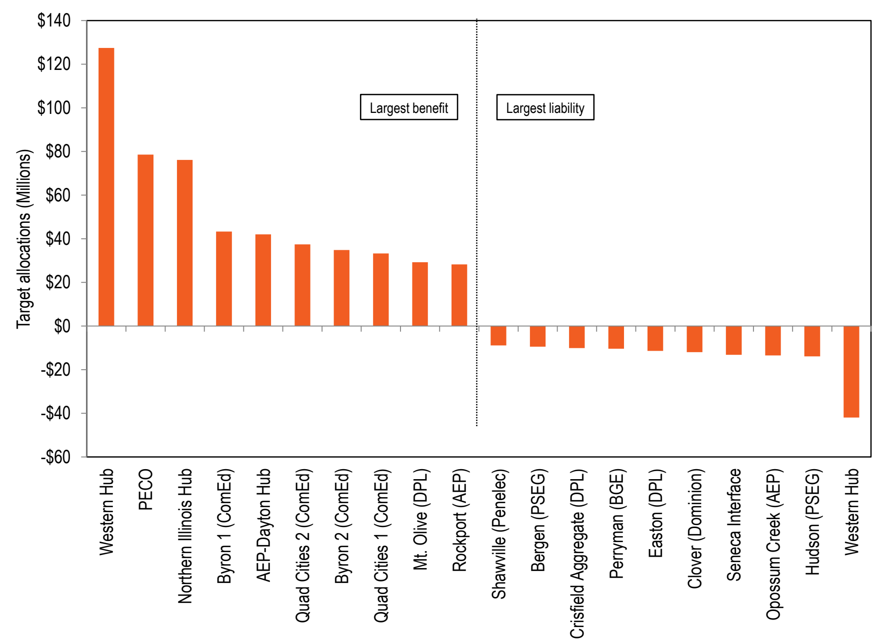


Figure 13-12 shows the ten largest positive and negative FTR target allocations, summed by source, for the 2014 to 2015 planning period. The top 10 sources with a positive target allocation accounted for 12.1 percent of total positive target allocations with the Western Hub accounting for 2.9 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 7.8 percent of all negative target allocations, with the Western Hub accounting for 2.2 percent.

Figure 13-12 Ten largest positive and negative FTR target allocations summed by source: 2014 to 2015 planning period



Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay and all generators receive their respective LMPs. When load in a constrained area pays more than the amount that generators receive, excluding losses, positive congestion revenue exists and is available to cover the target allocations of

FTR holders. The load MW exceed the generation MW in constrained areas because part of the load is served by imports using transmission capability into the constrained areas. That is why load, which pays for the transmission capability, receives ARRs to offset congestion in the constrained areas. Generating units that are the source of such imports are paid the price at their own bus, which does not reflect congestion in constrained areas. Generation in constrained areas receives the congestion price and all load in constrained areas pays the congestion price. As a result, load congestion payments are greater than the congestion-related payments to generation.[15] 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. 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. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs during the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning year. For example, the 2013 to 2014 planning period was not revenue adequate, and thus this uplift charge was collected from FTR participants. There was excess congestion revenue at the end of the 2014 to 2015 planning period, which is distributed to FTR participants in the same manner that the FTR uplift is applied.

FTR revenues are primarily comprised of hourly congestion revenue, from the day-ahead and balancing markets.[16] 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 13-18 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.[17]

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

15 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."

16 When hourly congestion revenues are negative, it is defined as a net negative congestion hour.

17 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)

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 the 2014 to 2015 planning period PJM paid MISO and NYISO a combined $33.2 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 $1,457.1 million of FTR revenues during 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 2014 to 2015 planning period, the top sink and top source with the highest positive FTR target allocations were the Northern Illinois Hub and Western Hub. The top sink with the largest negative FTR target allocation was the Western Hub and the top source with the largest negative FTR target allocation was the Western Hub.

This high level of revenue adequacy was primarily due to actions taken by PJM to address prior low levels of revenue adequacy. PJM's actions included PJM's assumption of higher outage levels and PJM's decision to include additional constraints (closed loop interfaces) both of which reduced system capability in the FTR auction model. PJM's actions led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs. 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. The result of this change in modeling was also that available FTR capacity decreased for the planning period. This decrease resulted in an increase in FTR nodal prices for the Annual FTR Auction. The result was fewer available ARRs, but an increased dollar per MW value for those ARRs. The results are in the total ARR target allocations in Table 13-18 and the dollars per MW increase in Figure 13-18.

Table 13-18 presents the PJM FTR revenue detail for the 2013 to 2014 planning period and the 2014 to 2015 planning period.

Table 13-18 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2013 to 2014 and 2014 to 2015

Accounting Element	2013/2014	2014/2015
ARR information		
ARR target allocations	$520.0	$765.9
FTR auction revenue	$593.9	$794.9
ARR excess	$71.7	$29.0
FTR targets		
Positive target allocations	$2,625.8	$1,551.6
Negative target allocations	($126.4)	($293.7)
FTR target allocations	$2,499.4	$1,257.8
Adjustments:		
Adjustments to FTR target allocations	($1.2)	($3.5)
Total FTR targets	$2,498.2	$1,254.4
FTR revenues		
ARR excess	$71.7	$29.0
Competing uses	$0.0	$0.0
Congestion		
Net Negative Congestion (enter as negative)	($55.0)	($69.6)
Hourly congestion revenue	$1,837.9	$1,463.8
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($44.3)	($33.2)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	$0.0	$0.0
Adjustments:		
Excess revenues carried forward into future months	$0.0	$63.7
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	$1,457.1
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$1,819.5	$1,457.1
Remaining deficiency	$678.7	($115.1)

Unallocated Congestion Charges

When total congestion revenue (day ahead plus balancing) at the end of an hour is negative, target allocations in that hour (based on day ahead CLMP values) 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 13-19 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.[18]

Table 13-19 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 13-20 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.

18 See *State of the Market Report for PJM*: Volume II, Section 4: Energy Uplift at "Energy Uplift Charges," for the impact of Unallocated Congestion Charges on Operating Reserve rates.

The total row in Table 13-20 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. October 2014, November 2014 and March 2015 had revenue shortfalls of $6.5 million, $17.7 million and $38.7, but were fully funded using excess revenue from previous months.

Table 13-20 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-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
Oct-14	$80.5	$80.5	91.9%	$80.5	100.0%	$0.0
Nov-14	$106.4	$106.4	83.3%	$106.4	100.0%	$0.0
Dec-14	$65.4	$58.2	100.0%	$58.2	100.0%	$7.2
Jan-15	$132.0	$123.5	100.0%	$123.5	100.0%	$8.5
Feb-15	$425.8	$316.8	100.0%	$316.8	100.0%	$109.1
Mar-15	$112.3	$112.3	64.6%	$112.3	100.0%	$0.0
Apr-15	$70.3	$60.8	100.0%	$70.3	100.0%	$9.5
May-15	$108.4	$98.6	100.0%	$108.4	100.0%	$9.8
Summary for Planning Period 2014 to 2015						
Total	$1,452.3	$1,251.6		$1,327.5	100.0%	$75.9
Jun-15	$103.7	$83.8	100.0%	$103.7	100.0%	$19.9
Summary for Planning Period 2015 to 2016						
Total	$103.7	$83.8		$103.7	100.0%	$19.9

Figure 13-13 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through June 2015. 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 13-13 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 ratio for revenue inadequate months in the current planning period may change if excess revenue is collected in the remainder of the planning period. March 2015 had high levels of negative balancing congestion that resulted in a payout ratio of 64.6 percent. However, there was enough excess from previous months to bring the payout ratio to 100 percent.

Figure 13-13 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through June 2015

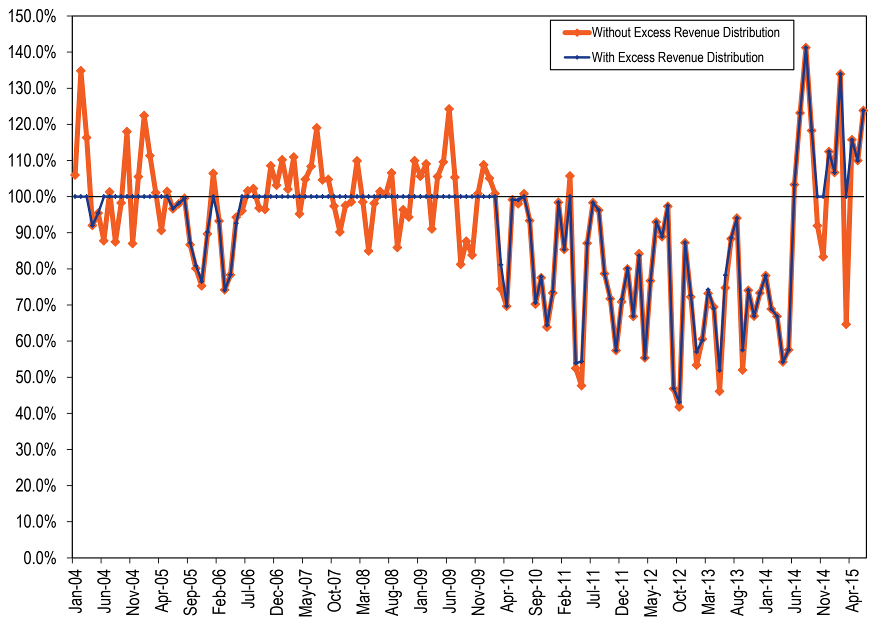


Table 13-21 shows the FTR payout ratio by planning period from the 2003 to 2004 planning period forward. Planning period 2013 to 2014 includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves. For the 2014 to 2015 planning period, there was excess congestion revenue to pay target allocations resulting in a reported payout ratio of 116.2 percent for the planning period. This excess will be distributed to FTR participants pro rata based on their net positive target allocations.

Table 13-21 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%
2015/2016	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 13-22 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 13-22 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 13-23 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.[19] 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 13-23 shows the PJM reported and actual monthly payout ratios for the 2014 to 2015 planning period. 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 all but October, November and March of the 2014 to 2015 planning period, there was an excess of FTR revenues, so total funding was actually over 100 percent. Additional revenue was distributed to future months of the planning period to cover any shortfall.

19 See PJM. "Manual 28: Operating Agreement Accounting," Revision 63 (December 19, 2013), p. 50.

Table 13-23 PJM Reported and Actual Monthly Payout Ratios: Planning period 2014 to 2015

	Reported Monthly Payout Ratio	Actual Monthly Payout Ratio
Jun-14	100.0%	100.0%
Jul-14	100.0%	100.0%
Aug-14	100.0%	100.0%
Sep-14	100.0%	100.0%
Oct-14	100.0%	100.0%
Nov-14	100.0%	100.0%
Dec-14	100.0%	100.0%
Jan-15	100.0%	100.0%
Feb-15	100.0%	100.0%
Mar-15	100.0%	100.0%
Apr-15	100.0%	100.0%
May-15	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.

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 13-24 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.

Table 13-24 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	-

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 13-25 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. October and November 2014 and March 2015 experienced revenue inadequacy, but excess revenue was distributed to them from previous months to ensure full funding. For months with no revenue inadequacies there is no change in payout ratio.

Table 13-25 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)
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)	$158,672,445	($109,435,464)	$69,520,938	100.0%	100.0%
Sep-14	$93,351,901	($18,360,141)	$230,425,062	($155,432,941)	$88,683,326	100.0%	100.0%
Oct-14	$115,053,632	($34,510,582)	$315,119,620	($234,573,734)	$80,529,041	100.0%	100.0%
Nov-14	$130,497,679	($24,118,185)	$318,604,763	($212,209,995)	$106,379,493	100.0%	100.0%
Dec-14	$80,517,779	($19,395,531)	$224,363,165	($163,240,917)	$65,392,809	100.0%	100.0%
Jan-15	$146,311,151	($22,842,202)	$410,273,039	($283,654,558)	$131,999,162	100.0%	100.0%
Feb-15	$374,621,111	($57,865,312)	$1,037,653,444	($719,673,940)	$425,826,022	100.0%	100.0%
Mar-15	$131,345,522	($19,051,127)	$414,369,580	($300,458,779)	$73,564,664	100.0%	100.0%
Apr-15	$88,627,007	($27,869,815)	$272,864,686	($211,944,617)	$70,299,122	100.0%	100.0%
May-15	$129,206,865	($30,649,084)	$392,526,758	($293,928,392)	$108,377,660	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	$1,549,603,363	($294,939,767)	$4,208,635,791	($2,947,744,437)	$1,413,528,267	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 13-26 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 13-26 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 13-27 shows the monthly positive, negative and total target allocations.[20] Table 13-27 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. If this change were implemented after excess planning period revenue was distributed, it would not result in additional revenue for the 2014 to 2015 planning period. However, if this change were implemented before excess planning period revenues were distributed, there would be an increase in the revenue available each month to pay prevailing flow FTRs, resulting in a decrease in the amount of excess from previous months that needs to be used to achieve revenue adequacy. This can be seen by a slight difference in the total revenue and adjusted counter flow total revenue columns for the three months, October, November and March, in the 2014 to 2015 planning period that were not revenue adequate. The result of this would be more excess available for distribution pro-rata at the end of the planning period.

20 Reported payout ratio may differ between Table 13-25 and Table 13-27 due to rounding differences when netting target allocations and considering each FTR individually.

Table 13-27 Counter flow FTR payout ratio adjustment impacts: Planning period 2013 to 2014 and 2014 to 2015

	Positive Target Allocations	Negative Target Allocations	Total Target Allocations	Total Congestion Revenue	Reported Payout Ratio*	Total Revenue Available	Adjusted Counterflow Payout Ratio	Adjusted Counter Flow Revenue Available
Jun-14	$218,239,158	($132,125,293)	$86,113,864	$88,974,913	100.0%	$221,100,206	100.0%	$221,100,206
Jul-14	$215,524,070	($131,065,807)	$84,458,264	$103,981,118	100.0%	$235,046,924	100.0%	$235,046,924
Aug-14	$158,672,445	($109,435,464)	$49,236,982	$69,520,938	100.0%	$178,956,402	100.0%	$178,956,402
Sep-14	$230,425,062	($155,432,941)	$74,992,120	$88,683,326	100.0%	$244,116,267	100.0%	$244,116,267
Oct-14	$315,119,620	($234,573,734)	$80,545,886	$80,529,041	100.0%	$315,102,775	100.0%	$315,102,775
Nov-14	$318,604,763	($212,209,995)	$106,394,768	$106,379,493	100.0%	$318,589,489	100.0%	$318,589,489
Dec-14	$234,209,679	($170,750,190)	$63,459,490	$65,392,809	100.0%	$236,142,998	100.0%	$236,142,998
Jan-15	$410,273,039	($283,654,558)	$126,618,482	$131,999,162	100.0%	$415,653,720	100.0%	$415,653,720
Feb-15	$1,037,653,444	($719,673,940)	$317,979,504	$425,826,022	100.0%	$1,145,499,962	100.0%	$1,145,499,962
Mar-15	$414,369,580	($300,458,779)	$113,910,801	$112,294,395	100.0%	$412,753,174	100.0%	$412,753,174
Apr-15	$272,864,686	($211,944,617)	$60,920,069	$70,299,122	100.0%	$282,243,739	100.0%	$282,243,739
May-15	$392,526,758	($293,928,392)	$98,598,366	$108,377,660	100.0%	$402,306,052	100.0%	$402,306,052
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	$4,218,482,305	($2,955,253,710)	$1,263,228,595	$1,452,257,998	100.0%	$4,407,511,707	100.0%	$4,407,511,707

* 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. For months with no revenue inadequacies there is no change in payout ratio.

Figure 13-14 shows the FTR surplus, collected day-ahead, balancing and total congestion payments from January 2005 through June 2015. August and December 2014 had positive total balancing congestion of $0.03 million and $4.4 million. March 2015 had balancing congestion of $70.0 million.

Figure 13-14 FTR surplus and the collected Day-Ahead, Balancing and Total congestion: January 2005 through June 2015

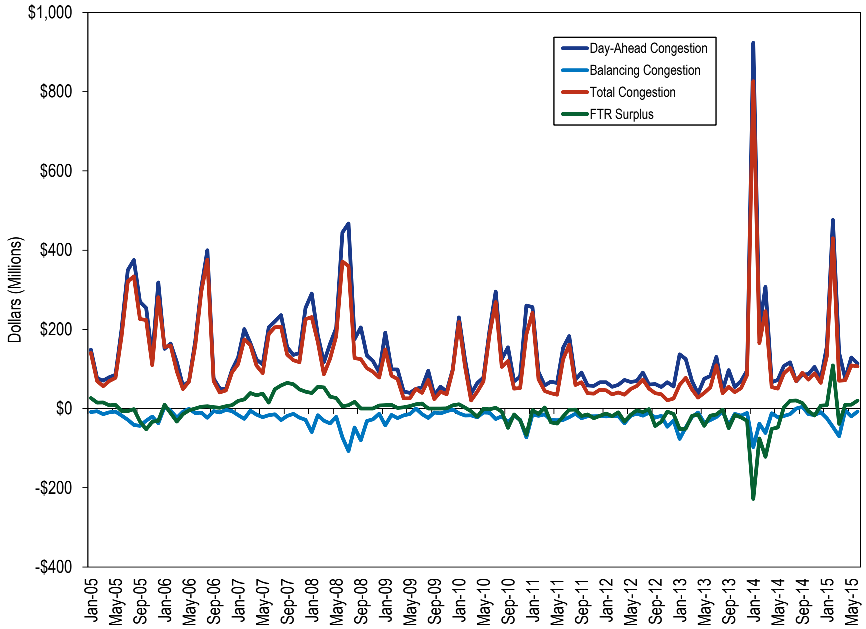
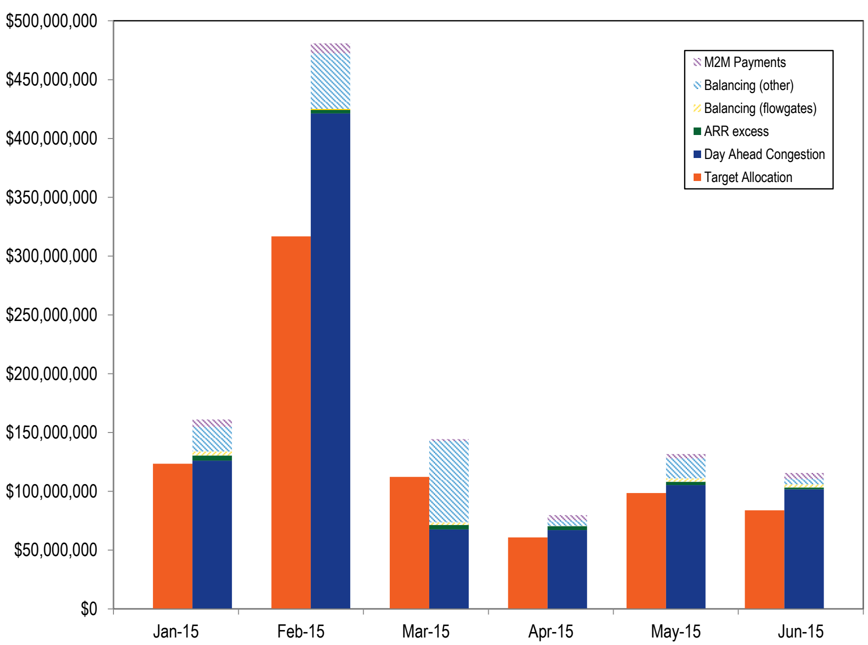


Figure 13-15 shows the relationship among monthly target allocations, balancing congestion, M2M payments and day-ahead congestion. The left column is the target allocations for all FTRs for the month. The total height of the right column is day ahead congestion revenues and the stripes are reductions to total congestion revenues. When the total height of the solid segments in the right column exceeds the height of the left column, the month is revenue adequate. For example, February 2015 was revenue adequate by $109.1 million. In the 2014 to 2015 planning period, day-ahead congestion exceeded target allocations and offsets were small, resulting in payout ratios over 100 percent. March was revenue inadequate by $38.7 million due to a large negative balancing congestion charge, but there was enough excess revenue in other months in the planning period to fully fund the month.

Figure 13-15 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.[21] 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 adequacy.

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. If there are excess ARR revenues, the excess revenue is given pro rata to FTR 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,

21 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.[22] 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. The top ten binding transmission constraints for the 2014 to 2015 planning period are shown in Table 13-29.

22 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.[23] 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.24 While transmission upgrades are being implemented, Stage 1A ARRs, and therefore FTRs, are overallocated which can lead to revenue inadequacy.
- **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

23 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.
24 See PJM. "Manual 6: Financial Transmission Rights" Revision 15 (October 10, 2013), p. 22.

agreements must also remain in effect for the planning period covered by the allocation.

- **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.[25] 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.[26]

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.[27] PJM may also adjust the outages modeled, adjust line limits and account for potential closed loop interfaces to address expected revenue inadequacies. The simultaneous feasibility requirement is necessary to ensure that there are adequate 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).[28]

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 entire 2014 to 2015 planning period, revenue adequacy was over 100 percent. Not every month was revenue adequate, but there was excess revenue from other months to make each month revenue adequate. The last time there were four months of consecutive funding of 100 percent or more was in the 2009 to 2010 planning period.

This high level of revenue adequacy was primarily due to actions taken by PJM to address prior low levels of revenue adequacy. PJM's actions included PJM's assumption of higher outage levels and PJM's decision to include additional constraints (closed loop interfaces) both of which reduced system capability

25 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), pp. 21.
26 *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.
27 PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), pp. 55-56.
28 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.

in the FTR auction model. PJM's actions led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs. 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.

While PJM's approach to outages in the Annual FTR Auction reduces revenue inadequacy, which was caused in part by Stage 1A ARR overallocations, it does not address the Stage 1A ARR overallocation 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 PJM's assumption of increased outages because they may not be prorated.

Figure 13-16 shows the historic allocations for Stage 1B and Stage 2 ARRs from the 2011 to 2012 to 2015 to 2016 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 13-16 Historic Stage 1B and Stage 2 ARR Allocations from the 2011 to 2012 through 2014 to 2015 planning periods

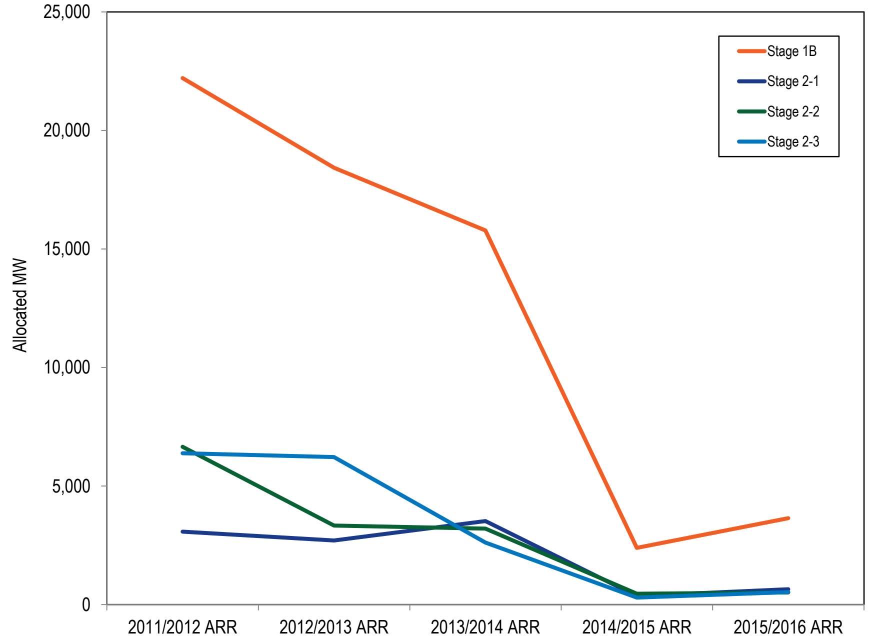


Table 13-28 shows the ARR allocations for the 2011 to 2012 through 2015 to 2016 planning periods. Stage 1A allocations cannot be prorated and have been slowly increasing. Stage 1B and Stage 2 allocations can be prorated. Stage 1B and Stage 2 allocations were steadily declining over the 2011 to 2012 through 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. There was a small increase in Stage 1B and Stage 2 ARR volume from the 2014 to 2015 planning period to the 2015 to 2016 planning period.

Table 13-28 Historic Stage 1B and Stage 2 ARR Allocations from the 2011 to 2012 through 2015 to 2016 planning periods

Stage	2011/2012 ARR	2012/2013 ARR	2013/2014 ARR	2014/2015 ARR	2015/2016 ARR
Stage 1A	64,159.9	67,299.6	67,861.4	68,837.7	71,874.0
Stage 1B	22,208.3	18,431.7	15,782.0	2,389.6	3,643.1
Stage 2-1	3,072.5	2,700.6	3,519.2	360.9	643.8
Stage 2-2	6,652.6	3,334.3	3,200.0	455.9	511.2
Stage 2-3	6,382.6	6,218.7	2,611.8	291.2	521.5
Total Stage 2	16,107.7	12,253.6	9,331.0	1,108.0	1,676.5

Table 13-29 shows the top 10 principal binding transmission constraints that limited the 2015 to 2016 ARR Stage 1A allocation. PJM was required to increase capability limits for several facilities in order to make the ARR allocation feasible.[29]

Table 13-29 Top 10 principal binding transmission constraints limiting the Annual ARR Allocation: Planning period 2015 to 2016

Constraint	Type	Control Zone
Breed - Wheatland	Flowgate	MISO
Wheatland - Petersburg	Flowgate	MISO
Wempletown	Transformer	ComEd
Wempletown	Transformer	ComEd
Nelson - Electric Junction	Flowgate	MISO
Cherry Valley - Silverlake	Flowgate	MISO
Pana North	Flowgate	MISO
Nelson - Cordova	Line	ComEd
Pana North	Flowgate	MISO
Nelson - Electric Junction	Flowgate	MISO

29 It is a requirement of Section 7.4.2 (i) in the OATT that any ARR request made in Stage 1A must be feasible and transmission capability must be raised if an ARR request is found to be infeasible.

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.[30] ARR reassignment occurs daily only if the LSE losing load has ARRs with a net positive economic value to that control zone. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. ARRs are reassigned to the nearest 0.001 MW and any MW of load may be reassigned multiple times over a planning period. Residual ARRs are also subject to the rules of ARR reassignment. This practice supports competition by ensuring that the offset to congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, these underlying self-scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may 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 $338,100 of revenue that were reassigned in the 2013 to 2014 planning period. There were 57,270 MW of ARRs associated with $506,000 of revenue that were reassigned for the 2014 to 2015 planning period.

30 See PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p. 28.

Table 13-30 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2013 and May 2015.

Table 13-30 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2013, through May 31, 2015

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2013/2014 (12 months)	2014/2015 (12 months)*	2013/2014 (12 months)	2014/2015 (12 months)*
AECO	971	608	$2.5	$3.1
AEP	8,006	2,606	$28.8	$39.2
AP	2,618	2,386	$51.7	$51.0
ATSI	6,792	8,627	$8.7	$70.9
BGE	3,672	3,264	$41.9	$52.7
ComEd	9,664	8,576	$69.9	$95.2
DAY	1,100	794	$2.1	$1.1
DEOK	7,568	6,888	$9.5	$13.9
DLCO	5,248	5,891	$11.1	$10.9
DPL	2,740	2,446	$24.6	$30.5
Dominion	5	20	$0.1	$0.3
EKPC	0	0	0	$0.0
JCPL	1,519	1,354	$4.5	$9.5
Met-Ed	1,043	1,018	$6.8	$11.2
PECO	2,883	2,949	$17.3	$27.1
PENELEC	1,265	1,024	$10.0	$15.4
PPL	3,197	3,958	$12.9	$20.6
PSEG	2,441	1,765	$24.2	$36.8
Pepco	3,134	3,046	$11.6	$16.4
RECO	222	49	$0.0	$0.0
Total	64,086	57,270	$338.1	$506.0

* Through 31-May-2015

Incremental ARRs (IARRs) for RTEP Upgrades

Table 13-31 lists the incremental ARR allocation volume for the current and previous planning periods from the 2008 to 2009 planning period through the 2015 to 2016 planning period.

Table 13-31 Incremental ARR allocation volume: Planning periods 2008 to 2009 through 2015 to 2016

Planning Period	Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2008/2009	15	890.5	890.5	100%	0	0%
2009/2010	14	530.5	530.5	100%	0	0%
2010/2011	14	531.0	531.0	100%	0	0%
2011/2012	15	595.0	595.0	100%	0	0%
2012/2013	15	687.4	687.4	100%	0	0%
2013/2014	17	1,087.4	1,087.4	100%	0	0%
2014/2015	18	1,447.4	1,447.4	100%	0	0%
2015/2016	18	1,290.5	1,290.5	100%	0	0%

Table 13-32 lists the three RTEP upgrade projects that were allocated a total of 678.2 MW of IARRs for the 2015 to 2016 planning period.

Table 13-32 IARRs allocated for the 2015 to 2016 Annual ARR Allocation for RTEP upgrades

		IARR Parameters		
Project #	Project Description	Source	Sink	Total MW
B0287	Install 600 MVAR Dynamic Reactive Device at Elroy 500kV	RTEP B0287 Source	DPL	190.6
B0328	TrAIL Project: 502 JCT - Loudoun 500kV	RTEP B0328 Source	Pepco	391.2
B0329	Cason-Suffolk 500 kV	RTEP B0329 Source	Dominion	96.4

Residual ARRs

Only ARR holders that had their Stage 1 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, residual ARRs are also 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. Residual ARRs awarded due to outages 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 13-33 shows the residual ARRs automatically allocated to eligible participants, along with the target allocations from the effective month. In the 2014 to 2015 planning period planning period, PJM allocated a total of 22,532.9 MW of residual ARRs, up from 15,417.5 MW for the 2013 to 2014 planning period with a total target allocation of $8.2 million for the 2014 to 2015 planning period, up from $4.7 million for the 2013 to 2014 planning period. This 46.2 percent increase in volume was a result of the significant reduction in the Annual ARR Stage 1B allocations. Some ARRs that were previously allocated in Stage 1B are now being allocated as Residual ARRs on a month to month basis without the option to self-schedule.

Table 13-33 Residual ARR allocation volume and target allocation: 2015

Month	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
Jan-15	4,068.7	1,559.2	38.3%	$454,212
Feb-15	3,685.7	1,536.9	41.7%	$492,060
Mar-15	7,930.9	1,735.0	21.9%	$387,576
Apr-15	4,882.1	1,676.7	34.3%	($11,359)
May-15	3,505.4	928.2	26.5%	$267,930
Jun-15	5,513.9	1,775.9	32.2%	$394,951
Total	29,586.7	9,211.9	31.1%	$1,985,370

Market Performance

Volume

Table 13-34 shows the volume of ARR allocations for each round of the 2014 to 2015 and 2015 to 2016 planning periods. The percentage cleared increased slightly in the 2015 to 2016 planning period from the prior planning period.

Table 13-34 Annual ARR Allocation volume: planning periods 2014 to 2015 and 2015 to 2016

Planning Period	Stage	Round	Requested Count	Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2014/2015	1A	0	19,287	68,843	68,838	100.0%	5	0.0%
	1B	1	14,235	35,104	2,390	6.8%	32,714	93.2%
	2	2	5,517	27,708	361	1.3%	27,347	98.7%
		3	5,817	27,914	456	1.6%	27,458	98.4%
		4	5,381	27,953	291	1.0%	27,662	99.0%
		Total	16,715	83,575	1,108	1.3%	82,467	98.7%
	Total		50,237	187,522	72,336	38.6%	115,186	61.4%
2015/2016	1A	0	21,508	71,874	71,874	100.0%	0	0.0%
	1B	1	14,915	38,848	3,643	9.4%	35,205	90.6%
	2	2	5,849	26,710	644	2.4%	26,066	97.6%
		3	4,773	25,900	511	2.0%	25,389	98.0%
		4	4,326	25,986	522	2.0%	25,464	98.0%
		Total	14,948	78,596	1,677	2.1%	76,919	97.9%
	Total		51,371	189,318	77,194	40.8%	112,124	59.2%

Stage 1A Infeasibility

Stage 1A ARRs are allocated for a 10 year period, with the ability for a participant to opt out of any planning period. PJM conducts a simultaneous feasibility analysis to determine the transmission upgrades required so that the long term ARRs can remain feasible. If a simultaneous feasibility test violation occurs in any year, PJM will identify or accelerate any transmission upgrades to resolve the violation and these upgrades will be recommended for inclusion in the PJM RTEP process.[31]

For the 2015 to 2016 planning period, Stage 1A of the Annual ARR Allocation was infeasible. As a result modeled system capability, in excess of actual system capability, was provided to the Stage 1A ARRs and added to the FTR auction. According to Section 7.4.2 (i) of the PJM OATT, the capability limits of the binding constraints rendering these ARRs infeasible must be increased in the model and these increased limits must be used in subsequent ARR and FTR allocations and auctions for the entire planning period, except in the case of extraordinary circumstances. These infeasibilities are due to newly monitored facilities where upgrades could not be planned in advance, facilities not owned by PJM and an overall reduced system capability due to loop flows.

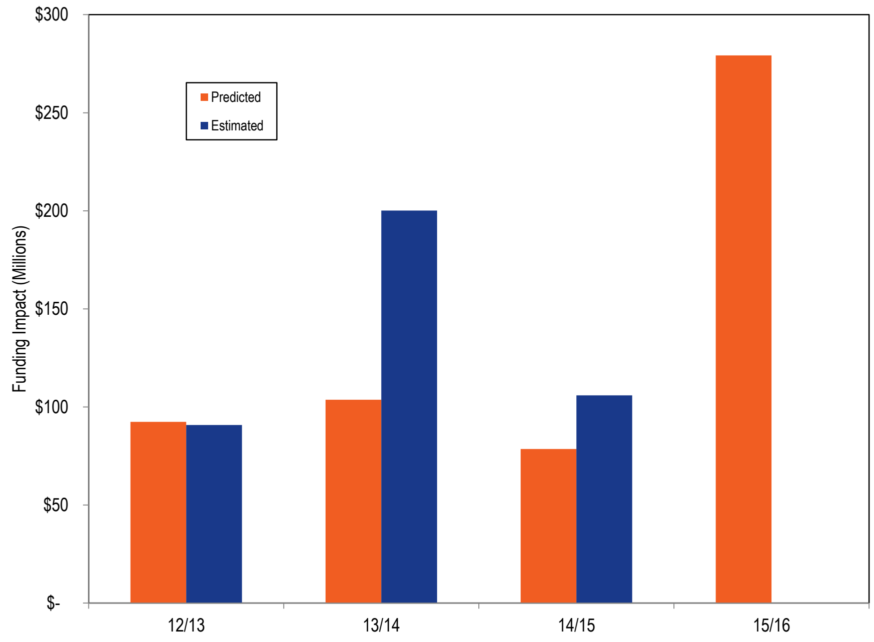
The result of this required increased of capability in the models is an overallocation of both ARRs and FTRs for the entire planning period and an associated reduction in ARR and FTR funding.

In order to eliminate the infeasibilities for the requested Stage 1A ARR allocations, PJM was required to raise the modeled capacity limits on 84 facilities, 24 of which were internal to PJM, a total of 6,271 MW.[32]

Figure 13-17 shows the predicted and estimated impact of Stage 1A infeasibilities on funding for the 2012 to 2013 through 2014 to 2015 planning periods, as well as the predicted impact on funding for the 2015 to 2016 planning period. The predicted funding is based on the infeasible ARR MW and the nodal price of the source and sink in the Annual FTR Auction. The estimated funding is calculated assuming every infeasible ARR MW is self scheduled, and uses the hourly congestion LMP values. In the 2014 to 2015 planning period Stage 1A ARR infeasibilities accounted for $105.9 million in over allocation.

31 PJM. "Manual 6: Financial Transmission Rights," Revision 15 (October 10, 2013), p22.
32 *PJM 2015/2016 Stage 1A Over allocation notice*, PJM FTRs, <http://www.pjm.com/~/media/markets-ops/ftr/annual-arr-allocation/2015-2016/2015-2016-stage-1a-over-allocation-notice.ashx> (March 5, 2015).

Figure 13-17 Stage 1A Infeasibility Funding Impact



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 $767.9 million in credits from the FTR auctions during the 2014 to 2015 planning period. The FTR auction revenue collected pays ARR holders' credits. During the 2014 to 2015 planning period, ARR holders received $735.3 million in ARR credits.

Table 13-35 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 2013 to 2014 planning period and the 2014 to 2015 planning periods. As seen here, due to decreased FTR volume leading to increased FTR nodal prices, auction revenue increased 34.7 percent while projected ARR target allocations increased 45.0 percent from the previous planning period.

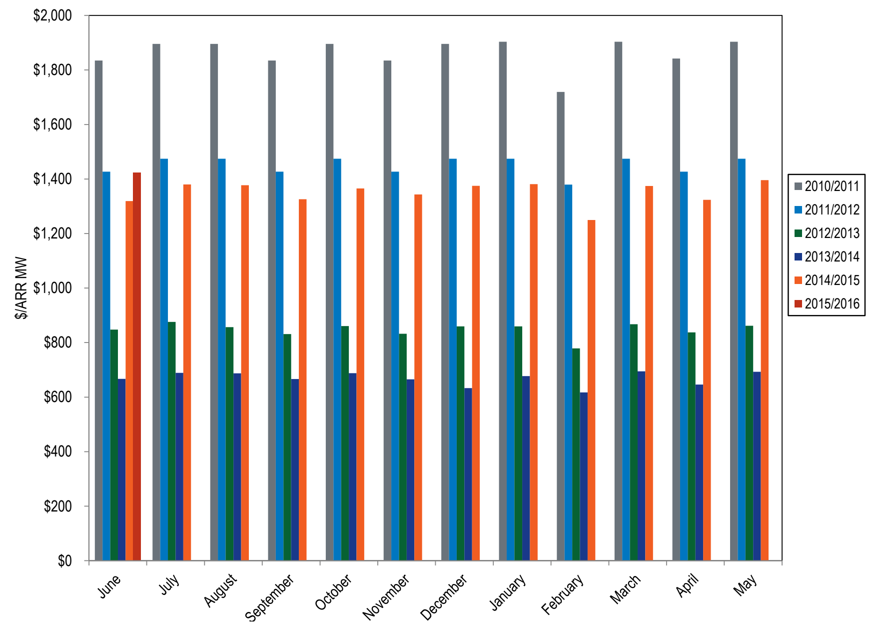
Figure 13-18 shows the dollars per ARR MW held for each month of the 2010 to 2011 through 2015 to 2016 planning periods. The ARR MW held do not include self scheduled FTRs and do include Residual ARRs starting in August 2012. FTR prices increased in the 2014 to 2015 Annual FTR Auction as a result of reduced supply caused by PJM's assumption of more outages in the model used to allocate Stage 1B and Stage 2 ARRs. The increased FTR prices result in an increase in dollars paid per ARR MW. For the 2014 to 2015 planning period, the total dollars per MW of ARR allocation was $11,279, while the previous planning period resulted in a dollars per MW of $6,692, a 68.5 percent increase in payment per allocated ARR MW. Some of the ARR MW lost from proration were provided in the Residual ARR process, but the residual allocations are not comparable to the ARRs awarded in the annual process because residual ARR allocations change each month and cannot be self scheduled as FTRs.

Table 13-35 Projected ARR revenue adequacy (Dollars (Millions)): Planning periods 2013 to 2014 and 2014 to 2015

	2013/2014	2014/2015
Total FTR auction net revenue	$568.8	$767.9
Annual FTR Auction net revenue	$558.4	$748.6
Monthly Balance of Planning Period FTR Auction net revenue*	$10.4	$19.3
ARR target allocations	$506.2	$735.3
ARR credits	$506.2	$735.3
Surplus auction revenue	$62.6	$32.6
ARR payout ratio	100%	100%
FTR payout ratio*	72.8%	100.0%

* Shows twelve months for 2013/2014 and twelve months for 2014/2015.

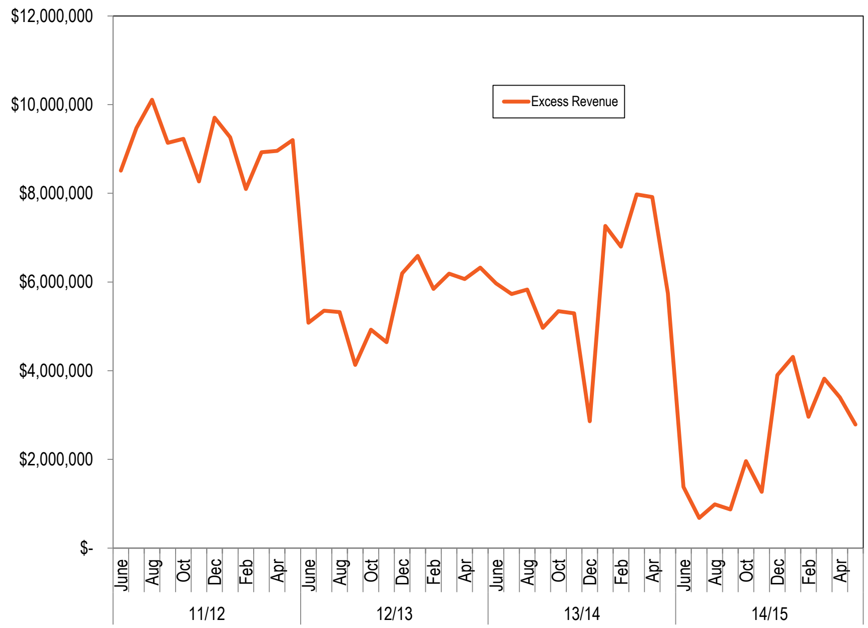
Figure 13-18 Dollars per ARR MW paid to ARR holders: Planning periods 2010 to 2011 through 2014 to 2015



Excess ARR Revenue

Figure 13-19 shows the monthly excess ARR revenue from the 2011 to 2012 through 2014 to 2015 planning periods. Excess ARR revenue is the revenue collected each month from FTR auctions in excess of ARR target allocations after PJM's implemented counter flow FTR clearing process. Beginning with the 2014 to 2015 planning period, market rules allow PJM to lower facility limits by clearing counter flow FTRs, without making the opposite prevailing flow FTR available, as long as ARRs remain revenue adequate. This allows PJM to use the excess ARR revenue to pay prevailing flow FTRs without increasing prevailing flow obligations. This action removes money from the excess ARR revenue stream and caused the large decrease in excess ARR revenue beginning in June 2014. Currently, excess ARR revenue is allocated pro rata to FTR holders.

Figure 13-19 Excess ARR revenue: Planning periods 2011 to 2012 through 2014 to 2015



ARR and FTR Revenue and Congestion

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 2014 to 2015 planning period, the total revenues received by the holders of all ARRs and FTRs offset 88.3 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 in Table 13-36. 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 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 2014 to 2015 planning period and for the 2013 to 2014 planning period.

The Congestion column shows the amount of congestion 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 congestion collected.

Table 13-36 shows the total offset due to ARRs and self-scheduled FTRs for the entire 2013 to 2014 and the 2014 to 2015 planning periods. ARRs and self-scheduled FTRs served as an effective offset against congestion. ARR and self-scheduled FTR revenues offset greater than 100 percent of the total congestion costs incurred by ARR holders for both the 2013 to 2014 and the 2014 to 2015 planning periods.

Effectiveness of ARRs and FTRs as an Offset to Congestion

Table 13-37 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 2014 to 2015 planning period. This compares the total offset provided by all ARRs and all FTRs to the total congestion costs. 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 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 2014 to 2015 planning period. The “FTR Auction Revenue” column shows the amount paid for 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. The last column shows the difference between the total ARR and FTR offset and the congestion cost.

Table 13-36 ARR and self-scheduled FTR congestion offset (in millions): Planning periods 2013 to 2014 and 2014 to 2015

Planning Period	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Offset
2013/2014	$336.2	$88.7	$424.9	$22.1	$432.2	>100%
2014/2015*	$485.1	$352.9	$837.9	$194.7	$643.3	>100%

* Shows twelve months through June 30, 2015

Table 13-37 shows the total offset due to ARRs and FTRs for the entire 2013 to 2014 and 2014 to 2015 planning periods. ARRs and FTRs served as an effective, but not total, offset against congestion. ARR and FTR revenues offset 88.3 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for 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 13-37 ARR and FTR congestion offset (in millions): Planning periods 2013 to 2014 and 2014 to 2015[33]

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*	$761.3	$1,261.8	$794.9	$1,228.2	1,390.34	($162.1)	88.3%

* Shows twelve months through June 30, 2015

33 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.